7 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 analysis includes the theoretical new entrant net revenues for 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, gas prices and coal prices increased in the first three months of 2026 compared to the first three months of 2025. The net effects were that in the first three months of 2026, average energy market theoretical net revenues increased by 213 percent for a new combustion turbine (CT), increased by 144 percent for a new combined cycle (CC), increased by 199 percent for a new coal plant (CP), increased by 64 percent for a new nuclear plant, increased by 1,326 percent for a new diesel (DS), increased by 29 percent for a new onshore wind installation, increased by 65 percent for a new offshore wind installation and increased by 10 percent for a new solar installation.
- The price of natural gas and coal increased in the first three months of 2026. The marginal costs of a new CT and CC were greater than the marginal costs of a new CP in January and February, and lower in March 2026.
- In the first three months of 2026, spark spreads in BGE and Western Hub increased and spark spreads in COMED and PSEG decreased compared to the first three months of 2025. In the first three months of 2026, dark and quark spreads increased in BGE, COMED, PSEG and Western Hub compared to the first three months of 2025.
- Of the 16 PJM nuclear plants analyzed, all are expected to cover their avoidable costs from energy and capacity market revenues in 2026, 2027 and 2028, without any subsidies.

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 calculation of expected energy and ancillary services net revenues using historical revenues that are scaled based on forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

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 alone 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. A basic purpose of the capacity market is to allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market. PJM's recent change to the definition of the VRR curve in the capacity market weakens the connection between the energy and capacity markets by discounting the net revenue offset, overstating net CONE and creating an arbitrary floor price and, as a result, undermines an important part of the fundamental PJM market design.[1]

PJM's introduction of a flawed form of ELCC for defining available unforced capacity has made the definition of reliability less clear. The ELCC derate factors are volatile and subject to changes for reasons that are not clear to generation owners or other market participants. There are significant issues with PJM's implementation of its approach to ELCC that result, among other things, in the undervaluing of gas fired generation capacity.

Net Revenue

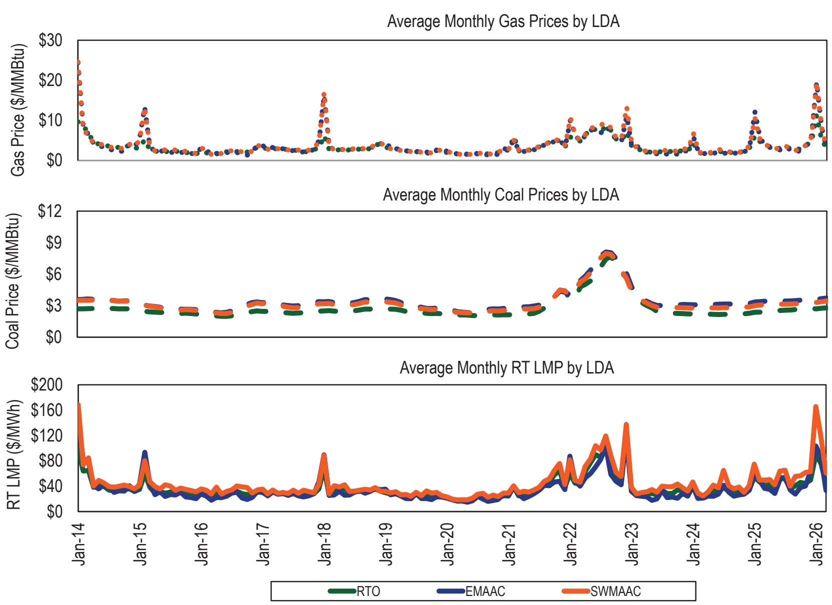
When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets including uplift payments, and from the provision of black start, and from subsidies like RECs, 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.[2] 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 markets, 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. The current definition of net revenue is not fully accurate as the FERC ordered definition uses price-based offers at times and does not include revenue from opportunity cost adders for environmentally constrained resources.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP in the first three months of 2026 increased $35.24 per MWh, or 67.5 percent, from the first three months of 2025, from $52.20 per MWh to $87.44 per MWh. Gas prices and coal prices increased in the first three months of 2026 compared to the first three months of 2025. The price of eastern natural gas was 43.3 percent higher, the price of western natural gas was 27.5 percent higher; the price of Northern Appalachian coal was 15.4 percent higher; the price of Central Appalachian coal was 7.8 percent higher; and the price of Powder River Basin coal was 6.0 percent higher (Figure 7-1). The price of ULSD NY Harbor Barge (ultra low sulfur diesel) was 22.3 percent higher in the first three months of 2026 than in the first three months of 2025.

1 See Protest of the Independent Market Monitor for PJM, Docket No. ER26-455-000 (December 8, 2025); 194 FERC ¶ 61,049 (2026).
2 Avoidable costs are sometimes referred to as going forward costs.

Figure 7-1 Energy market net revenue factor trends: 2014 through March 2026



Spark, Dark, and Quark Spreads

The spark, dark, and quark spreads are 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, the dark spread compares power prices to the cost of coal, and the quark spread compares power prices to the cost of uranium. 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.

In the first three months of 2026, spark spreads in BGE and Western Hub increased and spark spreads in COMED and PSEG decreased compared to the first three months of 2025. In the first three months of 2026, dark and quark spreads increased in BGE, COMED, PSEG and Western Hub compared to the first three months of 2025. In the first three months of 2026, the volatility of spark, dark and quark spreads increased in BGE, COMED, PSEG and Western Hub compared to the first three months of 2025.[3]

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviations.

Table 7-1 Peak hour spark, dark, and quark spreads ($/MWh)

	BGE			COMED			PSEG			Western Hub		
Jan-Mar	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2025	$23.06	$34.02	$46.93	$10.90	$18.95	$20.93	($6.60)	$20.68	$37.32	$14.68	$27.83	$40.74
2026	$36.69	$66.81	$81.62	$3.76	$19.54	$21.43	$0.58	$39.65	$56.97	$21.97	$52.42	$67.24
Percent change	59%	96%	74%	(66%)	3%	2%	(109%)	92%	53%	50%	88%	65%

Table 7-2 Peak hour spark, dark, and quark spread standard deviation ($/MWh)

	BGE			COMED			PSEG			Western Hub		
Jan-Mar	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2025	$54.9	$64.9	$64.6	$28.7	$32.1	$31.8	$97.8	$38.7	$38.1	$56.4	$45.6	$45.2
2026	$125.8	$152.7	$152.6	$95.7	$62.8	$62.7	$114.0	$98.5	$98.3	$125.1	$117.1	$117.0
Percent change	129%	135%	136%	233%	95%	97%	17%	154%	158%	122%	157%	159%

Figure 7-2 and Figure 7-3 show the hourly spark and dark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

3 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh. Dark and quark spreads use a heat rate of 10,000 Btu/kWh

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2021 through March 2026[4]

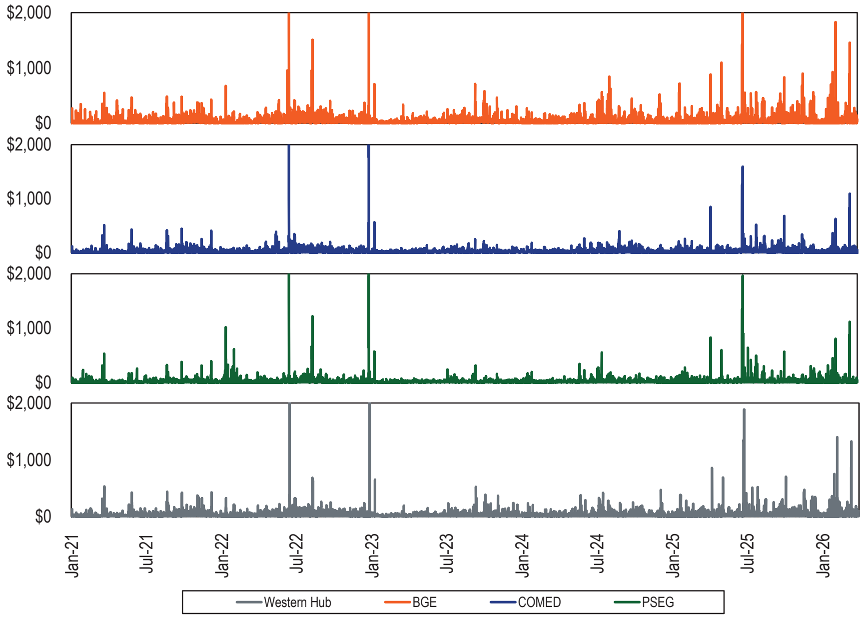
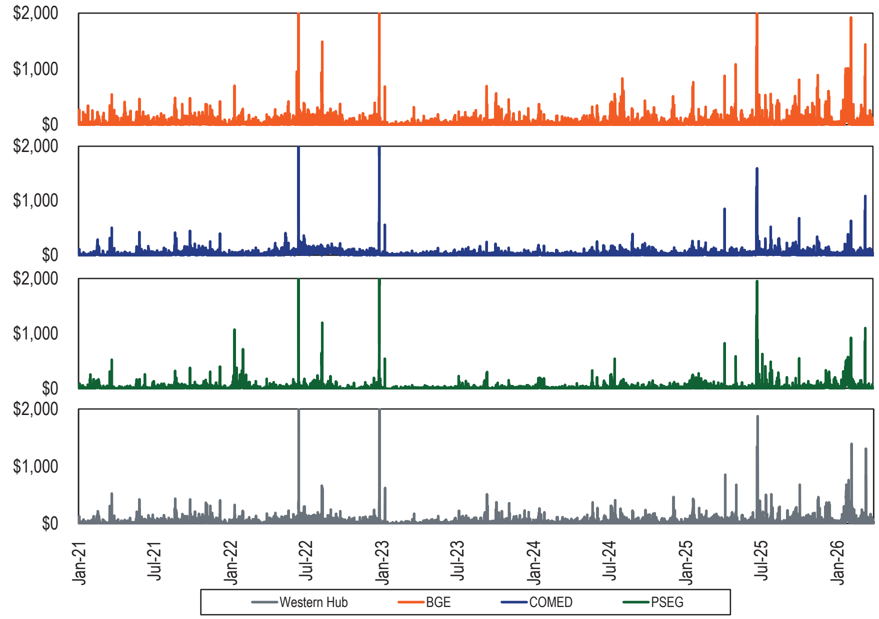


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2021 through March 2026[5]



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 unit's operations and potential net revenue in PJM markets.

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

4 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.

5 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, daily coal prices, and average transportation costs by coal type; Powder River Basin coal for COMED, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

- The CT plant is a single GE Frame 7HA.03 CT with an installed capacity of 409.3 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction, and dual fuel capability.
- The CC plant includes two single shaft 1x1 GE Frame 7HA.02 CTs, each with a single combustion turbine, heat recovery steam generator, and steam turbine with a total installed capacity of 1,362 MW, equipped with SCR for NO_x reduction, dry cooling, duct burners, and dual fuel capability.
- 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 baghouse 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 94 Siemens 3.2 MW wind turbines with an installed capacity of 300.8 MW.
- The offshore wind installation includes of 37 Siemens 11.0 MW wind turbines with an installed capacity of 406.0 MW.
- The solar installation is a 1,120 acre ground mounted tracking solar farm with an installed AC capacity of 200 MW.
- The battery storage unit is a 200 MW, 4 hour battery capable of providing 200 MW for 4 hours, or 800 MWh.

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.[6] [7] 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.[8] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[9]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[10]

Zonal net revenues reflect average zonal LMP, and fuel costs based on locational fuel indices and zone specific fuel delivery charges.[11] 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.[12] 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.[13] Net revenues are calculated for all zones except OVEC.[14]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[15] [16] Starting in 2025, energy market offers include major maintenance costs. For the CT unit, the unit is dispatched with a start cost of $36,699/start. For the CC and CP unit, major maintenance is included as a cost per MWh. Unit costs used to dispatch the unit are shown, including all components, in Table 7-3.

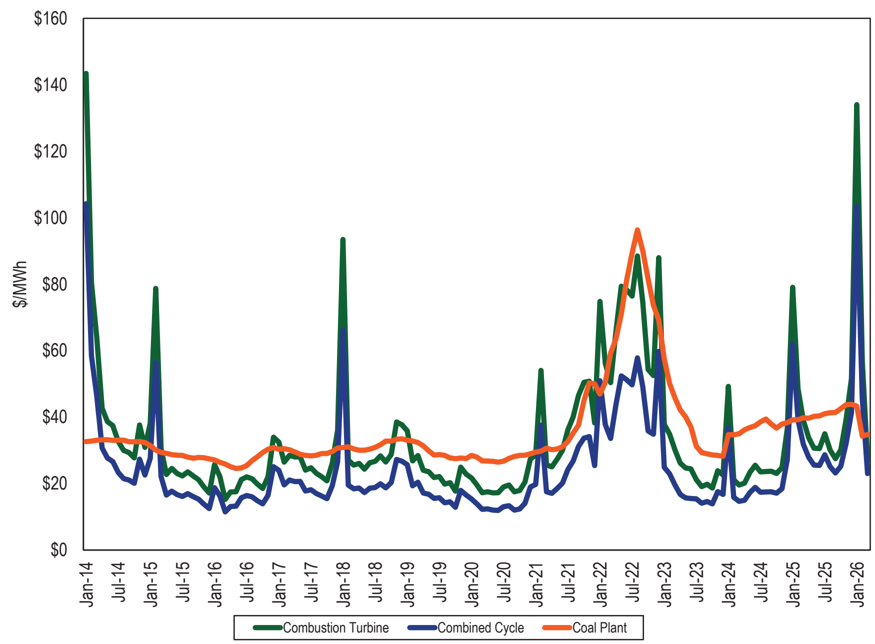
6 Hourly ambient conditions supplied by DTN.
7 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
8 CO_2 emission allowance costs only included for states participating in RGGI.
9 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
10 Outage figures obtained from the PJM eGADS database.
11 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 warm starts.
12 Gas daily cash prices obtained from Platts.
13 Coal prompt month prices obtained from Platts.
14 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.
15 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid
16 VOM rates provided by Pasteris Energy, Inc.

Table 7-3 Average operating costs: January through March, 2026

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)	Major Maintenance ($/MWh)	Start Costs ($/Start)
CT	$72.63	9,241	$0.43	$0.00	$36,669
CC	$57.29	6,369	$0.64	$2.88	$0
CP	$37.46	9,250	$5.09	$1.01	$0
DS	$215.80	9,660	$0.25	$0.00	$0
Nuclear	$0.00	NA	$0.00	$0.00	$0
Wind	$0.00	NA	$0.00	$0.00	$0
Wind (off shore)	$0.00	NA	$0.00	$0.00	$0
Solar	$0.00	NA	$0.00	$0.00	$0

A comparison of the monthly average operating cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CT plant and the CC plant have been less than those of the CP plant but the costs of the CT plant and 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 average monthly operating costs of a new CC and CT were greater than the marginal cost of a new CP in January and February 2026, but not in March. Marginal costs are based on spot fuel costs. Individual generation plants may have contracts for coal that differ significantly from spot prices.

Figure 7-4 Average short run marginal costs: 2014 through March 2026



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 unit capacity factors. Table 7-4 shows the average capacity factor for new units. The capacity factors for a new CT, a new CC, and a new CP increased in the first three months of 2026 compared to the first three months of 2025.

Table 7-4 Average capacity factor: 2014 through March 2026

Jan-Mar	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	44%	69%	74%	11%	91%	33%	11%
2015	61%	74%	67%	8%	92%	32%	13%
2016	74%	79%	43%	1%	92%	33%	14%
2017	51%	73%	41%	0%	94%	34%	13%
2018	58%	80%	40%	7%	94%	37%	13%
2019	47%	79%	27%	1%	93%	33%	13%
2020	53%	80%	6%	0%	93%	31%	12%
2021	38%	78%	33%	2%	93%	31%	12%
2022	37%	71%	36%	1%	92%	33%	14%
2023	43%	70%	5%	0%	94%	34%	13%
2024	57%	78%	27%	0%	92%	31%	14%
2025	50%	67%	48%	2%	92%	36%	15%
2026	71%	74%	50%	15%	92%	32%	14%

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 additional 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 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 all zones in the first three months of 2026 as a result of higher spark spreads (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through March, 2014 through 2026 (Dollars per installed MW-year)[17]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$37,754	$12,776	$9,793	$5,094	$6,806	$7,471	$971	$2,519	$11,918	$1,695	$3,835	$1,963	$13,480	587%
AEP	$54,108	$28,204	$17,445	$8,061	$29,985	$9,977	$8,681	$7,386	$18,450	$12,380	$15,404	$22,217	$51,757	133%
APS	$67,470	$45,378	$13,746	$6,445	$36,990	$5,997	$2,111	$7,015	$12,276	$4,577	$20,649	$30,618	$111,319	264%
ATSI	$35,579	$23,015	$15,204	$8,790	$37,051	$10,895	$8,913	$9,488	$17,233	$10,038	$21,444	$26,129	$58,474	124%
BGE	$43,148	$12,147	$19,132	$8,307	$12,933	$5,766	$2,798	$8,385	$13,858	$4,775	$9,915	$11,737	$78,559	569%
COMED	$22,324	$11,462	$8,184	$3,957	$10,373	$4,047	$4,209	$3,279	$8,827	$5,801	$11,047	$9,241	$17,705	92%
DAY	$32,065	$20,233	$15,044	$7,517	$31,940	$11,113	$10,418	$13,494	$20,461	$11,963	$24,520	$25,157	$65,831	162%
DOM	$39,668	$16,211	$18,598	$7,708	$15,105	$7,316	$5,139	$6,897	$14,534	$9,912	$12,217	$14,128	$64,275	355%
DPL	$38,694	$12,217	$6,240	$3,796	$6,485	$3,500	$502	$11,557	$17,751	$3,812	$4,333	$5,544	$24,828	348%
DUKE	$29,200	$17,892	$14,061	$6,192	$38,188	$9,490	$8,904	$12,405	$18,741	$10,707	$22,062	$21,680	$62,346	188%
DUQ	$14,592	$9,130	$14,864	$4,724	$8,098	$3,872	$4,217	$4,285	$5,038	$8,827	$11,083	$7,158	$16,866	136%
EKPC	$49,038	$21,659	$15,107	$6,595	$20,778	$8,411	$7,595	$7,901	$18,881	$10,591	$15,102	$16,291	$33,221	104%
JCPLC	$41,229	$14,179	$7,559	$6,342	$7,018	$6,376	$990	$2,333	$10,957	$1,279	$3,807	$2,407	$15,017	524%
MEC	$41,388	$20,993	$13,828	$7,711	$11,234	$5,616	$5,731	$5,579	$19,247	$8,363	$11,150	$7,711	$15,972	107%
PE	$81,671	$58,960	$24,023	$9,259	$38,540	$10,088	$8,218	$11,934	$32,468	$16,618	$27,356	$37,168	$66,714	79%
PECO	$41,809	$20,891	$12,766	$6,174	$9,570	$5,030	$4,413	$3,208	$13,760	$3,414	$6,085	$4,824	$14,217	195%
PEPCO	$46,885	$13,007	$10,982	$6,099	$11,383	$4,754	$1,679	$5,131	$11,822	$3,399	$6,913	$8,807	$78,157	787%
PPL	$148,531	$84,974	$20,750	$10,291	$45,447	$7,185	$4,138	$8,804	$29,476	$11,364	$18,076	$23,259	$65,034	180%
PSEG	$52,790	$28,103	$15,489	$8,117	$10,758	$6,631	$1,107	$5,878	$14,460	$1,216	$4,564	$2,762	$15,679	468%
REC	$31,162	$16,289	$7,900	$5,640	$5,466	$5,443	$1,063	$11,775	$16,528	$2,421	$6,134	$3,939	$16,471	318%
PJM	$58,381	$24,386	$14,036	$6,841	$19,707	$6,949	$4,590	$7,463	$16,334	$7,158	$12,785	$14,137	$44,296	213%

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] The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CC plant energy market net revenues were higher in all zones in the first three months of 2026 as a result of higher spark spreads (Table 7-6).

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

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through March, 2014 through 2026 (Dollars per installed MW-year)[19]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$51,917	$21,960	$14,306	$11,375	$14,242	$15,408	$6,819	$5,979	$10,640	$2,590	$5,504	$8,289	$24,980	201%
AEP	$63,214	$35,476	$22,439	$14,388	$37,756	$18,967	$14,283	$15,052	$35,234	$23,401	$23,098	$31,097	$61,632	98%
APS	$79,776	$54,676	$25,811	$14,554	$46,949	$16,367	$11,146	$16,400	$26,257	$11,383	$29,802	$38,699	$116,074	200%
ATSI	$40,769	$31,458	$20,863	$14,986	$43,292	$19,794	$14,512	$18,167	$34,136	$21,081	$29,001	$34,230	$65,291	91%
BGE	$57,866	$21,830	$30,782	$16,487	$23,231	$15,669	$12,098	$17,573	$20,653	$12,285	$17,500	$20,906	$91,893	340%
COMED	$24,402	$18,254	$13,878	$8,627	$14,200	$9,662	$9,432	$7,621	$18,334	$13,220	$16,357	$14,917	$25,177	69%
DAY	$35,604	$28,773	$20,747	$14,010	$39,039	$20,098	$15,942	$22,208	$37,397	$23,344	$32,063	$33,488	$72,319	116%
DOM	$50,643	$25,250	$24,676	$14,431	$20,823	$16,407	$11,574	$14,918	$27,562	$21,155	$18,246	$25,295	$72,869	188%
DPL	$50,053	$18,656	$12,529	$5,832	$9,759	$4,873	$1,035	$12,599	$19,035	$5,009	$7,126	$13,113	$35,930	174%
DUKE	$31,977	$26,108	$19,795	$12,381	$44,259	$18,282	$14,548	$20,636	$35,334	$21,868	$29,446	$30,175	$69,010	129%
DUQ	$18,875	$12,222	$19,372	$10,714	$16,465	$10,886	$10,477	$10,658	$13,879	$19,823	$18,686	$13,999	$23,565	68%
EKPC	$57,036	$29,698	$20,355	$12,851	$29,400	$16,973	$13,540	$16,353	$34,287	$21,801	$23,306	$24,977	$47,064	88%
JCPLC	$57,370	$23,293	$12,163	$12,537	$14,412	$14,416	$6,985	$5,854	$8,413	$2,226	$5,935	$9,288	$26,754	188%
MEC	$52,805	$30,724	$17,860	$13,766	$19,939	$13,968	$11,572	$13,004	$23,692	$18,800	$19,340	$16,382	$31,291	91%
PE	$91,359	$59,225	$26,285	$15,380	$44,819	$19,147	$13,657	$20,663	$49,248	$27,081	$34,479	$45,274	$75,791	67%
PECO	$55,336	$32,397	$16,873	$12,277	$19,415	$12,909	$10,228	$9,982	$14,538	$10,883	$12,657	$12,747	$24,243	90%
PEPCO	$61,605	$23,012	$23,146	$13,829	$19,546	$14,156	$9,378	$11,412	$16,309	$7,647	$10,518	$18,539	$85,800	363%
PPL	$145,442	$78,794	$23,078	$15,942	$49,592	$14,995	$9,980	$16,706	$45,065	$21,615	$24,878	$30,920	$75,640	145%
PSEG	$72,991	$40,604	$19,821	$14,442	$21,129	$15,592	$7,789	$9,595	$10,796	$1,945	$6,971	$8,431	$26,958	220%
REC	$47,382	$23,878	$12,337	$11,761	$11,689	$13,869	$7,363	$13,360	$16,154	$3,396	$9,392	$10,786	$24,976	132%
PJM	$100,026	$31,814	$19,856	$13,029	$26,998	$15,122	$10,618	$13,937	$24,848	$14,527	$18,715	$22,078	$53,863	144%

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. The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CP plant energy market net revenues were higher in all zones in the first three months of 2026 as a result of higher dark spreads (Table 7-7).

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

Table 7-7 Energy net revenue for a new entrant CP: January through March, 2014 through 2026 (Dollars per installed MW-year)[20]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$107,792	$40,142	$3,745	$1,178	$28,013	$3,213	$0	$3,211	$5,701	$1,201	$4,480	$11,650	$65,164	459%
AEP	$70,843	$23,058	$7,315	$8,104	$25,314	$5,842	$351	$12,337	$10,989	$182	$11,588	$33,748	$65,306	94%
APS	$82,000	$30,858	$1,920	$4,398	$26,869	$2,782	$0	$5,977	$6,193	$502	$9,419	$35,459	$105,611	198%
ATSI	$78,162	$24,868	$5,334	$9,185	$26,251	$5,642	$53	$9,672	$10,838	$231	$10,655	$32,270	$57,687	79%
BGE	$128,660	$45,329	$11,098	$4,976	$32,968	$3,458	$73	$9,554	$14,019	$1,848	$9,595	$21,079	$124,817	492%
COMED	$64,272	$19,375	$3,431	$6,920	$9,375	$5,332	$66	$10,349	$28,239	$10,727	$17,382	$26,749	$51,631	93%
DAY	$71,016	$23,143	$5,092	$7,464	$22,695	$5,662	$325	$14,065	$10,634	$170	$12,419	$33,170	$65,130	96%
DOM	$109,775	$50,579	$13,462	$5,084	$35,980	$5,116	$384	$11,383	$27,235	$2,531	$14,983	$43,456	$119,086	174%
DPL	$131,295	$53,979	$6,464	$3,809	$33,539	$4,046	$6	$11,384	$15,972	$2,625	$7,068	$18,235	$80,465	341%
DUKE	$65,469	$20,425	$4,336	$5,817	$27,387	$4,441	$101	$12,785	$9,633	$181	$11,784	$30,285	$62,024	105%
DUQ	$61,674	$16,396	$4,816	$7,965	$25,460	$4,699	$27	$8,965	$8,870	$205	$9,419	$28,862	$52,800	83%
EKPC	$65,433	$19,528	$3,750	$5,444	$16,902	$3,322	$55	$11,588	$10,416	$156	$11,453	$30,750	$63,095	105%
JCPLC	$112,807	$41,387	$2,170	$1,327	$28,138	$2,940	$0	$3,215	$6,930	$1,123	$4,468	$11,353	$66,416	485%
MEC	$124,027	$49,857	$4,409	$4,229	$33,221	$4,316	$525	$8,670	$27,403	$2,333	$12,249	$35,032	$81,811	134%
PE	$92,537	$38,559	$4,808	$3,194	$24,903	$3,599	$35	$9,517	$22,472	$1,506	$14,034	$40,268	$71,604	78%
PECO	$105,865	$39,385	$1,975	$1,169	$27,881	$2,761	$0	$4,481	$12,370	$1,478	$6,933	$19,126	$69,036	261%
PEPCO	$106,471	$32,196	$2,494	$1,062	$25,772	$1,733	$0	$5,175	$7,692	$1,646	$7,561	$17,185	$117,107	581%
PPL	$105,142	$38,500	$2,031	$1,309	$27,030	$1,634	$0	$4,743	$12,199	$1,424	$6,940	$17,506	$73,344	319%
PSEG	$141,330	$60,005	$5,254	$3,272	$31,064	$4,276	$0	$4,396	$14,469	$1,102	$4,952	$11,985	$68,004	467%
REC	$138,906	$61,121	$4,860	$3,287	$29,033	$4,966	$0	$8,166	$17,485	$1,312	$5,787	$13,051	$68,326	424%
PJM	$98,174	$36,434	$4,938	$4,459	$26,890	$3,989	$100	$8,482	$13,988	$1,624	$9,658	$25,561	$76,423	199%

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 in the first three months of 2026 as a result of higher quark spreads (Table 7-8).

20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
21 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through March, 2014 through 2026 (Dollars per installed MW-year)[22]

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$211,846	$115,640	$48,725	$58,221	$94,760	$60,423	$37,593	$55,190	$102,930	$56,927	$55,917	$98,494	$158,191	61%
AEP	$138,944	$79,965	$52,917	$58,719	$81,608	$58,767	$40,931	$61,127	$98,835	$63,536	$60,622	$97,370	$144,498	48%
APS	$160,110	$97,683	$55,589	$60,569	$92,244	$60,182	$40,555	$60,590	$104,382	$65,867	$62,706	$102,770	$200,294	95%
ATSI	$147,452	$81,034	$52,730	$60,761	$85,634	$60,612	$41,365	$60,525	$97,928	$63,827	$61,128	$98,592	$138,185	40%
BGE	$221,336	$117,188	$72,903	$67,346	$105,209	$64,215	$43,501	$68,896	$119,282	$73,785	$70,433	$117,280	$236,744	102%
COMED	$121,565	$67,311	$47,298	$54,992	$57,591	$52,559	$38,015	$57,449	$80,606	$54,163	$52,802	$69,678	$101,088	45%
DAY	$138,517	$77,939	$52,634	$59,527	$80,788	$60,909	$42,956	$65,079	$101,345	$66,272	$64,247	$97,389	$145,593	49%
DOM	$190,797	$112,959	$62,378	$63,021	$102,639	$62,157	$40,958	$63,882	$117,847	$70,088	$67,860	$114,205	$218,411	91%
DPL	$224,316	$126,346	$61,073	$63,399	$100,951	$60,325	$38,079	$69,344	$114,601	$58,926	$57,725	$103,576	$171,417	65%
DUKE	$131,887	$74,773	$51,588	$57,464	$86,563	$58,821	$41,383	$63,281	$99,134	$64,682	$61,540	$93,643	$141,783	51%
DUQ	$127,759	$70,888	$52,008	$59,245	$84,336	$58,959	$41,119	$58,969	$94,431	$62,450	$58,645	$94,200	$131,469	40%
EKPC	$131,844	$73,721	$50,862	$56,994	$72,894	$57,057	$40,988	$61,600	$100,027	$63,735	$60,692	$94,241	$142,534	51%
JCPLC	$218,343	$116,586	$46,100	$59,689	$94,793	$59,323	$37,785	$54,901	$106,644	$57,806	$56,743	$100,455	$161,091	60%
MEC	$207,794	$111,544	$46,218	$59,539	$95,281	$59,162	$38,361	$57,647	$115,503	$63,277	$61,832	$103,155	$165,234	60%
PE	$170,103	$98,672	$50,863	$58,911	$87,072	$59,494	$39,506	$59,862	$109,907	$64,444	$66,000	$110,021	$156,262	42%
PECO	$209,402	$114,373	$45,162	$57,657	$94,548	$57,937	$36,838	$54,446	$102,865	$54,644	$54,082	$96,681	$155,165	60%
PEPCO	$217,980	$114,824	$65,798	$65,002	$102,966	$63,377	$42,283	$65,197	$117,467	$71,732	$69,283	$117,043	$238,678	104%
PPL	$208,338	$113,104	$46,485	$59,062	$91,735	$55,819	$36,183	$55,245	$105,871	$58,668	$55,041	$94,795	$160,245	69%
PSEG	$234,034	$124,111	$48,419	$60,394	$97,373	$61,330	$37,947	$60,042	$112,895	$59,048	$57,877	$100,779	$164,057	63%
REC	$231,133	$125,393	$47,495	$60,714	$94,786	$61,717	$38,526	$66,729	$120,425	$62,811	$64,030	$108,364	$168,285	55%
PJM	$182,175	$100,703	$52,862	$60,061	$90,189	$59,657	$39,744	$61,000	$106,146	$62,834	$60,960	$100,637	$164,961	64%

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 2026 as a result of higher and more volatile energy prices (Table 7-9).

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.

Table 7-9 Energy market net revenue for a new entrant DS: January through March, 2014 through 2026 (Dollars per installed MW-year)

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$32,171	$11,172	$1,895	$131	$9,687	$1,171	$19	$760	$5,193	$209	$512	$473	$21,059	4,356%
AEP	$14,072	$2,816	$316	$18	$3,182	$228	$121	$1,129	$526	$275	$322	$1,170	$14,673	1,154%
APS	$17,632	$6,050	$391	$64	$5,853	$225	$79	$718	$727	$284	$502	$2,622	$50,758	1,836%
ATSI	$13,724	$2,448	$256	$70	$2,327	$203	$127	$688	$524	$307	$245	$583	$7,889	1,254%
BGE	$48,591	$9,773	$2,207	$843	$11,091	$588	$226	$2,349	$3,729	$402	$1,307	$6,210	$68,827	1,008%
COMED	$11,036	$1,626	$152	$0	$603	$164	$96	$1,304	$392	$217	$218	$319	$4,471	1,302%
DAY	$13,842	$2,296	$269	$17	$1,401	$246	$143	$1,362	$531	$283	$573	$703	$11,161	1,489%
DOM	$42,074	$9,235	$1,282	$390	$13,183	$385	$145	$1,180	$3,572	$317	$1,732	$9,471	$74,173	683%
DPL	$35,919	$12,810	$1,670	$732	$11,197	$1,176	$19	$10,663	$6,142	$786	$957	$2,460	$32,052	1,203%
DUKE	$13,051	$1,892	$399	$11	$2,689	$207	$121	$1,597	$489	$268	$319	$618	$11,092	1,694%
DUQ	$12,607	$2,016	$255	$72	$2,615	$181	$152	$715	$511	$288	$244	$526	$7,208	1,271%
EKPC	$14,101	$2,087	$493	$10	$1,485	$205	$122	$1,861	$505	$270	$470	$1,470	$14,154	863%
JCPLC	$32,414	$11,631	$456	$209	$10,693	$1,131	$17	$707	$4,934	$221	$490	$456	$20,391	4,375%
MEC	$31,497	$10,905	$425	$167	$10,574	$357	$109	$903	$5,658	$261	$589	$788	$24,896	3,058%
PE	$15,656	$5,284	$266	$95	$4,610	$94	$145	$696	$618	$253	$320	$870	$15,941	1,732%
PECO	$31,741	$11,085	$421	$173	$9,516	$1,071	$21	$734	$5,107	$202	$544	$705	$22,984	3,162%
PEPCO	$50,549	$8,848	$1,182	$394	$11,047	$466	$168	$1,124	$3,910	$316	$1,489	$6,289	$75,337	1,098%
PPL	$32,438	$11,661	$397	$199	$8,376	$82	$23	$755	$2,701	$243	$483	$573	$23,182	3,947%
PSEG	$31,987	$11,287	$520	$205	$9,756	$1,481	$19	$1,131	$5,266	$219	$488	$502	$20,393	3,960%
REC	$29,526	$12,515	$507	$200	$8,823	$1,325	$21	$5,124	$5,167	$220	$472	$1,091	$19,580	1,695%
PJM	$29,787	$7,372	$688	$200	$6,935	$549	$94	$1,775	$2,810	$292	$614	$1,895	$27,011	1,326%

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly by zone assuming the unit generated at the average hourly capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW.[23]

Onshore wind energy market net revenues excluding RECs in the AEP, APS, and PE were higher in the first three months of 2026 as a result of increases in energy prices.

23 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
AEP	$45,406	$26,566	$21,777	$22,697	$38,566	$23,727	$13,525	$18,024	$35,754	$23,155	$22,084	$39,107	$46,732	19%
APS	$53,819	$33,489	$19,391	$24,579	$39,477	$19,314	$13,487	$17,251	$33,236	$23,017	$21,296	$43,231	$77,277	79%
COMED	$39,397	$23,379	$16,746	$21,821	$24,103	$20,127	$11,754	$18,216	$27,570	$19,795	$17,750	$24,848	$24,114	(3%)
PE	$66,094	$43,528	$21,076	$25,331	$41,510	$20,090	$12,783	$17,270	$34,758	$20,404	$18,162	$38,003	$45,569	20%

Wind units in the four zones were assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[24] Renewable energy credits were between 27 and 89 percent of the total energy market net revenue of an onshore wind installation.

Table 7-11 RECs revenue for an onshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
AEP	$11,245	$11,601	$10,807	$3,988	$5,573	$5,660	$7,027	$10,523	$19,155	$25,788	$27,310	$23,458	$19,706	(16%)
APS	$12,105	$11,296	$8,733	$4,082	$4,964	$4,448	$6,781	$10,144	$15,933	$24,475	$24,840	$24,124	$20,576	(15%)
COMED	$13,057	$11,750	$9,231	$4,222	$5,422	$5,498	$6,991	$12,050	$19,583	$26,724	$29,488	$25,441	$21,496	(16%)
PE	$13,521	$13,483	$9,992	$4,320	$5,359	$4,772	$6,727	$10,600	$16,356	$22,305	$20,366	$20,531	$16,467	(20%)

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly for relevant zones assuming the unit generated at a 40 percent capacity factor.

Offshore wind energy market net revenues excluding RECs were higher in the first three months of 2026 as a result of higher energy prices.

Table 7-12 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$85,651	$48,092	$21,071	$24,600	$40,720	$26,205	$16,368	$22,664	$47,210	$22,908	$23,108	$39,968	$61,702	54%
DOM	$88,644	$45,463	$25,403	$26,668	$45,330	$25,880	$17,241	$27,419	$51,619	$28,667	$28,684	$52,561	$95,236	81%
DPL	$91,499	$52,339	$24,464	$26,906	$43,334	$25,814	$16,556	$33,490	$54,108	$24,587	$23,238	$42,434	$67,958	60%

24 RECs prices obtained from Evolution Markets, Inc.

The offshore wind unit in ACEC was assumed to receive NJ wind RECs. The offshore wind unit in DOM and DPL was assumed to receive the higher of the MD or PA Tier I REC for the purposes of calculating RECs revenue.[25] Renewable energy credits were between 22 and 38 percent of the total energy market net revenue of an offshore wind installation.

Table 7-13 RECs revenue for an offshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$13,819	$13,997	$10,451	$4,420	$5,441	$5,750	$8,428	$13,421	$20,265	$27,726	$31,482	$24,530	$23,588	(4%)
DOM	$13,718	$13,716	$10,180	$4,212	$5,243	$5,715	$8,375	$13,419	$20,340	$27,294	$30,296	$23,640	$21,158	(10%)
DPL	$13,718	$13,716	$10,180	$4,212	$5,243	$5,715	$8,375	$13,419	$20,340	$27,294	$30,296	$23,640	$21,158	(10%)

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]

Solar energy market net revenues excluding RECs in the first three months of 2026 were higher in ACEC, DOM, and DPL as a result of higher energy prices. Solar energy market net revenues excluding RECs in the first three months of 2026 were lower in JCPLC and PSEG as a result of lower capacity factors.

Table 7-14 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$21,536	$13,316	$5,993	$6,914	$10,062	$7,282	$4,438	$5,187	$11,826	$5,528	$5,009	$11,211	$11,887	6%
DOM	-	-	$11,030	$12,432	$16,098	$10,274	$6,915	$9,150	$19,472	$10,914	$10,293	$22,543	$29,440	31%
DPL	-	-	$8,621	$9,593	$12,531	$8,845	$5,452	$7,086	$13,396	$7,862	$6,346	$12,880	$19,039	48%
JCPLC	$20,041	$10,930	$4,953	$6,140	$8,959	$6,448	$3,984	$4,666	$10,983	$5,145	$4,191	$9,704	$7,977	(18%)
PSEG	$19,380	$14,236	$6,048	$6,760	$10,192	$7,759	$4,895	$6,894	$13,527	$5,994	$4,809	$10,942	$9,019	(18%)

The solar installation was assumed to receive the highest of the DC, MD or NJ Solar REC, based on locational eligibility, for the purposes of calculating RECs revenue.[27] Renewable energy credits were between 66 and 479 percent of the total energy market net revenue of a solar installation.

25 RECs prices obtained from Evolution Markets, Inc.
26 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
27 RECs prices obtained from Evolution Markets, Inc.

Table 7-15 RECs revenue for a solar installation (Dollars per installed MW-year): January through March, 2014 through 2026

	Jan-Mar													
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Change in 2026 from 2025
ACEC	$41,783	$61,011	$77,407	$58,852	$58,108	$63,190	$58,863	$60,395	$64,866	$55,709	$58,796	$62,129	$48,766	(22%)
DOM	-	-	$20,073	$4,500	$3,647	$18,748	$29,338	$26,295	$25,413	$22,702	$24,553	$25,320	$19,377	(23%)
DPL	-	-	$17,082	$3,595	$2,869	$17,161	$24,688	$24,457	$17,899	$20,519	$19,775	$18,938	$14,800	(22%)
JCPLC	$40,306	$48,240	$63,743	$51,389	$52,376	$56,826	$52,807	$56,603	$58,249	$51,629	$49,391	$53,886	$38,183	(29%)
PSEG	$35,001	$54,050	$76,049	$56,814	$57,974	$64,597	$64,327	$62,180	$65,401	$58,461	$54,099	$56,948	$38,808	(32%)

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity market 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 94 percent of their total costs in the BGE Zone, 82 percent of their total costs in the PSEG Zone, and 52 percent of their total costs in the COMED Zone, including the return on and of capital, on a cumulative basis through March 2026. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered over 100 percent of their total costs on a cumulative basis in the BGE Zone, 93 percent of their total costs in PSEG Zone, and 65 percent of their 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. Covering 100 percent of total costs in this analysis includes earning the assumed rate of return. It is equivalent to being paid gross CONE, calculated using the defined parameters including the cost of capital. Units earned a positive rate of return even when earning less than the rate of return used in the gross CONE calculation.

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, ignoring the benefits of competition on increasing efficiency, reducing costs and improving technology and ignoring the possibility of over earning 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 2026 and 2012 through March 2026 [28]

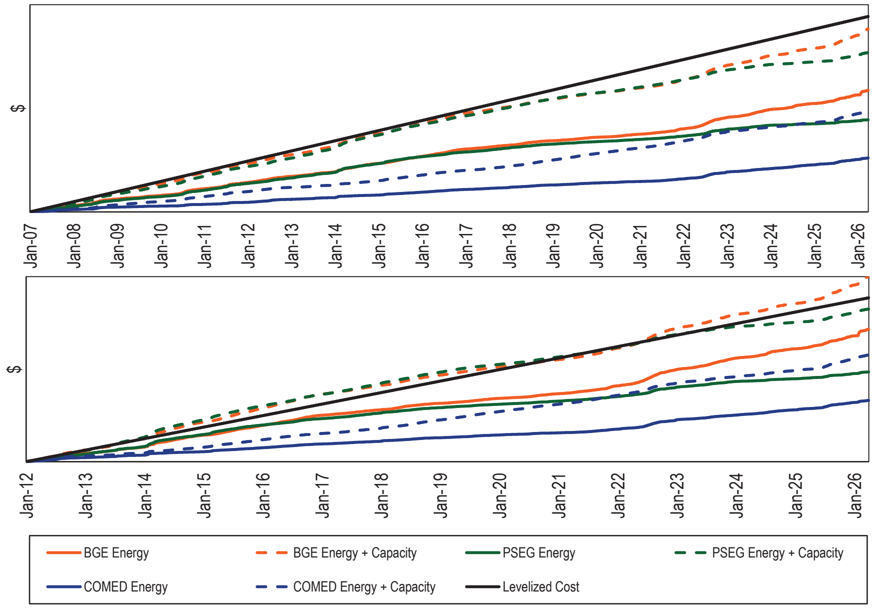


Table 7-16 shows the percent of levelized total costs recovered from the start date through March 2026. Table 7-16 also shows the return (IRR) earned from the start date through March 2026. For example, for a CC built in BGE in 2012, the resource would have earned a 14 percent IRR compared to the 12 percent used in the gross CONE calculation. In contrast, for a CC built in ComEd in 2012, the resource would have earned a 2 percent IRR compared to the 12 percent used in the gross CONE calculation.

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.

Table 7-16 Percent of levelized total costs recovered

2007 through March 2026 and 2012 through March 2026	2007 CC	2012 CC
Percent of levelized costs covered at 12% IRR		
BGE	94%	113%
COMED	52%	65%
PSEG	82%	93%
IRR at which levelized costs are covered		
BGE	9%	14%
COMED	0%	2%
PSEG	7%	11%

The assumptions used for this analysis are shown in Table 7-17.

Table 7-17 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%

Cost to Build vs Cost to Acquire

The MMU presented the cost to buy a new CT and a new CC during the Quadrennial Review process in 2025. (See Table 7-18.)

Table 7-18 Capital cost build up of a new EMAAC CT and CC[29]

Capital Costs ($ in 000s)	Combustion Turbine	Combined Cycle
Plant Proper EPC	$424,390	$1,610,970
Electric Interconnect/System Upgrades	$13,616	$39,672
Gas Interconnect	$20,228	$28,216
Water and Sewer Connection	$0	$7,771
Equipment Spares	$6,567	$11,943
Initial Fuel and Other Inventory	$4,988	$9,977
Mobilization and Startup	$2,837	$7,041
Land Purchase/Land Reservation Payment	$2,866	$9,171
Construction Period/Upfront Land Lease	$0	$0
Decommissioning Bond Costs	$0	$0
Development Expenses	$8,208	$10,944
Legal Fees	$2,551	$3,279
Permits	$2,760	$3,690
Emission Reduction Credits	$43,122	$105,459
Financing Fees	$5,667	$20,175
Interest During Construction	$0	$0
Owner's Contingency	$10,610	$40,274
Sales Tax	$549	$1,910
Other	$0	$0
Total Project Overnight Cost-No IDC ($ in 000s)	$548,960	$1,910,493
Total Project Cost ($/kW)	$1,253	$1,345

Buying an existing resource is an alternative to buying a new unit. Selected recent transactions including gas plants or primarily thermal generation portfolios in the US with announced prices are shown in Table 7-19. Not all transactions are in PJM. Recent transactions for new combined cycles are close to or at a premium to the MMU estimate of total project cost in $/kW.

29 The MMU retained Pasteris Energy, Inc. to develop the revenue requirements of a new entrant ("Gross CONE") combustion turbine ("CT") and combined cycle ("CC") power plant located in five PJM Locational Deliverability Areas ("LDA") on a 2028 dollar basis for commercial operation in the 2028/2029 Delivery Year as part of the Quadrennial Review. Stantec Consulting Services, Inc. ("Stantec") a power plant design and engineering firm with CT and CC plant design experience was contracted by Pasteris Energy, Inc. to determine the plant proper capital cost estimate for the CONE CT and CC power plant at the five locations within PJM. The power plant construction estimates were developed based on data from recent actual construction proposals by Stantec and input obtained from multiple construction contractors. For these estimates, labor rates and labor productivity for each CONE Area were verified and used to develop the direct and indirect construction costs.

Table 7-19 Selected recent transactions[30]

Date Announced	Date Closed	Buyer	Seller	Description of Assets	Unit Type	Fuel	Location	Price ($ in millions)	MW	$/kW
1/15/2026	-	Talen Energy	Energy Capital Partners	Waterford (OH) Darby (OH) Lawrenceburg (IN)	1 Combustion Turbine 2 Combined Cycles	Natural Gas	IN, OH	$3,450	2,600	$1,327
1/5/2026	-	Vistra	Cogentrix (Quantum Capital Group)	10 units	2 Combustion Turbine 7 Combined Cycles 1 Cogeneration Unit	Natural Gas	CT, MD, ME, NH, NJ, PA, RI, TX	$4,000	5,500	$727
9/15/2025	-	Blackstone	Ardian	Hill Top Energy Center	1 Combined Cycle	Natural Gas	PA	$1,000	620	$1,613
9/15/2025	9/24/2025	CPS Energy	PROENERGY	4 units	4 Combustion Turbines	Natural Gas	TX	$1,387	1,632	$850
9/11/2025	9/11/2025	PowerTransitions (Partners Group)	Talen Energy	Camden Power Plant (NJ) Dartmouth Power Plant (MA)	2 Combustion Turbines	Natural Gas	NJ, MA	$450	226	$1,991
7/17/2025	11/25/2025	Talen Energy	Caithness, BlackRock	Guernsey Power Station (OH) Moxie Freedom Energy Center (PA)	2 Combined Cycles	Natural Gas	OH, PA	$3,500	2,941	$1,190
5/15/2025	10/22/2025	Vistra	Lotus Infrastructure Partners	7 units Greenleaf (CA) Garrison (DE) Beaver Falls (NY) Fairless (PA) Manchester (RI)	2 Combustion Turbines 5 Combined Cycles	Natural Gas	CA, DE, NY, PA, RI	$1,900	2,600	$731
5/12/2025	1/30/2026	NRG Energy	LS Power	18 units	18 units	Natural Gas	9 states in Northeast, TX	$12,000	13,000	$923
4/14/2025	6/9/2025	Capital Power	LS Power	Rolling Hills (OH) Hummel (PA)	2 Combined Cycles	Natural Gas	OH, PA	$2,200	2,147	$1,025
3/18/2025	6/16/2025	Partners Group	Middle River	Middle River portfolio 11 units	9 Combustion Turbines 2 Combined Cycle	Natural Gas	CA	$2,200	1,900	$1,158
3/12/2025	4/10/2025	NRG	Rockland Capital	6 units Victoria, Victoria Port II, SJRR, Port Comfort, Chamon, Wharton	5 Combustion Turbines 1 Combined Cycle	Natural Gas	TX	$560	738	$759
1/24/2025	8/5/2025	Blackstone	Ares Management	Potomac Energy Center	1 Combined Cycle	Natural Gas	VA	$1,000	774	$1,292
1/10/2025	1/7/2026	Constellation	Calpine	Calpine portfolio 79 units	79 units	Natural Gas Geothermal	USA	$26,600	27,000	$985
8/5/2024	1/31/2025	Quantum Capital Group	Carlyle	Cogentrix Energy 11 units	11 units	Natural Gas	MA, MD, ME, NH NJ, PA, RI, TX	$3,000	5,300	$566
6/28/2024	6/30/2025	AEP	J-Power USA	Green Country Power Plant	1 Combined Cycle	Natural Gas	OK	$730	795	$918
3/27/2024	5/1/2024	CPS Energy	Talen	Barney Davis, Nueces Bay, Laredo	1 Combustion Turbine 2 Combined Cycles	Natural Gas	TX	$785	1,710	$459
11/20/2023	2/9/2024 and 2/16/2024	Capital Power Corporation	CSG Investments	Harquahala (AZ) La Paloma (CA)	2 Combined Cycles	Natural Gas	AZ, CA	$1,100	1,608	$684
11/13/2023	9/29/2025	TotalEnergies	TexGen	Wolf Hollow I, Colorado Bend I, La Porte	1 Combustion Turbine 2 Combined Cycles	Natural Gas	TX	$635	1,500	$423
9/23/2021	9/30/2022	Alabama Power	Harbert Power Fund V	Calhoun Generating Facility	4 Combustion Turbines	Natural Gas	AL	$179	743	$241
8/13/2021	2/18/2022 and 2/23/2022	ArcLight Energy Partners Fund VII	PSEG	PSEG Fossil portfolio 13 units	13 units	Coal Natural Gas	NJ, CT, MD, NY	$1,920	6,750	$284
2/28/2021	12/1/2021	Generation Bridge (ArcLight Energy Partners Fund VII)	NRG Energy	8 units Sunrise, Long Beach (CA) Middletown, Montville, Devon, CT Jets (CT) Arthur Kill, Oswego (NY)	1 Combined Cycle 7 CT/Oil	Natural Gas, Oil	CA, CT, NY	$620	4,900	$127

30 All transaction information is public.

The average transaction price paid in $/kW has been generally increasing as shown in Table 7-20. There is a range in the data in part a result of the fact that some of the transactions include portfolios of resources and in part due to the relative ages of the acquired resources.

Table 7-20 Selected recent transactions price trends

Year Announced	Natural Gas Average $/kW
2026	$1,027
2025	$1,138
2024	$648
2023	$554

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.[31] [32] 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, which is for 2023.[33] NEI average operating costs have decreased since their peak in 2012 (a 7.5 percent decrease from 2012 through 2023 for all plants including single and multiple unit plants in nominal dollars; a 33.0 percent decrease in real 2023 dollars).[34] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 32.8 percent decrease from 2012 through 2023 for all plants including single and multiple unit plants in nominal dollars; a 51.1 percent decrease in real 2023 dollars).[35] 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.

31 Operating costs from: Nuclear Energy Institute (February 2025). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. 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.

32 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.

33 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 generating costs than BWR reactors.

34 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 2.6 percent from 2022 to 2023 in nominal dollars. Operating costs for multiple unit plants increased by 6.0 percent from 2022 to 2023 in nominal dollars.

35 Capital expenditures have decreased 20.6 percent since 2012 for single unit plants and 35.0 percent for multiple unit plants in nominal dollars.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[36] 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.[37] 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. In 2020, PJM energy prices were at the lowest level since the introduction of competitive markets, even lower than in 2016. Average energy prices in 2022 were higher than energy prices in any year since the inception of PJM markets in 1999. Based on forward prices as of December 31, 2025, expected nuclear plant energy revenues for 2026, 2027 and 2028 are higher than actual revenues in all years since 2014, with the exception of 2022. The actual net revenue results for individual nuclear plants are a function of the degree to which actual unit costs are less than or greater than the benchmark NEI data.

Table 7-21 shows energy market prices, Table 7-22 and Table 7-23 show capacity market prices and Table 7-24 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.[38] [39] The analysis excludes the Catawba 1 nuclear unit. Partial data is provided for the Cook, North Anna, and Surry nuclear units.[40] The AEP Cook nuclear units

36 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 $1.05 per MWh for a nuclear power plant operating at a capacity factor of 0.951 percent.

37 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*.

38 Installed capacity is from NEI fact sheets accessed April 23, 2025 <https://www.nei.org/resources/fact-sheets/u-s-nuclear-plants>.

39 Constellation plans to restore TMI Unit 1 to service. Exelon. "Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid," (September 20, 2024) <https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.

40 Capacity market revenues are not included for the FRR units because the units were not in the capacity market.

are designated FRR. North Anna 1 and 2 and Surry 1 and 2 were part of the Dominion FRR for the 2022/2023 and 2023/2024 and 2024/2025 Delivery Years.[41] [42] [43] FRR units receive cost of service revenues and are not subject to PJM market revenues. Duke's 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. Historical 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 or ELCC rate.[44]

Table 7-21 Nuclear unit day-ahead LMP: 2008 through 2025

	ICAP	Average DA LMP ($/MWh)																	
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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	$37.07	$67.02	$29.63	$30.28	$43.49
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	$33.74	$58.20	$25.78	$23.31	$33.71
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	$32.81	$57.70	$25.36	$23.74	$33.96
Calvert Cliffs	1,726	$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	$41.24	$78.11	$35.45	$37.05	$54.51
Cook	2,177	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44	$25.07	$19.59	$34.81	$63.46	$28.88	$28.28	$42.50
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54	$37.34	$68.07	$29.63	$30.46	$45.69
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	$34.32	$59.35	$25.11	$24.36	$33.93
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	$30.16	$60.64	$22.97	$26.42	$40.08
LaSalle	2,265	$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	$33.54	$57.90	$25.55	$23.05	$33.92
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	$31.05	$61.25	$23.16	$26.06	$39.97
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	$39.99	$76.51	$33.75	$35.11	$52.50
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	NA	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$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	$30.77	$61.29	$23.01	$26.08	$39.97
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	$37.76	$68.56	$30.39	$31.23	$45.36
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	$31.39	$57.82	$25.01	$23.42	$34.53
Salem	2,285	$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	$30.12	$60.59	$22.95	$26.40	$40.04
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	$39.30	$74.21	$32.74	$33.65	$49.76
Susquehanna	2,494	$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	$30.36	$59.60	$23.77	$24.13	$36.03
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	NA	NA	NA	NA	NA	NA	NA

41 See "Resources Designated in 2022/2023 FRR Capacity Plans as of April 23, 2021," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-resources-designated-in-frr-plans.ashx>.
42 See "Resources Designated in 2023/2024 FRR Capacity Plans as of May 19, 2021," <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-resources-designated-in-frr-plans.pdf>.
43 See "Resources Designated in 2024/2025 FRR Capacity Plans as of November 8, 2022," <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-resources-designated-in-frr-plans.pdf>.
44 ELCC rates used starting with the 2025/2026 Delivery Year. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

Table 7-22 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2027/2028 [45] [46]

	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	22/23	23/24	24/25	25/26	26/27	27/28
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50	$34	$29	$270	$329	$333
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Calvert Cliffs	1,726	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49	$270	$329	$333
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29	$270	$329	$333
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
LaSalle	2,265	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA	$444	$329	$333
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-	-	-	-	-	-	-
Peach Bottom	2,550	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29	$270	$329	$333
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29	$270	$329	$333
Salem	2,285	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$54	$270	$329	$333
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA	$444	$329	$333
Susquehanna	2,494	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49	$270	$329	$333
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	-	-	-	-	-	-

45 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>. For the 2022/2023 Delivery Year, Surry is part of Dominion FRR.

46 Cook is designated FRR. North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year. North Anna and Surry are in the PJM Capacity Market beginning with the 2025/2026 Delivery Year.

Table 7-23 Nuclear unit capacity market revenue ($/MWh): 2008 through 2027[47] [48]

	ICAP	Capacity Revenue ($/MWh)																			
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
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	$3.81	$4.93	$3.80	$1.76	$1.35	$7.40	$13.24	$14.42
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	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
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	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
Calvert Cliffs	1,726	$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	$5.10	$4.97	$2.97	$2.15	$7.77	$13.24	$14.42
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.35	$7.40	$13.24	$14.42
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	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
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	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
LaSalle	2,265	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
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	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
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	$3.81	$4.93	$2.52	NA	NA	$11.32	$16.38	$14.42
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	-	-	-	-	-	-	-	-	-	-
Peach Bottom	2,550	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.76	$1.35	$7.40	$13.24	$14.42
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	$8.58	$8.35	$5.28	$2.10	$1.35	$7.40	$13.24	$14.42
Salem	2,285	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.00	$2.26	$7.84	$13.24	$14.42
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	$3.81	$4.93	$2.52	NA	NA	$11.32	$16.38	$14.42
Susquehanna	2,494	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.06	$5.10	$4.97	$2.97	$2.15	$7.77	$13.24	$14.42
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	-	-	-	-	-	-	-	-	-

47 Capacity revenue through the 2024/2025 Delivery Year is calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the annual class average capacity factor. Class average EFORd and capacity factor is from *2025 Annual State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market. Capacity revenue beginning the 2025/2026 Delivery Year is calculated by adjusting the BRA Capacity Price for calendar year, by the class average ELCC. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

48 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>. Constellation is planning to restart Three Mile Island Unit 1. Constellation. "Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid," (September 20, 2024) <https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.

Table 7-24 Nuclear unit costs: 2008 through 2024[49] [50]

	ICAP	NEI Costs ($/MWh)																
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
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	$27.03	$27.18	$28.63	$29.53	$29.53
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	$27.03	$27.18	$28.63	$29.53	$29.53
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	$27.03	$27.18	$28.63	$29.53	$29.53
Calvert Cliffs	1,726	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
Cook	2,177	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
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	$39.64	$37.42	$41.08	$41.62	$41.62
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	$27.03	$27.18	$28.63	$29.53	$29.53
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	$27.03	$27.18	$28.63	$29.53	$29.53
LaSalle	2,265	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
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	$27.03	$27.18	$28.63	$29.53	$29.53
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	$27.03	$27.18	$28.63	$29.53	$29.53
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	-	-	-	-	-	-	-
Peach Bottom	2,550	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
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	$39.64	$37.42	$41.08	$41.62	$41.62
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	$27.03	$27.18	$28.63	$29.53	$29.53
Salem	2,285	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53
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	$27.03	$27.18	$28.63	$29.53	$29.53
Susquehanna	2,494	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18	$28.63	$29.53	$29.53

Hope Creek, Quad Cities, and Salem have all received state subsidies since 2019.[51] [52] The NJ Board of Public Utilities, having received no applications as of December 1, 2023, closed the third eligibility period of the ZEC program for the period beginning June 1, 2025.[53] This was a result of the introduction of a new federal nuclear subsidy under the Inflation Reduction Act. Braidwood, Byron, Dresden, and LaSalle will receive a state subsidy if necessary to meet a target net revenue value, in dollars per MWh, from the energy and capacity markets.[54] All existing nuclear plants will receive a federal subsidy if necessary to meet a target revenue value, in dollars per MWh, from the energy market.[55]

The Inflation Reduction Act added a significant new federal subsidy for existing nuclear power plants.[56] All existing nuclear plants will receive the Zero Emission Nuclear Power Production Credit (Nuclear PTC) if revenues from energy, ancillary, capacity markets, and any state subsidies are between $25.00/MWh and $43.75/MWh, adjusted for inflation. The Nuclear PTC of $3.00/MWh is increased by a factor of five to $15.00/MWh if certain prevailing wage requirements are

49 Operating costs from: Nuclear Energy Institute (February 2025). "Nuclear Costs in Context," <https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context>. Operating Costs for 2024 and beyond are set equal to 2023 costs.

50 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>.

51 Illinois Commerce Commission, Report to the General Assembly in Compliance with Section 1-75(d-5) of the [CEJA, Public Act 102-0662,] 20 ILCS 3855/1-75(d-5)(F)(2) (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.

52 *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).

53 See *New Jersey BPU, In the Matter of the Third Eligibility Period for the Zero Emission Certificate Program Pursuant to N.J.S.A. 48:3-87.3 TO 87.7*, Order Closing the Third Eligibility Period of the Zero Emission Certificate Program, Docket No. EO23080548 (February 14, 2024).

54 CEJA, Public Act 102-0662, 20 ILCS 3855/1-75.

55 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

56 See Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

met. The Nuclear PTC creates a revenue floor of $40.00/MWh and does not create a revenue ceiling. If nuclear revenues are greater than $43.75/MWh, the Nuclear PTC subsidy does not apply and units keep all profits.

Table 7-25 shows the subsidy received by nuclear units in PJM in $/MWh since 2019.

Table 7-25 Nuclear unit subsidies in $/MWh: 2019 through 2026[57]

	Subsidy ($)							
	2019	2020	2021	2022	2023	2024	2025	2026
Beaver Valley	$0.0	$0.0	$0.0	$0.0	$0.0	$146.4	$0.0	$0.0
Braidwood	$0.0	$0.0	$0.0	$0.0	$0.0	$292.8	$41.1	$0.0
Byron	$0.0	$0.0	$0.0	$0.0	$0.0	$286.8	$36.6	$0.0
Calvert Cliffs	$0.0	$0.0	$0.0	$0.0	$0.0	$52.5	$0.0	$0.0
Cook	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Davis Besse	$0.0	$0.0	$0.0	$0.0	$0.0	$71.3	$0.0	$0.0
Dresden	$0.0	$0.0	$0.0	$0.0	$0.0	$216.6	$29.0	$0.0
Hope Creek	$67.4	$95.6	$97.5	$97.1	$98.3	$118.0	$40.7	$0.0
LaSalle	$0.0	$0.0	$0.0	$0.0	$0.0	$283.8	$36.7	$0.0
Limerick	$0.0	$0.0	$0.0	$0.0	$0.0	$231.3	$0.0	$0.0
North Anna	$0.0	$0.0	$0.0	$0.0	$0.0	$109.2	$0.0	$0.0
Oyster Creek	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Peach Bottom	$0.0	$0.0	$0.0	$0.0	$0.0	$262.6	$0.0	$0.0
Perry	$0.0	$0.0	$0.0	$0.0	$0.0	$92.6	$0.0	$0.0
Quad Cities	$245.3	$244.9	$249.8	$209.2	$79.0	$85.0	$69.6	$17.7
Salem	$131.5	$186.5	$190.2	$189.4	$191.6	$230.5	$66.1	$0.0
Surry	$0.0	$0.0	$0.0	$0.0	$0.0	$113.2	$0.0	$0.0
Susquehanna	$0.0	$0.0	$0.0	$0.0	$0.0	$291.2	$0.0	$0.0
Three Mile Island	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Table 7-26 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 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021 and 2022, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. In 2023, only two nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy and capacity prices. In 2024, all nuclear plants with the exception of Davis Besse covered their fuel costs, operating costs, and incremental capital expenditures. The surplus or shortfall assumes that the unit receives the DA LMP, reactive capability revenue, cleared its full unforced capacity at the BRA locational clearing price, receives a subsidy if qualified, and has costs equal to the NEI average costs.[58] Unforced capacity is determined using the annual class average EFORd or ELCC rate.[59]

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market in some years as a result of decisions by plant owners about how to offer the plants in the capacity market auctions. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not accurately reflect the economic viability of the plants. 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. Quad Cities and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[60] Quad Cities did not clear in the 2020/2021 Auction.[61] Dresden and most of Byron did not clear in the 2021/2022 Auction.[62] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[63] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[64]

57 Quad Cities ZECS prices by delivery year are from the Illinois Power Agency final payment calculation notices. Quad Cities subsidies for calendar year 2025 include five months of capacity revenue from the 2024/2025 Delivery Year subsidies and seven months of subsidies revenue for the 2025/2026 Delivery Year.

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

59 ELCC rates used starting with the 2025/2026 Delivery Year. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

60 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

61 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

62 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>.

63 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>.

64 NuclearNewswire. "Byron, Dresden, Quad Cities Fail to Clear in PJM Capacity Auction," (June 8, 2021) <https://www.ans.org/news/article-2967/byron-dresden-quad-cities-fail-to-clear-in-pjm-capacity-auction/>.

Nuclear unit revenue is a combination of energy market revenue, ancillary services 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, an average of 0.1 percent and a maximum of 1.7 percent in 2020, an average of 0.0 percent and a maximum of 0.3 percent in 2021, an average of 0.0 percent and a maximum of 0.0 percent in 2022, an average of 0.0 percent and a maximum of 0.1 percent in 2023, an average of 0.6 percent and a maximum of 4.9 percent in 2024, an average of 0.1 percent and a maximum of 0.8 percent in 2025, and an average of 0.0 percent and a maximum of 0.0 percent in the first three months of 2026.[65]

Table 7-26 shows the surplus or shortfall for the 16 nuclear plants in PJM in $/MWh, including subsidies.

Table 7-26 Nuclear unit surplus (shortfall) based on public data in $/MWh: 2008 through 2025

	ICAP	Surplus (Shortfall) ($/MWh)																	
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
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	($2.7)	$15.0	$42.4	$2.1	$12.0	$21.6
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.2)	($1.6)	$5.9	$3.9	($0.0)	$15.1	$35.0	($1.5)	$10.3	$13.9
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.6)	($2.8)	$5.8	$3.2	($0.6)	$14.1	$34.5	($1.9)	$10.6	$13.9
Calvert Cliffs	1,726	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($0.9)	$19.4	$54.6	$9.1	$13.5	$32.9
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.3)	($15.1)	$5.9	$31.6	($10.0)	($0.0)	$11.7
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.6)	($0.1)	$7.1	$4.5	$0.5	$15.7	$36.2	($2.1)	$10.8	$14.0
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($1.9)	$1.6	$12.3	$8.8	$7.8	$21.0	$48.0	$6.9	$11.7	$23.0
LaSalle	2,265	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.6)	($1.9)	$6.0	$3.7	($0.2)	$14.8	$34.7	($1.8)	$10.0	$13.9
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	$1.6	($2.6)	$11.6	$38.2	($3.3)	$11.2	$18.4
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	($2.0)	$17.9	NA	NA	NA	$34.5
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	NA	NA	NA	NA	NA
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.9	$0.6	($2.8)	$11.4	$38.3	($3.3)	$11.3	$18.5
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.9)	($15.2)	$6.2	$32.0	($9.3)	$0.0	$11.3
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.3	$18.8	$14.4	$29.4	$48.7	$3.1	$1.2	$17.3
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.2	$8.5	$7.5	$20.7	$47.6	$6.6	$11.4	$22.7
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	$4.2	($2.5)	$17.4	NA	NA	NA	$31.9
Susquehanna	2,494	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.7)	($6.9)	$8.3	$35.9	($2.8)	$10.7	$14.3
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	NA	NA	NA	NA	NA

Table 7-27 shows the surplus or shortfall for the 16 nuclear plants in PJM in dollars, including subsidies.

65 Analysis is based on actual unit generation and 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.

Table 7-27 Nuclear unit surplus (shortfall) based on public data ($M): 2008 through 2025

	ICAP	Surplus (Shortfall) ($ in millions)																	
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Beaver Valley	1,808	$393.5	$93.3	$156.3	$131.1	($49.4)	$21.0	$174.8	$47.7	($8.9)	$35.7	$204.3	$51.0	($42.5)	$223.0	$632.2	$28.2	$178.2	$321.7
Braidwood	2,337	$482.3	$48.3	$122.8	$65.2	($118.7)	($49.6)	$138.9	($22.7)	($65.2)	($33.3)	$110.8	$70.7	($4.2)	$290.0	$674.9	($32.4)	$197.7	$266.6
Byron	2,300	$465.5	($24.2)	$64.1	($10.5)	($178.9)	($68.6)	$93.2	($116.7)	($185.2)	($55.5)	$106.4	$56.6	($14.8)	$267.5	$654.7	($40.0)	$201.5	$263.3
Calvert Cliffs	1,726	$865.9	$297.3	$406.9	$254.8	$64.5	$208.4	$449.6	$201.4	$100.7	$84.7	$229.8	$74.0	($15.3)	$275.3	$778.7	$128.6	$191.9	$470.9
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($98.0)	($51.4)	$48.6	($8.6)	($31.5)	($63.7)	($8.4)	($47.2)	($111.5)	$42.1	$232.3	($76.7)	($1.9)	$85.4
Dresden	1,797	$380.7	$44.6	$112.9	$65.7	($77.7)	($15.0)	$134.6	$4.4	($26.5)	($5.5)	$102.2	$62.2	$4.1	$231.7	$536.2	($34.9)	$159.3	$205.6
Hope Creek	1,172	$523.2	$164.8	$237.0	$163.2	$24.8	$119.9	$251.6	$60.5	($23.2)	$11.2	$114.5	$79.9	$70.3	$200.6	$461.3	$63.3	$109.7	$220.3
LaSalle	2,265	$464.9	$45.9	$119.9	$61.5	($114.1)	($35.3)	$144.7	($16.3)	($69.8)	($37.5)	$109.0	$66.1	($5.6)	$277.3	$648.5	($35.8)	$186.8	$259.2
Limerick	2,242	$1,003.7	$316.3	$457.2	$307.6	$47.8	$226.5	$476.3	$120.1	($41.1)	$25.3	$221.7	$28.2	($48.7)	$213.8	$707.9	($63.4)	$208.5	$341.6
North Anna	1,892	$813.9	$228.5	$397.7	$262.7	$3.5	$89.3	$362.6	$170.2	$44.3	$71.2	$246.5	$71.4	($33.3)	$279.3	NA	NA	NA	$540.6
Oyster Creek	608	$239.0	$42.4	$79.7	$35.9	($41.1)	$16.4	$82.3	($23.4)	($58.2)	($49.6)	NA	NA	NA	NA	NA	NA	NA	NA
Peach Bottom	2,550	$1,133.0	$356.3	$508.8	$338.5	$48.4	$259.6	$537.6	$122.6	($53.0)	$23.7	$242.9	$9.1	($63.3)	$237.2	$805.9	($75.2)	$237.3	$388.4
Perry	1,240	NA	NA	NA	NA	($135.8)	($65.3)	$56.6	($3.5)	($43.2)	($77.5)	$16.9	($61.1)	($155.2)	$62.6	$327.2	($98.4)	($1.1)	$115.1
Quad Cities	1,819	$363.1	($6.7)	$36.3	($27.7)	($199.0)	($103.5)	$8.6	($115.3)	($145.0)	($54.5)	$62.7	$274.3	$207.9	$439.8	$728.9	$42.0	$12.7	$257.4
Salem	2,285	$1,021.3	$322.8	$461.9	$317.9	$48.2	$233.1	$490.0	$117.1	($45.5)	$21.3	$222.5	$155.5	$136.9	$390.3	$898.3	$123.0	$213.8	$415.5
Surry	1,676	$676.9	$190.3	$334.4	$226.4	($0.4)	$71.2	$298.9	$148.8	$33.5	$60.4	$219.1	$53.2	($38.4)	$237.8	NA	NA	NA	$440.6
Susquehanna	2,494	$965.9	$312.8	$461.6	$332.2	$29.4	$229.0	$506.6	$129.9	($39.7)	$31.2	$201.0	($34.4)	($141.3)	$172.0	$742.6	($58.4)	$223.5	$296.6
Three Mile Island	803	$270.5	$42.9	$88.2	$30.2	($63.7)	$5.9	$90.7	($45.2)	($82.3)	($68.1)	($25.3)	NA	NA	NA	NA	NA	NA	NA

In order to evaluate the expected viability of nuclear plants, analysis was based on forward energy market prices for 2026, 2027, and 2028 and known capacity market prices for 2026, 2027, and 2028. 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 through the 2027/2028 Delivery Year, actual energy prices will vary from forward values. Nuclear plants may choose to sell their output at a range of forward prices and for a range of future years.

Table 7-28 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2026 through 2028. Capacity revenues for calendar year 2026 include five months of capacity revenue from the 2025/2026 Delivery Year and seven months of capacity revenue for the 2026/2027 Delivery Year. Capacity revenues for calendar year 2028 include five months of capacity revenue from the 2027/2028 Delivery Year and seven months of capacity revenue assuming a clearing price of $333.44/MW-Day for the 2028/2029 Delivery Year.[66] The 2028/2029 BRA has not yet been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[67] Forward prices are as of March 31, 2026. The capacity prices are known through May 31, 2028, based on PJM capacity auction results.

66 The price of $333.44/MW-day in unforced capacity was the clearing price for the 2027/2028 Base Residual Auction.
67 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 2025 data.

Table 7-28 Forward prices in PJM energy markets, capacity revenue, and annual costs

	ICAP	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)			2024 NEI Costs ($/MWh)		
	(MW)	2026	2027	2028	Reactive	2026	2027	2028	Fuel	Operating	Capital
Beaver Valley	1,808	$55.93	$57.48	$56.37	$0.21	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Braidwood	2,337	$43.65	$42.57	$41.95	$0.17	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Byron	2,300	$46.49	$44.97	$44.28	$0.15	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Calvert Cliffs	1,726	$75.78	$66.41	$65.02	$0.19	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Cook	2,177	$53.56	$53.62	$52.56	$0.13	NA	NA	NA	$5.27	$18.03	$6.23
Davis Besse	894	$58.69	$57.90	$56.80	$0.21	$13.24	$14.42	$14.50	$5.50	$25.40	$10.72
Dresden	1,797	$47.05	$45.85	$45.17	$0.23	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Hope Creek	1,172	$55.86	$53.56	$52.51	$0.47	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
LaSalle	2,265	$44.25	$43.10	$42.46	$0.13	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Limerick	2,242	$55.41	$53.15	$52.10	$0.10	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
North Anna	1,892	$73.03	$66.39	$65.02	$0.18	$16.38	$14.42	$14.50	$5.27	$18.03	$6.23
Peach Bottom	2,550	$55.47	$53.14	$52.09	$0.31	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Perry	1,240	$58.49	$59.40	$58.25	$0.21	$13.24	$14.42	$14.50	$5.50	$25.40	$10.72
Quad Cities	1,819	$47.18	$45.67	$44.95	$0.13	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Salem	2,285	$55.81	$53.53	$52.48	$0.35	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23
Surry	1,676	$68.90	$63.23	$61.89	$0.16	$16.38	$14.42	$14.50	$5.27	$18.03	$6.23
Susquehanna	2,494	$49.90	$48.38	$47.37	$0.32	$13.24	$14.42	$14.50	$5.27	$18.03	$6.23

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant.

Based on the FERC order allowing the inclusion of major maintenance in energy offers, major maintenance costs can no longer be included in gross ACR values offered in the capacity market.[68] 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 incremental 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 incremental capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

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 7-29, the capacity price required to cover avoidable costs in $/MWh is calculated by taking the total NEI costs in $/MWh and subtracting the total expected energy and ancillary services revenues in $/MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average capacity factor. Total expected ancillary services revenue is unit specific reactive capability revenue.[69] The capacity price required to cover avoidable costs in $/MW-day is calculated by multiplying the required price in $/MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-29, the capacity price required to cover avoidable costs is $0/MW-day for all units in 2026, 2027 and 2028 using NEI data as reported including capital expenditures, and is $0/MW-day for all plants, excluding capital expenditures as a proxy for major maintenance, in 2026, 2027 and 2028.[70] Net revenues based on forward energy prices alone are greater than or equal to avoidable costs in 2026, 2027 and 2028 without any contribution from capacity market revenues for all plants. The result is that net ACR values for 2026, 2027 and 2028 in Table 7-29 are zero.

68 See 167 FERC ¶ 61,030 at P 41 (2019).

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

70 PJM's tariff definition of avoidable costs excludes major maintenance. PJM includes major maintenance costs in the definition of short run marginal costs in energy offers.

Table 7-29 Net ACR

	ICAP (MW)	Net ACR ($/MWh) 2026	2027	2028	Net ACR ($/MW-Day) 2026	2027	2028	Net ACR Excluding Capital ($/MW-Day) 2026	2027	2028
Beaver Valley	1,808	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Braidwood	2,337	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Byron	2,300	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Calvert Cliffs	1,726	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cook	2,177	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dresden	1,797	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hope Creek	1,172	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LaSalle	2,265	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Limerick	2,242	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
North Anna	1,892	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Peach Bottom	2,550	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Quad Cities	1,819	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Salem	2,285	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Surry	1,676	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Susquehanna	2,494	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table 7-30 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 2024 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-30 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

The 2025 nuclear unit surplus values are shown in Table 7-30 based on forward prices as of March 31, 2026, NEI average costs, and expected subsidy values.[71] The current analysis, based on forward prices for energy, known forward prices for capacity, and an assumed clearing price of $333.44/MW-Day for the 2028/2029 Delivery Year, shows that all PJM nuclear plants analyzed are expected to have a surplus without any subsidy amount in 2026, 2027 and 2028.[72]

Table 7-30 Nuclear unit forward annual surplus (shortfall) for 2026, 2027 and 2028[73 74 75]

	Surplus (Shortfall) ($/MWh) 2026	2027	2028	Subsidy ($/MWh) 2026	2027	2028	Surplus (Shortfall) Excluding Subsidy ($ in millions) 2026	2027	2028	Surplus (Shortfall) Including Subsidy ($ in millions) 2026	2027	2028
Beaver Valley	$39.73	$42.37	$41.34	$0.00	$0.00	$0.00	$510.4	$620.48	$622.62	$510.4	$620.5	$622.6
Braidwood	$27.44	$27.46	$26.91	$0.00	$0.00	$0.00	$420.5	$511.83	$523.10	$420.5	$511.8	$523.1
Byron	$30.27	$29.86	$29.24	$0.00	$0.00	$0.00	$467.9	$549.55	$559.66	$467.9	$549.6	$559.7
Calvert Cliffs	$59.57	$51.30	$49.99	$0.00	$0.00	$0.00	$777.9	$720.79	$719.03	$777.9	$720.8	$719.0
Cook	NA	NA	NA	$0.00	$0.00	$0.00	NA	NA	NA	NA	NA	NA
Davis Besse	$30.40	$30.70	$29.68	$0.00	$0.00	$0.00	$182.9	$219.90	$220.77	$182.9	$219.9	$220.8
Dresden	$30.86	$30.74	$30.13	$0.00	$0.00	$0.00	$374.5	$442.61	$450.58	$374.5	$442.6	$450.6
Hope Creek	$39.77	$38.45	$37.47	$0.00	$0.00	$0.00	$335.6	$363.98	$365.75	$335.6	$364.0	$365.7
LaSalle	$28.02	$27.99	$27.42	$0.00	$0.00	$0.00	$418.4	$505.92	$516.65	$418.4	$505.9	$516.6
Limerick	$39.17	$38.04	$37.06	$0.00	$0.00	$0.00	$630.7	$688.52	$692.00	$630.7	$688.5	$692.0
North Anna	$59.95	$51.28	$49.98	$0.00	$0.00	$0.00	$865.3	$839.23	$788.13	$865.3	$839.2	$788.1
Peach Bottom	$39.31	$38.03	$37.06	$0.00	$0.00	$0.00	$720.4	$782.86	$786.88	$720.4	$782.9	$786.9
Perry	$30.20	$32.20	$31.12	$0.00	$0.00	$0.00	$251.6	$320.46	$321.17	$251.6	$320.5	$321.2
Quad Cities	$30.95	$30.56	$29.92	$1.17	$1.17	$0.00	$380.4	$445.34	$452.81	$398.2	$463.1	$452.8
Salem	$39.67	$38.42	$37.44	$0.00	$0.00	$0.00	$652.4	$709.08	$712.52	$652.4	$709.1	$712.5
Surry	$55.82	$48.12	$46.86	$0.00	$0.00	$0.00	$708.7	$699.18	$654.39	$708.7	$699.2	$654.4
Susquehanna	$33.75	$33.27	$32.34	$0.00	$0.00	$0.00	$587.5	$666.81	$671.32	$587.5	$666.8	$671.3

71 Gross receipts used to calculate the unit subsidy include energy revenue, ancillary services revenue, capacity revenue, and state ZECs subsidies, and assumes the unit meets prevailing wage requirements and receives the Zero Emission Nuclear Power Production Credit 5 times multiplier. Effectively, nuclear power plants will receive the higher of the state or federal subsidy amount.

72 On February 20, 2025, PJM filed with FERC to establish a maximum price of approximately $325/MW-day in unforced capacity and a minimum price of approximately $175/MW-day, both in unforced capacity (UCAP) terms for all capacity auctions for the 2026/2027 and 2027/2028 Delivery Years. See Docket No. ER25-135

73 The state subsidy value for Braidwood, Byron, Dresden, and LaSalle is calculated by taking the applicable Baseline Cost less forward energy prices and known capacity prices.

74 The federal subsidy value for nuclear plants is defined in the Inflation Reduction Act of 2022, Public Law 117-169 (August 16, 2022).

75 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year. North Anna and Surry rejoined the PJM Capacity Market beginning with the 2025/2026 Delivery Year.