Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units.

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and gas prices were higher in the first three months of 2021 than in the first three months of 2020.
- In the first three months of 2021, average energy market net revenues increased by 55 percent for a new combustion turbine (CT), 32 percent for a new combined cycle (CC), 9,549 percent for a new coal plant (CP), 53 percent for a new nuclear plant, 1,892 percent for a new diesel (DS), 38 percent for a new onshore wind installation, 67 percent for a new offshore wind installation and 27 percent for a new solar installation compared to the first three months of 2020.
- The price of natural gas increased by significantly more than the price of coal in the first three months of 2021, as a result of very high gas prices in mid February. As a result, the marginal costs of a new CC and a new CT were greater than the marginal cost of a new CP in February 2021 but lower in January and March.
- Based on Western Hub prices, the spark spread in the first three months of 2021 decreased by 7 percent while the spark spread standard deviation increased by 148 percent and the dark spread increased by 134 percent while the dark spread standard deviation decreased by 189 percent.

Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking estimate of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Adopted 2020.)

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

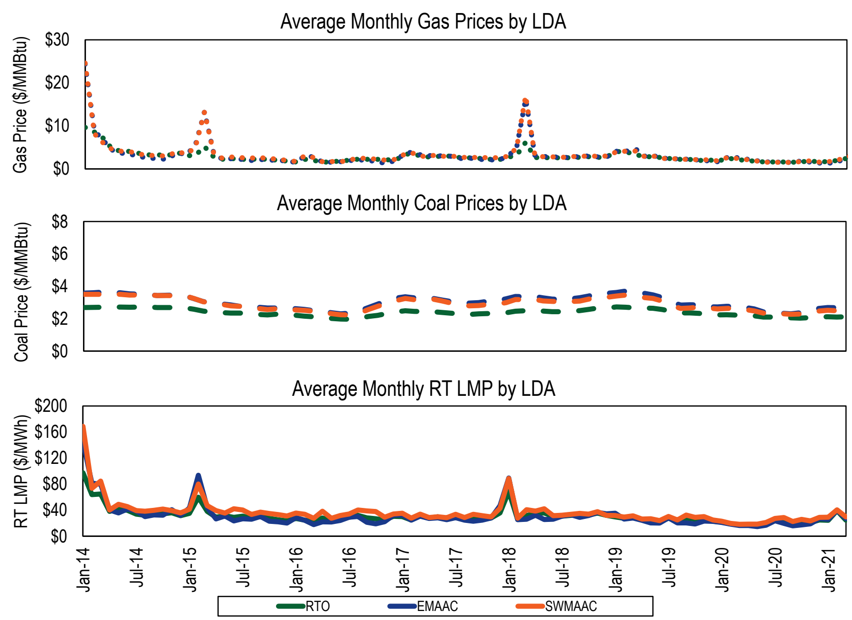
Net Revenue

When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services, less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenue is the contribution to fixed costs, which include a return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.[1] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. PJM real-time energy market prices increased significantly in the first three months of 2021. The load-weighted, average real-time LMP was 55.3 percent higher in the first three months of 2021 than in the first three months of 2020, $30.84 per MWh versus $19.85 per MWh. Gas prices increased in the first three months of 2021 compared to the first three months of 2020, as a result of very high gas prices in mid February. Gas price volatility increased and gas price differences among regions increased. Western PJM gas prices were much higher in mid February than eastern PJM gas prices although both increased significantly. Coal prices were relatively unchanged for the entire time period and across PJM. The price of eastern natural gas was 84.9 percent higher and the price of western natural gas was 259.2 percent higher; the price of Northern Appalachian coal was 4.5 percent higher; the price of Central Appalachian coal was 15.7 percent higher; the price of Powder River Basin coal was 1.9 percent lower (Figure 7-1).[2]

Figure 7-1 Energy market net revenue factor trends: 2014 through March 2021



1 Avoidable costs are sometimes referred to as going forward costs.

2 Average daily gas prices in COMED were above $129/MMBTU from February 13 through February 16, 2021.

Spark Spreads and Dark Spreads

The spark or dark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power, converted to a cost per MWh. The spark spread compares power prices to the cost of gas and the dark spread compares power prices to the cost of coal. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

Spark spreads increased in the first three months of 2021 compared to the first three months of 2020 with the exception of COMED, and the volatility of spark spreads increased. Dark spreads increased significantly in the first three months of 2021 compared to the very low levels in the first three months of 2020.

Table 7-1 shows average peak hour spreads for the January through March, by year and Table 7-2 shows the associated standard deviations.

Table 7-1 Peak hour spreads ($/MWh): January through March, 2014 through 2021

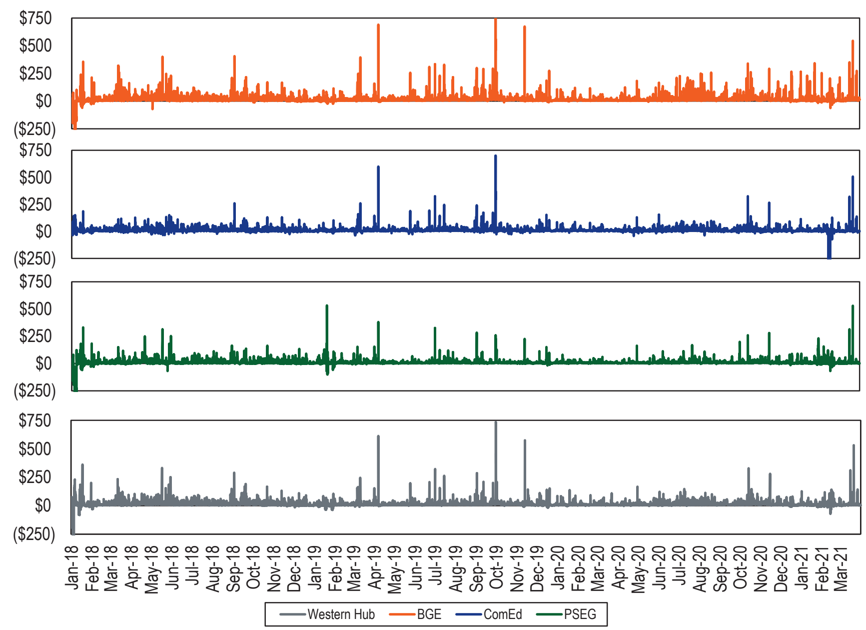
	BGE		COMED		PSEG		Western Hub	
Jan-Mar	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2014	$36.35	$118.47	$8.36	$67.19	$14.16	$110.22	$23.48	$91.81
2015	$8.67	$44.83	$16.92	$33.83	$8.48	$54.31	$13.50	$38.40
2016	$21.69	$23.85	$12.51	$21.25	$7.42	$10.43	$17.31	$15.93
2017	$13.95	$15.47	$8.50	$22.64	$8.86	$9.48	$11.26	$11.81
2018	$1.16	$35.31	$11.14	$24.98	($10.32)	$22.18	$5.45	$28.10
2019	$11.15	$13.15	$7.84	$22.17	$7.50	$6.13	$8.44	$10.77
2020	$10.08	$8.62	$9.00	$14.40	$7.52	$2.90	$9.77	$7.85
2021	$15.92	$23.95	($18.67)	$26.31	$9.18	$12.41	$10.48	$18.34

Table 7-2 Peak hour spread standard deviation ($/MWh): January through March, 2014 through 2021

	BGE		COMED		PSEG		Western Hub	
Jan-Mar	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2014	$166.8	$218.4	$132.1	$129.2	$152.3	$167.6	$162.2	$158.9
2015	$49.5	$59.7	$28.8	$33.0	$54.0	$64.2	$46.8	$50.5
2016	$22.5	$23.6	$10.0	$10.1	$12.5	$16.8	$14.4	$15.3
2017	$18.8	$20.3	$9.5	$9.6	$13.1	$15.7	$13.5	$13.9
2018	$88.5	$57.5	$18.3	$21.9	$95.7	$55.9	$74.8	$47.7
2019	$20.2	$21.8	$14.2	$14.6	$26.8	$33.0	$17.1	$16.7
2020	$10.5	$10.5	$8.3	$8.5	$6.3	$6.4	$11.4	$11.2
2021	$38.0	$40.4	$144.4	$34.1	$27.3	$31.8	$28.2	$32.3

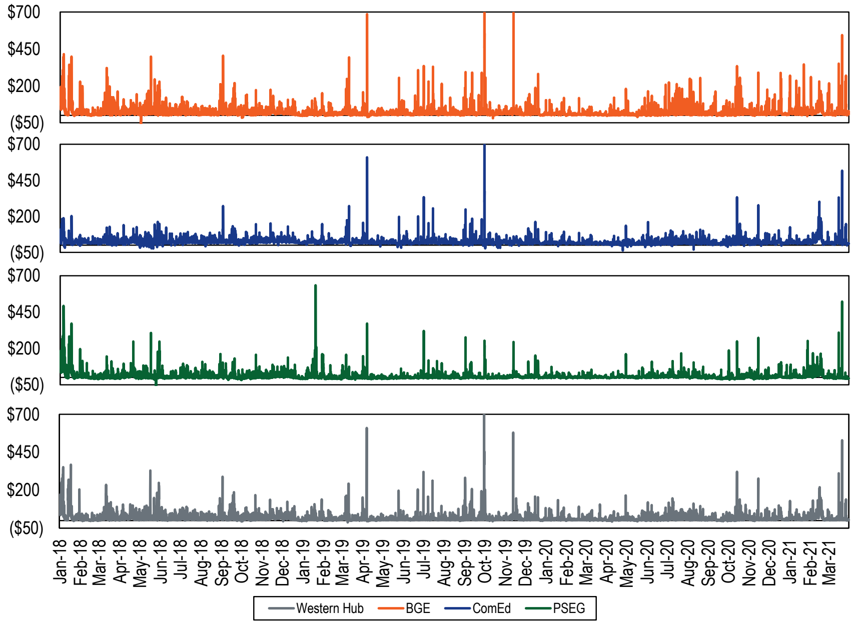
Figure 7-2 shows the hourly spark spread for peak hours for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2018 through March 2021[3]



3 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2018 through March 2021[4]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new entrant includes eight power plant configurations:

- The CT plant is a single GE Frame 7HA.02 CT with an installed capacity of 360.1 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant includes two GE Frame 7HA.02 CTs and a single steam turbine generator with an installed capacity of 1,137.2 MW, equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT, with steam reheat, and SCR for NO_x reduction.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 37 Siemens 2.7 MW wind turbines with an installed capacity of 99.9 MW.
- The offshore wind installation includes of 43 Siemens 7.0 MW wind turbines with an installed capacity of 301.0 MW.
- The solar installation is a 35.5 acre ground mounted fixed tilt solar farm with an installed AC capacity of 10 MW.

4 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs and daily coal prices; Powder River Basin coal for ComEd, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[5] [6] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[7] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[8]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[9] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day annual planned outage in the fall season.

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[10] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[11] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[12] Net revenues are calculated for all zones except OVEC.[13]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[14] [15] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

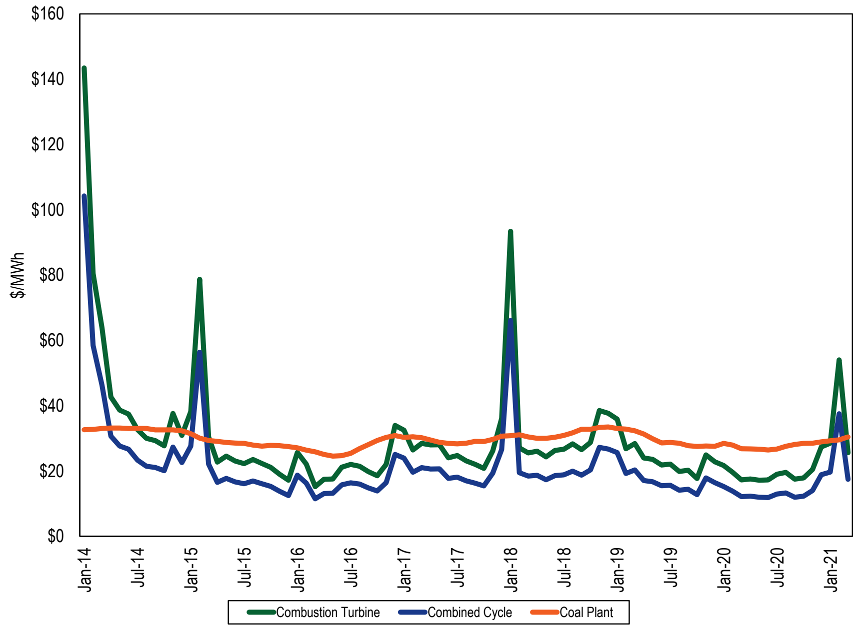
Table 7-3 Average short run marginal costs: January through March, 2021

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$36.04	9,241	$0.36
CC	$24.90	6,296	$1.41
CP	$29.76	9,250	$4.21
DS	$147.20	9,660	$0.25
Nuclear	$0.00	NA	$0.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-4). The marginal costs of a new CC and a new CT were greater than the marginal cost of a new CP in February 2021 as a result of higher gas prices.

5 Hourly ambient conditions supplied by DTN.
6 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
7 CO_2 emission allowance costs only included for states participating in RGGI, including New Jersey.
8 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
9 Outage figures obtained from the PJM eGADS database.
10 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
11 Gas daily cash prices obtained from Platts.
12 Coal prompt month prices obtained from Platts.
13 The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.
14 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
15 VOM rates provided by Pasteris Energy, Inc.

Figure 7-4 Average short run marginal costs: 2014 through March 2021



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new entrant run hours. The new entrant coal plant ran for significantly more hours in the first three months of 2021 than in the first three months of 2020, returning to levels consistent with years prior to 2020. Table 7-4 shows the average run hours by a new entrant unit.

Table 7-4 Average run hours: January through March, 2014 through 2021[16]

	CT	CC	CP	DS	Nuclear
2014	1,041	1,827	2,092	145	2,160
2015	1,427	1,996	1,818	101	2,160
2016	1,794	2,120	1,197	17	2,184
2017	1,149	2,117	1,181	6	2,160
2018	1,307	2,023	1,199	90	2,160
2019	1,060	2,056	793	8	2,160
2020	1,252	2,098	173	5	2,184
2021	867	2,031	1,071	20	2,160

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two hours, including start costs. If the unit was not already committed day-ahead, it was run in real time in standalone profitable blocks of at least two hours, or any profitable hours bordering the profitable day-ahead or real-time block.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The economically dispatched new entrant CT ran for more than twice as many hours as large CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were higher in 14 of 20 zones in the first three months of 2021 as a result of significantly higher and more variable energy prices offset in part by high gas prices in mid February (Table 7-5).

16 Previous year run hours changed slightly since 2020 Quarterly State of the Market report for PJM: January through March. Run hours and net revenues are fully recalculated for the previous year when calculating for the annual 2020 State of the Market Report for PJM and may change slightly due to parameter updates or changes in market settlements data.

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through March, 2014 through 2021 (Dollars per installed MW-year)[17]

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$37,754	$12,776	$9,793	$5,094	$6,806	$7,471	$971	$2,335	141%
AEP	$54,108	$28,204	$17,445	$8,061	$29,985	$9,977	$8,681	$6,920	(20%)
APS	$67,470	$45,378	$13,746	$6,445	$36,990	$5,997	$2,111	$6,771	221%
ATSI	$35,579	$23,015	$15,204	$8,790	$37,051	$10,895	$8,913	$9,099	2%
BGE	$43,148	$12,147	$19,132	$8,307	$12,933	$5,766	$2,798	$7,914	183%
COMED	$22,324	$11,462	$8,184	$3,957	$10,373	$4,047	$4,209	$2,543	(40%)
DAY	$32,065	$20,233	$15,044	$7,517	$31,940	$11,113	$10,418	$13,110	26%
DOM	$39,669	$16,211	$18,598	$7,708	$15,105	$7,316	$5,139	$6,468	26%
DPL	$38,694	$12,217	$6,240	$3,796	$6,485	$3,500	$502	$11,400	2,170%
DUKE	$29,200	$17,892	$14,061	$6,192	$38,188	$9,490	$8,904	$11,911	34%
DUQ	$14,592	$9,130	$14,864	$4,724	$8,098	$3,872	$4,217	$3,931	(7%)
EKPC	$49,038	$21,659	$15,107	$6,595	$20,778	$8,411	$7,595	$7,417	(2%)
JCPLC	$41,229	$14,179	$7,559	$6,342	$7,018	$6,376	$990	$2,183	120%
MEC	$41,388	$20,993	$13,828	$7,711	$11,234	$5,616	$5,731	$5,162	(10%)
PE	$81,671	$58,960	$24,023	$9,259	$38,540	$10,088	$8,218	$11,635	42%
PECO	$41,809	$20,891	$12,766	$6,174	$9,570	$5,030	$4,413	$2,836	(36%)
PEPCO	$46,885	$13,007	$10,982	$6,099	$11,383	$4,754	$1,679	$4,707	180%
PPL	$148,553	$84,974	$20,750	$10,291	$45,447	$7,185	$4,138	$8,473	105%
PSEG	$52,790	$28,103	$15,489	$8,117	$10,758	$6,631	$1,107	$5,889	432%
REC	$31,162	$16,289	$7,900	$5,640	$5,466	$5,443	$1,063	$11,580	989%
PJM	$58,381	$24,386	$14,036	$6,841	$19,707	$6,949	$4,590	$7,114	55%

17 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[18] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were higher in 16 of 20 zones in the first three months of 2021 as a result of significantly higher energy prices offset in part by high gas prices in mid February (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through March, 2014 through 2021 (Dollars per installed MW-year)[19]

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$51,917	$21,960	$14,306	$11,375	$14,242	$15,555	$6,938	$6,030	(13%)
AEP	$63,214	$35,476	$22,439	$14,388	$37,756	$19,117	$14,404	$15,274	6%
APS	$79,776	$54,676	$25,811	$14,554	$46,949	$16,517	$11,267	$16,637	48%
ATSI	$40,769	$31,458	$20,863	$14,986	$43,292	$19,944	$14,633	$18,416	26%
BGE	$57,866	$21,830	$30,782	$16,487	$23,231	$15,814	$12,218	$17,808	46%
COMED	$24,402	$18,254	$13,878	$8,627	$14,200	$9,801	$9,551	$7,761	(19%)
DAY	$35,604	$28,773	$20,747	$14,010	$39,039	$20,249	$16,064	$22,487	40%
DOM	$50,643	$25,250	$24,676	$14,431	$20,823	$16,553	$11,694	$15,138	29%
DPL	$50,053	$18,656	$12,529	$5,832	$9,759	$4,941	$1,069	$12,699	1,088%
DUKE	$31,977	$26,108	$19,795	$12,381	$44,259	$18,431	$14,670	$20,904	42%
DUQ	$18,875	$12,222	$19,372	$10,714	$16,465	$11,025	$10,595	$10,833	2%
EKPC	$57,036	$29,698	$20,355	$12,851	$29,400	$17,123	$13,661	$16,578	21%
JCPLC	$57,326	$23,293	$12,163	$12,537	$14,412	$14,564	$7,105	$5,967	(16%)
MEC	$52,805	$30,724	$17,860	$13,766	$19,939	$14,113	$11,694	$13,201	13%
PE	$91,359	$59,225	$26,285	$15,380	$44,819	$19,297	$13,778	$20,931	52%
PECO	$55,336	$32,397	$16,873	$12,277	$19,415	$13,054	$10,350	$10,151	(2%)
PEPCO	$61,605	$23,012	$23,146	$13,829	$19,546	$14,300	$9,497	$11,589	22%
PPL	$145,463	$78,794	$23,078	$15,942	$49,592	$15,145	$10,102	$16,946	68%
PSEG	$72,991	$40,604	$19,821	$14,442	$21,129	$15,740	$7,909	$9,768	24%
REC	$47,382	$23,878	$12,337	$11,761	$11,689	$14,013	$7,483	$13,447	80%
PJM	$100,026	$31,814	$19,856	$13,029	$26,998	$15,265	$10,734	$14,128	32%

18 All starts associated with combined cycle units are assumed to be warm starts.
19 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CP plant energy market net revenues were higher in all zones as a result of significantly higher energy prices and flat coal prices (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through March, 2014 through 2021 (Dollars per installed MW-year)[20]

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$107,792	$40,142	$3,745	$1,178	$27,616	$3,213	$0	$3,622	NA
AEP	$70,724	$23,049	$7,207	$7,989	$25,147	$5,842	$351	$14,139	3,927%
APS	$82,000	$30,858	$1,920	$4,367	$26,577	$2,782	$0	$6,767	NA
ATSI	$78,044	$24,868	$5,250	$9,070	$26,103	$5,642	$53	$11,050	20,656%
BGE	$128,660	$45,329	$11,045	$4,976	$32,587	$3,458	$73	$10,806	14,697%
COMED	$64,187	$19,365	$3,321	$6,818	$9,309	$5,332	$66	$11,789	17,659%
DAY	$70,902	$23,132	$4,989	$7,351	$22,582	$5,662	$325	$16,056	4,848%
DOM	$109,653	$50,560	$13,348	$5,025	$35,570	$5,116	$384	$12,984	3,282%
DPL	$131,152	$53,979	$6,464	$3,809	$33,156	$4,046	$6	$12,867	204,490%
DUKE	$65,351	$20,314	$4,263	$5,715	$27,293	$4,441	$101	$14,616	14,313%
DUQ	$61,547	$16,396	$4,752	$7,852	$25,393	$4,699	$27	$10,240	37,519%
EKPC	$65,318	$19,449	$3,685	$5,339	$16,816	$3,322	$55	$13,586	24,414%
JCPLC	$112,807	$41,387	$2,170	$1,327	$27,748	$2,940	$0	$3,626	NA
MEC	$124,027	$49,857	$4,409	$4,229	$32,741	$4,316	$525	$9,779	1,761%
PE	$92,537	$38,559	$4,808	$3,194	$24,633	$3,599	$35	$10,838	30,900%
PECO	$105,865	$39,385	$1,975	$1,169	$27,486	$2,761	$0	$5,072	NA
PEPCO	$106,471	$32,196	$2,494	$1,062	$25,469	$1,733	$0	$5,828	NA
PPL	$105,142	$38,500	$2,031	$1,309	$26,658	$1,634	$0	$5,369	NA
PSEG	$141,330	$60,005	$5,254	$3,272	$30,535	$4,276	$0	$4,985	NA
REC	$138,906	$61,121	$4,860	$3,287	$28,539	$4,966	$0	$9,236	NA
PJM	$98,121	$36,423	$4,900	$4,417	$26,598	$3,989	$100	$9,663	9,549%

20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours and output reflects the class average equivalent availability factor.[21]

New entrant nuclear plant energy market net revenues were higher in all zones as a result of significantly higher energy prices (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through March, 2014 through 2021 (Dollars per installed MW-year)[22 23]

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$211,846	$115,640	$48,725	$58,221	$94,760	$60,423	$37,593	$55,024	46%
AEP	$138,944	$79,965	$52,917	$58,719	$81,608	$58,767	$40,931	$60,943	49%
APS	$160,110	$97,683	$55,589	$60,569	$92,244	$60,182	$40,555	$60,408	49%
ATSI	$147,452	$81,034	$52,730	$60,761	$85,634	$60,612	$41,365	$60,343	46%
BGE	$221,336	$117,188	$72,903	$67,346	$105,209	$64,215	$43,501	$68,689	58%
COMED	$121,565	$67,311	$47,298	$54,992	$57,591	$52,559	$38,015	$57,276	51%
DAY	$138,517	$77,939	$52,634	$59,527	$80,788	$60,909	$42,956	$64,884	51%
DOM	$190,797	$112,959	$62,378	$63,021	$102,639	$62,157	$40,958	$63,690	56%
DPL	$224,316	$126,346	$61,073	$63,399	$100,951	$60,325	$38,079	$69,135	82%
DUKE	$131,887	$74,773	$51,588	$57,464	$86,563	$58,821	$41,383	$63,091	52%
DUQ	$127,759	$70,888	$52,008	$59,245	$84,336	$58,959	$41,119	$58,792	43%
EKPC	$131,844	$73,721	$50,862	$56,994	$72,894	$57,057	$40,988	$61,415	50%
JCPLC	$218,343	$116,586	$46,100	$59,689	$94,793	$59,323	$37,785	$54,736	45%
MEC	$207,794	$111,544	$46,218	$59,539	$95,281	$59,162	$38,361	$57,473	50%
PE	$170,103	$98,672	$50,863	$58,911	$87,072	$59,494	$39,506	$59,682	51%
PECO	$209,402	$114,373	$45,162	$57,657	$94,548	$57,937	$36,838	$54,283	47%
PEPCO	$217,980	$114,824	$65,798	$65,002	$102,966	$63,377	$42,283	$65,001	54%
PPL	$208,338	$113,104	$46,485	$59,062	$91,735	$55,819	$36,183	$55,079	52%
PSEG	$234,034	$124,111	$48,419	$60,394	$97,373	$61,330	$37,947	$59,862	58%
REC	$231,133	$125,393	$47,495	$60,714	$94,786	$61,717	$38,526	$66,528	73%
PJM	$182,175	$100,703	$52,862	$60,061	$90,189	$59,657	$39,744	$60,817	53%

21 The annual class average *equivalent availability* factor was used in the calculation of energy market net revenues.

22 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

23 The net revenues have changed since the *2018 State of the Market Report for PJM*. The marginal cost of the nuclear plant has been reduced from $8.50/MWh to $0/MWh. Unit fuel costs have been moved to ACR.

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were higher in all zones in the first three months of 2021 as a result of significantly higher and more variable energy prices (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through March, 2014 through 2021 (Dollars per installed MW-year)

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$32,171	$11,172	$1,895	$131	$9,687	$1,171	$19	$804	4,236%
AEP	$14,072	$2,816	$316	$18	$3,182	$228	$121	$1,193	887%
APS	$17,632	$6,050	$391	$64	$5,853	$225	$79	$761	868%
ATSI	$13,724	$2,448	$256	$70	$2,327	$203	$127	$730	476%
BGE	$48,591	$9,773	$2,207	$843	$11,091	$588	$226	$2,486	1,001%
COMED	$11,036	$1,626	$152	$0	$603	$164	$96	$1,369	1,329%
DAY	$13,842	$2,296	$269	$17	$1,401	$246	$143	$1,442	908%
DOM	$42,074	$9,235	$1,282	$390	$13,183	$385	$145	$1,270	778%
DPL	$35,919	$12,810	$1,670	$732	$11,197	$1,176	$19	$11,509	61,612%
DUKE	$13,051	$1,892	$399	$11	$2,689	$207	$121	$1,679	1,291%
DUQ	$12,607	$2,016	$255	$72	$2,615	$181	$152	$757	400%
EKPC	$14,101	$2,087	$493	$10	$1,485	$205	$122	$1,946	1,496%
JCPLC	$32,414	$11,631	$456	$209	$10,693	$1,131	$17	$750	4,218%
MEC	$31,497	$10,905	$425	$167	$10,574	$357	$109	$950	770%
PE	$15,656	$5,284	$266	$95	$4,610	$94	$145	$738	411%
PECO	$31,741	$11,085	$421	$173	$9,516	$1,071	$21	$777	3,601%
PEPCO	$50,549	$8,848	$1,182	$394	$11,047	$466	$168	$1,212	623%
PPL	$32,438	$11,661	$397	$199	$8,376	$82	$23	$799	3,332%
PSEG	$31,987	$11,287	$520	$205	$9,756	$1,481	$19	$1,189	6,147%
REC	$29,526	$12,515	$507	$200	$8,823	$1,325	$21	$5,283	24,951%
PJM	$29,787	$7,372	$688	$200	$6,935	$549	$94	$1,882	1,892%

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly assuming the unit generated at the average capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW.[24] The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[25]

Onshore wind energy market net revenues were higher as a result of significantly higher energy prices.

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2021

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
AEP	$45,406	$26,566	$21,777	$22,697	$38,566	$23,727	$13,525	$18,024	33%
APS	$53,819	$33,489	$19,391	$24,579	$39,477	$19,314	$13,487	$17,251	28%
COMED	$39,397	$23,379	$16,746	$21,821	$24,103	$20,127	$11,754	$18,216	55%
PE	$66,094	$43,528	$21,076	$25,331	$41,510	$20,090	$12,783	$17,270	35%

24 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
25 The 1603 payment is a direct payment of 30 percent of the project cost. The use of the 1603 option is based on observed behavior in the PJM markets.

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated at a 45 percent capacity factor. The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).

Offshore wind energy market net revenues were higher as a result of higher energy prices.

Table 7-11 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2021

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$96,357	$54,104	$23,705	$27,675	$45,810	$29,481	$18,414	$25,497	38%
DPL	$102,937	$58,882	$27,522	$30,270	$48,750	$29,041	$18,625	$37,677	102%
DOM	$99,725	$51,146	$28,579	$30,001	$50,997	$29,115	$19,397	$30,847	59%

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone with an installed capacity greater than 3 MW.[26] The unit is credited with SRECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[27]

Solar energy market net revenues were higher as a result of significantly higher energy prices.

Table 7-12 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through March, 2014 through 2021

	Jan-Mar								
Zone	2014	2015	2016	2017	2018	2019	2020	2021	Change in 2021 from 2020
ACEC	$21,536	$13,316	$5,993	$6,914	$10,062	$7,282	$4,438	$5,187	17%
DOM	-	-	$11,030	$12,432	$16,098	$10,274	$6,915	$9,150	32%
DPL	-	-	$8,621	$9,593	$12,531	$8,845	$5,452	$7,086	30%
JCPLC	$20,041	$10,930	$4,953	$6,140	$8,959	$6,448	$3,984	$4,594	15%
PSEG	$19,380	$14,236	$6,048	$6,760	$10,192	$7,759	$4,895	$6,894	41%

26 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
27 The 1603 payment is a direct payment of 30 percent of the project cost.

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 87 percent of their total costs in the BGE and PSEG Zones and 45 percent of total costs in the ComEd Zone, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the PSEG Zone and 98 percent of total costs in the BGE Zone and 56 percent of total costs in the ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation.

Figure 7-5 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

Figure 7-5 Historical new entrant CC revenue adequacy: 2007 through March 2021 and 2012 through March 2021[28]

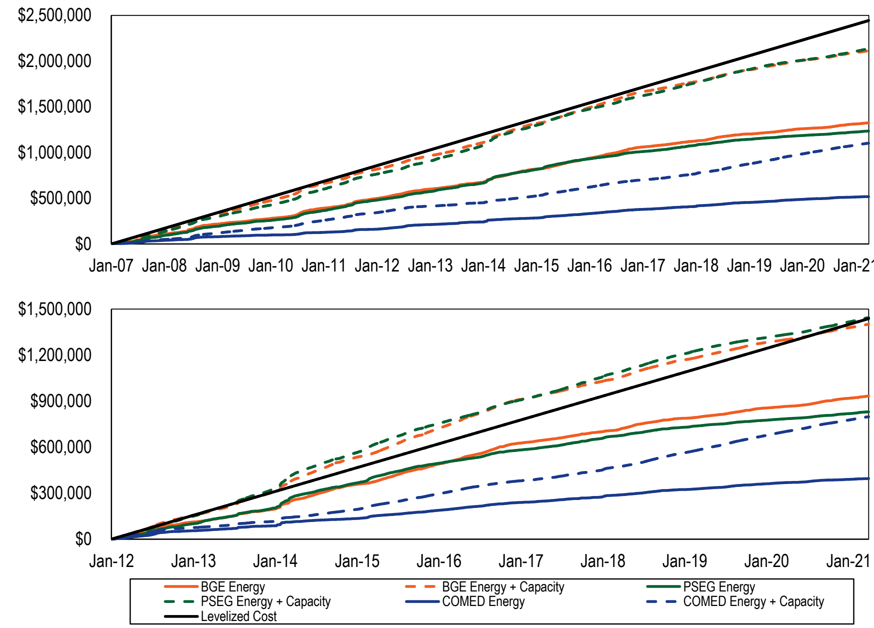


Table 7-13 shows the percent of levelized total costs recovered.

Table 7-13 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	87%	98%
ComEd	45%	56%
PSEG	87%	100%

28 The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for ComEd, and Texas Eastern M3 for PSEG.

Assumptions used for this analysis are shown in Table 7-14.

Table 7-14 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[29] [30] The analysis includes the most recent operating cost data and incremental capital expenditure data for single unit plants and multi unit plants published by NEI, for 2019.[31] This is likely to result in conservatively high costs for the forward looking analysis. NEI average operating costs have decreased since their peak in 2012 (11.5 percent decrease from 2012 through 2019 for all plants including single and multiple unit plants).[32] NEI average incremental capital expenditures have decreased since their peak in 2012 (45.6 percent decrease from 2012 through 2019 for all plants including single and multiple unit plants).[33] NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[34] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs based on current year prices.[35] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. Energy prices in 2020 were lower than 2019 prices, but forward energy prices for 2021 through 2023 are above 2019 energy prices. The result is that nuclear plant energy revenues based on forward period prices are expected to be higher than 2019 energy revenues. The results for nuclear plants are also sensitive to changes in costs and whether actual unit costs are less than or greater than the benchmark NEI data.

Table 7-15 includes the publicly available data on energy market prices, Table 7-16 and Table 7-17 show capacity market prices and Table 7-18 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[36] The analysis excludes the Cook nuclear units and the

29 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/Nuclear-Costs-in-Context.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.

30 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

31 NEI also provides average costs by plant run by operators with one plant or multiple plants, by market, and by type of nuclear reactor. Plants run by operators with multiple plants have lower average costs than plants run by operators with a single plant. Plants participating in wholesale markets have lower average costs than plants in regulated markets. PWR reactors have lower average costs than BWR reactors.

32 Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants decreased by $3.22/MWh, or 11.6 percent, from 2018 to 2019, a likely result of both cost reductions and the exclusion of recently retired single unit plants. Operating costs for single unit plants decreased by $2.01/MWh or 7.6 percent from 2012 to 2019. Operating costs for multiple unit plants decreased by $0.44/MWh, or 2.5 percent, from 2018 to 2019, and decreased by $2.21/MWh, or 11.5 percent, from 2012 to 2019.

33 Capital expenditures have decreased 46.0 percent since 2012 for single unit plants and 44.5 percent for multiple unit plants.

34 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.07 per MWh for a nuclear power plant operating at a capacity factor of 0.933 percent.

35 The MMU submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program*. Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring.*

36 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.

Catawba 1 nuclear unit. The Cook nuclear units are designated FRR and receive cost of service revenues and are not subject to PJM market revenues.[37] Catawba 1 is not in PJM but is pseudo tied to PJM.

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

Table 7-15 Nuclear unit day-ahead LMP: 2008 through 2020

	ICAP	Average DA LMP ($/MWh)												
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35	$26.22	$20.33
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11	$22.88	$18.23
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96	$22.19	$17.66
Calvert Cliffs	1,708	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25	$23.41	$18.73
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93	$22.45	$17.32
LaSalle	2,271	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08	$22.68	$17.31
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44	$27.39	$21.06
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	$34.03	$23.68	$18.07
Peach Bottom	2,347	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54	$21.13	$15.95
Salem	2,328	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50	$26.65	$20.41
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76	$23.47	$19.07

37 See "Resources Designated in 2021/2022 FRR Capacity Plans as of May 1, 2018," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-resources-designated-in-frr-plans.ashx?la=en>.

Table 7-16 BRA capacity market clearing prices ($/MW-Day): 2008 through 2021[38]

	ICAP	BRA Capacity Price ($/MW-Day)														
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Calvert Cliffs	1,708	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
LaSalle	2,271	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-
Peach Bottom	2,347	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196
Salem	2,328	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140
Susquehanna	2,520	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140

38 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Capacity revenues are not presented for calendar year 2022 because the 2022/2023 BRA has not been run.

Table 7-17 Nuclear unit capacity market revenue ($/MWh): 2008 through 2021[39 40]

	ICAP	Capacity Revenue ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.82	$5.03
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Calvert Cliffs	1,708	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.07	$5.21
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.82	$5.85
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
LaSalle	2,271	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.82	$5.03
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	NA	NA	NA	NA
Peach Bottom	2,347	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.82	$5.85
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.60	$8.52
Salem	2,328	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.06	$7.74
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.82	$5.03
Susquehanna	2,520	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.07	$5.21
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.07	$5.21

39 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the 2019 class average capacity factor of 0.933 percent. Class average capacity factor is from *2019 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

40 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Table 7-18 Nuclear unit costs: 2008 through 2020[41] [42]

	ICAP	NEI Costs ($/MWh)												
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$38.40
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	NA	NA	NA
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$38.40
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$28.38
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	NA	NA

Table 7-19 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM and Oyster Creek and Three Mile Island calculated using historic LMP and cost data. In 2016, 13 nuclear plants, with a total capacity of 25,075 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2017, seven nuclear plants with a total capacity of 12,658 MW, in addition to Oyster Creek and Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. In 2018, one nuclear plant, with a total capacity of 894 MW, in addition to Oyster Creek and Three Mile Island, did not recover all its fuel costs, operating costs, and capital expenditures. In 2019, two nuclear plants, with a total capacity of 4,654 MW, in addition to Three Mile Island, did not recover all their fuel costs, operating costs, and capital expenditures. Although Susquehanna shows a shortfall in 2019, cost reductions mean that Susquehanna did cover their fuel costs, operating costs, and capital expenditures.[43] The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[44] Unforced capacity is determined using the annual class average EFORd rate.

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market as a result of decisions by plant owners about how to offer the plants. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not reflect the economic viability of the plants unless the plants offer accurate net avoidable costs and fail to clear. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Three Mile Island did not clear in the 2018/2019 Auction[45] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[46] Three Mile Island and Quad Cities did not clear in the 2020/2021 Auction.[47] Three Mile Island, Dresden, and most of Byron did not clear in the 2021/2022 Auction.[48] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[49]

41 Operating costs from: Nuclear Energy Institute (October, 2020). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>.
42 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.
43 Talen Energy Investor Day, February 12, 2019.
44 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
45 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
46 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
47 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.
48 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.
49 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.

Nuclear unit revenue is a combination of energy market revenue, ancillary market revenue and capacity market revenue. Negative energy market prices do not have a significant impact on nuclear unit revenue. Since 2014, negative energy market prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018, an average of 0.0 percent and a maximum of 0.2 percent in 2019, and an average of 0.1 percent and a maximum of 1.7 percent in 2020.[50]

In 2020, no nuclear plants covered their fuel costs, operating costs, and capital expenditures as a result of lower energy prices, based on current year (2020) prices.

Table 7-19 Nuclear unit surplus (shortfall) based on public data: 2008 through 2020[51]

	ICAP	Surplus (Shortfall) ($/MWh)												
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.7	($4.0)
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.1)	($1.5)	$6.0	$3.9	($1.3)
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.5)	($2.7)	$5.8	$3.2	($1.9)
Calvert Cliffs	1,708	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($2.2)
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.2)	($13.8)
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.5)	($0.0)	$7.2	$4.6	($0.7)
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($2.0)	$1.6	$12.3	$1.7	($3.6)
LaSalle	2,271	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.5)	($1.8)	$6.0	$3.8	($1.5)
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.7	($3.9)
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($3.3)
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA
Peach Bottom	2,347	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.8	$0.7	($4.1)
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.3)	$1.9	($5.8)	($13.9)
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.4	$2.1	($3.7)
Salem	2,328	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.3)	$1.3	$11.9	$1.4	($3.9)
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$4.1	($4.0)
Susquehanna	2,520	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.0	($1.4)	($8.0)
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2021, 2022 and 2023 and known capacity market prices for 2021. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values. Nuclear plants may sell their output at a range of forward prices and for a range of future years.

50 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.
51 The values for 2016 through 2019 have changed slightly from previous values to account for reactive supply and voltage control revenues.

Table 7-20 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2021 through 2023. Capacity revenues are not presented for calendar year 2022 and 2023 because the 2022/2023 BRA has not been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[52] Forward prices are as of April 1, 2021. The 2021 energy prices include actual day-ahead market prices through March 31, 2021, and forward prices for April through December 2021.The capacity prices are known based on PJM capacity auction results.

Table 7-20 Forward prices in PJM energy markets, capacity revenue, and annual costs[53]

	ICAP	Average Forward LMP ($/MWh)			Capacity Revenue ($/MWh)	2019 NEI Costs ($/MWh)		
	(MW)	2021	2022	2023	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$26.82	$28.09	$27.22	$5.03	$6.06	$17.00	$5.32
Braidwood	2,337	$24.43	$25.42	$24.63	$8.52	$6.06	$17.00	$5.32
Byron	2,300	$23.69	$24.58	$23.81	$8.52	$6.06	$17.00	$5.32
Calvert Cliffs	1,708	$28.77	$29.41	$28.50	$5.21	$6.06	$17.00	$5.32
Davis Besse	894	$27.12	$28.35	$27.47	$5.85	$6.50	$24.60	$7.30
Dresden	1,797	$25.15	$26.12	$25.31	$8.52	$6.06	$17.00	$5.32
Hope Creek	1,172	$23.67	$25.14	$24.35	$7.74	$6.06	$17.00	$5.32
LaSalle	2,271	$24.35	$25.33	$24.54	$8.52	$6.06	$17.00	$5.32
Limerick	2,242	$23.61	$25.09	$24.30	$7.74	$6.06	$17.00	$5.32
North Anna	1,892	$27.98	$28.66	$27.76	$5.03	$6.06	$17.00	$5.32
Peach Bottom	2,347	$23.31	$24.82	$24.04	$7.74	$6.06	$17.00	$5.32
Perry	1,240	$27.15	$28.29	$27.41	$5.85	$6.50	$24.60	$7.30
Quad Cities	1,819	$21.96	$22.54	$21.84	$8.52	$6.06	$17.00	$5.32
Salem	2,328	$23.66	$25.14	$24.35	$7.74	$6.06	$17.00	$5.32
Surry	1,676	$27.43	$27.63	$26.77	$5.03	$6.06	$17.00	$5.32
Susquehanna	2,520	$22.33	$23.00	$22.28	$5.21	$6.06	$17.00	$5.32

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant. Under the Commission's December 19, 2019, MOPR Order, a competitive offer in the capacity market for a subsidized nuclear plant is defined to be net avoidable costs.[54] As a result, subsidized nuclear plants could make offers in the capacity market as low as but no lower than net avoidable costs. The capacity price required to cover net avoidable costs, when compared to recent capacity market prices, is an indicator of whether nuclear plants subject to the MOPR rules would clear in a capacity auction.

Based on the FERC order about inclusion of maintenance expense in energy offers, major maintenance costs can no longer be included in gross ACR values.[55] The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel, operating cost, and capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM, given that NEI does not provide a breakout of major maintenance. NEI capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

While the FERC order on major maintenance defines a competitive offer under the MOPR order, all generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

In Table 7-21, the capacity price required to cover avoidable costs in $ per MWh is calculated by taking the total NEI costs in $ per MWh and subtracting the total expected energy and ancillary services revenues in $ per MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average equivalent availability factor. Total expected ancillary services revenue is reactive capability revenue.[56] The capacity price required to cover avoidable costs in $ per MW-day is calculated

52 Forward prices on April 1, 2021. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2020 data.

53 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

54 See 169 FERC ¶ 61,239 at P 148.

55 See 167 FERC ¶ 61,030 at P 41.

56 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.

by multiplying the required price in $ per MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-21, for 2022, using forward prices as of April 1, 2021, the capacity price required to cover avoidable costs ranges from $0/MW-day for a multiple unit plant to $220.01/MW-day for a single unit plant for NEI data as reported including capex as a proxy for major maintenance, and from $0/MW-day for multiple unit plants to $57.25/MW-day for a single unit plant, excluding capital expenditures as a proxy for major maintenance.

Table 7-21 Net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2021	2022	2023	2021	2022	2023	2021	2022	2023
Beaver Valley	1,808	$1.32	$0.05	$0.92	$29.44	$1.02	$20.53	$0.00	$0.00	$0.00
Braidwood	2,337	$3.70	$2.71	$3.51	$82.59	$60.47	$78.17	$0.00	$0.00	$0.00
Byron	2,300	$4.48	$3.59	$4.36	$99.89	$80.09	$97.11	$0.00	$0.00	$0.00
Calvert Cliffs	1,708	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$11.04	$9.80	$10.68	$246.14	$218.56	$238.19	$83.38	$55.80	$75.42
Dresden	1,797	$2.90	$1.93	$2.75	$64.73	$43.13	$61.22	$0.00	$0.00	$0.00
Hope Creek	1,172	$4.28	$2.81	$3.60	$95.48	$62.63	$80.31	$0.00	$0.00	$0.00
LaSalle	2,271	$3.84	$2.87	$3.65	$85.73	$63.88	$81.49	$0.00	$0.00	$0.00
Limerick	2,242	$4.63	$3.15	$3.94	$103.28	$70.27	$87.87	$0.00	$0.00	$0.00
North Anna	1,892	$0.23	$0.00	$0.45	$5.12	$0.00	$10.01	$0.00	$0.00	$0.00
Peach Bottom	2,347	$4.79	$3.27	$4.06	$106.70	$72.99	$90.42	$0.00	$0.00	$0.00
Perry	1,240	$11.01	$9.87	$10.75	$245.42	$220.01	$239.67	$82.66	$57.25	$76.91
Quad Cities	1,819	$6.24	$5.66	$6.36	$139.21	$126.23	$141.89	$20.60	$7.62	$23.27
Salem	2,328	$4.59	$3.11	$3.91	$102.40	$69.43	$87.10	$0.00	$0.00	$0.00
Surry	1,676	$0.78	$0.59	$1.44	$17.46	$13.07	$32.19	$0.00	$0.00	$0.00
Susquehanna	2,520	$5.77	$5.10	$5.82	$128.67	$113.70	$129.70	$10.05	$0.00	$11.08

Table 7-22 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2019 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-22 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

Changes in forward energy market prices can significantly affect expected profitability of nuclear plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that only three plants, Davis Besse, Perry, and Susquehanna would not cover their annual avoidable costs in 2021. Two of these plants, Davis Besse and Perry, are single unit sites which have higher operating costs per MWh than multiple unit plants and show an annual shortfall of $5.19 and $5.16 per MWh in 2021. In March 2018, Davis Besse and Perry requested deactivation in 2021 but reversed the decision based on new subsidies in Ohio. On March 31, 2021, Ohio repealed the subsidies for nuclear units.[57] Susquehanna has reduced its operating costs below the NEI average costs and is not operating at a loss when the unit specific information is accounted for.[58]

Hope Creek, Quad Cities, and Salem all currently receive subsidies. Based on forward prices as of April 1, 2021 and NEI average costs, none of these units need a subsidy.

57 *See* Ohio S.B. 44/H.B. 128; *see also* Ohio Governor Mike DeWine's Website, News Release: "Governor DeWine Signs Ohio Transportation Budget," which can be accessed at: <https://governor.ohio.gov/wps/portal/gov/governor/media/news-and-media/transportation-budget-signed-03312021>.

58 Bank of America Global Research, October 26, 2020.

Table 7-22 Nuclear unit forward annual surplus (shortfall)[59 60]

	ICAP (MW)	Surplus (Shortfall) ($/MWh) 2021	Subsidy ($/MWh) 2021	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2021	Surplus (Shortfall) Including Subsidy ($ in millions) 2021
Beaver Valley	1,808	$3.71		$56.1	$56.1
Braidwood	2,337	$4.82		$93.6	$93.6
Byron	2,300	$4.04		$77.5	$77.5
Calvert Cliffs	1,708	$5.79		$81.9	$81.9
Davis Besse	894	($5.19)		($37.0)	($37.0)
Dresden	1,797	$5.62		$83.7	$83.7
Hope Creek	1,172	$3.46	$10.00	$33.9	$129.3
LaSalle	2,271	$4.68		$88.3	$88.3
Limerick	2,242	$3.11		$58.5	$58.5
North Anna	1,892	$4.81		$75.5	$75.5
Peach Bottom	2,347	$2.96		$58.3	$58.3
Perry	1,240	($5.16)		($51.1)	($51.1)
Quad Cities	1,819	$2.28	$16.50	$35.1	$279.4
Salem	2,328	$3.15	$10.00	$61.5	$251.0
Surry	1,676	$4.25		$59.3	$59.3
Susquehanna	2,520	($0.56)		($9.8)	($9.8)

59 Report to the General Assembly in Compliance with Section 1-75(d-5) of the Illinois Power Agency Act 20 ILCS 3855/1-75(d-5)(F)(2). Illinois Commerce Commission. August 2019. The report finds that while total ZECs payments are limited by rate impact caps and volume caps, the law's limitation does not unduly constrain the procurement of ZECs.

60 *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Hope Creek, Order Determining the Eligibility of Hope Creek Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080559 (April 27, 2021). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 1, Order Determining the Eligibility of Salem Unit 1 Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080557 (April 27, 201). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 2, Order Determining the Eligibility of Salem Unit 2 Nuclear Generator to Receive ZECs*. BPU Docket No. ER20080557 (April 27, 2021).