Part 2

Virginia State Corporation Commission
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4.1.3 Energy Efficiency Adjustment

The load forecasts in this 2020 Plan include a downward post-model adjustment for energy efficiency ("EE"). The EE adjustment to the forecasts can be broken down into two distinct categories. The first category ("Category 1 Programs") consists of previously-approved EE programs that remain effective, along with programs that are currently pending approval before the SCC in Case No. PUR-2019-00201. The second category ("Category 2 Program") is a "generic" EE program that is designed to meet the requirements of the: (i) VCEA; and (ii) GTSA. Specifically, the Category 2 Program was designed to increase the level of EE to meet the 2022 through 2025 EE targets set in the VCEA and to meet the GTSA requirement to propose $870 million in EE programs by 2028. Alternative Plan A includes only adjustment for Category 1 Programs. Alternative Plans B through D include adjustment for both Category 1 and Category 2 Programs.

To estimate the Category 2 Program, the Company first determined the projected 2028 EE savings and EE costs associated with the Category 1 Programs. Using this information, the Company then determined the added EE savings necessary to meet the EE targets of the VCEA and also the EE savings needed to achieve the $870 million in EE-related spending by 2028. The Category 2 Program volumes were determined assuming a generic EE program fixed price of $200/MWh, which is based on the Company's 2018 solicitation to vendors. This approach is a theoretical assumption used for planning purposes only. In reality, the level of energy efficiency savings included in this 2020 Plan may not materialize in the same manner as modeled due to many outside factors. These factors could include but are not limited to the ability of future vendors to deliver program savings at the fixed price, the desire of customers to participate in the program at that price, and the effectiveness of the program to be administered at that price. Therefore, the costs and level of savings modeled for the Category 2 Program are placeholders that will be revised as future phases of actual EE programs are developed and implemented.

The Category 2 Program forecast uses a start date of January 1, 2021, and grows at a pace that will meet the 2022, 2023, 2024, and 2025 EE targets required in the VCEA. The Program continues to grow until the total EE spend equates to $870 million in 2028. After 2028, the Category 2 Program levels out for a five-year period, and then begins a slow downward trajectory that simulates a loss in program participation. Figures 4.1.3.1 and 4.1.3.2 identify the EE energy and capacity adjustments to the load forecasts used in this 2020 Plan. As stated, Alternative Plan A includes only adjustment for Category 1 Programs, while Alternative Plans B through D include adjustment for both Category 1 and Category 2 Programs.

Figure 4.1.3.1 – EE Energy Forecast

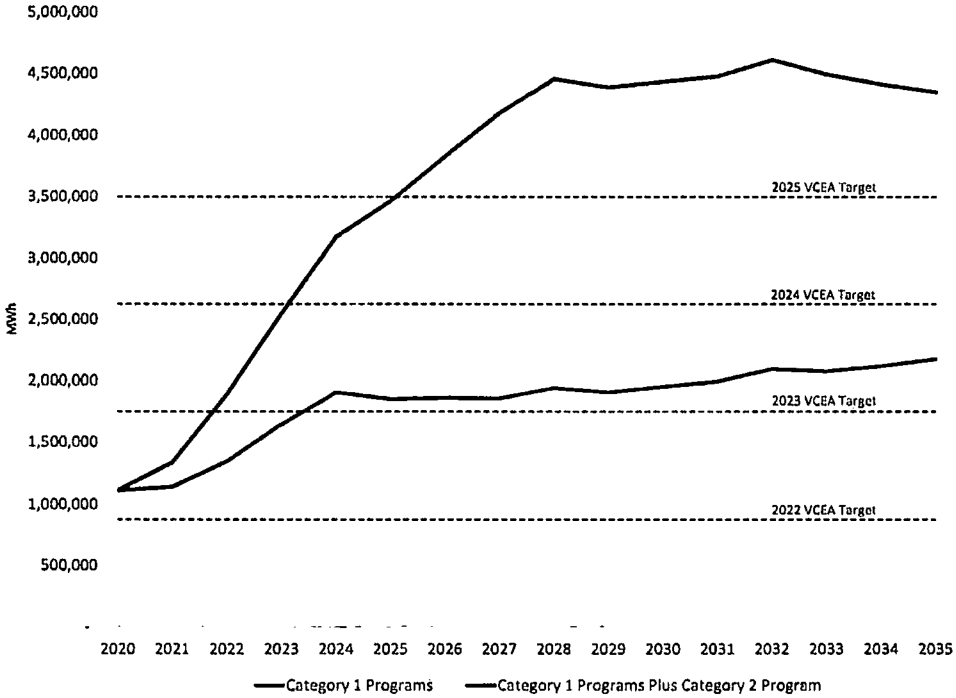
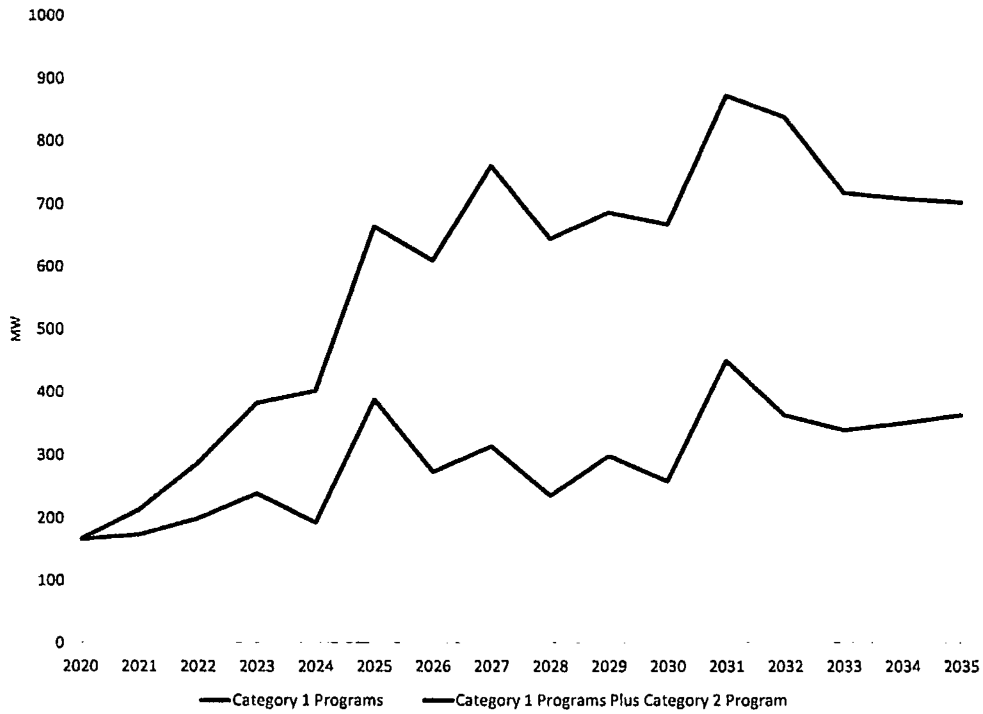
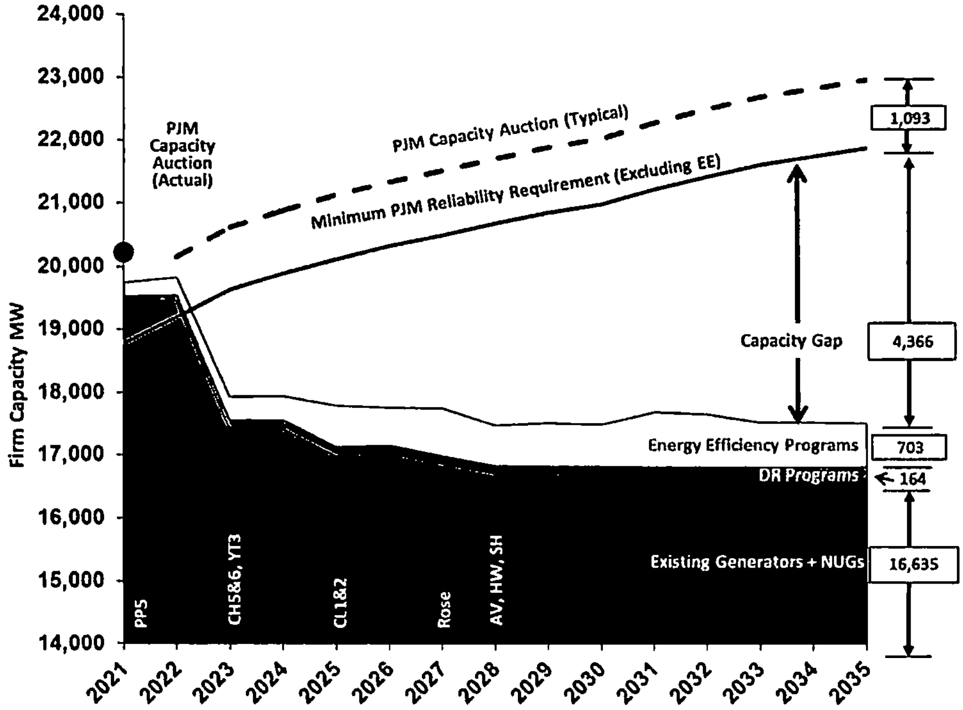


Figure 4.1.3.2 – EE Coincident Summer Peak Demand Forecast



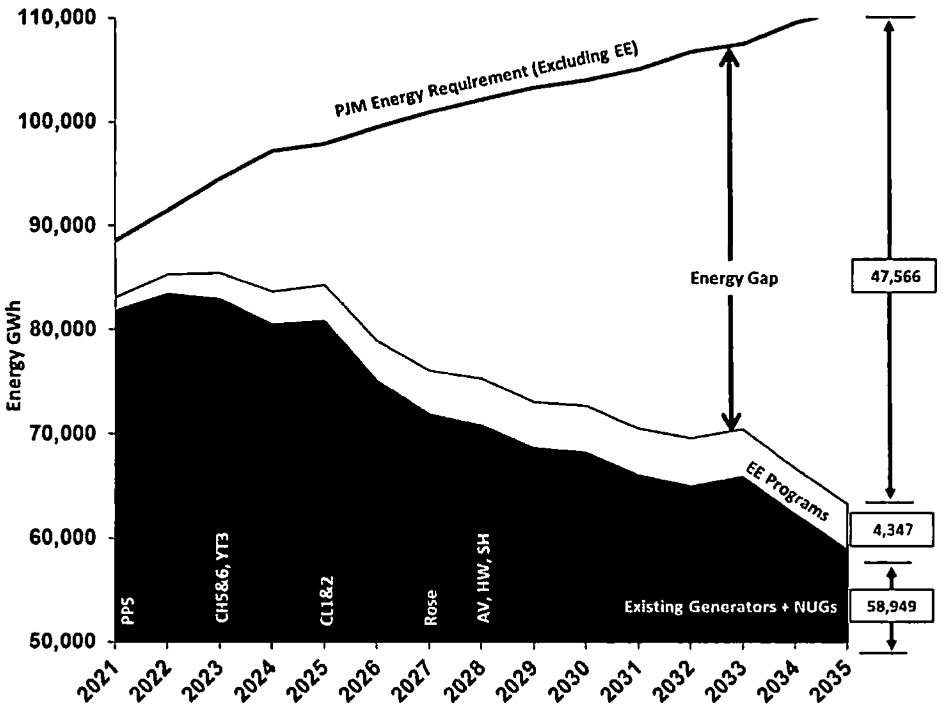
The Company also modeled EE as a supply-side resource in the PLEXOS model. The modeling of EE as a load reducer and as a supply-side resource resulted in effectively identical results. Figures 4.1.3.3 and 4.1.3.4 show the Company's current capacity and energy position with DSM modeled as a supply-side resource using unit retirement assumptions for Alternative Plan B.

Figure 4.1.3.3 - Current Company Capacity Position (2021 to 2035)



Notes: "Existing Generators + NUGS" also include generation under construction; "DR" = demand response; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

Figure 4.1.3.4 - Current Company Energy Position (2021 to 2035)



Notes: "Existing Generators + NUGS" also include generation under construction; "EE" = energy efficiency; "PP5" = Possum Point Unit 5 (oil); "CH5&6" = Chesterfield Units 5 & 6 (coal); "YT3" = Yorktown Unit 3 (oil); "CL1&2" = Clover Units 1 & 2 (coal); "Rose" = Rosemary (oil); "AV" = Altavista (biomass); "HW" = Hopewell (biomass); "SH" = Southampton (biomass).

4.1.4 Retail Choice Adjustment

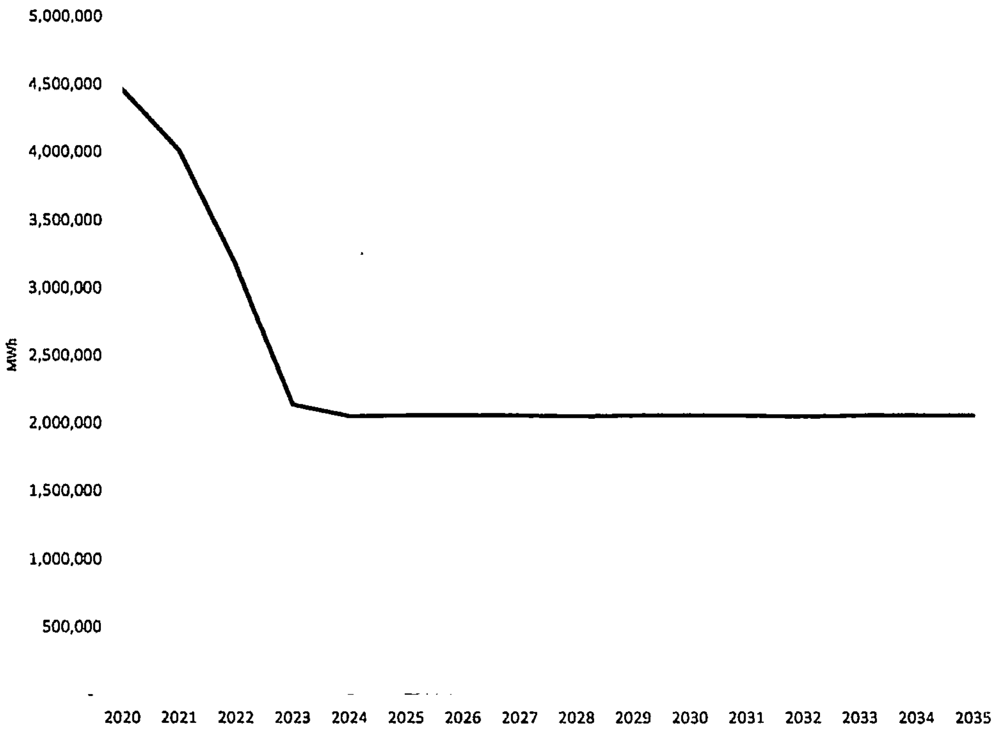
The load forecasts in this 2020 Plan include a downward post-modeling adjustment for customers within the Company's service territory who have chosen (or may choose) to purchase energy and capacity from third-party retail electric suppliers under Va. Code § 56-577 ("Choice Customers"). To develop this forecast the Company first determined the number of current and potential Choice Customers for 2019 and 2020. This included those customers eligible to participate in the pilot program established by House Bill No. 889 in the 2020 Regular Session of the Virginia General Assembly for up to 200 MW of non-residential load to aggregate and purchase electricity from third-party suppliers. Based on this total set of customers, the Company then determined the average energy and peak demand for each of these customers over the last three years.

The summation of each customer's average annual energy and capacity use then formed the starting point for the Choice Customer forecast. This Choice Customer starting point is composed of two different types of customers. The first set is customers that have pursued, or may pursue, third-party supply under Va. Code § 56-577 A 3 or A 4 ("A 3 and A 4 Choice Customers"), while the second set is made up of customers that have opted, or may opt, for third-party supply under Va. Code § 56-577 A 5 ("A 5 Choice Customers"). Given that A 3 and A 4

Choice Customers must provide five years' advanced written notice before returning to purchase electricity from the Company, the Company assumed in this forecast adjustment that those customers would remain under third-party supply for the entire Study Period. To the extent A 3 and A 4 Choice Customers file written notice to return to Company service, the Company can factor this load into its future load forecast adjustments. Given that A 5 Choice Customers have no similar advance written notice requirement, the Company must remain cognizant that those customers could return to Company service at any time and must plan accordingly as the default service provider. In addition, A 5 Choice Customers will no longer be able to purchase electricity from third-party suppliers if the SCC approves the Company's proposed Rider TRG pending in Case No. PUR-2019-00094. Therefore, the Company assumed in this forecast that A 5 Choice Customers gradually return to full Company service by the end of 2023. Figures 4.1.4.1 and 4.1.4.2 identify the Choice Customer peak demand and energy forecast adjustment in this 2020 Plan.

Figure 4.1.4.1 – Choice Customer Energy Forecast

Figure 4.1.4.2 – Choice Customer Coincident Summer Peak Demand Forecast



4.1.5 Voltage Optimization Adjustment

As part of its Grid Transformation Plan, discussed further in Section 8.3, the Company seeks to fully deploy AMI across its service territory, and then use this technology to enable voltage optimization. Voltage optimization, if approved and deployed, would lead to energy and capacity savings. Because of the preparation schedule associated with this 2020 Plan, Alternative Plans B, C, and D include a post-model downward adjustment to the load forecast to account for the savings associated with voltage optimization as proposed in the Grid Transformation Plan. Figures 4.1.5.1 and 4.1.5.2 reflect the peak demand and energy savings forecast adjustment resulting from voltage optimization.

Figure 4.1.5.1 – Voltage Optimization Coincident Summer Peak Demand Forecast

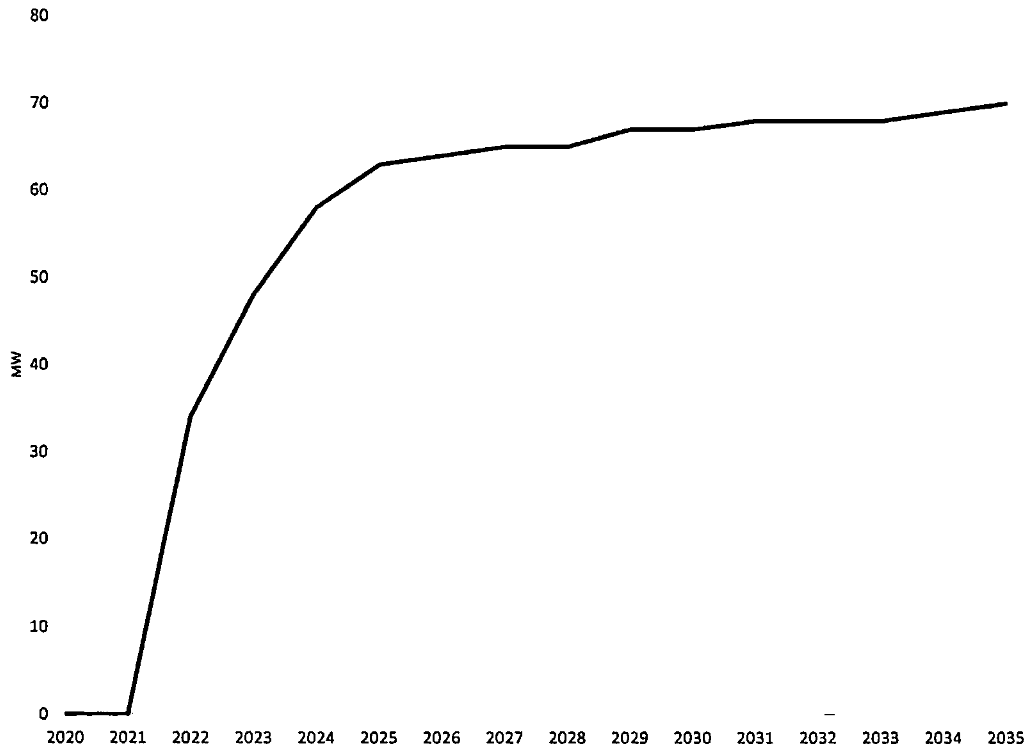
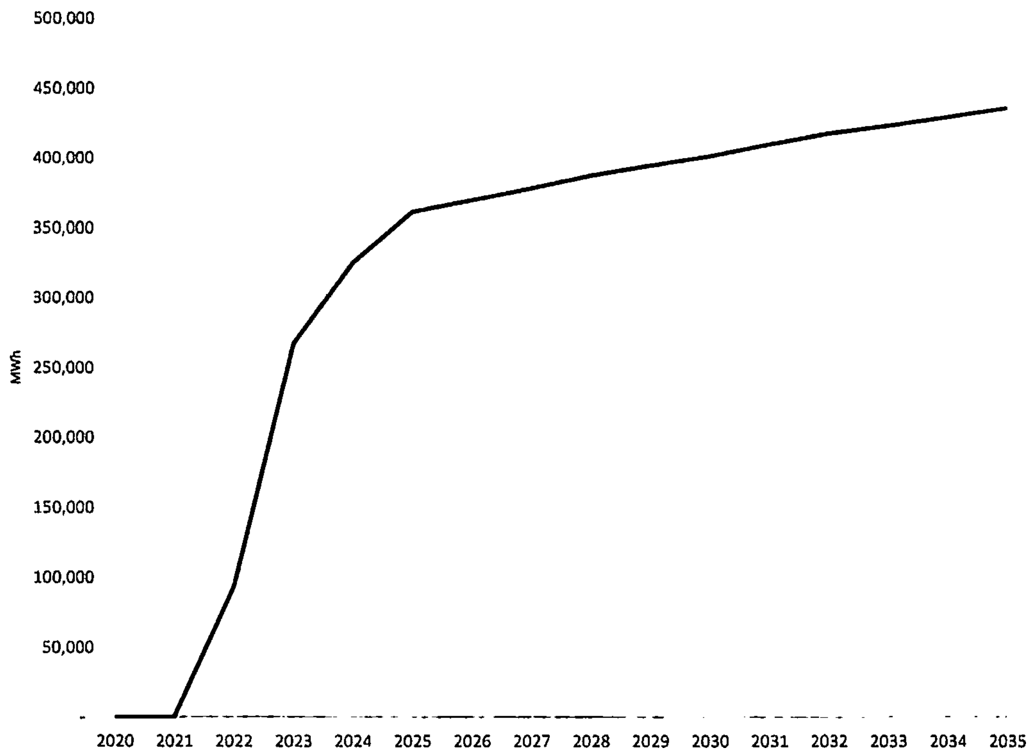


Figure 4.1.5.2 – Voltage Optimization Energy Forecast



4.2 Capacity Market Assumptions

The Company participates in the PJM capacity planning process to ensure supply of capacity resources for its customer load. As a member of PJM, the Company has the option to buy capacity in order to satisfy the mandated reliability requirements either (i) through the RPM forward capacity market or (ii) through the FRR alternative. PJM's planning years (referred to as "delivery years" for RPM) run from June 1 to May 31. The Company has satisfied its capacity obligation through the RPM auction through May 31, 2022.

Short-Term Capacity Planning

As a PJM member, the Company is a signatory to PJM's Reliability Assurance Agreement, which obligates the Company to purchase sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone using its annual load forecast and reserve margin guidelines as inputs. PJM then conducts a capacity auction process for meeting these input requirements up to three years into the future. This auction process includes the base RPM auction as well as and subsequent incremental auctions that are held to allow market sellers and PJM to adjust positions for changes such as construction delays or outage assumptions. This auction process determines the clearing reserve margin and the capacity price for each zone for the delivery year that is three years in the future (*e.g.*, the 2018 base RPM auction procured capacity for the delivery year 2021/2022).

PJM has delayed the 2019 and 2020 auction processes due to the pending FERC MOPR proceeding discussed in Section 1.6.1. Following resolution of this proceeding, PJM plans to compress the timelines for these auctions, currently targeting late 2020 or early 2021 for resuming the RPM auction process.

Currently, the Company offers its capacity resources, including owned and contracted generation, into the RPM auction as a generation provider. As an LSE, the Company is then obligated to purchase capacity to cover its PJM auction-determined capacity requirements.

In the future, the Company could satisfy its capacity obligation through the FRR alternative. As discussed in Section 1.6.2, this alternative would allow the Company to self-supply its capacity obligation. Importantly for modeling purposes, however, the modeling is indifferent to whether the Company satisfies its capacity obligation through the RPM auction or through the FRR alternative. Operating under the FRR alternative, the Company would self-supply its capacity obligation. Instead of collecting a capacity revenue stream for generating resources, the Company assumes generating resources would obtain capacity benefit by *avoiding* capacity market purchases. For modeling purposes, the Company would continue to use capacity market forecasts and assume generating resources collect capacity benefits by avoiding capacity purchases under FRR. Further, the modeling is indifferent to whether the Company operates under the FRR alternative because the Company models the forecasted reserve margin at the minimum reserve margin, which is also the obligation under FRR. Figure 2.1.1 indicates both the minimum PJM reserve requirement (*i.e.*, the solid line) and the typical market reserve requirement (*i.e.*, the dashed line).

Long-Term Capacity Planning – Reserve Requirements

The Company uses PJM's reserve margin guidelines to determine its long-term capacity requirement. PJM conducts an annual reserve requirement study to determine an adequate level of capacity in its footprint to meet the target level of reliability, measured as a loss of load expectation equivalent to one day of outage in ten years. To satisfy the NERC and Reliability First Corporation Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment, and Documentation, PJM's 2019 Reserve Requirement Study recommended using an installed reserve margin of 15.9% for delivery year 2020/2021, 15.1% for delivery year 2021/2022, 14.9% for delivery year 2022/2023, and 14.8% for delivery year 2023/2024.

PJM develops reserve margin estimates for planning years rather than calendar years. Because PJM is a summer peaking entity, and because the summer period of PJM's planning year coincides with the calendar year summer period, calendar and planning year reserve requirement estimates are determined based on the identical summer time period. For example, the Company uses PJM's 2020/2021 delivery year assumptions for the 2020 calendar year in this 2020 Plan because it represents the expected peak load during the summer of 2020.

The Company makes one assumption when applying the PJM reserve margin to the Company's modeling efforts. Since PJM uses a shorter planning period than the Company (*i.e.*, ten years for PJM rather than 15 years for the Company), the Company uses the most recent PJM Reserve Requirements Study and assumes the reserve margin value for delivery year 2023 would continue throughout the Study Period. Figure 4.2.1 shows the adjusted load forecast used in the modeling of Alternative Plans B, C, and D.

Figure 4.2.1 – PJM Adjusted Load Forecast

Year	PJM DOM Zone Coincident Peak (MW)	DOM LSE Equivalent (MW)	DOM LSE Adjustments[1] (MW)	PJM Reserve Requirement (%)	DOM LSE Reserve Requirement (MW)	Total DOM LSE Peak Requirement (MW)
2021	19,486	16,802	705	15.1 %	2,431	18,528
2022	19,837	17,105	693	14.9 %	2,445	18,857
2023	20,178	17,339	683	14.8 %	2,474	19,190
2024	20,462	17,644	723	14.8 %	2,504	19,425
2025	20,651	17,807	944	14.8 %	2,496	19,359
2026	20,880	18,004	915	14.8 %	2,529	19,618
2027	21,072	18,170	1,083	14.8 %	2,529	19,616
2028	21,250	18,323	962	14.8 %	2,569	19,931
2029	21,404	18,456	992	14.8 %	2,585	20,048
2030	21,572	18,601	998	14.8 %	2,605	20,208
2031	21,756	18,759	1,156	14.8 %	2,605	20,208
2032	22,008	18,977	1,163	14.8 %	2,636	20,450
2033	22,176	19,121	1,022	14.8 %	2,679	20,779
2034	22,326	19,251	1,030	14.8 %	2,697	20,917
2035	22,249	19,357	1,011	14.8 %	2,715	21,061

Notes: (1) "DOM LSE Adjustments" include adjustments to the load forecast for energy efficiency, retail choice, and voltage optimization as discussed in Sections 4.1.3, 4.1.4, and 4.1.5, respectively.

As discussed in Section 1.6.2, the Company has historically purchased reserves in excess of the approximately 15% planning reserve margin. Given this history, Figure 2.1.1, as well as the capacity figures in Appendix 2A, display a second capacity requirement labeled "PJM Capacity Auction (Typical)" that includes an additional 5% reserve requirement target that is commensurate with the upper bound where the RPM market has historically cleared. All Alternative Plans were optimized to meet the PJM coincident summer peak load forecast as discussed in Section 4.1.1, which is labeled as "Minimum PJM Reliability Requirement (Net of EE)" in Figure 2.1.1, as well as the capacity figures in Appendix 2A.

Actual reserve margins in each year may vary based upon the outcome of the forward RPM auctions, revisions to the PJM RPM rules, and annual updates to load and reserve requirements. Appendix 4H provides a summary of PJM's summer and winter peak load and energy forecast, while Appendix 4I provides a summary of projected PJM reserve margins for summer peak demand.

4.3 Capacity Value Assumptions

Since the fall of 2018, PJM has been developing a probabilistic analysis aimed at valuing the capacity value of renewable resources. This approach utilizes a concept called effective load carrying capability ("ELCC"). As defined by PJM, ELCC is a measure of the additional load that the system can supply with the particular generator of interest without a change in reliability. ELCC can also be defined as the equivalent MW of a traditional generator that results in the same reliability outcome based on what a particular generator of interest (such as an intermittent generator) can provide. The metric of reliability used by PJM is loss of load expectation, a probabilistic metric that is driven by the timing of high loss-of-load probability hours. Therefore, PJM states that a resource that contributes a significant level of capacity during high-risk hours will have a higher capacity value (*i.e.*, a higher ELCC) than a resource that delivers the same capacity only during low-risk hours. "High-risk hours" are those hours that PJM expects the peak demand to occur.

For the purposes of the 2020 Plan, the Company has used the PJM ELCC studies published to date to estimate the capacity value of solar resources. This approach indicated the capacity value of solar is currently in the 45% range, but decreases over time as the solar saturation grows. PJM currently performs its load forecasts, installed reserve margins, reliability metrics, and ELCC calculations at the hourly or daily level.

The Company has assumed approximately 30% capacity value for offshore wind. This capacity value is based on the PJM-approved capacity value associated with the Company's proposed offshore wind queue projects because, to date, PJM has not published an ELCC-based analysis for offshore wind.

For storage resources, PJM currently adheres to a 10-hour run requirement for determining capacity value. This rule dictates that for capacity market participation, a storage resource with duration less than 10 hours will be de-rated down to the capacity value equal to the resource's duration as a fraction of 10 hours. This rule is currently under review by FERC. PJM has also recently initiated an effort to develop ELCC calculations for storage resources. The storage approach would likely incorporate the dispatch characteristics and duration of storage resources. Because of these pending initiatives, the Company has modeled the capacity value of storage resources using PJM's existing 10-hour requirement for the purposes of the 2020 Plan.

4.4 Commodity Price Assumptions

The Company utilizes a single source to provide multiple scenarios for the commodity price forecast to ensure consistency in methodologies and assumptions. The Company performed the analyses in this 2020 Plan using energy and commodity price forecasts provided by ICF Resources, LLC ("ICF") in all periods except the first 36 months of the Study Period. The forecasts used for natural gas, coal, power, emissions (SO_x, NO_x) and renewable energy certificate ("REC") prices rely on forward market prices as of December 31, 2019, for the first 18 months of the Study Period and then blended forward prices with ICF estimates for the next 18 months. Beyond the first 36 months, the Company used the ICF commodity price forecast exclusively. The forecast used for capacity and CO_2 prices are provided by ICF for all years forecasted within this 2020 Plan. The capacity prices are provided on a calendar year basis and reflect the results of the PJM RPM base residual auction through the 2021/2022 delivery year, thereafter transitioning to the ICF capacity forecast beginning with the 2022/2023 delivery year.

In the 2020 Plan, the Company utilized four commodity forecasts:

- No CO_2 Tax
- Mid-Case Federal CO_2 with Virginia in RGGI

- Virginia in RGGI
- High-Case Federal CO_2

Appendix 4O provides the annual prices for each commodity forecast.

These commodity forecasts approached carbon scenarios using various potential outcomes to regulations or legislation designed to reduce CO_2 emissions. The Virginia in RGGI commodity forecast addressed RGGI on a standalone basis. To address the potential for more stringent regulation or legislation at the federal level, the High-Case Federal CO_2 commodity forecast was developed. The combined impact of RGGI and more moderate federal CO_2 regulation or legislation is addressed in the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast.

The Company utilized the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast for Alternative Plans B through D, and the No CO_2 Tax commodity forecast in Plan A. The Company ran sensitivities on Alternative Plan B, keeping the same build plan, but then applying the Virginia in RGGI commodity forecast and, separately, the High-Case Federal CO_2 commodity forecast. The intent of these sensitivities is to show the effect on NPV using a range of commodity prices. Figure 4.4.1 displays the results of these sensitivities.

Figure 4.4.1 – Commodity Forecast Sensitivity

	Plan B	**Plan B Commodity Forecast Sensitivity 1**	**Plan B Commodity Forecast Sensitivity 2**
Load Forecast	Mid-Case Federal CO_2	Virginia in RGGI	High-Case Federal CO_2
NPV Total	$66.2 B	$65.7 B	$67.6 B

As can be seen, using the High-Case Federal CO_2 commodity forecast results in a higher NPV because of higher CO_2 prices, all other Plan B assumptions being equal. The sensitivity using the Virginia in RGGI commodity forecast results in a similar NPV as Alternative Plan B because of the similarities in pricing between these two forecasts.

Because of the preparation schedule associated with this 2020 Plan, the commodity price forecasts do not include the regional impacts on commodity prices that may result from the VCEA. As with all forecasts, there remain multiple possible outcomes for future prices that fall outside of the commodity prices developed for this 2020 Plan. History has shown that unforeseen events and events not contemplated five or ten years before their occurrence can result in significant changes in market fundamentals. The effects of unforeseen events should be considered when evaluating the viability of long-term planning objectives. The commodity price forecasts analyzed in the 2020 Plan present reasonably likely outcomes given the current understanding of market fundamentals, but do not present all possible outcomes.

4.4.1 Mid-Case Federal CO_2 with Virginia in RGGI Commodity Forecast

The Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast was developed for the Company to address a future market environment where both regional and federal carbon regulations affect electric generation units. The Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast reflects both (i) Virginia being a full member of RGGI in 2021 and (ii) a federal carbon program. The federal carbon program assumed in this forecast is driven by regulations reflecting a federal policy consistent with the goals identified under the last iteration of the federal Clean Power Plan ("CPP"). ICF recalculated the CPP mass caps to reflect the changes in emission levels since the EPA first determined the CPP state budgets. While it is likely that future regulation would include different requirements than the CPP, ICF relied on the requirements of this representative "mid" case for future CO_2 regulations of the power sector. This representation assumes that states adopt mass-based standards within a national trading structure covering all states, except California which maintains a state-specific program. It also assumes that existing and new sources are included under the cap-and-trade program; RGGI and the California-specific programs continue as individual programs. This type of CO_2 program is assumed to begin in 2026 because it would not require legislative action at the federal level.

Utilizing the Mid-Case Federal CO_2 with RGGI in Virginia commodity forecast allows the Company to evaluate Alternative Plans using a commodity price forecast that reflects ICF's independent view of future market conditions with Virginia being a full participant in RGGI and modest regulations on carbon emissions from electric generation activities at the federal level. ICF's independent, internal views of key market drivers include: (i) market structure and policy elements that shape allowance markets; (ii) fuel and power market fundamentals ranging from expected capacity and pollution control installations; (iii) environmental regulations; and (iv) fuel supply-side issues. The development process assesses the effect of environmental regulations on the power and fuel markets and incorporates ICF's views on the outcome of new regulatory initiatives.

Figure 4.4.1.1 presents a comparison of average fuel, power, and REC prices used in the 2018 Plan and the 2019 update to the 2018 Plan (the "2019 Update") relative to those used in this 2020 Plan. See Appendix 4P for additional details of these forecasts, including fuel, allowance, power price forecasts, and the PJM RTO capacity price forecast. See Appendix 4R for delivered fuel prices and primary fuel expense from the PLEXOS model output using the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast.

Figure 4.4.1.1 –Fuel, Power, and REC Price Commodity Forecast Comparison

	Planning Period Comparison Average Value (Nominal $)		
Fuel Price	2018 Plan Federal CO_2 [3]	2019 Update Virginia in RGGI [3]	2020 Plan Mid-Case Federal CO_2 with Virginia in RGGI [3]
Henry Hub Natural Gas[1] ($/MMbtu)	4.29	3.81	4.05
Zone 5 Delivered Natural Gas[1] ($/MMbtu)	3.71	3.54	3.68
CAPP CSX: 12,500 1%S FOB ($/MMbtu)	2.66	2.42	2.97
No. 2 Oil ($/MMbtu)	18.52	17.78	17.89
1% No. 6 Oil ($/MMbtu)	11.93	11.56	11.52
Electric and REC Prices			
PJM-DOM On-Peak ($/MWh)	41.29	38.94	44.58
PJM-DOM Off-Peak ($/MWh)	34.36	32.79	34.78
PJM Tier 1 REC Prices[4] ($/MWh)	5.73	6.72	9.13
RTO Capacity Prices[2] ($/KW-yr)	59.33	62.50	57.34

Notes: 1) Zone 5 natural gas price used in Plan analyses. Henry Hub prices shown to provide market reference.
2) Capacity price represents actual clearing price from the PJM RPM base residual auction through delivery year 2020/2021 for 2018 Plan, and through delivery year 2021/2022 for the 2020 Plan and 2019 Update.
3) 2018 Planning Period 2019-2033, 2019 Planning Period 2020-2034, 2020 Planning Period 2021-2035.
4) The 2018 Plan column reflects the PJM Tier 1 REC prices as filed in the 2018 Compliance Filing.

4.4.2 No CO_2 Tax Commodity Forecast

The No CO_2 Tax commodity forecast anticipates a future without any new regulations or restrictions on CO_2 emissions beyond those already in place or previously approved. DOM Zone peak energy prices are slightly lower than the Mid-Case Federal CO_2 with Virginia in RGGI commodity forecast across the Planning Period because there is no incremental requirement to comply with CO_2 regulation targets to pass through to power prices. Given forthcoming law in Virginia imposing CO_2 regulation, this assumption is, in the Company's view, no longer reasonable. The No CO_2 Tax forecast is utilized only in analysis of Alternative Plan A, which is presented solely to measure additional costs of various planning scenarios.

4.4.3 Virginia in RGGI Commodity Forecast

The Virginia in RGGI commodity forecast includes New Jersey and Virginia as new participants in RGGI (Virginia in 2021), along with the nine existing RGGI states. The key assumptions regarding market structure and the use of an integrated, internally-consistent fundamental based modeling methodology remain consistent with those utilized in the other commodity forecast except that the carbon program modeled is RGGI and that there is no federal program addressing CO_2 reduction targets.

RGGI utilizes an emissions containment reserve ("ECR") as a trigger to limit downward pressure on the CO_2 allowance price. The ECR price trigger starts at $6 in 2021 and increases at 7% annually. If triggered, the ECR withholds up to 10% of the auction budget of states opting to implement the ECR (the ECR is modeled for all states but Maine and New Hampshire). In the

Virginia in RGGI commodity forecast, the RGGI prices are forecasted to be below the ECR trigger price and, therefore, in ICF's model the emission budget (cap) is reduced by 10% in the years it is triggered. Even with the 10% reduction in allowances, the market clearing prices remain below the ECR trigger prices. The reason for the lower clearing prices is that the CO_2 allowance supply in this case is driven not by coal generation displacement, but by the state policies (in member states) that continue to drive non-fossil generation growth. Carbon reductions are being driven by the high RPS targets in many of the RGGI states, with several states targeting 50% renewable or clean energy standards by the 2030 to 2035 timeframe, and further increasing beyond those years. Additionally, offshore wind procurements are modeled in 7 of the 11 RGGI states (*i.e.*, RI, VA, CT, MA, MD, NJ, NY), providing added clean energy in the RGGI region and displacing fossil resources. As noted earlier, the Virginia in RGGI commodity forecast does not include the regional effects of VCEA on RGGI allowance prices; therefore, the forecast does not account for the additional carbon reductions associated with the revised RPS requirements in Virginia.

4.4.4 High-Case Federal CO_2 Commodity Forecast

The High-Case Federal CO_2 commodity forecast addresses a scenario with a more stringent CO_2 regulatory environment implemented nationwide. In this commodity forecast, CO_2 regulation is addressed as a legislative approach to a national mass cap-and-trade program that begins in 2028 and targets an approximately 80% reduction from 2005 sector emissions by 2050. This target is similar to CO_2 reduction levels being discussed by several states, and it is consistent with what was proposed under the Waxman-Markey Bill in 2009. Load under this scenario increases relative to the other cases because of state electrification efforts. The tightening carbon cap and higher load compared to the No CO_2 Tax commodity forecast leads to higher renewable buildout and lower nuclear retirements. The "high" case includes existing and new sources under a national cap and trade program. This representation assumes that all states participate in the program except for California, which maintains its state-specific program. In this commodity forecast, ICF assumed that Virginia does not join RGGI. Compared to the Mid Case Federal CO_2 with RGGI in Virginia commodity forecast, the power prices are lower in the near term, while post-2025 all hours prices are roughly 36% higher on average. The higher power price is driven by CO_2 allowance price in excess of $100/ton by 2050.

4.4.5 Capacity Price Forecasting Methodology

In most wholesale electricity markets, electric power generators are paid for providing:

- Energy: the actual electricity consumed by customers;
- Capacity: standing ready to provide a specified amount of electric energy; and
- Ancillary Services: a variety of operations needed to maintain grid stability and security, including frequency control, spinning reserves, and operating reserves.

The purpose of a mandatory capacity market is to encourage new investments where they are most needed on the grid. PJM's capacity market (*i.e.*, the RPM), ensures long-term grid reliability by procuring the appropriate amount of supply- and demand-side resources needed to meet predicted peak demand in the future. In a capacity market, utilities or other electricity suppliers are required to purchase adequate resources to meet their customers' demand plus a reserve amount. Suppliers offer supply- or demand-side resources into the capacity market at a price. To the extent the supply offer clears the market, then those capacity resources are obligated to supply energy (or reduce energy in the case of demand-side resources) when dispatched, or pay penalty fees.

The RPM is designed to provide financial incentives to attract and maintain sufficient capacity to meet the load demands anticipated by PJM; in concept, revenues from energy and ancillary services plus capacity payments should equal the amount necessary to attract new entry. Parallel to the actual market construct, forecasting of long-term capacity prices is based on estimating the amount of capacity revenue a generation resource requires, in addition to revenue from energy and ancillary services. The capacity revenue forecast represents the amount by which a resource's cost exceeds its forecasted wholesale electricity market revenues. The basic concept utilized in forecasting is that in order to maintain appropriate reserve levels to assure reliable electric service, generating resources will require sufficient revenue to cover expenses and, when necessary, support the required new investment. When wholesale market energy and ancillary services revenue is not sufficient, then capacity revenues are required to fill this gap.

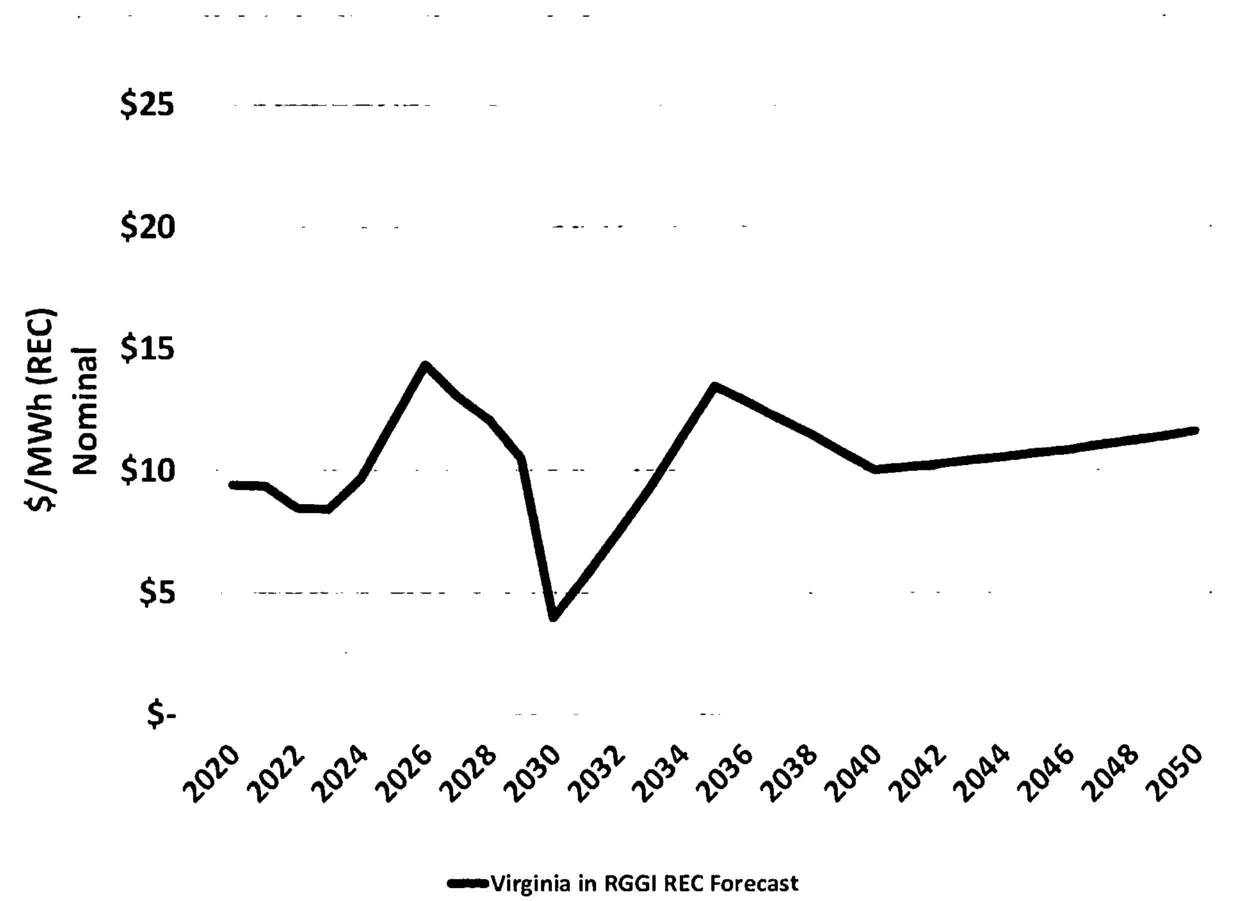
When forecasting capacity prices over long periods, it is reasonable to assume markets will move toward equilibrium and will provide sufficient revenue to support existing resources and incent investment in new resources that require equity returns on the capital expended for development and construction of the new resource. In markets with excess capacity, existing resources generally set the capacity price. These resources require revenue to cover only operating expenses and do not include equity returns or significant going forward capital expenditures. Because of this, the capacity price tends to be lower in markets with excess capacity. However, over the long term, the market is expected to move to an equilibrium status where sufficient revenues are provided, which assures adequate resource capacity and encourages market efficiency. Note that while long-term forecasts tend toward an equilibrium pricing, it is expected that actual markets will continue to follow an up-and-down cycle that moves around equilibrium levels. Long-term forecasts for capacity focus on the equilibrium level pricing rather than attempting to estimate the cyclical movement.

For these reasons, the issues surrounding the FERC MOPR Order described is Section 1.6.1 do not change the methods used to develop long-term capacity price forecasts.

4.4.6 REC Price Forecasting Methodology

Together with ICF, the Company developed a revised methodology for forecasting REC Tier 1 prices from what was presented in the 2018 Plan. A white paper describing the forecasting methodology and providing details related to the revised methodology for forecasting REC prices is provided in Appendix 4Q. The white paper also includes a section that illustrates the impact on REC prices if the federal tax credits for production tax credits and investment tax credits are extended indefinitely. Figure 4.4.6.1 provides a graph of the REC price forecast for the Virginia in RGGI commodity forecast.

Figure 4.4.6.1 – Tier 1 REC Forecast Comparison



The shape of the REC price forecast illustrated in Figure 4.4.6.1 reflects the fundamental changes occurring in the PJM states' RPS programs and the advancement of state-sponsored offshore wind development. The early price rise forecasted for Tier 1 RECs reflect recently enacted increases in RPS programs in several PJM states. These same states have implemented offshore wind procurement programs designed to supply large amounts of RECs to meet the expanding RPS requirements. The curve through 2030 reflect these fundamental developments, with prices rising as demand for RECs increase with the expanding RPS requirements, but then declining sharply as the large amounts of offshore wind procured by the states provide ample amounts of RECs to meet demand. As noted earlier, these results do not include the regional impacts of the VCEA.

4.5 Virginia Renewable Portfolio Standard Assumptions

In Virginia, the VCEA established a mandatory RPS as discussed in Section 1.2. In this 2020 Plan, the Company optimized the model for each Alternative Plan according to its typical process. The Company then determined whether additional renewable resources were needed to meet the annual RPS requirements, and added additional renewable resources (either Company-build or PPA) as needed. The Company assumed that it could construct or purchase renewable resources at less than the $45/MWh deficiency payment in the VCEA.

4.6 Solar-Related Assumptions

4.6.1 Solar Capacity Factor

For Alternative Plans A and D, the Company modeled future solar resources using a capacity factor of 19%, which is the average capacity factor of the Company's owned solar tracking fleet in the Commonwealth for the most recent three-year period (*i.e.*, 2017, 2018, 2019). For Plans B and C, the Company modeled future solar resources using a design solar capacity factor of 25% based on average modeled output from solar tracking resources.

4.6.2 Solar Company-Build vs. PPA

For solar resources in Alternative Plan A, the Company allowed the model to select either Company-build cost-of-service solar or third-party PPA solar limited at 480 MW per year, which is an assumption on the amount of solar generation available each year. For Alternative Plans B through D, the Company modeled solar PPAs as 35% of the solar generation capacity placed in service over the Study Period. These Alternative Plans exceed the 480 MW per year modeling constraint to meet the requirements of the VCEA.

4.6.3 Solar Interconnection and Integration Costs

The integration of intermittent solar generation into the electric grid involves multiple considerations. Solar generation must first be physically interconnected to the electric grid, either at the transmission or distribution level. The developer of a solar generating facility typically pays the costs to physically interconnect the resource, including any upgrades required near the point of interconnection to assure grid stability. The Company refers to these costs in this 2020 Plan as solar interconnection costs. As increasing volumes of solar generation are interconnected to the grid, additional system-level upgrades must be made by the Company to address grid stability and reliability issues caused by the intermittent nature of these resources. The Company refers to the costs related to these upgrades in this 2020 Plan as solar integration costs. All of these costs are incorporated in the NPV for "Total System Costs" shown in Figure 2.4.1.

In this 2020 Plan, three different categories of solar resources were available in PLEXOS: (i) Company-build solar; (ii) solar PPAs; and (iii) small-scale solar (*i.e.*, less than 3 MW). The Company assumed interconnection cost of $94/kW for Company-build solar and $125.50/kW for small-scale solar. The Company assumed $0 in interconnection costs for solar PPAs because the PPA price from the developer includes interconnection costs.

For solar integration costs, this 2020 Plan includes three categories of system upgrades costs based on different issues caused by the intermittent nature of solar resources:

- **Transmission Integration Costs**: These costs represent physical enhancements to the transmission system needed to resolve low voltage and thermal conditions caused by integrating significant volumes of solar generation. Figure 4.6.3.1 shows the incremental integration costs as solar generation is added to the system.

- **Generation Re-dispatch Costs**: This category represents costs resulting from real-time variability of load and generator availability compared to day-ahead forecasted load and generator availability. The analysis the Company performed resulted in the cost curve shown in Figure 4.6.3.3, which the Company used to add a specific amount per MWh of solar generation by year.
- **Regulating Reserves Costs**: This category represents ancillary payments the Company must make to resources to ensure that the system can balance intra-day or intra-hour differences in load and generation. Figure 4.6.3.4 shows the net cost to customers of regulating reserves included in each Alternative Plan.

The sections below explain the analyses performed for each of these three categories. While the Company has refined its methods to estimate the solar integration costs compared to prior Plans, more analysis is required in order to fully assess the necessary grid modifications and associated costs of integrating increasing amounts of solar generation.

<u>Transmission Integration Costs</u>

The transmission integration costs were assessed by performing a steady state power flow analysis where a total of 7,000 MW of solar generation is present on the transmission grid. Within this analysis, all possible interconnection locations and sizes were selected from the PJM generation interconnection queue to accurately reflect the behaviors of solar developers. Ten different scenarios were considered; the sites that make up the 7,000 MW were a randomly selected subset from the total list of sites from the PJM queue.

Using these ten different solar cases, the PSS®E power flow model were assessed under 2022 PJM light load demand conditions. This analysis included the retirement of certain existing generation units. Additional assumptions included maximum solar generation output (with reactive power support of +/- 0.95 power factor), and displacement of generation from other Company-owned facilities.

The results of these modeling cases identified several low voltage and thermal violations that would require physical enhancements to the Company's transmission system. As noted, this analysis was conducted assuming the addition of 7,000 MW of solar generation. In this 2020 Plan, all Alternative Plans include the addition of significantly more solar generation. Figure 4.6.3.1 shows the incremental integration costs assumed for Company-build solar as additional solar generation is added to the system.

Figure 4.6.3.1 – Total Solar Interconnection and Integration Costs

Solar (COS) MW	Total Cost	Comments
Less than 7,000	$ 94 /kW	Interconnections costs
7,000 – 15,000	$159 /kW	Additional transmission integration costs
15,001 – 25,000	$224 /kW	Additional transmission integration costs
25,001 – 35,000	$289 /kW	Additional transmission integration costs
35,001 – 45,000	$354 /kW	Additional transmission integration costs

Future Plans will expand on this analysis by studying the addition of more significant volumes of solar generation. The Company will also expand this analysis to consider dynamic system conditions and other sensitivity analyses that model sudden fluctuations of solar generation output and the need for other grid services described in Section 7.5.

Generation Re-dispatch Costs

Re-dispatch generation costs are defined in this 2020 Plan as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. Historically, these types of events were driven by load variations due to actual weather that differs from what was forecasted for the period in question. Most power system operators assess the generation needs for a future period, typically the next day, based on load forecasts and commit a series of generators to be available for operation in that period. These committed generators are expected to operate in an hour-to-hour sequence that minimizes total cost. Once within that period, however, actual load may vary from what was planned and the committed generators may operate in a less than optimal hour-to-hour sequence. The resulting additional costs due to real time variability are known as re-dispatch costs.

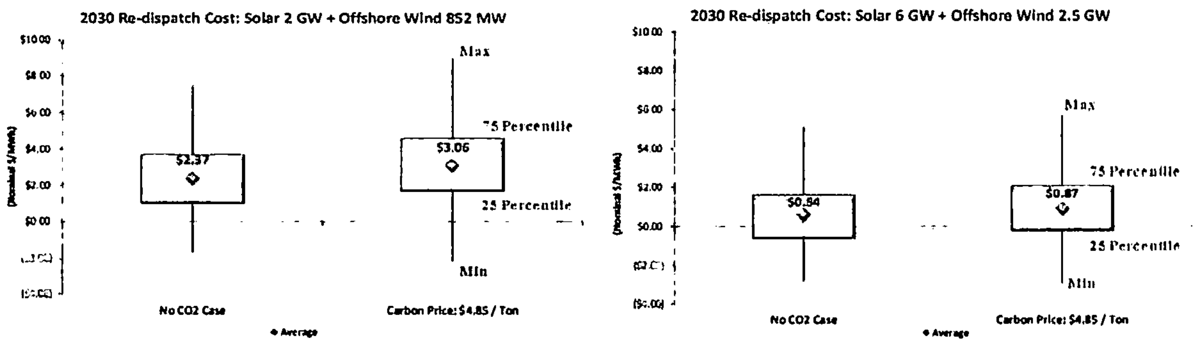
As more intermittent generation—like solar—is added to the grid, additional uncertainty about re-dispatch costs is added due to factors such as unpredictable cloud cover or changes in wind speed. In order to assess the resulting re-dispatch costs, the Company performed a simulation analysis to determine the cost impact on generation operations at varying levels of solar penetration.

To study the effects of these intermittent resources, the Company first performed a historical 20-year irradiance study (1998 to 2017) of 22 locations within the PJM region plus North Carolina and South Carolina using the National Solar Radiation Database ("NSRDB") provided by the National Renewable Energy Laboratory ("NREL"). Based on the irradiance data in the NSRDB, for each studied location, the Company produced a base hourly solar generation profile along with a set of 200 different hourly solar simulation profiles.

To perform its generation re-dispatch cost analysis, the Company utilized the Aurora planning model with a simulation topology of the Eastern Interconnection. The results from the Aurora model captured not only the DOM Zone hourly prices interactively but also the potential system cost impacts from intermittent resources outside the Company's service territory. This is an improvement over what was provided in the 2018 Plan.

The Company determined scenarios by assuming different levels of the CO_2 prices using assumptions provided by ICF, and two different levels of solar penetration and wind resources by 2030: (i) 2 GW of solar with 852 MW of offshore wind and (ii) 6 GW of solar with 2.5 GW of offshore wind. The renewable penetration level for other states in the Eastern Interconnection was set to a level that met the requirements in the applicable state RPS programs. For each scenario, the Company performed a base case Aurora simulation by using the base hourly solar generation profiles, and performed an additional 200 simulations by using the unit commitment decision determined by the base case and applying different hourly solar simulation profiles from the irradiance study to re-optimized the system cost. The total system cost for each simulation was compared to the base case system cost. This delta system cost is composed of the respective differences in fuel cost, variable O&M cost, emission cost, and purchase/sale cost. The re-dispatch cost is the delta of the system cost divided by the total solar generation. The analysis results are shown in Figure 4.6.3.2.

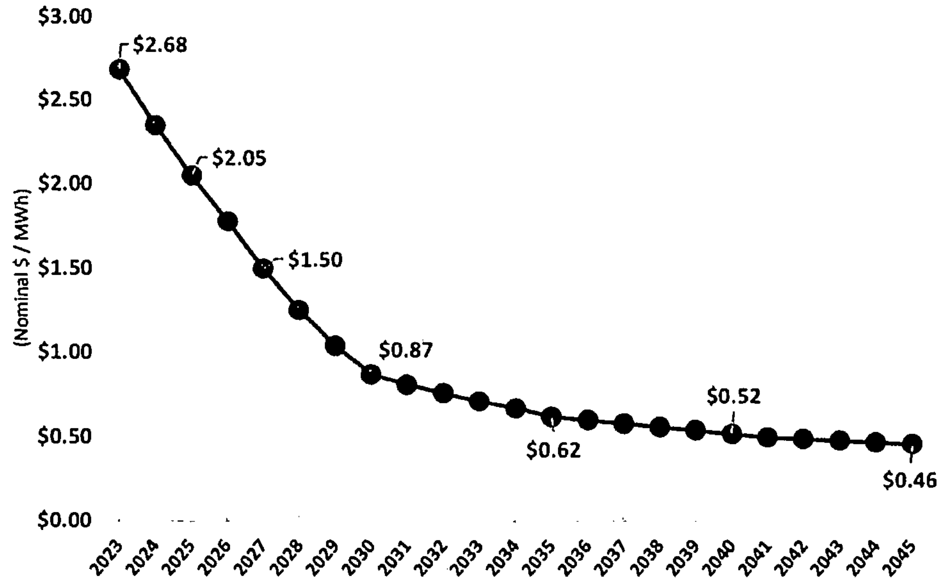
Figure 4.6.3.2 – Re-Dispatch Analysis Results



The analysis shows that, under the same level of the solar penetration, higher CO_2 prices result in slightly higher re-dispatch costs along with slightly higher cost volatility. The results also show, however, that as solar penetration increases, the overall re-dispatch costs decrease. This is because higher solar penetration lowers the DOM Zone energy hourly price, which results in lower re-dispatch costs.

Due to the scale of the simulation, the Company only performed the analysis for the study year of 2030. Using this data, the Company constructed a generation re-dispatch cost curve for the Study Period, as shown in Figure 4.6.3.3. These values were used as a variable cost adder for all solar generation evaluated in this 2020 Plan.

Figure 4.6.3.3 - Generation Re-dispatch Cost Results ($/MWh)



Even the 6 GW solar penetration level assessed in this analysis was significantly lower than the volume of solar generation added in all Alternative Plans. In future analyses, the Company will study the addition of more significant volumes of solar generation. The Company will also study the possibilities of incorporating the sensitivities of other intermittent resources, such as onshore and offshore wind generating units within the study footprint.

Regulating Reserve Costs

Regulating reserves are defined in this 2020 Plan as additional reserves needed to balance the uncertainty of forecast errors of net load that occur during a typical power system operational day. These reserves exclude contingency reserves, which are defined as the loss of a major power system generation or transmission system asset. Within the PJM market, these regulating reserves are an ancillary service, the cost of which is charged to customers. Revenues collected for this ancillary service are paid to resources available to supply (or reduce) additional energy to correct forecast errors. Unlike contingency reserves, regulating reserves are needed to either increase ("up reserves") or decrease ("down reserves") generation in any given operational hour. These reserves also differ from re-dispatch costs; they are paid to the resource whether they are used or not during the operating hour. The regulating reserve costs ensure that the transmission system has adequate resources available to handle forecast uncertainty. The system pays for regulating reserves so that it has the capability to quickly re-dispatch. In contrast, the operating costs to dispatch these regulating resources (to mitigate forecast errors and stabilize the transmission system) are part of re-dispatch costs.

Historically, the level of regulating reserves was primarily driven by the uncertainty associated with load during any given operating day. The intermittent nature of solar and wind generation adds to this uncertainty. Accordingly, the levels of regulating reserves will need to increase to compensate for this added uncertainty.

A variety of resources can be used to address system uncertainty: energy storage, unscheduled combustion turbine capacity, unscheduled duct burner capacity (on scheduled combined cycle units), intraday purchases and sales, and interruptible load.

In order to assess the increase of regulating reserves that will result from increasing volumes of solar generation, the Company utilized the Electric Power Research Institute ("EPRI") Dynamic Assessment and Determination of Operating Reserves ("DynADOR") tool. This tool calculates operating reserves based on correlations to other variables (*e.g.*, forecasted generation, time of day) and can be used to evaluate solar, wind, and load variations separately and in combination.

For the purposes of this study, the Company used solar data from the Morgan's Corner Solar Facility and wind speed data from Norfolk Airport. The study's timeframe was three years, from April 2016 to March 2019. Norfolk's surface wind speeds were adjusted by a constant wind gradient coefficient to achieve the 42% capacity factor observed in NREL's 2008 to 2012 Wind Tool Kit study of a point located in the Virginia Wind Energy Area. Forecasted wind speeds at 4:00 PM the previous day were used to simulate a day-ahead forecast of wind energy.

Using the solar and wind data described above, the DynADOR tool was set to determine the level of operating reserves needed for 1,000 MW (nameplate) of solar capacity and 1,000 MW (nameplate) of wind capacity each at a 95% confidence interval. This analysis assumed no diversity benefit from the combination of solar and wind, nor any diversity benefits from geography spread. These model results were then applied to the PJM solar and wind renewable expansion plans included in the ICF Virginia in RGGI commodity forecast for each year of the Study Period. This resulted in an hourly level of regulating services needed for each year of the Study Period.

One of the key observations from this study was the benefit during daylight hours of having both solar and wind generation. Because the forecast errors of solar and wind were not highly correlated, the operating reserves were significantly lower in combination than when evaluated independently and added together. This demonstrates the value of having a diverse portfolio of intermittent generation (in addition to the inherent diversity of geographic distribution). Accordingly, the next phase of this study will broaden the impact of increasing renewables generation to assess the benefit of diversity at the PJM level. Solar and wind hourly data from NREL were used to estimate the hourly benefit of technology and geographic diversity throughout PJM. This data was then used to calculate an hourly PJM diversity factor that was multiplied against the combined total of solar and wind hourly regulating reserves, which results in a lower overall hourly regulating reserve volume.

Once the volume of solar and wind (in MW) was determined as described above, the next phase of the analysis was to determine a market price for these reserves. Because of its historical structure that resulted in more definitive regression results, the Company chose the PJM Day-Ahead Secondary Reserves market as a basis to forecast a regulating reserve price. Participation in this market is restricted to dispatchable resources (generation, energy storage, and interruptible load) that are not scheduled in the day-ahead energy market. This market excludes intermittent resources, nuclear, and run-of-river hydro units. The resource must be able to bring the bid energy on the grid within 30 minutes of notification. This market varies in demand and pricing through the year. In 2019, this market averaged $0.39/MW, but hours ranged from $0.00 to over $20.00. Regression was used on these hourly results to shape a relationship between incremental reserves demand (net of incremental reserves supply) and a forecasted market price. This regulating reserve price construct was then applied to the hourly regulating reserve volumes to assess the annual costs of incremental regulating reserves resulting from increased intermittent renewable build within the PJM region.

The results of this analysis reflect the hourly (per MW) cost of regulating reserves gradually increases from $0.61 in 2021 to $20.18 in 2045. This occurs because the rate that PJM is forecasted to increase the need for regulating reserves (driven by the level of renewables build) grows more quickly within PJM than the projected addition of resources that provide regulation reserves in PJM. The forecasts of resource additions (both renewable and regulating resources) is based on ICF projections in states other than Virginia. Virginia resource additions are based on the projections in this 2020 Plan for the Company; for Appalachian Power Company and other sellers of electric power in Virginia, the projections assume solar and wind resource additions according to the RPS requirements for Appalachian Power Company.

From a Company perspective, regulating costs will be incurred when the regulating costs to serve the Company's load exceed the revenue received from PJM for the Company units that supply this ancillary service. Figure 4.6.3.4 shows the net cost to customers included in this 2020 Plan. The Company will continue its analysis of regulating reserves needed for system stability incorporating technological advancements that may mitigate these potential costs, and will present its results in future Plans and update filings.

Figure 4.6.3.4 – Company Net Regulating Reserves Cost of Market Purchases ($000,000)

Year	Plan A	Plan B	Plan C	Plan D
2021	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -
2030	$ -	$ -	$ -	$ -
2031	$ -	$ -	$ -	$ -
2032	$ -	$ -	$ -	$ -
2033	$ -	$ -	$ -	$ -
2034	$ -	$ 72	$ 73	$ 31
2035	$ -	$ 104	$ 105	$ 48
2036	$ -	$ 109	$ 44	$ -
2037	$ -	$ 93	$ -	$ -
2038	$ -	$ 153	$ 69	$ 52
2039	$ -	$ 167	$ 24	$ 28
2040	$ -	$ 247	$ 57	$ 76
2041	$ -	$ 362	$ 145	$ 183
2042	$ -	$ 402	$ 78	$ 137
2043	$ -	$ 502	$ 327	$ 378
2044	$ -	$ 523	$ 357	$ 346
2045	$ -	$ 607	$ 717	$ 827

Note: Zero values indicate that the DOM LSE has adequate regulating reserves to supply reserve requirements from the LSE's load and renewable generation portfolio that year.

4.7 Storage-Related Assumptions

As discussed further in Section 5.5, two types of energy storage resources were available in the PLEXOS model—battery energy storage systems and pumped storage. For BESS, the Company used cost estimates from the request for proposals for the recently-approved BESS pilot at Scott Solar Facility. This BESS is based on a 4-hour discharge configuration. For pumped storage, the Company used preliminary internal cost estimates for a large pump storage facility to be located in southwest Virginia.

In Plans B through D, the Company set constraints requiring the PLEXOS model to select 2,700 MW of energy storage by 2035, consistent with the VCEA, including 300 MW of pumped storage. Third-party owned energy storage will make up 35% of the 2,700 MW. Given the lack of sufficient pricing for storage PPAs, however, the Company did not differentiate between Company-owned and third-party-owned energy storage resources in this 2020 Plan.

4.8 Gas Transportation Cost Assumptions

Natural gas is largely delivered on a just-in-time basis, and vulnerabilities in gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective. Mitigating strategies such as storage, firm fuel contracts, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, and overall fuel diversity all help to alleviate this risk.

There are two types of pipeline transportation service contracts: firm and interruptible. Natural gas provided under a firm service contract is available to the customer at all times during the contract term and is not subject to a prior claim from another customer. For a firm service contract, the customer typically pays a facilities charge representing the customer's share of the capacity construction cost and a fixed monthly capacity reservation charge. Interruptible service contracts provide the customer with natural gas subject to the contractual rights of firm customers. The Company currently uses a combination of both firm and interruptible service to fuel its natural gas-fired generation fleet.

The Company included natural gas transportation costs in its modeling. The Company assumed firm transportation service for CCs and interruptible transportation service for CTs. The Company assumed interruptible transportation service for CTs because these peaking resources typically operate with less than 20% capacity factors and because they are typically equipped with on-site oil backup.

Pipeline deliverability can affect electrical system reliability. A physical disruption to a pipeline or compressor station can interrupt or reduce the flow pressure of gas supply to multiple EGUs at once. Electrical systems also have the ability to adversely affect pipeline reliability. For example, the sudden loss of a large efficient generator can force numerous smaller gas-fired CTs to be started in a short period of time. This sudden change in demand may cause drops in pipeline pressure that could reduce the quality of service to other pipeline customers, including other generators. Electric transmission system disturbances may also interrupt service to electric gas compressor stations, which can disrupt the fuel supply to electric generators.

4.9 Least-Cost Plan Assumptions

Alternative Plan A presents a least-cost plan using assumptions required by the SCC. Specifically, Plan A uses the PJM Load Forecast adjusted for only existing and proposed energy efficiency as discussed in Section 4.1.3, and uses the No CO_2 Tax commodity forecast as discussed in Section 4.4.2. For Plan A, the Company did not force the model to select any specific resources, and did not exclude any reasonable resource options. The potential unit retirements shown in Plan A are those that are financially at risk for retirement based on market conditions.

4.10 VCEA-Related Assumptions

The Company modeled the requirements and targets contained in the VCEA when it passed the General Assembly on March 5, 2020, as this was the best available information at the time the Company completed its modeling. Virginia Governor Northam signed the VCEA into law without amendment on April 11, 2020. In addition to the VCEA, the Company modeled "other relevant legislation" from the 2020 Regular Session of the Virginia General Assembly (i) related to RGGI as discussed in Section 1.3 and (ii) related to the aggregation pilot as discussed in Section 1.10.

Chapter 5: Generation – Supply-Side Resources

This chapter provides an overview of the Company's existing supply-side generation, the generation resources under construction or development, and the Company's analysis of future supply-side generation. This chapter also provides a discussion of challenges related to the development of significant volumes of solar resources.

5.1 Existing Supply-Side Generation

5.1.1 System Fleet

Figure 5.1.1.1 shows the Company's 2019 capacity resource mix by unit type.

Figure 5.1.1.1 - 2019 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity (MW)	Percentage (%)
Coal	3,684	17.7%
Nuclear	3,348	16.1%
Natural Gas	8,413	40.3%
Pumped Storage	1,808	8.7%
Oil	2,143	10.3%
Renewable	667	3.2%
NUG-Coal	0	0.0%
NUG- Natural Gas Turbine	0	0.0%
NUG- Solar	592	2.8%
NUG- Contracted	198	0.9%
Company Owned	20,063	96.2%
Company Owned and NUG Contracted	20,853	100.0%
Purchases	0	0.0%
Total	20,853	100.0%

Due to differences in operating and fuel costs of various types of units and in PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is dispatched by PJM within PJM's larger footprint, ensuring that customers in the Company's service territory receive the economic benefit of all resources in the PJM power pool regardless of the source. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 5.1.1.2 and 5.1.1.3 provide the Company's 2019 actual capacity and energy mix.

Figure 5.1.1.2 - 2019 Actual Capacity Mix

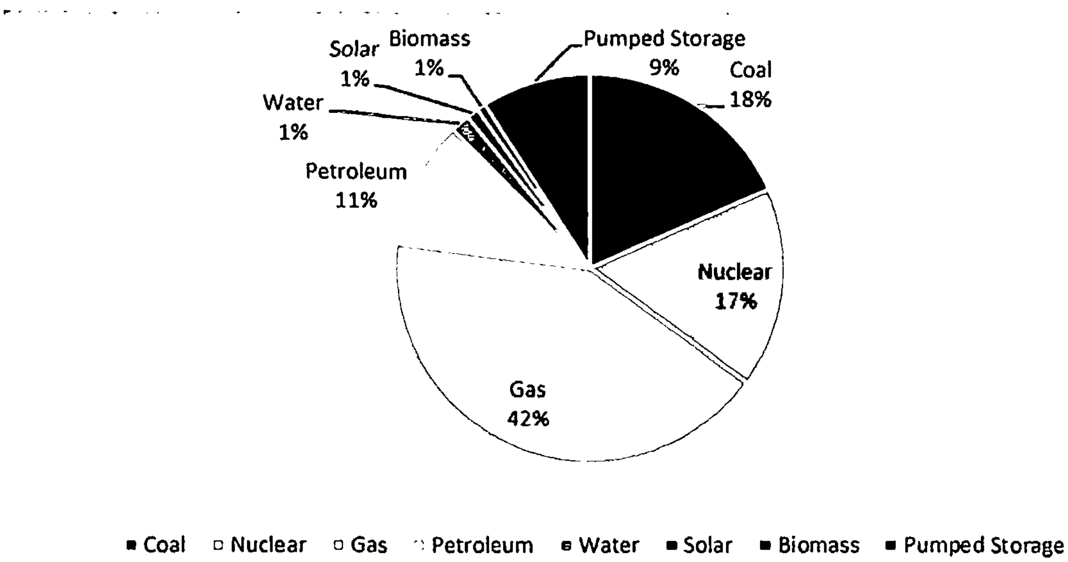
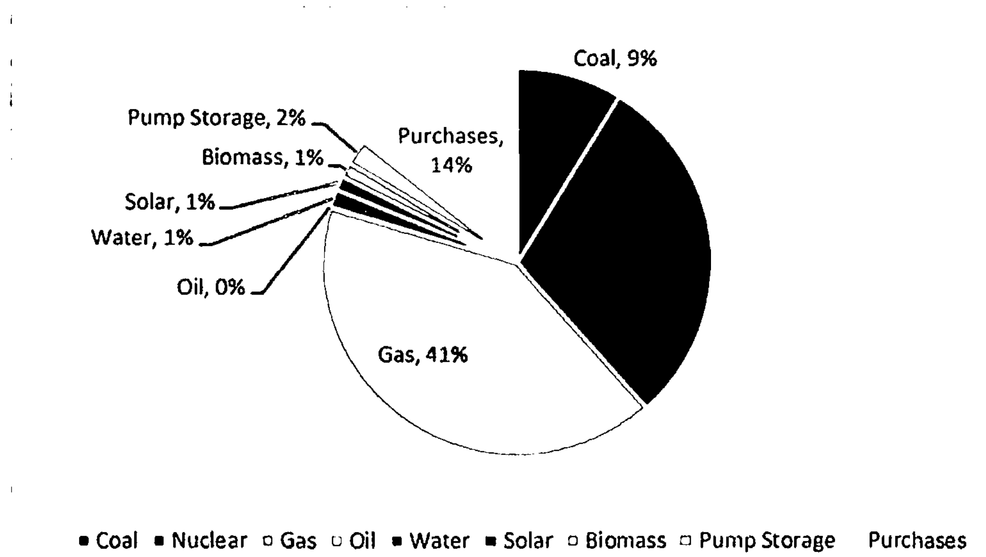


Figure 5.1.1.3 - 2019 Actual Energy Mix

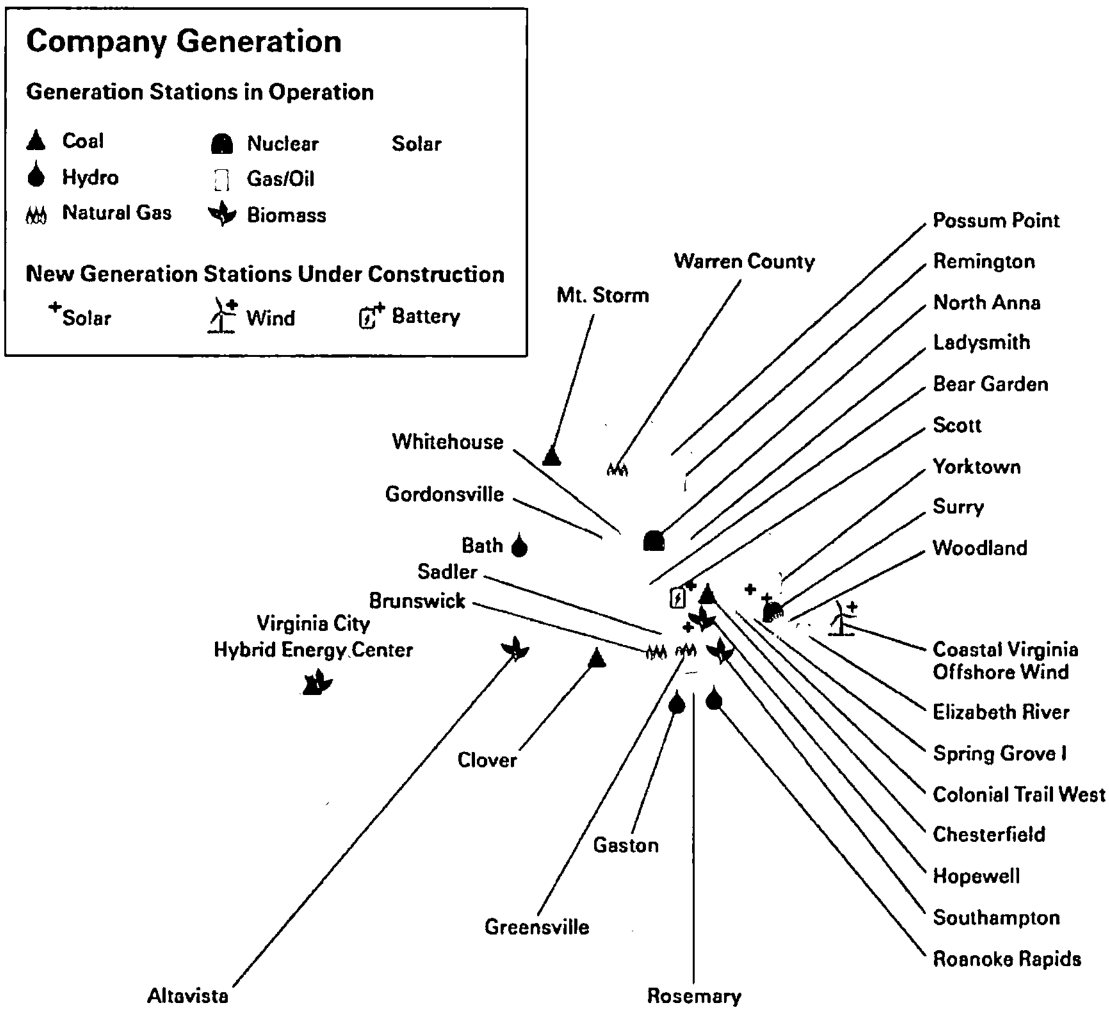


Appendices 5A through 5E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Appendix 5F provides a summary of the existing capacity by fuel class. Appendices 5G and 5H provide energy generation by type and by the system output mix. Appendix 5I provides a list of all Company-build or third-party PPA solar and wind generating facilities placed in service, under construction, or under development since July 1, 2018. Appendix 5O provides a list of renewable resources, and Appendix 5P provides a list of potential supply-side resources. Appendices 5Q and 5R present the Company's summer capacity position and seasonal capability, respectively. Appendix 5S provides the construction cost forecast for Alternative Plan B.

5.1.2 *Company-Owned System Generation*

The Company's existing system generating resources are located at multiple sites distributed throughout its service territory, as shown in Figure 5.1.2.1. This diverse fleet of 90 generation units includes 4 nuclear, 8 coal, 9 CCs, 40 CTs, 3 biomass, 2 heavy oil, 6 pumped storage, 14 hydro, and 4 solar with a total summer capacity of approximately 20,063 MW.

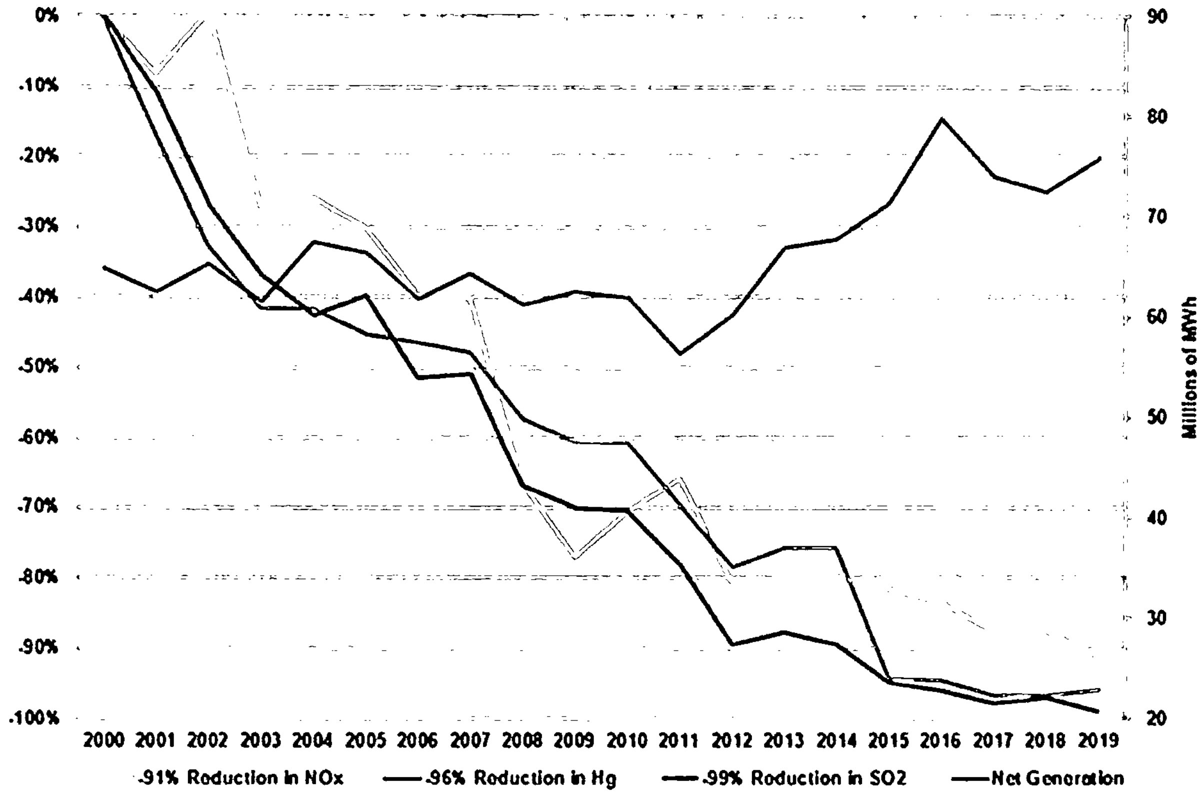
Figure 5.1.2.1 – Company Generation Resources



The Company currently owns and operates 667 MW of renewable resources, including solar, hydro, and biomass, with an additional 210 MW (nameplate) under construction. The Company also owns and operates four nuclear facilities (3,348 MW), providing significant zero-carbon generation for its customers.

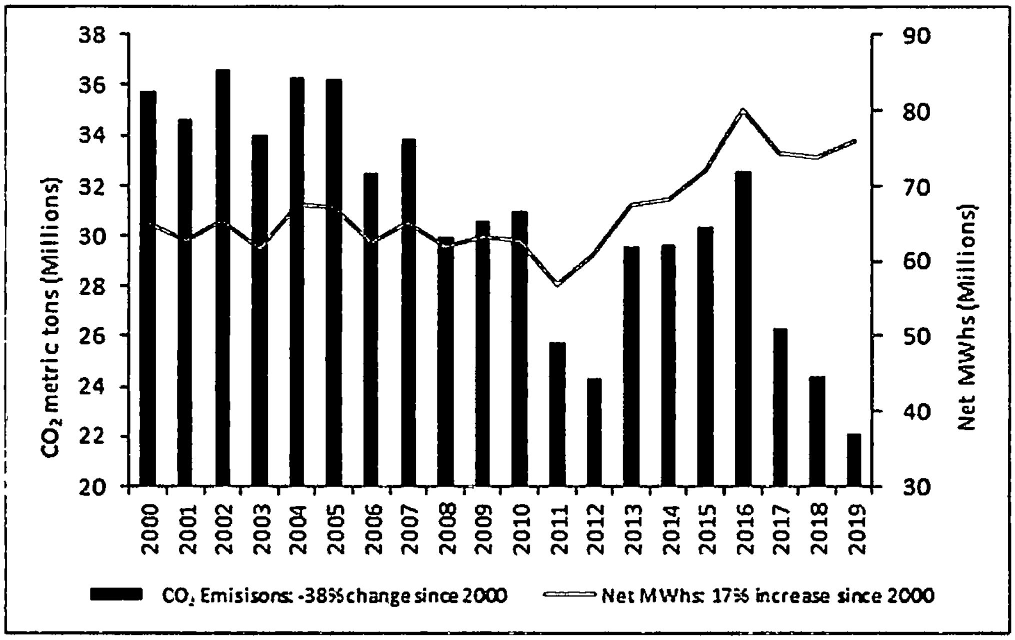
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, the conversion to dry ash handling, and the addition of air pollution controls. This strategy has resulted in significant reductions of air pollutants such as NOx, SO_2, and mercury, as shown in Figure 5.1.2.2, and has also reduced the amount of coal ash generated and the amount of water used.

Figure 5.1.2.2 – Company Annual Reduction in Emissions by Percent



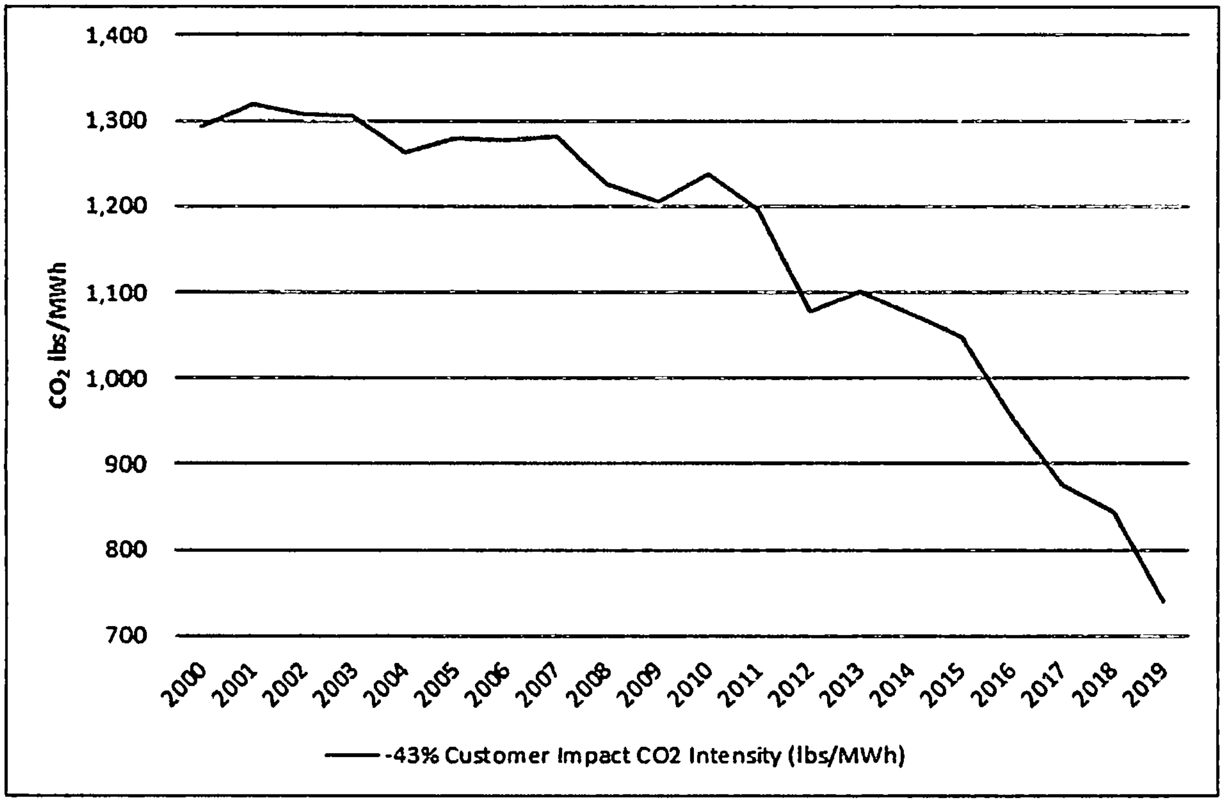
The Company develops a comprehensive GHG inventory annually. The Company's direct CO_2 equivalent emissions (based on ownership percentage) were 22.1 million metric tons in 2019 compared to 24.6 million metric tons in 2018. The Company has been a leader in reducing CO_2 emissions through retiring certain units; building additional efficient and lower-emitting natural gas-fired power generating sources and carbon-free renewable energy sources, such as solar; and maintaining its existing fleet of non-emitting nuclear generation. As shown in Figure 5.1.2.3, from 2000 through 2019, the Company has reduced the CO_2 emissions in tons from its power generation fleet serving Virginia jurisdictional customers by 38%, while power production has increased by 17%.

Figure 5.1.2.3 – Company CO_2 Mass Reductions versus Net Generation



The Company's integrated business strategy has also resulted in significant reduction in CO_2 emission intensity. CO_2 intensity is the amount of emissions per MWh delivered to customers. This calculation includes emissions from any source used to deliver power to customers, including Company-owned generation, NUGs, and net purchased power. As shown in Figure 5.1.2.4, customer impact CO_2 intensity has decreased by 43% since 2000.

Figure 5.1.2.4 – Customer Impact CO_2 Intensity



5.1.3 Non-Utility Generation

A portion of the Company's load and energy requirement is supplemented with contracted NUGs. The Company has existing contracts with fossil-burning and renewable behind-the-meter NUGs for capacity of approximately 812 MW (nameplate).

For modeling purposes, the Company assumed that its NUG capacity would be available as a firm generating capacity resource in accordance with current contractual terms. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm generating capacity resource. The Company assumed that NUGs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned, sponsored supply, or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter into future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

5.2 Evaluation of Existing Generation

The Company continuously evaluates various options with respect to its existing fleet, cognizant of environmental regulations and other policy considerations.

5.2.1 Retirements

As discussed in Section 1.2, the VCEA mandates the retirement of carbon-emitting generation on a specific schedule unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric services:

- Chesterfield Units 5 and 6 (coal) and Yorktown Unit 3 (heavy oil) by 2024;
- Altavista, Hopewell, and Southampton (biomass) by 2028; and
- All remaining generation units that emit CO_2 as a byproduct of combustion by 2045.

Separate from these mandates, and consistent with prior Plans, the Company completed a unit evaluation economic analysis focused on coal-fired, heavy-oil fired, and large combined cycle Company generation facilities under market conditions.

Global assumptions included potential carbon regulations as well as market forecasts consistent with four ICF commodity forecast scenarios: No CO_2 Tax, Mid-Case Federal CO_2 with Virginia in RGGI, Virginia in RGGI and High-Case Federal CO_2.

A combination of PLEXOS production-cost modeling software and Excel models were used to calculate a unit NPV to customers over the next ten years. Unit NPVs were derived by comparing the total unit costs, including O&M and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues. Negative NPV results indicated an economic benefit of unit retirement to customers compared to continued operations of the unit in the PJM market.

The results of the analysis are included in Figure 5.2.1.1. In general, it can be concluded that the Company's coal-fired power plants located in Virginia continue to face pressure due to unfavorable market conditions and carbon regulations. Coal-fired generating facilities Chesterfield Units 5 and 6 and Clover Units 1 and 2 had negative NPVs under all four scenarios, including No CO_2 Tax. Mount Storm's coal-fired Units 1 through 3 showed positive NPVs in all four cases with a higher upside potential under Virginia in RGGI and the No CO_2 Tax scenarios. Heavy oil-fired power station Yorktown Unit 3 had negative NPVs in all four scenarios.

Figure 5.2.1.1 – Retirement Analysis Results

Units	No CO_2 Tax	Virginia in RGGI	Mid-Case Federal CO_2 with Virginia in RGGI	High-Case Federal CO_2
Chesterfield 5 - 6	-	-	-	-
Clover 1 - 2	-	-	-	-
Mt. Storm 1 - 3	+	+	+	+
Yorktown 3	-	-	-	-

Based on the above results and other factors, including but not limited to power prices and the retirement-related mandates in the VCEA, the Company anticipates retiring Yorktown Unit 3 and Chesterfield Units 5 and 6 in 2023. Other than these units, inclusion of a unit retirement in this 2020 Plan should be considered as tentative only. The Company has not made any decision regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6. The Company's final decisions regarding any unit retirement will be made at a future date. Appendix 5J lists the generating units for potential retirement.

5.2.2 Uprates and Derates

Efficiency, generation output, and environmental characteristics of units are reviewed as part of the Company's normal course of business. Many of the uprates and derates occur during routine maintenance cycles or are associated with standard refurbishment. However, several unit ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations. Appendix 5K provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

5.2.3 Environmental Regulations

There are a number of final, proposed, and anticipated EPA regulations that will affect certain units in the Company's current fleet of generation resources. Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife. For further discussion on significant developments to environmental regulation, see Sections 1.3 and 1.11.

5.3 Generation Under Construction

The Company currently has four generation projects under construction for which the SCC has issued a certificate of public convenience and necessity: (i) the CVOW demonstration project; (ii) Spring Grove 1 Solar Project; (iii) Sadler Solar Project; and (iv) the Battery Energy Storage System at Scott Solar Facility. Appendix 3A provides details on each project.

5.4 Generation Under Development

The Company currently has solar, offshore wind, pumped storage, and CT generation projects under development. The Company is also pursuing subsequent license extensions for its nuclear facilities. The following sections provide details on these projects, as does Appendix 3B.

The Company has paused material development activities for North Anna 3 following receipt of the combined operating license ("COL") in 2017. The Company is currently incurring minimal capital costs associated with North Anna 3 specific to the administrative functions of maintaining the COL.

5.4.1 Solar

The Company issued a request for proposal ("RFP") for new solar and wind resources in August 2019. The Company is currently evaluating the results of that RFP and intends to bring new Company-build and PPA resources before the SCC for approval as part of its annual plan regarding the development of solar, onshore wind, and energy storage required by the VCEA.

5.4.2 *Offshore Wind*

The Company is actively participating in offshore wind policy and innovative technology development to identify ways to advance offshore wind generation responsibly and cost-effectively.

The CVOW demonstration project—the Mid-Atlantic's first offshore wind project in a federal lease area—is under construction with a targeted in-service date by the end of 2020. This demonstration project is an important first step toward offshore wind development for Virginia and the United States. Along with clean energy, it is providing the Company valuable experience in permitting, constructing, and operating offshore wind resources, which will help inform utility-scale development of the adjacent 112,800 acre wind lease area.

As discussed in Section 1.2, the VCEA specifies that the construction or purchase of up to 5,200 MW of offshore wind capacity is in the public interest. In September 2019, the Company filed with PJM to interconnect more than 2,600 MW of offshore wind capacity by 2026 ("CVOW commercial project"), enough to power more than 650,000 homes during peak winds.

On January 7, 2020, the Company selected Siemens Gamesa Renewable Energy as the preferred turbine supplier for the CVOW commercial project with the intent to provide their latest state-of-the-art wind turbine, based on its proven Offshore Direct Drive platform. Ongoing efforts of this project include ocean survey work that will be performed in 2020 to support the development of the Construction and Operations Plan, which is expected to be submitted to the Bureau of Ocean Energy Management in late 2020. Pending regulatory approval, the CVOW commercial project is expected to be in-service by the end of 2026.

5.4.3 *Pumped Storage*

Pumped storage hydroelectric power is a mature proven storage technology. It can also serve as a system-stabilizing asset to accommodate the intermittent and variable output of renewable energy sources such as solar and wind. Virginia Senate Bill No. 1418 became law effective on July 1, 2017, and supported construction of "one or more pumped hydroelectric generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source . . . located in the coalfield region of the Commonwealth." On September 6, 2017, the Company filed a preliminary permit application with FERC for a location in Tazewell County, Virginia. This application was approved on December 11, 2017, and the Company is continuing to conduct feasibility studies for a potential pumped storage facility at the Tazewell County site.

5.4.4 *Extension of Nuclear Licensing*

An application for a subsequent license renewal is allowed during a nuclear plant's first period of extended operation—that is, in the 40 to 60 years range of its service life. Surry Units 1 and 2 entered into that initial license renewal period in 2012 and 2013, respectively. North Anna Units 1 and 2 entered or will enter into that period in 2018 and 2020, respectively. The Company has continued to track the preliminary cost estimates for the extension of the nuclear licenses at its Surry and North Anna Units.

In November 2015, the Company notified the NRC of its intent to file for subsequent license renewal for its two nuclear units (1,676 MW total) at Surry in order to operate an additional 20 years, increasing their operating life from 60 to 80 years. As with other nuclear units, Surry was originally licensed to operate for 40 years and then renewed for an additional 20 years. Absent subsequent license renewal approval, the existing licenses for Surry Units 1 and 2 will expire in 2032 and 2033, respectively. In support of the application development, the NRC finalized guidance documents in early July 2017, related to developing and reviewing subsequent license renewal applications. The Surry subsequent license renewal application was submitted to the NRC on October 15, 2018, in accordance with Title 10 of the Code of Federal Regulations ("CFR") Part 54.

The Surry subsequent license renewal application was subsequently declared "technically sufficient and available for docketing" by the NRC on December 10, 2018, which began the safety and environmental reviews required for the renewed licenses. Several NRC audits and public meetings have been conducted during both the safety and environmental reviews in late 2018 and 2019 related to this licensing action. The NRC staff has asked requests for additional information ("RAIs") during this review period seeking clarification or additional action to be taken by the Company prior to entering the subsequent period of operation. These environmental and safety RAIs have been addressed to the satisfaction of the NRC staff.

As a result, the NRC issued the Final Safety Evaluation Report ("SER") for Surry Power Station on March 9, 2020. On the basis of its review of the Surry subsequent license renewal application, the NRC staff determined that the requirements of 10 CFR 54.29(a) have been met for the subsequent license renewal of Surry Units 1 and 2. The NRC also issued the Final Supplemental Environmental Impact Statement ("FSEIS") on April 6, 2020. The NRC staff's conclusion was "that the adverse environmental impacts of license renewal for Surry are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable."

The Advisory Committee on Reactor Safeguards ("ACRS") Full-Committee meeting was conducted on April 8, 2020, with unanimous approval by the committee to approve the renewal of the operating licenses for Surry Units 1 and 2.

The NRC Director of Nuclear Reactor Regulation will make a decision for renewed licenses for Surry Units 1 and 2 based on the issuance of the FSEIS, Final SER and the ACRS letter of recommendation in June 2020. This will preserve the option to continue operation of Surry Units 1 and 2 until 2052 and 2053, respectively.

The Company notified the NRC in November 2017 of its plans to file an subsequent license renewal application for its two nuclear units (1,672 MW total) at North Anna in accordance with 10 CFR Part 54 in late 2020. Absent subsequent license renewal approval, the existing licenses for the two units will expire in 2038 and 2040, respectively. The review process for North Anna will remain unchanged, so the expected outcome would be similar to Surry. The renewed licenses for North Anna would be expected 18 months following the NRC declaring the subsequent license renewal application as technically sufficient and available for docketing, which is expected within 45 to 60 days following the Company's submittal. Currently, the forecast receipt of the renewed licenses for North Anna Units 1 and 2 is June 2022, based on a targeted submittal date in October 2020.

5.4.5 Combustion Turbines

In order to preserve the option to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities in the near term, the Company is evaluating sites and equipment for the construction of gas-fired CT units.

5.5 Future Supply-Side Generation Resources

The process of selecting alternative resource types starts with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzes the current commercial status and market acceptance of the alternative resources. This analysis includes determining whether particular alternatives are feasible in the short- or long-term based on the availability of resources or fuel within the Company's service territory or PJM. The technology's ability to be dispatched is based on whether the resource is able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand and supply conditions. Further, analysis of the alternative resources requires consideration of the viability of the resource technologies available to the Company. This step identifies the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks.

The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel and O&M. Figure 5.5.1 summarizes the resource types that the Company reviewed as part of the generation planning process. Those resources considered for further analysis in the busbar (*i.e.*, LCOE) screening model are identified in the final column.

Further analysis was conducted in PLEXOS to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matched the resources found to be cost-effective in this screening process. This PLEXOS simulation analysis further refines the Company's analysis and assists in selecting the type and timing of additional resources that economically fit the customers' current and future needs.

Figure 5.5.1 - Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource	PLEXOS Resource
Combined Cycle - 3X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 2X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 1X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Aero-derivative Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Large Nuclear	Baseload	Yes	Uranium	Yes	No
Nuclear Small Modular Reactor	Baseload	Yes	Uranium	Yes	Yes
Biomass	Baseload	Yes	Renewable	Yes	No
Fuel Cell	Baseload	Yes	Natural Gas	Yes	No
Supercritical Pulverized Coal with CCS	Intermediate	Yes	Coal	Yes	No
Solar & Aero-derivative CT	Peak	Yes	Renewable	Yes	No
Solar	Intermittent	No	Renewable	Yes	Yes
Wind - Onshore	Intermittent	No	Renewable	Yes	Yes
Wind - Offshore	Intermittent	No	Renewable	Yes	Yes
Battery Generic (30 MW)	Peak	Yes	Varies	Yes	Yes
Pumped Storage (300 MW)	Peak	Yes	Renewable	Yes	Yes
Combined Heat and Power	Peak	Yes	Varies	Yes	Yes

5.5.1 Supply-Side Resource Options

The following sections provide details on certain newer supply-side resource options the Company has considered. Previous Plans provide additional details on the more proven technologies, including biomass, CCs, CTs, nuclear, and solar. In addition, Section 5.4 provides additional details on generation currently under development, including offshore wind and pumped storage.

Aero-derivative Combustion Turbine

Aero-derivative CT technology consists of a gas generator that has been derived from an existing aircraft engine and used in an industrial application. Designed for a small footprint and low weight using modular construction, aero-derivative CTs utilize advanced materials for high efficiency and fast start-up times with little or no cyclic life penalty. Aero-derivative CTs have been designed for quick removal and replacement, allowing for fast maintenance and greatly reduced downtimes, and resulting in high unit availability and flexibility. This is a fast ramping and flexible generation resource that can effectively be paired with intermittent, non-dispatchable renewable resources, such as solar and wind.

Combined Heat and Power / Waste Heat to Power

Combined heat and power ("CHP") is the use of a power station to generate electricity and useful thermal energy from a single fuel source. CHP plants capture the heat that would otherwise be wasted to provide useful thermal energy, usually in the form of steam or hot water. The recovery of otherwise wasted thermal energy in the CHP process allows for more efficient fuel usage.

CHP's reduction in primary energy use through fuel efficiency leads to lower greenhouse gas emissions.

Waste heat to power ("WHP") is a type of combined heat and power that generates electricity through the recovery of qualified waste heat resources. WHP captures heat byproduct discarded by existing industrial processes and uses that heat to generate power. Industrial processes that involve transforming raw materials into useful products all release hot exhaust gases and waste streams that can be captured to generate electricity. WHP is another form of clean energy production.

The Company will continue to track this technology and its associated economics based on site and fuel resource availability.

Energy Storage

There are five main types of energy storage technologies: electromechanical, electrochemical, thermal, chemical, and electrical.

Electromechanical storage involves creating potential energy, which can be converted to kinetic energy. Pumped storage hydro, the most commonly used electromechanical storage technology, requires pumping large quantities of water to a reservoir at a higher elevation than the source, which creates potential energy that can be converted to kinetic energy that then spins a water turbine. Pumped storage hydro is a mature technology compared to other types of energy storage, and it represents the largest amount of installed storage capacity in the United States. See Section 5.4.3 for a discussion of the pumped storage hydroelectric facility under development. Other examples of electromechanical storage include flywheels and compressed air energy storage.

Electrochemical (or battery) storage involves storing electricity in chemical form. One advantage of electrochemical storage is the fact that electrical and chemical energy share the same carrier—the electron—which limits efficiency losses due to converting one form of energy to another. Lithium ion is now the most commonly used type of battery in utility-scale projects because lithium ion costs have been falling rapidly for nearly a decade. This decrease in cost is attributable to advancements in battery design, efficiency gains in manufacturing, and increased supply. Other examples of electrochemical storage include lead acid batteries, sodium sulfur batteries, and flow batteries.

Batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications. Batteries can be used to provide energy for a power station black start, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. Batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. Battery storage technology approximates dispatchability for these variable energy resources. The primary challenge facing battery systems is the cost. Other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems. The SCC recently approved the Company's application to pilot three lithium ion battery energy storage systems for different use cases. The results of these pilots will inform future deployment of batteries.

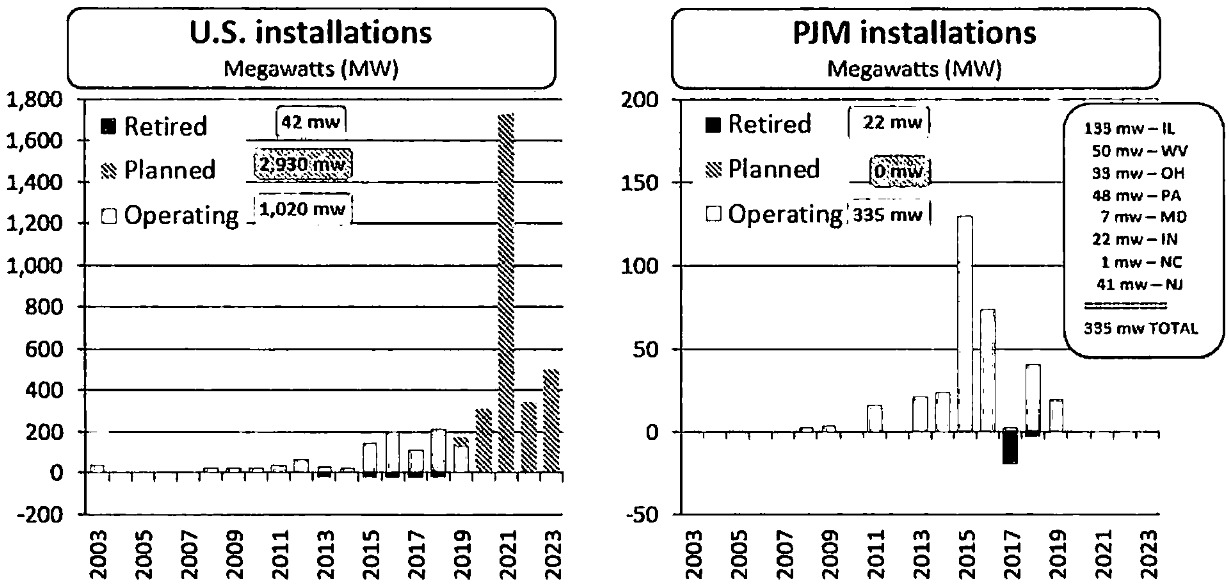
Thermal storage involves converting stored heat into energy, or supplying cool air to reduce air conditioning load. Water heaters, ice storage, and chilled water storage are all examples of thermal storage.

Chemical storage involves altering the molecular structure of compounds (such as water) by splitting or combining molecules. For example, hydrogen gas can be created by splitting H_2O molecules into H_2 and O_2. The H_2 (hydrogen gas) can be stored and later burned to produce steam to power a turbine. Another example of chemical storage is power-to-gas conversion, which converts electrical power into gaseous fuel.

Electrical storage primarily refers to super capacitors and magnetic energy storage, which can provide short, powerful bursts of energy to jumpstart other technologies.

Cost considerations and technology maturity have restricted widespread deployment of most of these technologies, with the exception of pumped storage hydroelectric power and batteries. At present, lithium-ion batteries and pumped storage are the most commercially viable energy storage technologies for utility-scale projects. Based on the most current information sourced from the U.S. Energy Information Administration, the amount of utility-scale battery storage installed in the entire United States is just over 1,000 MW, as shown in Figure 5.5.1.1. Of those 1,000 MW, only 335 MW are located within the PJM region.

Figure 5.5.1.1 – Utility-Scale Battery Storage Installations



As discussed in Section 1.2, the VCEA requires the Company to build 2,700 MW of energy storage by 2035. The Company will continue to study energy storage to determine the feasibility of constructing this quantity of energy storage capacity.

Fuel Cell

Fuel cells convert chemical energy from hydrogen-rich fuels into electricity and heat, there is no burning of the fuel. Fuel cells emit water and CO_2, resulting in power production that is almost entirely absent of NO_x, SO_x, or particulate matter. Similar to a battery, a fuel cell is comprised of many individual cells that are grouped together to form a fuel cell stack. Each individual cell contains an anode, a cathode, and an electrolyte layer. When a hydrogen-rich fuel, such as clean natural gas or renewable biogas, enters the fuel cell stack, it reacts electrochemically with oxygen (*i.e.*, ambient air) to produce electric current, heat, and water. While a typical battery has a fixed supply of energy, fuel cells continuously generate electricity as long as fuel is supplied. Fuel cells were invented in 1932 and put to commercial use by NASA in the 1950s. They are now most common as a power source for buildings and remote areas, but continual improvements in technology are quickly bringing them into wider use.

Integrated-Gasification Combined Cycle with Carbon Capture Sequestration

Integrated-gasification CC plants use a gasification system to produce synthetic natural gas from coal that is then used to fuel a CC. The gasification process produces a pressurized stream of CO_2 before combustion, which, as research suggests, provides some advantages in preparing the CO_2 for CCS systems. Integrated-gasification CC systems remove a greater proportion of other air effluents in comparison to traditional coal units.

Reciprocating Internal Combustion Engine

Reciprocating internal combustion engines use reciprocating motion to convert heat energy into mechanical work. Stationary reciprocating engines differ from mobile reciprocating engines in that they are not used in road vehicles or non-road equipment.

There are two basic types of stationary reciprocating engines, spark ignition and compression ignition. Spark ignition engines use a spark (across a spark plug) to ignite a compressed fuel-air mixture. Typical fuels for such engines are gasoline and natural gas. Compression ignition engines compress air to a high pressure, heating the air to the ignition temperature of the fuel, which then is injected. The high compression ratio used for compression ignition engines results in a higher efficiency than is possible with spark ignition engines. Diesel fuel oil is normally used in compression ignition engines, although some are duel-fueled (*i.e.*, natural gas is compressed with the combustion air and diesel oil is injected at the top of the compression stroke to initiate combustion).

Small Modular Reactors

Small modular reactors ("SMRs") are utility-scale nuclear units with electrical output of 300 MW or less. SMRs are manufactured largely off-site in factories, and then delivered and installed on-site in modules. The smaller power output of SMRs when compared to conventional baseload nuclear units currently in operation offers a number of advantages, including reduced land surface area, potential for reduced security and emergency planning zone requirements, lower initial capital and operating costs, and flexibility in meeting specific power needs by staging multiple units in the same or multiple locations. A typical SMR design entails underground placement of reactors and spent-fuel storage pools and a natural cooling feature that can continue to function in the absence of external power. SMR design development and permitting have advanced with some designs currently under review by the NRC. The Company will continue to monitor the industry's ongoing research and development regarding this technology. The federal government recently approved partial co-funding for up to two demonstration projects. The Company is reviewing and evaluating the potential for participation in this funding opportunity in support of its emission reduction targets.

5.5.2 Levelized Busbar Costs / Levelized Cost of Energy

The Company's busbar model was designed to estimate the levelized cost of energy of various generating resources on an equivalent basis. The busbar results show the LCOE of various generating resource technologies at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include fuel, heat rate, emissions, variable and fixed O&M costs, expected service life, and overnight construction costs.

Figures 5.5.2.1 and 5.5.2.2 display summary results of the busbar model comparing the economics of the different technologies. The results are separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources for the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.

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Figure 5.5.2.1 - Dispatchable LCOE (2023 COD)

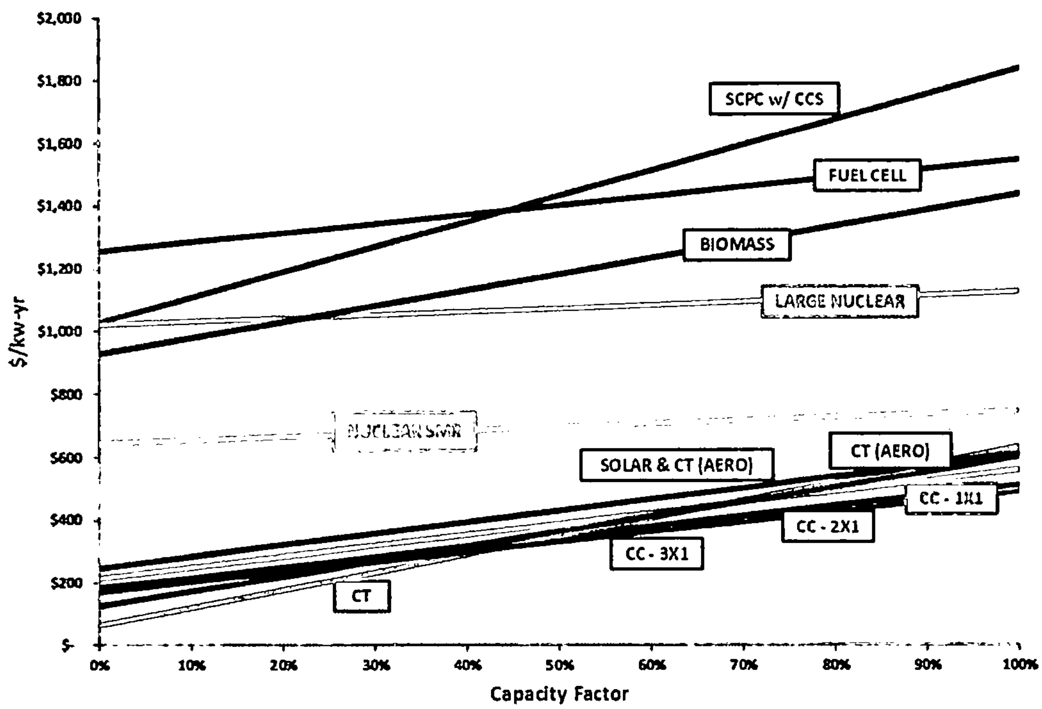
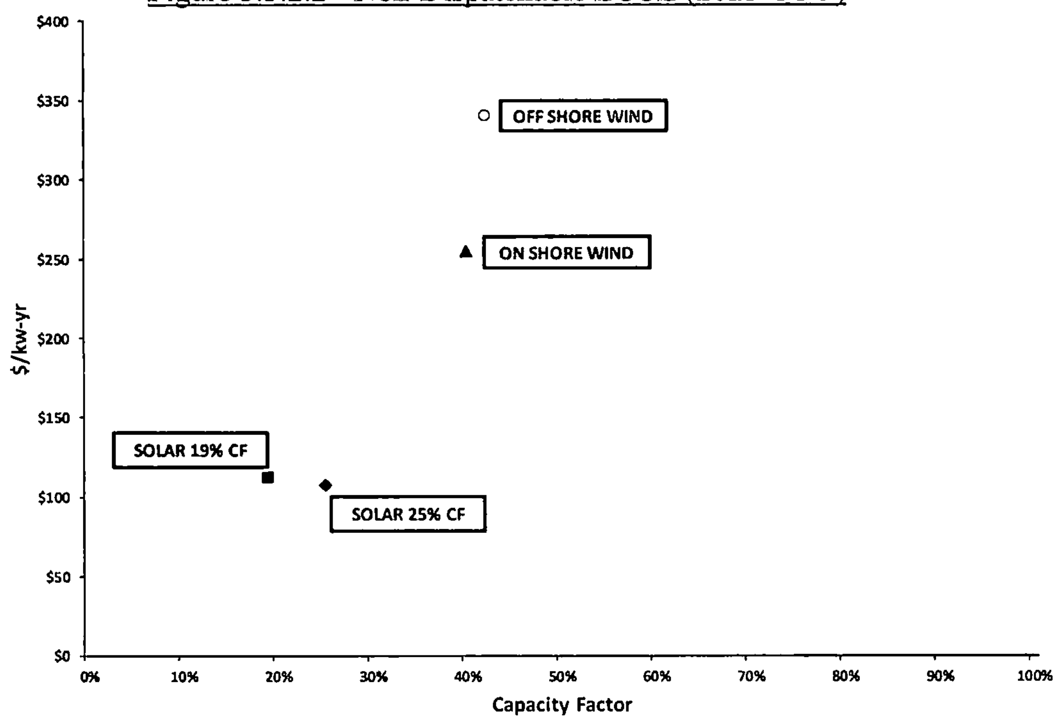


Figure 5.5.2.2 - Non-Dispatchable LCOE (2023 COD)



Appendix 5M contains the tabular results of the screening level analysis. Appendix 5N displays the assumptions for heat rates, fixed and variable O&M expenses, expected service lives, and the estimated construction costs.

In Figure 5.5.2.1, the lowest values represent the lowest cost assets at the associated capacity factors along the x-axis. Therefore, one should look to the lowest curve (or combination of curves) when searching for the lowest cost combination of assets at operating capacity factors between 0% and 100%. Resources with LCOE above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher LCOE resources, however, may be necessary to achieve other constraints like those required by carbon regulations. Figures 5.5.2.1 and 5.5.2.2 allow comparative evaluation of resource types.

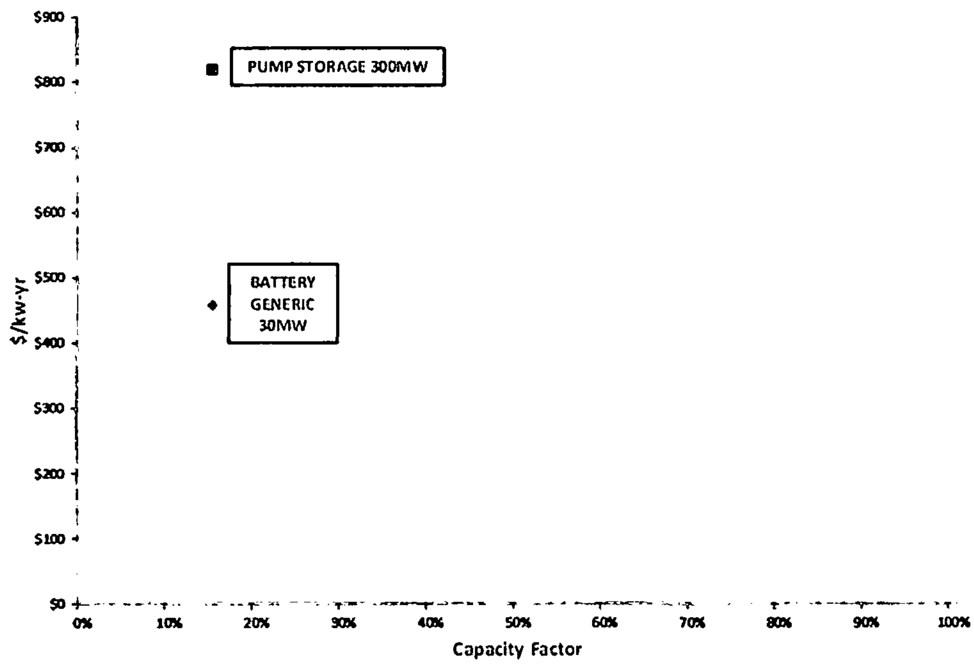
In Figure 5.5.2.1, the value of each cost curve at 0% capacity factor depicts the amount of invested total fixed cost of the unit. The slope of the unit's cost curve represents the variable cost of operating the unit, including fuel, emissions, and any REC or production tax credit ("PTC") value a given unit may receive.

Figure 5.5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods than dispatchable resources, requiring more capacity to maintain the same level of system reliability. Non-dispatchable resources may require additional grid equipment and technology changes in order to maintain grid stability.

As shown in Figure 5.5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 25% for meeting the Company's peaking requirements. The CC 3x1 technology is the most economical option for capacity factors greater than approximately 25%. As depicted in Figure 5.5.2.2, solar is a competitive choice at capacity factors of approximately 25%.

Figure 5.5.2.3 shows the estimated LCOE for a 300 MW pumped storage facility and generic 30 MW 4-hour battery. All LCOE are based on a 15% capacity factor, which was derived from the historical performance of the Company's pumped storage facilities, and projected performance of future energy storage technologies, as calculated by the PLEXOS model.

Figure 5.5.2.3 - Energy Storage LCOE (2023 COD)



The assessment of alternative resource types and the busbar screening process provides a simplified foundation in selecting resources for further analysis. However, the busbar curve is static in nature because it relies on an average of all of the cost data of a resource over its lifetime.

5.5.3 Third-Party Market Alternatives

During the last several years, the Company has increased its engagement of third-party solar developers in both its Virginia and North Carolina service territories.

In Virginia, the Company has issued an annual RFP for utility-scale solar and wind generating facilities since 2015. These RFPs have resulted in both Company-owned solar facilities and solar PPAs. Outside of the utility-scale solar and wind RFPs, the Company entered into PPA agreements for several solar facilities totaling 67 MW. The Company has also issued RFPs for small-scale solar resources. The Company will continue to issue annual RFPs for solar and wind resources, consistent with the competitive procurement requirements of the VCEA.

In North Carolina, the Company has signed 91 PPAs totaling approximately 686 MW (nameplate) of new solar NUGs. Of these, 572 MW (nameplate) are from 80 solar projects that were in operation as of March 2020. The majority of these projects are qualifying facilities contracting to sell capacity and energy at the Company's published North Carolina Schedule 19 rates in accordance with the Public Utility Regulatory Policies Act.

5.6 Challenges Related to Significant Volumes of Solar Generation

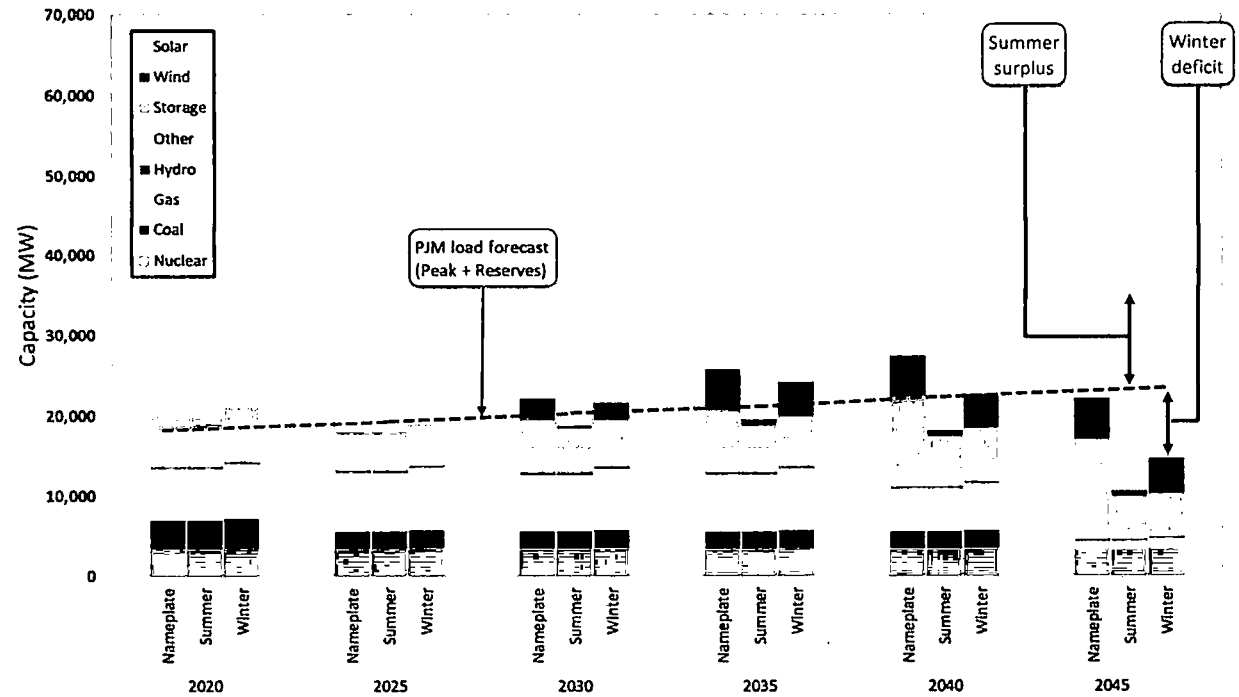
All Alternative Plans in this 2020 Plan include significant development of solar resources, as shown in Section 2.2. Based on current technology, challenges will arise as increasing amounts of these non-dispatchable, intermittent resources are added to the system. This section seeks to identify these challenges, which include intra-day, intra-month, and seasonal challenges posed by the interplay of solar generation and load, as well challenges related to system restoration. This section also discusses challenges related to constructing the level of solar generation in Alternative Plans B through D. In this 2020 Plan, Alternative Plan B best addresses these challenges based on current technology. But the Company stands ready to meet these challenges with continued study, technological advancement, and innovation, and will provide the results of these advancements in future Plans and update filings.

5.6.1 Challenges Related to Capacity

Solar generation significantly contributes to meeting peak demand in the summer, but barely contributes to meeting winter peak demand. This is because summer peak demand occurs during late afternoon hours when the sun is typically shining and, consequently, when the solar facilities are producing energy. In contrast, winter peak demand typically occurs in the early morning hours when the sun is beginning to rise, and when solar facilities are just starting to ramp up production.

As the Company adds increasing amounts of solar resources to the system, this will result in the system having excess capacity in the summer, but not having enough capacity in the winter. For example, Figure 5.6.1.1 shows the nameplate capacity, summer capacity, and winter capacity of existing and new resources in Alternative Plan D compared to the 2020 PJM Load Forecast. As can be seen, the Company has approximately 11,500 MW more capacity than needed in the summer in Alternative Plan D, but then has a deficit of approximately 8,800 MW in the winter.

Figure 5.6.1.1 – Alternative Plan D Capacity in Summer and Winter



Notes: "Other" = biomass, small combustion turbines, NUGs, demand response, purchases, & heavy oil units

Adding energy storage resources is one way the Company could meet this winter capacity deficit. The capacity value of energy storage resources is limited, however, by the size of the resource and by the time it takes to recharge. Significantly more energy storage capacity would be needed, both in magnitude and duration, as the peak gets steeper and as the period that those resources are expected to support the system becomes longer. The combination of these factors would likely lead to an overbuilt system (*i.e.*, a system with higher resource nameplate capacity compared to peak load). In addition, many forms of utility-scale energy storage are still in the early stages of development, as discussed further in Section 5.5.1, with higher costs relative to other current technologies. Technological advancements may provide other options to meet this challenge in the long term without necessitating an overbuild of the system.

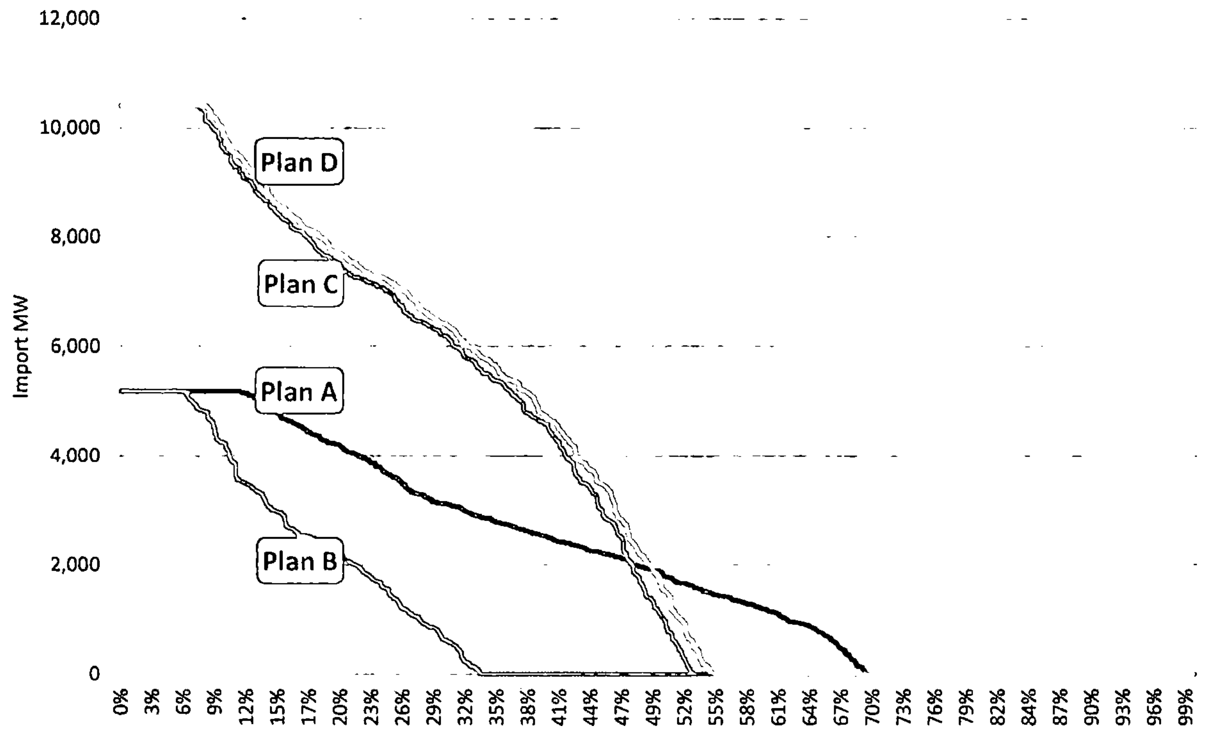
The Company could also meet this challenge related to winter capacity in the future by buying capacity to fill the deficit to the extent required by PJM market rules. In this 2020 Plan, the Company assumed it would meet any winter deficit with capacity from the market. Historically, the Company was able to self-supply to meet the vast majority of all its capacity needs; Alternative Plans C and D rely heavily on the market to maintain the reliability of the system.

5.6.2 *Challenges Related to Energy*

In addition to challenges related to winter capacity, development of significant volumes of solar generation also present challenges related to energy. Specifically, the Company would likely need to import a significant amount of energy during the winter, but would need to export significant amounts of energy during the spring and fall. Figure 5.6.2.1 shows the level of imports for each Alternative Plan. Figure 5.6.2.2 shows what percentage of time in the year 2045 the Company must use imports to meet load. In addition, Figure 5.6.2.2 shows the percentage of time in year 2045 that imports are constrained by system limitations—5,200 MW for Plans A and B, and 10,400 MW for Plans C and D.

Figure 5.6.2.1 – Annual Imports for Each Alternative Plan

Figure 5.6.2.2 – Year 2045 Import Duration Curve



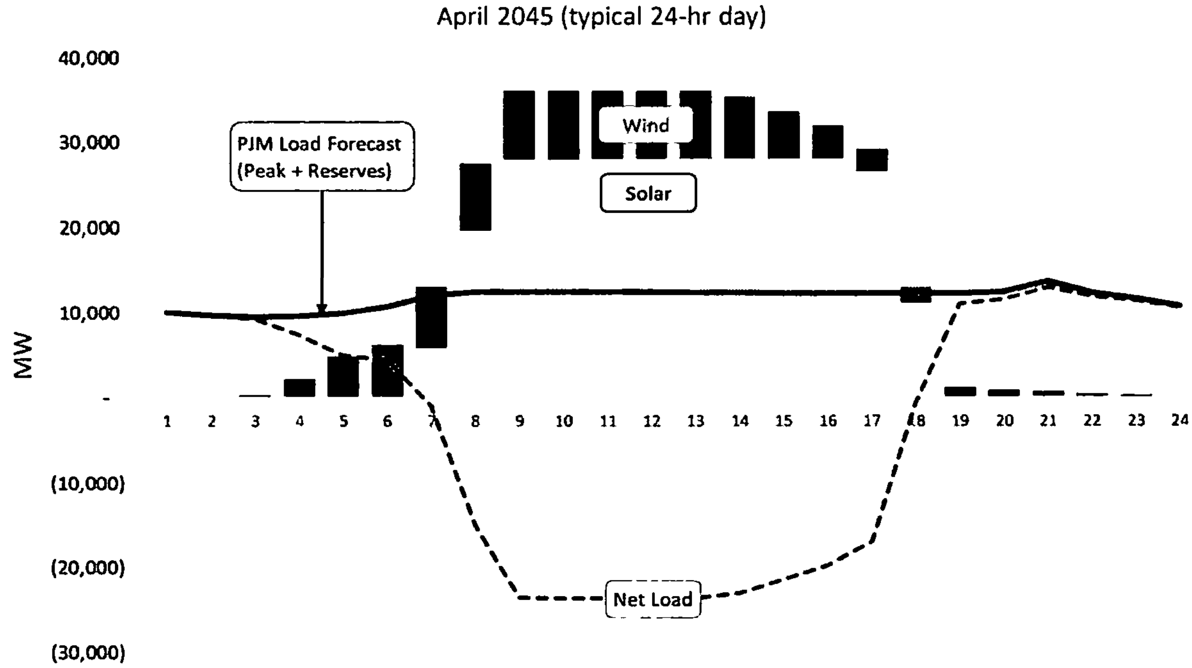
Importing significant energy presents its own challenges. Section 7.5 includes a discussion of the upgrades that would be needed to the Company's transmission system to physically import these increased levels of energy, as well as an estimate of those costs. Notably, relying on increased imports could also contribute to regional CO_2 emission because the imported power from PJM would come in part from carbon-emitting generation in the PJM region. Figure 2.2.6 shows regional carbon emissions for each Alternative Plan.

5.6.3 Challenges Related to the Solar Production Profile

Output from solar facilities generally tracks the sun, ramping up in the morning as the sun rises, producing consistently throughout the day subject to cloud cover, and then ramping down as the sun sets. This production profile generally (although not perfectly) fits well with customer demand in the summertime because customer demand is higher during the afternoon hours when solar production is high. In the spring and fall, however, as increasing amounts of solar generation is added to the system, solar can produce more energy than is needed to meet customer demand during the daytime.

Figure 5.6.3.1 shows the capacity of the solar and wind resources in Alternative Plan D during a typical day in April compared to the PJM Load Forecast. As can be seen, the inclusion of large amounts of solar and wind generation significantly alters the shape of the net load profile (*i.e.*, forecasted load less the non-dispatchable solar and wind energy) causing a dip in the middle of the day. This profile is commonly referred to as a "duck curve" because it produces a profile that resembles the silhouette of a duck. As Figure 5.6.3.1 shows, the Company would need additional energy at dawn and dusk, but would have excess energy during the daytime.

Figure 5.6.3.1 – Solar and Wind Capacity Compared to Load Forecast



The Company could address this challenge with additional energy storage resources, though some energy would be lost when storage resources are used. The Company could also increase the amount of energy it exports subject to system need, though this would be limited by transmission export capacity. The Company may also be limited in its ability to export excess energy in the spring and fall to the extent neighboring states elect to develop significant volumes of solar resources similar to Virginia and also have excess energy.

In some instances, it would become more economic to "dump" this excess energy when compared to the costs of building additional energy storage resources, increasing transmission export capacity, or facing negative market energy prices. From an operational perspective, energy is "dumped" by lowering the output levels of certain solar facilities during periods of low demand. One possible clean energy solution to this challenge, however, would be to utilize long-term storage solutions for this dump energy. For example, the Company could utilize this excess energy to create carbon-free hydrogen fuel that could subsequently be used in natural gas-fired generators. When hydrogen fuel is used in gas-fired generators, the byproduct is water rather than CO_2. The Company will continue to study these types of innovative alternatives to address challenges caused by increasing levels of solar generation on the system. Based on the advancements and innovations in the industry in the next 25 years, Virginia may need to adjust its RPS to accommodate other potential technologies that would provide clean energy while maintaining system reliability.

Another potential issue caused by the solar production profile shown in Figure 5.6.3.1 is the steep generation changes in the dawn and dusk periods. In a three-hour period, the system would have to ramp over 30,000 MW of supply—an extremely large magnitude, especially over that short of a duration. Essentially, the Company would be ramping up and down its entire fleet of dispatchable resources twice a day. Backup generation resources along with energy storage resources may be required to manage these large transitions.

5.6.4 Challenges Related to Black Start and System Restoration

"Black start" refers to the critical process of restoring the system without relying on the external transmission network to recover from a total or partial shutdown. Development of significant volumes of solar generation also present challenges in a black start event. The system has traditionally been set up to rely on dispatchable, quick-start units for black start, such as combustion turbines. Initial power from these units are used to start larger dispatchable generators, allowing even larger units (*e.g.*, nuclear) and customers to reconnect to the grid in a very logical and coordinated process. This process is largely a manual process for grid operators as they must maintain a fine balance between energy supply and demand; black start units thus have strict operational requirements to be available around-the-clock and be able to produce steady and predictable output. Such requirements impose difficulties for non-dispatchable, intermittent solar resources to be included in the system restoration plan.

In this 2020 Plan, Alternative Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability and energy independence, including challenges related to black start. The Company will continue to study how to address these black start-related challenges as the Company transition to a cleaner future, as discussed further in Section 7.5.5.

5.6.5 Challenges Related to Constructability

Beyond the system challenges that arise from adding increasing amounts of intermittent generation to the system, solar developers—including the Company—will face increasing challenges in permitting and constructing the amount of solar generation envisioned by the VCEA, as modeled in Alternative Plans B through D.

Utility-scale solar generating facilities require a significant amount of land. Based on current technology, every one megawatt of solar capacity requires approximately 10 acres of land. The VCEA requires this new solar capacity to be located in Virginia. Acquiring this amount of land—and receiving the required permits for that land—could prove increasingly difficult as development continues.

This difficulty in acquiring land and permitting projects will be exacerbated if localities and members of the public continue to raise objections to siting solar facilities in their communities. For example, in October 2019, the Culpepper County Board of Supervisors adopted new provisions to its Utility Scale Solar Development Policy intended "to limit 'utility scale solar sprawl.'" These new provisions would limit total solar development in the county to 2,400 acres—1% of the total land mass in Culpeper—and would limit the size of individual projects to 300 acres (the equivalent of approximately 30 MW). As another example, in Spotsylvania County, Virginia, neighboring property owners and community members have filed complaints with the county's board of zoning appeals related to the development of a 6,300 acres utility-scale solar facility.

Aside from the land, the supply chain organization for the solar industry will be challenged to meet the level of solar generation in Alternative Plans B through D. This includes both equipment suppliers and construction contractors. Specifically, world-wide panel manufacturers will need to ramp up production as the demand for solar generation increases both inside the Company's service territory and across the United States. Additionally, qualified construction contractors for building utility-scale solar facilities will need to expand and train a large a labor force. Utilizing a skilled vendor to construct the solar facilities will be an important factor going forward, as the land available for future solar development is expected to be less optimal, requiring more design and engineering work to meet output targets.

Chapter 6: Generation – Demand-Side Management

This chapter provides a description of the DSM planning process, and an overview of approved, proposed, and rejected DSM programs. See Section 4.1.3 for discussion of how the Company adjusted the load forecasts used in this 2020 Plan to account for energy efficiency targets. This chapter also provides the energy efficiency-related analysis required by the GTSA.

In this 2020 Plan, there is a total reduction of 1,120 GWh by 2020 in DSM-related savings. By 2025, there are 3,459 GWh of reductions included in the PLEXOS modeling for this 2020 Plan. Projected energy savings include reductions from identified sources (*i.e.*, DSM programs approved by and proposed to the SCC), as well as unidentified sources (*i.e.*, "generic" DSM as discussed below). For modeling purposes, neither the identified nor the unidentified sources included free-ridership effects. If these sources had included free-ridership effects, the reductions by 2020 and 2025 would be 945 GWh and 3,028 GWh, respectively. Projected savings attributable to DSM programs in 2025 are shown in Figure 6.1.

There are several drivers that will affect the Company's ability to meet the current level of projected energy and demand reductions, including the cost-effectiveness of the DSM programs when filed, the SCC and NCUC approval of newly filed programs, the continuation of existing programs, the final outcome of proposed environmental regulations, the full implementation of AMI and the customer information platform through the Company's Grid Transformation Plan, and customers' willingness to participate in approved DSM programs.

Figure 6.1 - DSM Program Projected Savings By 2025

	Program	Projected MW Reduction	Projected GWh Savings	Status (VA/NC)
Phase I	Air Conditioner Cycling Program	54	-	Approved / Approved
	Residential Low Income Program	2	8	Completed / Completed
	Residential Lighting Program	-	-	
	Commercial Lighting Program	-	-	Closed / Closed
	Commercial HVAC Upgrade	1	4	
Phase II	Non-Residential Distributed Generation Program	12	1	Extension Approved / Rejected
	Non-Residential Energy Audit Program	-	-	Completed /Completed
	Non-Residential Duct Testing and Sealing Program	8	81	
	Residential Bundle Program	7	29	
	Residential Home Energy Check-Up Program	*1*	*10*	
	Residential Duct Sealing Program	*1*	*2*	
	Residential Heat Pump Tune Up Program	-	-	
	Residential Heat Pump Upgrade Program	*4*	*17*	
Phase III	Non-Residential Window Film Program	4	4	
	Non-Residential Lighting Systems & Controls Program	19	115	
	Non-Residential Heating and Cooling Efficiency Program	7	34	
Phase IV	Income and Age Qualifying Home Improvement Program	2	17	Extension Approved/Approved
	Residential Appliance Recycling Program	-	-	Completed
Phase V	Small Business Improvement Program	16	90	Approved/Approved
	Residential Retail LED Lighting Program (NC only)	1	7	No Plans/Completed
Phase VI	Non-Residential Prescriptive Program	8	21	Approved/Approved
Phase VII	Residential Efficient Products Marketplace Program	6	436	
	Non-Residential Lighting Systems & Controls Program	9	43	
	Residential Appliance Recycling Program	4	28	
	Non-Residential Heating and Cooling Efficiency Program	9	42	
	Non-Residential Window Film Program	2	9	
	Residential Home Energy Assessment Program	15	88	
	Non-Residential Office Program	2	26	
	Non-Residential Small Manufacturing Program	3	15	
	Residential Customer Engagement Program	15	51	Approved/Future
	Residential Smart Thermostat Management Program (DR)	83	-	
	Residential Smart Thermostat Management Program (EE)	4	23	
Phase VIII	Non-Residential Midstream EE Products	12	19	Proposed/Future
	Non-Residential New Construction	5	21	
	Residential EE Kits	3	38	
	Residential Home Retrofit	6	21	
	Residential Manufactured Housing	4	17	
	Multifamily Program	21	68	
	HB 2789 HVAC Component	6	19	
	Residential New Construction	17	32	
	Non-Residential Small Business Improvement Enhanced	14	47	
	Residential Electric Vehicle EE/DR	6	2	
	Residential Electric Vehicle Peak Shaving	1	0	

6.1 DSM Planning Process

The Company has historically used the following process related to its DSM programs:

The GTSA established the DSM stakeholder group, which helps to generate program ideas. The Company takes those ideas and develops them into more concrete program parameters, which are then compiled into an RFP of candidate program designs and implementation services sent to qualified vendors. The Company develops assumptions for new DSM programs by engaging vendors through a competitive RFP process to submit proposals for candidate program design and implementation services. As part of the bid process, basic program design parameters and descriptions of candidate programs are requested. The Company generally prefers, to the extent practical, that the program design vendor is ultimately the same vendor that implements the program in order to maintain as much continuity as possible from design to implementation.

Once proposals through an RFP process are received, the Company's energy conservation group works with its supply chain group to systematically review the proposals. Program designs are reviewed for responsiveness to the RFP, practicality of the design, technology requirements, staffing plan, marketing plan, reasonableness of the measures proposed, overlap with existing measures, cost reasonableness, previous experience, work history with the Company, expected ability to deliver the services proposed, and ability of the proposing firm to comply with the Company's terms and conditions, data protection requirements, and financial requirements. Proposals must contain detailed information regarding measure load profiles and market penetration projections in a specific format that allows modeling of the program as a demand side resource when compared against other resources, including supply-side resources.

Candidate designs that are judged to be reasonable, based on preliminary review, are evaluated for cost-effectiveness from a multi-perspective approach using four of the standard tests from the California Standards Practice Manual: (i) the Participant Test, (ii) Utility Cost Test, (iii) Total Resource Cost ("TRC") Test, and (iv) Ratepayer Impact Measure Test. Each test uses the NPV of costs and benefits. Tests are conducted at a program level.

PLEXOS does not have the ability to conduct cost-benefit evaluations for DSM within the model itself, leading to the need for an additional model, tool, or process. For this reason, the Company has continued its use of Strategist for DSM evaluations using consistent data between the models. The inputs into Strategist are consistent with those in PLEXOS for the 2020 Plan. The Company looks at the results of all of the cost-benefit test scores, as well as NPV results, to evaluate whether to file for regulatory approval of a potential program or program extension.

If the programs are cost effective based on the modeling results, or otherwise legislatively deemed to be in the public interest for policy reasons, the programs are then filed with the SCC for approval. The SCC approval process lasts approximately eight months. For the programs that are approved, the Company works with the RFP suppliers to finalize a contract for full implementation of the program. Once all details are finalized, a new DSM program can be launched for participation by eligible customers.

Finally, the Company conducts evaluation, measurement and verification of all DSM programs and provides reports to the SCC each May for the prior calendar year on specific program metrics, including participation, spending, and energy and demand savings.

6.2 Approved DSM Programs

Appendix 6A provides program descriptions for the currently active DSM programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and its plans to achieve each program's penetration goals. Appendices 6B, 6C, 6D, and 6E provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each approved program.

In July 2019, the Company filed for NCUC approval of the (i) Residential Home Energy Assessment Program, (ii) Residential Efficient Products Marketplace Program, (iii) Residential Appliance Recycling Program, (iv) Non-Residential Window Film Program, (v) Non-Residential Small Manufacturing Program, (vi) Non-Residential Office Program, (vii) Non-Residential Lighting Systems & Controls Program, and (viii) Non-Residential Heating and Cooling Efficiency Program. In November 2019, the NCUC issued its Final Order approving all eight programs.

The Company also currently offers one DSM pricing tariff, the standby generation ("SG") rate schedule, to enrolled commercial and industrial customers in Virginia. This tariff provides incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed. Two customers are on SG in Virginia. The SG rate schedule provides a direct means of implementing load reduction during peak periods by transferring load normally served by the Company to a customer's standby generator. The customer receives a bill credit based on a contracted capacity level or the average capacity generated during a billing month when SG is requested. During a load reduction event, a customer receiving service under the SG rate schedule is required to transfer a contracted level of load to its dedicated on-site backup generator. Figure 6.2.1 provides estimated load response data for summer/winter 2019.

Figure 6.2.1 - Estimated Load Response Data

	Summer 2019		Winter 2019	
Tariff	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	19	2	0	0

The Company modeled this existing DSM pricing tariff over the Study Period based on historical data from the Company's customer information system. Projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future.

6.3 Proposed DSM Programs

On December 3, 2019, the Company filed for SCC approval in Case No. PUR-2019-00201 of eleven new DSM programs and extension of one existing program. The eleven proposed programs in Phase VIII are:

- Residential Electric Vehicle (EE & DR);
- Residential Electric Vehicle (Peak Shaving);

- Residential Energy Efficiency Kits;
- Residential Home Retrofit;
- Residential Manufactured Housing;
- Residential New Construction;
- Residential/Non-Residential Multifamily;
- Non-Residential Midstream Energy Efficient Products;
- Non-Residential New Construction;
- Small Business Improvement Program Enhanced; and
- HB 2789 Heating and Cooling/Health and Safety.

In addition, the Company filed for an extension of the existing Air Conditioner Cycling Program and expedited approval to launch three of the Phase VII programs. The SCC must issue its Final Order in Case No. PUR-2019-00201 by August 2020.

Through House Bill No. 2789 from the 2019 Regular Session of the Virginia General Assembly, the Company is required to seek approval of a three-year rebate program targeting low-income, elderly, and disabled customers. The program would incentivize energy conservation measures that reduce residential heating and cooling costs and enhance the health and safety of residents (at least $25 million available in rebates). Another program targeting participants in the above-described program must incentivize installation of solar equipment (not to exceed $25 million). In December 2019, the Company filed for approval of the energy efficiency component of the rebate program. The solar stakeholder group continues to develop the solar component of this program.

Appendix 6F provides program descriptions for the proposed DSM programs. Appendices 6G, 6H, 6I and 6J provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each proposed program.

6.4 Future DSM Initiatives

The Company is currently conducting an appliance saturation study and, once completed, will begin a new DSM market potential study within the Company's service territory. This market potential study will provide additional guidance regarding what additional DSM measures are achievable.

As noted in Section 6.1, during the first and second quarter of each year, the Company conducts an RFP process to solicit designs and recommendations for a broad range of DSM programs. The Company anticipates continuing this process for the foreseeable future. Within this process, detailed proposals are requested for programs that include measures identified in the most recent DSM Potential Study, as well as other potential cost-effective measures based upon current market trends.

Load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations for the Company in determining which DSM resources to deploy in the future. The use of these DSM resources largely depends on the circumstances and cannot be prescribed in any definitive manner. The Company will continue to identify and seek approval to implement DSM programs that are cost effective or meet public policy goals.

As to cost-effective DSM available to respond to the growth of the winter peak, the Company's Distributed Generation Program is currently available to eligible non-residential customers in Virginia and provides dispatchable demand savings during winter periods to non-residential customers who meet participation requirements based upon size. The Company currently has a demand response residential thermostat control program pending approval in Virginia, which would also provide winter demand and energy savings. Further, the Company's other proposed DSM programs noted in Section 6.3 address both summer and winter peaks as well as energy requirements. While demand response programs can be used to reduce peak periods explicitly, energy efficiency programs can also provide reductions during winter hours. The Company is also participating in a stakeholder process required by the GTSA to help it identify potential opportunities for future energy efficiency and demand response programs. This effort will hopefully lead to future DSM initiatives that will address both summer and winter peak hours.

Appendices 6K and 6L provide the system-level coincidental peak savings and energy savings for future undesignated EE programs.

6.5 Rejected DSM Programs

The Company rejected the following programs as part of the 2019 DSM process: (i) Non-Residential Agricultural EE, (ii) Non-Residential Strategic Energy Management, and (iii) Non-Residential Telecommunications Optimization. A list of these and other rejected DSM programs from prior integrated resource planning cycles is shown in Appendix 6M. Rejected programs may be re-evaluated and included in future DSM portfolios.

6.6 GTSA Energy Efficiency Analysis

Enactment Clause 18 of the GTSA required the Company to "incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the utility's carbon intensity."

The Company is committed to meeting state energy goals, which is why the Company offers energy conservation programs to help customers save energy and maximize savings while also reducing emissions and the Company's carbon intensity. The GTSA sets the target of proposing $870 million of spending on energy efficiency between 2018 and 2028. Of this amount, the VCEA directs that at least 15% be for programs aiding low-income, elderly, veteran, and disabled customers. The VCEA further sets the target of reaching 5% energy efficiency savings (based on 2019 jurisdictional electricity sales) by 2025.

The Company has determinedly sought approval of new DSM programs from the SCC—including 22 new programs in the last two years—to meet these targets. The Company is also actively involved in regular stakeholder meetings to generate new program concepts and then utilizes an annual solicitation of new measures and program re-designs from expert vendors within the industry.

The Company considers the stakeholder forum, which provides transparency and inclusivity in the process, to represent the best opportunity to develop a long-term plan for energy efficiency measures that will ultimately achieve the DSM policy goals set by the Commonwealth.

Enactment Clause 18 of the GTSA also directed that utility considerations of energy efficiency within its long-term plan shall include analysis of the following:

- Energy efficiency programs for low-income customers in alignment with billing and credit practices;
- Energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions;
- Programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers;
- Options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers;
- The extent that electricity rates account for the amount of customer electricity bills in the Commonwealth and how such extent in the Commonwealth compares with such extent in other states, including a comparison of the average retail electricity price per kWh by rate class among all 50 states;
- An analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relevant factors; and
- Other issues as may seem appropriate.

6.6.1 Considerations for Certain Customers Groups and Options for Combining Distributed Generation, Energy Storage, and Energy Efficiency

The Company's existing Residential Income and Age Qualifying Home Improvement Program provides in-home energy assessments and installation of select energy-saving products at no cost to eligible participants. The Program is available to qualified customers in the Company's Virginia service territory. The Program conforms to the Virginia Department of Housing and Community Development qualification guidelines, which is currently set at 60% state median income. It is also available to customers who are 60 years or older with a household income of 120% of the state median income. Notably, the Company has proposed changing eligibility for this and future income-based programs to use area median income to allow greater eligibility among participants living in higher-income areas of the state that may still be in need. The Program is available to qualified individuals living in single-family homes, multifamily homes, and mobile homes. Based on evaluation, measurement and verification, however, this Program's participants have largely—more than 90%—come from multifamily living situations.

Additionally, a special subgroup focused on low income DSM program improvements is meeting as part of the stakeholder process and making valued suggestions for future improvements that will result in better alignment with the state's federally funded program. The Company has and will continue to work with the Department of Housing and Community Development to establish alignment with programs where helpful and beneficial.

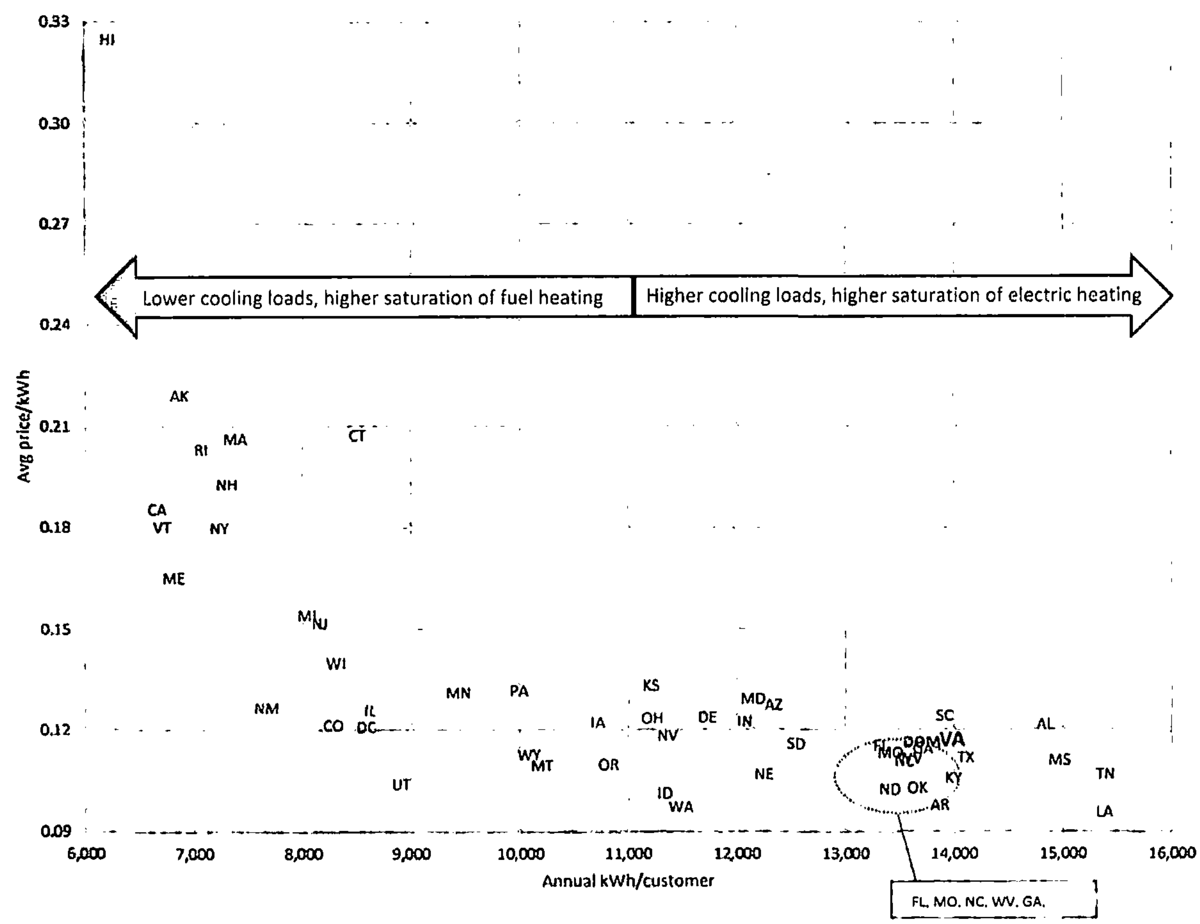
Finally, in December 2019, the Company requested SCC approval of the first component of the House Bill 2789 (Heating and Cooling/Health and Safety) Program as part of its DSM Phase VIII proposal. Virginia House Bill 2789 requires that a petition be submitted for a program for income qualifying, elderly and disabled individuals consisting of two components. The first component would offer incentives for the installation of measures that reduce residential heating and cooling costs and enhance the health and safety of residents, including repairs and improvements to home heating and cooling systems and installation of energy-saving measures in the house, such as insulation and air sealing. The second component would offer incentives to participants of the first component for the installation of equipment to generate electricity from sunlight. The Company expects to request approval of the second component associated with solar generation equipment in a future filing.

6.6.2 Electricity Rate and Consumption Comparison

Electricity bills are driven by a combination of electricity rates and electricity consumption. The following charts show where each state and the Company falls by electricity rate and consumption.

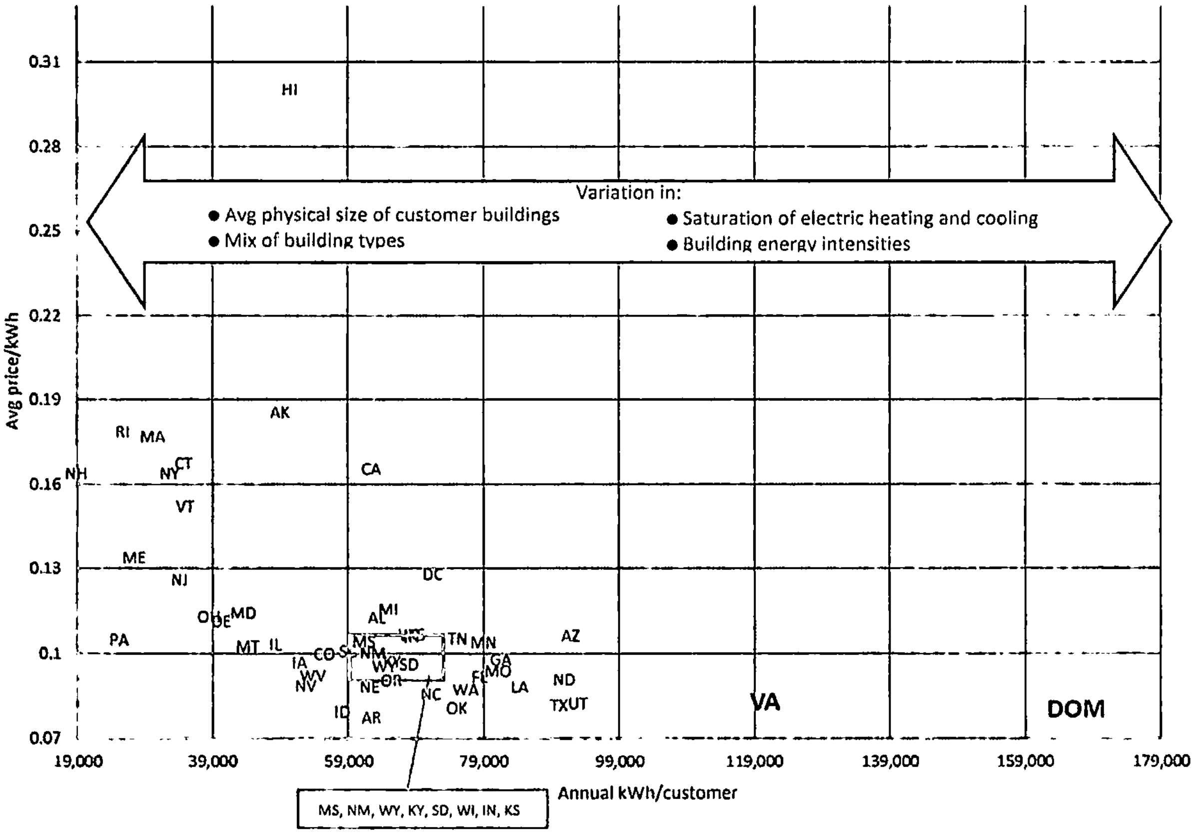
In the residential sector, the Company and Virginia as a whole fall within a cluster of mostly southern states with below-average rates and relatively high consumption. The consumption level reflects a high saturation of electric heating equipment compared to other parts of the U.S., paired with high cooling loads.

Figure 6.6.2.1 – States by Residential Average Price per kWh and Consumption per Household



In the commercial sector Virginia is an extreme outlier in consumption per customer, averaging more than 120,000 kWh per year. The Company is one of three utilities in Virginia with average commercial consumption over 100,000 kWh per year; the others are the City of Harrisonburg and Virginia Tech Electrical Services. In contrast, the lowest average commercial consumption belongs to Community Electric Cooperative at less than 14,000 kWh per commercial customer, comparable to a home. The primary drivers of commercial consumption are the size of the customer (building square feet, number of employees) and the type of building activity. Denser urban areas tend to have larger commercial buildings and therefore higher average commercial consumption, and the Company's service territory captures many of Virginia's densest urban areas. The Company also has a high concentration of data centers among its commercial customers. Data centers are extremely energy intensive, as the densely packed computing equipment they contain produces waste heat that drives high space cooling loads. Because of the extreme differences among commercial customers, building efficiencies are typically compared based on energy intensity (energy use per square foot) and only among similar building types (offices with offices and restaurants with restaurants).

Figure 6.6.2.2 – States by Average Commercial Price per kWh and Average Consumption per Commercial Customer



6.6.3 National Comparison of Primary Fuel Sources for Generation

The Company engaged DNV GL Energy Insights U.S.A. ("DNV GL") to analyze fuel source for generation, as well as the additional metrics referred to in the legislation. This analysis is provided in Appendix 6N.

6.6.4 Other Relevant Issues for Energy Efficiency Analysis

DNV GL, on behalf of the Company, also regularly assesses both the current stock of appliances through an appliance saturation study, and the potential for electric energy (kWh) and demand (kW) savings from Company-sponsored DSM programs through a Market Potential Study of both residential and commercial customers. The most recent iteration of this process is currently underway and results are expected by late 2020. The results will include

- Estimates of the magnitude of potential savings on an annual basis;
- Estimates of the costs associated with achieving those savings; and
- Calculations of the cost effectiveness of the measures based on the estimates above from a TRC perspective assuming PJM market price estimates.

The Company and DNV GL conducted previous Market Potential Studies in 2015 and 2017; the 2017 Market Potential Study was updated in 2018 to reflect changes to eligibility for commercial customers due to the GTSA. Appliance Saturation Studies and Residential Conditional Demand Analyses were conducted in 2013 and 2016, and included mail and electronic surveys of residential and commercial customers.

The Market Potential Studies estimate three basic types of energy efficiency potential:

- Technical potential: The complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.
- Economic potential: The technical potential of those energy efficiency measures that are cost-effective when compared to supply-side alternatives.
- Achievable program potential: The amount of savings that would occur in response to specific program funding, marketing, and measure incentive levels. In this study, the Company looked at the potential available under two funding scenarios—50% incentives and 75% incentives.

The Company, through its DSM stakeholder process, uses the information contained in the Market Potential Studies to help develop ideas for potential DSM programs to include measures that may be cost beneficial. The most recent Market Potential Study is typically released with a Company solicitation for DSM programs.

6.7 Overall DSM Assessment

At the end of the Planning Period (*i.e.*, 2035), energy reductions projected for the identified DSM programs are approximately 1,373 GWh. This compares to 1,276 GWh identified in the 2019 Update, or an approximately 8% increase in energy reductions. The majority of the increase in energy reductions is attributed to the proposed Phase VIII DSM programs included in the 2019 Virginia DSM filing.

The capacity reductions at the end of the Planning Period for the identified DSM programs are 383 MW in this 2020 Plan. This compares to 405 MW in the 2019 Update, or an approximately 5% decrease in demand reductions. This decrease is largely attributable to (i) the Non-Residential Prescriptive Program not yet realizing adoption of high energy and high capacity reduction measures; and (ii) corrected design assumptions for the Residential Thermostat Programs.

In this 2020 Plan, the unidentified DSM resources are presented as an unidentified generic block of energy efficiency reductions priced at $200/MWh to meet the GTSA and VCEA requirements, as explained in Section 4.1.3. For comparison, in the 2019 Update, the Company included an unidentified generic block of energy efficiency reductions to meet the requirements of the GTSA only.

See Section 4.1.3 for a discussion of the energy efficiency reductions used as adjustments to the load forecast in this 2020 Plan. Figures 4.1.3.1 and 4.1.3.2 show these energy efficiency energy and capacity adjustments, respectively.

Figure 6.7.3 presents a comparison of the Company's expected demand-side management costs relative to expected supply-side costs. The costs are provided on a levelized cost per MWh basis for both supply- and demand-side options. The supply-side options' levelized costs are developed by determining the revenue requirements, which consist of the dispatch cost of each of the units and the revenue requirement associated with the capital cost recovery of the resource. The demand-side options' levelized cost is developed from the cost-benefit runs. The costs include the yearly program cash flow streams that incorporate program costs, customer incentives, and evaluation, measurement, and verification costs. The NPV of the cash flow stream is then levelized over the Planning Period using the Company's weighted average cost of capital. The costs for both types of resources are then sorted from lowest cost to highest cost and are shown in Figure 6.7.3.

Figure 6.7.3 – Comparison of per MWh Costs of Selected Generation Resources

Comparison of per MWh Costs of Selected Generation	Capacity Factor	Cost ($/MWh) no RECs	Cost ($/MWh) with RECs
Residential Efficient Products Marketplace Program	n/a	$11	n/a
Non-Residential Heating and Cooling Efficiency Program	n/a	$30	n/a
Residential EE Kits	n/a	$33	n/a
Multifamily Program	n/a	$33	n/a
Small Business Improvement Program	n/a	$37	n/a
Non-Residential Window Film Program	n/a	$43	n/a
Residential Home Retrofit	n/a	$44	n/a
Residential Customer Engagement Program	n/a	$46	n/a
Non-Residential Lighting Systems and Controls Program	n/a	$48	n/a
Non-Residential Office Program	n/a	$55	n/a
Solar	25%	$58	$49
Non-Residential Small Business Improvement Enhanced	n/a	$60	n/a
Residential Manufactured Housing	n/a	$60	n/a
CC - 3X1	80%	$61	n/a
Non-Residential Small Manufacturing Program	n/a	$61	n/a
Residential Home Energy Assessment Program	n/a	$61	n/a
Residential Smart Thermostat Management Program (EE)	n/a	$62	n/a
Residential Appliance Recycling Program	n/a	$64	n/a
CC - 2X1	80%	$64	n/a
Non-Residential Midstream EE Products	n/a	$65	n/a
Residential New Construction	n/a	$67	n/a
CC - 1X1	80%	$70	n/a
CC - 3X1 w/ CCS	80%	$71	n/a
Non-Residential New Construction	n/a	$74	n/a
CC - 2X1 w/ CCS	80%	$80	n/a
Wind - Onshore	40%	$82	$73
Greenfield Nuclear SMR (Unit 1)	92%	$92	n/a
Wind - Offshore	42%	$101	$92
CT	20%	$101	n/a
CT (Aero)	20%	$126	n/a
Large Nuclear	92%	$139	n/a
Biomass	90%	$185	$176
HB 2789 HVAC Component	n/a	$188	n/a
Fuel Cell	90%	$193	n/a
VCHEC w/ CCS	50%	$195	n/a
Solar & CT (Aero)	20%	$202	$193
Energy Storage - NREL	15%	$252	$252
Residential Income and Age Qualifying Home Improvement Progran	n/a	$258	n/a
SCPC w/ CCS	50%	$327	n/a
Non-Residential Prescriptive Program	n/a	$334	n/a
Residential Electric Vehicle EE	n/a	$342	n/a
Battery Generic (30 MW)	15%	$349	n/a
Pump Storage (300 MW)	15%	$624	n/a

Notably, the Company does not use levelized costs to screen DSM programs. DSM programs also produce benefits in the form of avoided supply-side capacity and energy cost that should be netted against DSM program cost. The DSM cost-benefit tests are the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options, and are the methods the Company uses to screen DSM programs.

Chapter 7: Transmission

This chapter provides an overview of the transmission planning process, as well as a list of current and future transmission projects. In addition, this chapter provides the results of the system reliability analysis performed to assess the potential effect of retiring all generating units that emit CO_2 as a byproduct of combustion by 2045.

7.1 Transmission Planning

The Company's transmission system is responsible for providing transmission service: (i) for redelivery to the Company's retail customers; (ii) to Appalachian Power Company, Old Dominion Electric Cooperative ("ODEC"), Northern Virginia Electric Cooperative, Central Virginia Electric Cooperative, and Virginia Municipal Electric Association for redelivery to their retail customers in Virginia; and, (iii) to North Carolina Electric Membership Corporation and North Carolina Eastern Municipal Power Agency for redelivery to their customers in North Carolina (*i.e.*, collectively, the DOM Zone). Also, several independent power producers ("IPPs") are interconnected with the Company's transmission system and are dependent on the Company's transmission system for delivery of their capacity and energy into the PJM market.

The Company is part of PJM, which is currently responsible for ensuring the reliability of, and coordinating the movement of, electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. The Company also is part of the Eastern Interconnection transmission grid, meaning its transmission system is interconnected, directly or indirectly, with all of the other transmission systems in the United States and Canada between the Rocky Mountains and the Atlantic Coast, except for Quebec and most of Texas. All of the transmission systems in the Eastern Interconnection are dependent on each other for moving bulk power through the transmission system and for reliability support.

The Company's transmission system is designed and operated to ensure adequate and reliable service to customers while meeting all regulatory requirements and standards. Specifically, the Company's transmission system is developed to comply with the NERC Reliability Standards, as well as the Southeastern Reliability Corporation supplements to the NERC Standards. Federally-mandated NERC Reliability Standards constitute minimum criteria with which all public utilities must comply as components of the interstate electric transmission system. Moreover, the Energy Policy Act of 2005 mandates that electric utilities follow these NERC Reliability Standards and imposes fines for noncompliance of approximately $1.3 million per day per violation.

The Company participates in numerous regional, inter-regional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. The Company is a member of PJM; PJM is registered with NERC as the Company's planning coordinator and transmission planner. Accordingly, the Company participates in the PJM regional transmission expansion plan ("RTEP") to develop the RTO-wide transmission plan for PJM.

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes. The PJM RTEP process includes both a 5-year and a 15-year outlook. The Company is actively involved in supporting the PJM RTEP process.

The Company also evaluates its ability to support expected customer growth through its internal transmission planning process. The results of this evaluation indicates if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate. If the need is confirmed, then the Company seeks approval for the transmission improvements from the appropriate regulatory body.

Additionally, the Company performs seasonal operating studies to identify facilities in its transmission system that could be critical during the upcoming season. The Company coordinates with neighboring utilities to maintain adequate levels of transfer capability to facilitate economic and emergency power flows.

7.2 Existing Transmission Facilities

The Company has approximately 6,800 miles of transmission lines in Virginia, North Carolina, and West Virginia at voltages ranging from 69 kV to 500 kV. These facilities are integrated into PJM.

7.3 Transmission Facilities Under Construction

A list of the Company's transmission lines and associated facilities that are under construction can be found in Appendix 7A. Through participation in the PJM RTEP as well as regional, inter-regional, and sub-regional studies described in Section 7.1, the Company annually assesses the reliability and adequacy of the interconnected transmission system to ensure the system is adequate to meet customers' electrical demands both in the near-term and long-term planning horizons.

7.4 Future Transmission Projects

Appendix 3D provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM as part of the RTEP process.

7.5 Transmission System Reliability Analysis

In order to understand the possible system reliability implications of Alternative Plans C and D—both of which retire all Company-owned carbon-emitting generation in 2045 resulting in close to zero CO_2 emissions from the Company's fleet in 2045—the Company performed a power flow analysis by developing a base power flow case and three different scenarios. To conduct this analysis, the Company made numerous simplifying assumptions. Standard transmission planning analysis is conducted in a near-term horizon (years 1 to 5) and a long-term horizon (years 6 to 10). The reliability analysis conducted for the evaluations of Alternative Plans C and D is 15 years and 30 years into the future, which is significantly longer than standard long-term reliability assessment timeframes. Because the timeframe for analysis was for an additional twenty years, the analysis was unable to account for the significant changes to the transmission systems topology (*e.g.*, transmission lines, load, generation resources) both in the DOM Zone and the Eastern Interconnection that will occur during this timeframe. In addition, the planning model used in this analysis models the Eastern Interconnection, which encompasses all the transmission facilities, generation resources and system loads from essentially the Rocky Mountains to the East Coast. This model incorporates the 2023 year topology of the transmission system and was the base case used for other model changes to perform the future year assessments. The only loads adjusted in this model for the future year assessments were in the DOM Zone, and were scaled up uniformly to levels projected for summer 2035, winter 2035 and summer 2050 based on the growth rates shown in 2020 PJM Load Forecast. The generation resources located in the DOM Zone were modified as discussed below.

In all power flow cases developed for this reliability analysis, approximately 900 MW of ODEC gas-fired generation and approximately 2,900 MW of IPP gas-fired generation was modeled on-line on the Company's system, as it is the Company's understanding that the VCEA does not require the retirement of these generating units. Additionally, approximately 21,000 MW of solar and approximately 5,400 MW of offshore wind were modeled as per PJM RTEP protocols (*i.e.*, PJM capacity factors used to calculate capacity injection rights).

The four power flow cases modeled all Company-owned carbon-emitting generation in 2045 as off-line (retired), except as modified below:

- Power Flow Case 1 (base case): Warren, Greensville and Brunswick County gas-fired CC generating units remained in service for each year under study.
- Power Flow Case 2: Warren and Greensville gas-fired CC generating units remained in service for each year under study.
- Power Flow Case 3: Warren gas-fired CC generating unit remained in service for each year under study.
- Power Flow Case 4: Brunswick, Greensville, and Warren County gas-fired CC generating units off-line (retired) for each year under study.

The initial results of the 2035 and 2050 analysis of all four power flow cases identified NERC reliability deficiencies on twenty-six 115 kV lines, thirty-two 230 kV lines, six 500 kV lines, and eleven transmission transformers that would need to be resolved to avoid NERC violations. The results of these studies are in no way a substitution for the actual generation retirement analysis and generation queue analysis that any generator must follow as part of PJM's RTEP process, especially if they are or want to be considered a PJM capacity resource.

Based on the summer 2035, winter 2035 and summer 2050 peak load runs described above, a first contingency incremental transfer capability analysis was performed. This analysis indicated that for Alternative Plans C and D, the Company's transmission system is not capable of importing the amounts of energy required without the development of significant interregional transfer capability or the addition of significant generation resources (as discussed below) in the DOM Zone, which would need to be directly connected to the Company's transmission system in order to be available to serve both the peak winter and peak summer loading conditions. The interregional transfer capability would be added by the addition of new multi-state transmission lines ("Interregional Transmission Lines"). These multistate lines would have to interconnect with generation resources located in the PJM system and terminating in major load centers in Virginia, like Northern Virginia, the Richmond metropolitan area, and the Hampton Roads metropolitan area. These Interregional Transmission Lines could be either alternating current ("AC") or direct current ("DC") transmission lines. The Trail Project, built in 2006 at a cost of approximately $1.2 billion and going from Pennsylvania to West Virginia to Virginia, was the most recent type of interregional transmission facility built on the PJM system. Further, additional generation resources located in the DOM Zone would be needed in order to address the amount of intermittent renewable resources being added to the system in the Planning Period. These generation resources would need to be quick start and capable of continued operation that is not impacted by weather conditions.

As shown in the Figure 5.6.2.2, Alternative Plans A, B, C, and D require the Company's transmission system to be able to import 5,200 MW to serve the DOM Zone load in the Planning Period, and between 5,200 MW (Alternative Plans A and B) and 10,400 MW (Alternative Plans C and D) to be able to serve DOM Zone load in the Study Period. The transmission impacts related to each of the Alternative Plans is summarized below.

- Plan A – Normal transmission planning expected with no additional transmission level import increase required to maintain 5,200 MW of import capability. Since Alternative Plan A has a smaller portion of its generation resources that are impacted by weather conditions (*i.e.*, renewable generation) and fewer generation retirements, this alternative still reflects the DOM Zone operating in a firm operational state not dependent upon weather conditions.
- Plan B – Normal transmission planning expected with no additional transmission level import increase costs required to maintain 5,200 MW of import capability. While Alternative Plan B has a larger amount of solar, energy storage, and offshore wind resources added as compared to Alternative Plan A, Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability, and energy independence issues as compared to Alternative Plan A and, therefore, construction of Interregional Transmission Lines are not anticipated.
- Plan C – This alternative will require additional transmission level import increase costs in order to construct Interregional Transmission Lines to obtain 10,400 MW of import capability. Alternative Plan C has a larger amount of solar, energy storage, and offshore wind resources added as compared to Alternative Plan A, as well as significantly more generation retirements of the existing DOM Zone generation fleet as compared to Alternative Plan A. As a result, four Interregional Transmission Lines would need to be constructed at a placeholder estimated cost of approximately $8.4 billion.
- Plan D – This alternative will require additional transmission level import increase costs in order to construct Interregional Transmission Lines to obtain 10,400 MW of import capability. While Alternative Plan D has a larger amount of solar resources added than Alternative Plan C and a larger amount of energy storage and offshore wind resources added as compared to Alternative Plan A, based on capacity factors, there is no change in the amount of generation retirements of the existing DOM Zone generation fleet as

compared to Alternative Plan C. As a result, four Interregional Transmission Lines would need to be constructed at a placeholder estimated cost of $8.4 billion.

Importantly, this analysis is high level, preliminary and made with numerous simplifying assumptions. Extensive additional analysis is needed over time. For example, this analysis does *not* address analysis and costs that arise from the loss of traditional rotating synchronous generators. Transitioning from traditional rotating synchronous generation to inverter-based (*i.e.*, intermittent renewable) solar- and wind-powered resources and the addition of large-scale energy storage facilities (*e.g.*, battery and pumped storage) will change the very nature of the electric grid, and requires a fundamental reevaluation of the electric grid for based on two primary results:

- The loss of dispatchable, or controllable generation and challenges associated with the addition of large-scale energy storage facilities; and
- The loss of stored kinetic energy.

Traditional generation sources are large rotating turbines usually powered by either heated steam or falling water, and therefore these generation sources and their output can be both predicted and controlled. Controlling the output of these generators is achieved by regulating the input supply of water or steam. Inverter-based generation relies on resources (*e.g.*, the sun and the wind) that cannot be controlled or predicted in this way. As a result, these generation sources are not dispatchable in response to changes in electrical demand and can be unavailable to serve peak loading conditions. This is the first fundamental difference that must be addressed. Currently, one of the ways PJM manages this is by calculating a dependable capacity rating for intermittent resources. This dependable capacity rating is what is required to be used in transmission planning analysis as part of PJM's FERC-approved RTEP process. While this capacity rating is designed to match the average output of intermittent resources in a region during peak summer loading conditions, it misses the range of conditions that the electric system may have to withstand, such as timeframes when intermittent generation output is close to 100% of its nameplate rating or during winter loading conditions when, for example, the solar generation output is essentially zero. The addition of large-scale storage facilities can support these challenges with solar- and wind-based resources, but these storage facilities will create new challenges themselves that must be addressed.

One essential challenge with the addition of large-scale storage facilities on the Company's system is that it will result in a significant increase in peak system load requirements. Storage will primarily be discharged (*i.e.*, behaving like a generator) at night time to serve system load when solar output across the system is zero. Therefore, the storage facilities will charge (*i.e.*, behaving like a load) during daylight hours, contributing to the peak system load conditions that occur across the daylight hours, like a summer peak load. For example, approximately 9,930 MW of storage could potentially be added as system load in Alternative Plans C and D, significantly increasing the peak load that the Company's transmission system must reliably serve consistent with NERC reliability criteria. It is also critical to note that the storage facilities must be charged up and available to serve the night time load; therefore, during daylight hours the uses of these storage facilities will be very limited, as the primary use must be charging up to be ready for the night time load.

The loss of stored kinetic energy is a more technical concern. The rotation of traditional turbines creates a reservoir of kinetic energy that automatically provides support when problems arise and balances the myriad of instantaneous discrepancies between generation and load at any moment in time. Inverter-based generation does not provide such a reservoir. This correlates to several areas of study that have not historically been necessary to consider during transmission system planning studies and analyses, but will be essential going forward. Today, these include the areas of study listed below, but the Company expects this list to grow and evolve over time.

- Inertia and frequency control;
- Short-circuit system strength;
- Power quality;
- Reactive resources and voltage control;
- System restoration and black start capabilities;
- Grid monitoring and control capabilities;
- Energy storage requirements; and
- High-voltage direct current ("HVDC").

7.5.1 Inertia and Frequency Control

Electrical inertia is the capacity of a system to resist changes in electrical frequency, which is the real-time balance between generation and load. Electrical inertial response acts to overcome an immediate imbalance between power supply and demand. Electrical inertia is directly related to the reservoir of stored kinetic energy inherent to the traditional rotating synchronous generators on the system. Inertia is what allows the electric grid to control the frequency deviations that occur all the time, which are caused by events such as load changes, transmission and distribution outages, generation shedding, and system instability. Inverter-based solar- and wind-powered resources have no rotating components and, as a result, typically do not contribute to system inertia. This can lead to significant problems in managing system frequency, leading to a less reliable electric grid under high penetration of inverter-based generation resources. This problem must be studied and resolved over time with new frequency control strategies and technologies that must be designed, tested, and implemented on the system. This could include new technologies and concepts that are being explored and researched now, including the emulation of inertia in inverter control systems.

7.5.2 Short-circuit System Strength

A short circuit, also known as a fault, is an undesirable electrical connection, such as a tree branch falling across electrical lines. When these short circuit events occur, it is critical to remove from service the faulted energized equipment as quickly as possible to ensure personnel and public safety, prevent or reduce equipment failure, and maintain the stability of the electric grid. This is done today in the timeframe of milliseconds to seconds by protection and control systems that are comprised of relays, circuit breakers, reclosers, and fuses installed across the entire system. In today's electric grid, a short circuit typically results in a spike in electrical current to that point and depressed voltage around the location of the fault. This occurs today because traditional rotating synchronous generators supply this significant amount of current during short-circuit events. The protection and control systems in operation today, across the entire system in generation plants, transmission and distribution substations, distribution circuits, and even inside customer facilities and homes, are all primarily designed to remove short circuit events by the detection of very high current.

Inverter-based generation resources (*e.g.*, solar and wind) do not provide any significant increase in current during short circuit events; rather they provide either no change in current or only a very nominal amount during the short circuit events. As traditional rotating synchronous generators are retired and replaced with more and more inverter-based generation, it is expected that the system will experience a fundamental change in short circuit behaviors across all levels of the grid, specifically lowering the currents and strength of short circuits. This will cause the Company's existing protection and control systems installed across the entire system to have major challenges in detecting these short circuit events and protecting the system, personnel, and the public. This problem must be studied and resolved over time, looking into new technologies that must be designed, tested, and implemented, such as new grid devices that provide fault current or new protection and control schemes on generation, transmission, distribution, and customer facilities that are have new designs and operating characteristics.

7.5.3 Power Quality

All standards for grid-tied systems set demands on the quality of the power supply. These systems have previously drawn from the centralized reservoir of kinetic energy previously discussed—the dispatchable nature of traditional generation and the fundamental frequency of the electric grid (*i.e.*, 60 Hertz ("Hz")). Electric grids dominated by inverter-based generation resources face challenges to reliable operation on two power quality aspects. First, the non-controllable variability of solar and wind resources leads to voltage and frequency fluctuations that require mitigation in order to balance the instantaneous supply and demand across the electric grid. Second, inverters operate by creating harmonic frequencies, multiples of the 60 Hz fundamental, and these harmonics can cause a variety of issues including reduced system transmission capacity and premature aging of electrical equipment. These power quality issues will have to be studied and resolved over time.

7.5.4 Reactive Resources and Voltage Control

Electrical generation can be divided into real power and reactive power. Real power does actual work (*e.g.*, creating heat and light). Reactive power supports electromagnetic fields required to control voltage levels and move real power across the electric grid. Traditional voltage regulation devices that adjust reactive power are traditional rotating synchronous generators, transformer load tap changers, voltage regulators, capacitor banks, and reactor banks. The variability (due to weather patterns) and historical operation of inverter-based resources will cause added voltage variability on the system, requiring the implementation of technologies that can automatically mitigate this variability to maintain stable voltage across the system. An example of these technologies is Flexible Alternative Current Transmission System ("FACTS") devices, with the two most common devices being static volt-ampere reactive compensators, and static synchronous compensators ("STATCOMs"). Another example is the concept of using the inherent ability of inverters to help control voltage. These technologies need to be studied, developed, tested, and deployed because the cost of mitigating voltage control could become cost-prohibitive.

7.5.5 System Restoration and Black Start Capabilities

Large-scale blackouts negatively impact the public, the economy, and the power system itself. A proper black start system restoration plan can help to restore power quickly and effectively. Black start—which restores electric power stations and the electric grid without relying on external connections—is the most critical scenario for system restoration. A black start unit is a generator that can start from its own power without the support from the power grid, which is essential in the event of a major system collapse or a system-wide blackout. Black start units, and the generation included in the system restoration plan, must be available 24/7 and must have constant and predictable output when operational. These requirements provide difficulties for solar- and wind-generation resources, causing challenges to future black start restoration plans that will need to be studied and resolved. In addition, current black start restoration procedures start from the transmission system and quick start synchronous generation stations and then work towards restoring the distribution system. However, with significant DERs, system restoration procedures will need be evaluated to account for these DERs, including investigation into new DER technology like grid-forming inverters used in microgrids.

7.5.6 Grid Monitoring and Control Capabilities

Electricity demand that has historically been inelastic is becoming more variable and dynamic due to rapid growth of DERs. Greater temporal granularity is required to understand coincidence of system loading and DER production. Furthermore, DER production and performance contain inherent uncertainty that must be considered. Additionally, the dynamics of system loading itself is changing as new equipment and resources are integrated as unmeasured / unmetered resources, impacting the ability to understand and forecast these quantities. Low visibility and lack of control is a key problem for customer-level DERs such as roof-top or community solar, battery storage, electric vehicle charging infrastructure, and DSM. As DERs increase across the grid, investments in additional grid monitoring resources and equipment are vital. A robust and secure communications network is especially important to ensure bandwidth capacity and satisfy communication latency requirements for monitoring and control systems. The Company has proposed investments that will provide this level of granularity at the distribution level as part of its Grid Transformation Plan, as discussed further in Section 8.3. As these investments are deployed, and as the Company develops the integrated distribution planning process discussed further in Section 8.1, the outputs generated by integrated distribution planning will feed into and inform further analyses related to required controls at the transmission level.

Beyond monitoring, maintaining grid stability requires robust coordination between inverter controls, grid system protection and control systems, and electrical equipment loading capabilities. In-progress updates to the Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547 will provide industry guidance on how inverter-based generation should provide automatic local (decentralized) voltage and frequency control and system disturbance ride through functionality. Decentralized control is not yet perfected, and the benefits of centralized control should still be weighed against potential failure modes inherent to decentralized algorithms. Extensive study and testing is needed to develop and deploy the safest and most reliable monitoring and control options possible. The Company is actively engaged in both the IEEE-1547 standards evaluation as well as research and development of inverter-based grid support functionality.

7.5.7 Energy Storage Requirements

Due to the intermittence and uncertainty of wind and solar generation, energy storage is vital. Excess energy from peak generation periods could also be collected with an energy storage system and released when load outpaces supply. However, significant study is needed to determine the requirements for efficient, reliable, cost-effective, and safe utilization of energy storage. Location, safety and environmental concerns, and end-of-life must be explored for all energy storage technologies and options. These battery storage pilot program discussed further in Section 8.5 will provide the Company with valuable insight and experience toward deployment of BESS in the future

7.5.8 High-voltage Direct Current

AC transmission cable systems are a mature technology, and the cost of HVDC technology is considerably higher than traditional AC transmission lines. This higher cost is mainly due to the converter stations at both ends of the DC connection. However, any AC cable length over six miles requires costly reactive power compensation infrastructure such as reactor banks, STATCOMs, or other FACTS devices. HVDC cables do not have this reactive power compensation requirement. Due to this, the cost per unit length of an HVDC line may be significantly less than a comparable high-voltage AC line over long distances. This potential lower cost is especially important when considering offshore generation and interregional transmission transfer capabilities to other areas of the system.

Other potential HVDC benefits include higher power transfer capability, smaller right-of-way requirements, lower power losses, dynamic real and reactive power control, fault ride-through, greater system strength tolerance, inertial emulation, frequency control, power oscillation damping, and black start capability. Since this HVDC technology is relatively new, the Company must rigorously study each of these applications along with other advanced control schemes to assure that it can deliver safe, reliable, and affordable power before implementing HVDC solutions.

7.5.9 Summary of Preliminary Results

In summary, the results and issues identified in this section are high level and preliminary in nature and the Company made several simplifying assumptions. As the parameters of the VCEA are identified and developed in greater detail, a comprehensive transmission plan will be developed that addresses these new technical challenges the transmission system will face. Nevertheless, Alternative Plans C and D will severely challenge the ability of the transmission system to meet customers' reliability expectations. For example, prolonged cold weather or multiple days of clouds and rain will greatly challenge the transmission system operators who must balance load and generation resources in real-time operations, while also maintaining compliance with NERC reliability requirements. While the Company will be able to develop a transmission expansion plan that will allow for the reliable operation of the transmission system consistent with the parameters identified in the VCEA, this expansion plan will require an investment level that exceeds current transmission level expenditures and will likely exceed the future transmission level costs initially identified in this 2020 Plan.

Chapter 8: Distribution

The Company's obligation to provide safe and reliable service carries on as the Company transitions toward a cleaner energy future. In fact, providing reliable and resilient service becomes inherently more important during this transition where availability of extensive DERs and expanding electrification are added essentials. As the distribution grid evolves to support a more dynamic energy system, the Company must continuously identify new scenarios and solutions to ensure safe and reliable service. Those solutions will likely include emerging technologies such as comprehensive distributed energy resource management systems, distribution-level STATCOMs, and customer-owned assets leveraged for grid support as non-wires alternatives. Regardless of which solutions are implemented, a robust telecommunication infrastructure that provides real-time situational awareness and supports analysis and control of grid components will be essential for an adaptable and responsive distribution system.

This chapter provides an overview of the distribution planning process, and an overview of current initiatives related to the distribution grid.

8.1 Distribution Planning

Current distribution planning methodologies and processes were designed for a distribution grid in a world of centralized large-scale generation and a one-way power flow. In the evolving paradigm where DERs and other emerging technologies are increasing on the distribution grid causing two-way power flows, the Company's distribution planning process must also evolve. Distribution grids with high penetration levels of inverter-based generation resources at the feeder level face challenges to reliable operation on two power quality aspects. First, the non-controllable variability of solar and wind resources leads to voltage fluctuations that require mitigation. Second, inverters operate by creating harmonic frequencies, multiples of the 60 Hz fundamental; these harmonics can cause a variety of challenges including reduced distribution grid capacity and premature aging of electrical equipment. These power quality issues, along with the emerging changes in the distribution grid's utilization, will have to be studied and solutions will have to be incorporated over time.

In September 2019, the Company filed a white paper that provided a detailed overview of the Company's current distribution planning process, the limitations of the current process, and the integrated distribution planning ("IDP") process that the Company planned to implement going forward (the "2019 IDP White Paper"). Appendix 8A provides the 2019 IDP White Paper.

As discussed in Section 4.0 of the 2019 IDP White Paper, true IDP will require changes to people's skills, the technologies and tools they use, and processes for performing planning activities. The Company has made progress on some of the identified enhancements:

- **Section 4.1 – People.** The Company has completed the centralization of modeling and analysis activities and continues to evaluate its organizational structure as integrated distribution planning matures.

- **Section 4.2 – Technologies.** The Company continues to evaluate options for advancing IDP. Without the granular data and situational awareness from full deployment of AMI, intelligent grid devices, and control systems proposed as part of the Grid Transformation Plan, the evolution of IDP will continue to be limited based on the technologies that the Company currently has deployed.

- **Section 4.3 – Processes and Tools.**
  - **Process Enhancement 1 – Comprehensive Feeder Level Forecasting.** The Company has developed initial net metering and utility-scale DER forecasts at the feeder level based on feeder head data where available. These forecasts will be integrated with the traditional feeder-level seasonal peak load forecast in support of long-term capacity planning on the distribution grid. With just a portion of residential customer energy usage data being collected by AMI, the Company continues to refine data analytics that approximate the peak demand of non-AMI metered residential customers based upon monthly billing data. This enhancement continues to be limited to forecasting peak demands.
  - **Process Enhancement 2 – Hosting Capacity Analysis.** The Company is on track to complete an initial hosting capacity analysis and make hosting capacity maps publicly available on the Company's website by the end of 2020. This initial analysis will be static based on the limited data inputs that are available. Improvements to the hosting capacity analysis will require additional data providing more granular visibility of the grid.
  - **Process Enhancement 3 – Multi-Hour Capacity Planning Analysis.** The Company has engaged in a research and development project with EPRI focused on modernizing distribution planning using automated processes and tools. The project is a multi-year effort with the objective of developing, testing, and demonstrating new methods and tools to automate planning assessments and support holistic decision-making in support of integrated distribution planning. Similar to the hosting capacity analysis, specific Grid Transformation Plan investments that gather highly granular grid data are necessary to support robust distribution grid analysis.
  - **Process Enhancement 5 – Non-Wires Alternatives Analysis.** The Company has started work on two battery storage pilot projects as discussed further in Section 8.5, one of which will study batteries as a non-wires alternative to reduce transformer loading. Additionally, the Company is preparing to start working on the Locks Campus Microgrid Demonstration Project that was recently approved as part of the Grid Transformation Plan. Aspects of non-wires alternative analysis are included in the EPRI research project discussed above. In the shorter term, the Company is engaged with EPRI on the development of tools to identify metrics, analytics, and practices for efficient screening of non-wires alternative projects based on economic suitability and technical feasibility. The objective of this effort is to enable more rapid determination of non-wires alternative feasibility and viability and support effective integration of DER into future resource plans. This research is a part of EPRI's 2020 research portfolio with prototype results expected by the end the year.

The Company will provide further updates on progress toward integrated distribution planning in future Plans and update filings.

8.2 Existing Distribution Facilities

The Company's existing distribution system in Virginia consists of more than 53,000 miles of overhead and underground cable, and over 400 substations operating at distribution voltage levels ranging from 4 kV to 46 kV. The distribution system utilizes a variety of devices for functions from voltage control to power flow management, and relies on multiple operating systems for various functions from customer billing to outage management.

Section III of the executive summary of the Grid Transformation Plan filed in Case No. PUR-2019-00154 (the "GT Plan Document") provided a detailed description of the Company's existing distribution system.

8.3 Grid Transformation Plan

With the passage of the GTSA, Virginia declared electric distribution grid transformation to be in the public interest, and mandated that utilities file a plan for grid transformation. The GTSA required that any such plan "shall include both measures to facilitate integration of distributed energy resources and measures to enhance physical electric distribution grid reliability and security."

The Company set forth its comprehensive plan to transform its electric distribution grid to facilitate the integration of DERs, to enhance reliability and security, and to improve the customer experience—the Grid Transformation Plan. The GT Plan Document described the need for grid modernization, the state of the existing distribution system, the development of the Grid Transformation Plan, an overview of the Grid Transformation Plan itself, and the associated customer benefits.

The Company has sought approval of the first three years of its ten-year Grid Transformation Plan (*i.e.*, 2019, 2020, and 2021) in two separate proceedings before the SCC, Case Nos. PUR-2018-00100 and PUR-2019-00154. The GT Plan Document includes information on the need, costs, and benefits of each of the proposed investments. Over these two proceedings, the SCC has approved as reasonable and prudent investments in (i) a customer information platform; (ii) a hosting capacity analysis; (iii) the Locks Campus Microgrid Project; (iv) mainfeeder hardening; (v) targeted corridor improvement; (vi) voltage island mitigation; (vii) telecommunications; (viii) physical and cyber security; and (ix) a Smart Charging Infrastructure Pilot Program to support managed charging for EVs. The SCC recently denied, without prejudice to the Company seeking approval of the Grid Transformation Plan in future petitions, investments in (i) AMI; (ii) a self-healing grid; (iii) advanced analytics; (iv) an enterprise asset management system; and (v) proactive component upgrades. Because of the preparation schedule associated with this 2020 Plan, for purposes of the NPV results, the Company has incorporated the costs and benefits as filed in Case No. PUR-2019-00154.

The passage of the VCEA has further emphasized the need for grid transformation. The VCEA requires energy efficiency programs to achieve annual targets that reach 5% by 2025, using a 2019 baseline. Full deployment of AMI across the Company's service territory enables advanced rate options, such as time-varying rates; enhances DSM programs by providing the energy usage data that will enable more targeted suggestions to customers for measures to optimize customers' energy savings; and provides the interval data to refine evaluation, measurement, and verification. AMI also enables voltage optimization, which, as can be seen in the forecast provided in Section 4.1.5, provides an effective energy efficiency program. The VCEA also envisions a significant build out of solar and wind resources. Much of this capacity would likely be connected to the distribution grid, including the 1,100 MW of small-scale solar. The situational awareness enabled by a self-healing, digital grid would prove invaluable to siting, interconnecting, and managing this significant level of renewable resources where it makes the most sense in terms of costs and benefits. Paired with the full deployment of AMI and other future investments, a self-healing, digital grid will enable more advanced and dynamic hosting capacity analysis, as well as advancements in integrated distribution planning as discussed in Section 8.1. Overall, the Grid Transformation Plan is vital to achieving the clean energy goals discussed in this 2020 Plan.

8.4 Strategic Undergrounding Program

The Company is continuing the SUP, which is in its seventh year. Originally conceived as a 4,000 mile program in 2014, the Company has converted approximately 1,325 miles of outage-prone overhead tap lines as of January 2020. A legislative sunset clause currently requires the SUP to conclude in 2028. More details on the SUP are available in the Company's annual filings with the SCC, which specify the miles of tap lines converted and their location, tap line reliability performance pre- and post-conversion, and system-wide reliability statistics.

Both local and system-wide benefits are key aspects of the SUP. Specifically, the SUP was designed to shorten restoration times in severe weather events by reducing the number of labor-intensive work locations associated with outage-prone single phase overhead tap lines, especially those in the rear of houses with significant tree coverage. By converting those tap lines to underground, directly served customers will either see a shorter outage or no outage. Perhaps more importantly, this enables crew redeployment to other outage locations, allowing a faster recovery after severe weather events for the benefit of all customers. The SUP remains the most effective and comprehensive solution for eliminating work associated with systemic tap line outages, and is complemented by the mainfeeder hardening program in the Grid Transformation Plan, which targets mainfeeders serving customers with the poorest reliability.

8.5 Battery Storage Pilot Program

The Company is beginning to study the use of battery energy storage systems on its distribution system through the pilot program established by the GTSA. The SCC recently approved the deployment of two BESS on the distribution system in Case No. PUR-2019-00124:

- Through BESS-1, the Company will deploy a 2 MW/4 MWh AC lithium-ion BESS that will study the prevention of solar back-feeding onto the transmission grid at a substation located in New Kent County; and
- Through BESS-2, the Company will deploy a 2 MW/4 MWh AC lithium-ion BESS that will study batteries as a non-wires alternative to reduce transformer loading at a substation located in Hanover County.

The SCC also approved deployment of a lithium-ion BESS at the Company's Scott Solar Facility to study solar plus storage.

These BESS provide the Company the opportunity to study important statutory objectives, and the information and experience gained from each will provide valuable insight and experience toward deployment of BESS in the future. The Company continues to explore additional unique energy storage use cases for future consideration within the battery storage pilot program.

8.6 Electric School Bus Program

The Company's Electric School Bus Program combines the Company's efforts with energy storage technologies and electric vehicles, while at the same time assisting customers' decarbonization efforts. In addition to reducing the carbon footprint of the Commonwealth and improving air quality for students, the batteries in electric school buses can be used to increase the stability and reliability of the grid, and can help to facilitate the integration of renewable energy resources such as solar and wind onto the distribution system. In Phase I of this Program, the Company intends to bring 50 electric school buses to 16 localities in the Company's service territory by the end of 2020.

This Electric School Bus Program, coupled with a modernized grid, will allow the Company to gain understanding and knowledge related to (i) the changes in system loading due to increased adoption of electric vehicle technology; (ii) the managed charging strategies necessary to accommodate a large presence of EVs on the grid; (iii) V2G technology that leverages bus batteries to store and inject energy onto the grid during periods of high demand when the buses are not needed for transport; and (iv) strategic deployment of EVs as resources for the benefit of customers and the grid.

8.7 Rural Broadband Pilot Program

The Company plans to participate in the pilot program established by House Bill 2691 from the 2019 Regular Session of the Virginia General Assembly to support the delivery of broadband service to unserved areas in Virginia. Through the broadband pilot program, the Company plans to leverage the telecommunications infrastructure deployed as part of the Grid Transformation Plan by using a portion of the fiber capacity to meet its own distribution system needs, and then leasing another portion to an internet service provider. By utilizing the telecommunication infrastructure for both operational needs and broadband access, the Company can reduce broadband deployment costs for internet service providers, which these providers would then use to deliver high-speed internet access to unserved residences and business. The Company has partnered with a subsidiary of Prince George Electric Cooperative to extend access to approximately 2,400 Company customers and 1,200 cooperative members in Surry County currently not offered broadband services. Additionally, the Company has entered into a memorandum of understanding with All Points Broadband, Northern Neck Electric Cooperative, and the Counties of King George, Northumberland, Richmond, and Westmoreland to advance a regional broadband partnership that aims to deliver fiber-optic broadband service to unserved households and businesses in Virginia's Northern Neck region.

Chapter 9: Other Information

This chapter provides other information in response to specific SCC or NCUC requirements.

9.1 Customer Education

The Company is committed to improving the customer experience. Key to achieving this goal is educating customers about their energy consumption and how to manage their costs, and empowering customers to take advantage of the numerous enhanced customer capabilities enabled by the Grid Transformation Plan and other initiatives.

The Company's customer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption and taking advantage of new incentives and offerings.

Website and Supporting Print Collateral

State: Virginia and North Carolina

The Dominion Energy website is a main hub for public education. The Company offers program- and project-specific information, factsheets, brochures, videos, and other supporting documents to provide background and updates on the benefits and enhanced capabilities associated with a variety of investments and initiatives. These include, but are not limited to, approved elements of the Grid Transformation Plan, major infrastructure projects, and new offerings (such as rates, tools and mobile apps) as they become available.
https://www.dominionenergy.com

Social Media

State: Virginia and North Carolina

The Company uses the social media channels of Twitter® and Facebook® to provide real-time updates on energy-related topics, promote Company messages, and provide two-way communication with customers. The Company also manages pages on YouTube® and Instagram for further outreach to the general public, residential customers, and business customers. LinkedIn is leveraged for reaching commercial and industrial customers.
The Company's Twitter® account is available online at: https://twitter.com/dominionenergy
The Company's Facebook® account is available online at:
https://www.facebook.com/dominionenergy
The Company's YouTube® account is available online at
https://www.youtube.com/user/DomCorpComm
The Company's Instagram account is available online at
https://www.instagram.com/dominionenergy/.
The Company's LinkedIn account is available online at
https://www.linkedin.com/company/dominionenergy//

News Releases

State: Virginia and North Carolina

The Company prepares news releases and reports on the latest developments regarding its customer-facing initiatives and provides updates on Company offerings and recommendations for saving energy as new information and programs become available. Current and archived news releases can be viewed at: https://news.dominionenergy.com/news.

Customer Information Platform
State: Virginia and North Carolina
The customer information platform—recently approved by the SCC as part of the Grid Transformation Plan—will enable the Company to provide customers with better information. For example, customers will be able to utilize various notification, billing, and pay options to more easily monitor usage and to take advantage of new rate structures and rate comparison tools. Overall, with the new capabilities and customer functionality within the customer information platform, customers will be in a better position to save time and money.

Energy Conservation Programs
State: Virginia and North Carolina
The Company's website has a section dedicated to energy conservation that contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Dozens of programs are featured on the website and include eligibility guidelines, program details, steps to enroll, and success stories, as well as contact information to speak with program specialists. Through consumer education using a variety of channels to reach multiple customer classes, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina.

Online Energy Calculators
State: Virginia and North Carolina
The Company is committed to helping customers save on their energy bills and provides saving tips and a "Lower My Bill Guide" on the Company website. Home and business energy calculators are provided as well to estimate electrical usage for homes and business facilities. The calculators can help customers understand specific energy use by location and discover new means to reduce usage and save money. For customers considering the environmental impact of transportation choices, a calculator is offered to compare emissions and cost savings of cars side-by-side with more efficient hybrid or all-electric vehicles. An appliance energy usage calculator and holiday lighting calculator are also available to customers. The energy calculators are available at: https://www.dominionenergy.com/home-and-small-business/ways-to-save/energy-saving-calculators.

Community Outreach – Trade Shows, Exhibits, and Speaking Engagements
State: Virginia and North Carolina
The Company conducts outreach seminars and speaking engagements in order to share relevant energy conservation program information to both residential and commercial audiences. The Company also participates in various trade shows and exhibits at energy-related events to educate customers on the Company's programs and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses and taking advantage of new rates and offerings as they become available. Company representatives positively impact the communities the Company serves through presentations to elementary, middle, and high school students about its programs, wise energy use, and environmental stewardship. Additional partnerships with the educational community are offered through

mentoring initiatives, philanthropic support and other means to strengthen science, technology, engineering, and mathematics competitiveness in an effort help prepare students for tomorrow's workplace. Information on educational grants, scholarships, and programs for teachers and students is available on the Company's website at: https://www.dominionenergy.com/company/community/educational-programs

For example, Project Plant It! is an educational community learning program available to students in the service areas where the Company conducts business. The program teaches students about the importance of trees and how to protect the environment through a variety of hands-on teaching tools such as a website with downloadable lesson plans for use at home and in classrooms, instructional videos, and interactive games. To enhance the learning experience, Project Plant It! provides each enrolled student with a redbud tree seedling to plant at home or at school. Since 2007, more than 500,000 tree seedlings will have been distributed to children in states where the Company operates. According to the Virginia Department of Forestry, this equates to about 1,250 acres of new forest if all the seedlings are planted and grow to maturity. Visit website for more information, https://projectplantit.com/.

9.2 Effect of Infrastructure Programs on Overall Resource Plan

The SCC directed an analysis of how the deployment and costs of infrastructure programs on the Company's transmission and distribution systems affect the Company's overall resource plan, including the Grid Transformation Plan, the Underground Transmission Line Pilot, the Battery Storage Pilot, and the Strategic Undergrounding Program. The following sections discuss each program in turn. Overall, the Grid Transformation Plan and the Battery Storage Pilot should directly affect the Company's overall resource plan in the future by facilitating the integration of DERs, and by potentially lowering demand through enhanced DSM. Deployment of these investments and further analysis is needed before the Company can quantify the reduction in costs associated with these effects on the proposed build plans.

9.2.1 Grid Transformation Plan

Many of the Grid Transformation Plan components described in Section 8.3 will have a meaningful influence on the Company's overall resource plan in the future, enabling awareness and analysis that will be critical for the Company to adapt to significant renewable capacity growth in the coming years.

As discussed in Section 8.1, the Company plans to implement an integrated distribution planning process going forward, which will provide inputs into future resource planning. Specifically, IDP will entail advanced distribution modeling and analysis capabilities that consider a range of possible futures where varying levels of DERs and emerging technologies are adopted on the distribution grid. Mature IDP is dependent on having highly granular and spatial visibility of existing grid conditions that is not available today; many of the Grid Transformation Plan components are foundational to IDP, including AMI, intelligent grid device, secure telecommunications infrastructure, and an advanced distribution management system with system capabilities for distributed energy resources management. In addition, advanced analytics are necessary to process this data, and provide the processes to suitably model the behavior of the entire distribution grid including the renewable resources. These applications can analyze weather patterns along with past generation profiles and forecast the generation that will be available from the DERs. Advanced analytics will also highlight opportunities for non-wires alternatives to be evaluated. As IDP capabilities increase, the Company can include a quantification of aggregate DER impacts to the Company's overall resource plan.

As part of the Grid Transformation Plan, the Company will make static hosting capacity maps for both utility-scale and net metering DER publicly available by the end of 2020. The situational awareness enabled by hosting capacity analysis will prove invaluable to siting, interconnecting, and managing significant levels of DER. As AMI and intelligent grid devices are deployed, and as grid visibility and operational capabilities increase, the hosting capacity analysis will become more dynamic and will support opportunities to reduce interconnection costs when DER output can be informed and adjusted through non-firm DER capacity agreements to avoid grid limitations utilizing a distributed energy resources management system.

The Grid Transformation Plan will also facilitate the integration of DERs by enhancing the reliability and resiliency of the grid, increasing the availability of the output from these DERs. Specifically, the mainfeeder hardening program will reduce sustained outages on poorly performing feeder segments, improving availability on outage prone mainfeeders to support both utility-scale and residential DERs.

Finally, the Grid Transformation Plan includes the Locks Campus Microgrid Demonstration Project. This pilot project marries several DER technologies and, similar to the Battery Storage Pilot, will provide the research and operational experience needed to prove the viability of advanced grid support capabilities, non-wires alternatives, and other functionality of DER on the Company's distribution grid.

In addition to facilitating the integration of DERs, the Grid Transformation Plan will affect the overall resource plan by potentially lowering demand through enhanced DSM. As discussed in Section 8.3, AMI enables advanced rate options, such as time-varying rates; enhances DSM programs by providing energy usage data that will enable more targeted suggestions to customers for measures to optimize energy savings; and provides the interval data needed for more refined evaluation, measurement, and verification. In addition, AMI enables voltage optimization, which can lead to significant energy savings, as discussed in Section 4.1.5. The Grid Transformation Plan also includes the Smart Charging Infrastructure Pilot Program, which will provide the information needed in furtherance of future managed charting pilots, programs, or rate designs that will support EV adoption while minimizing the impact of EV charging on the distribution grid. Managing increasing EV charging load could also minimize costs for the Company and its customers, such as the need for additional distribution upgrades or the need for more fast ramping peaker plants.

9.2.2 Battery Storage Pilot Program

The Battery Storage Pilot Program discussed in Section 8.5 will provide the Company the opportunity to study important statutory objectives, and the information and operational experience gained from each project will provide valuable insight and experience toward integration of the significant energy storage capacity. Indeed, one of the pilot projects seeks to study solar plus storage, with both AC- and DC-coupled BESS, the results of which will inform the deployment of this paired application in the future.

9.2.3 Underground Line Programs

Two of the Company's infrastructure programs relate to undergrounding lines—the Strategic Undergrounding Program and the Underground Transmission Line Pilot. As discussed in Section 8.4, the Strategic Undergrounding Program converts the most outage-prone electric distribution tap lines to underground to improve customer reliability. An indirect benefit of the SUP to the overall resource plan may be to support expanded residential DER by improving availability on the formerly outage-prone tap lines. The Underground Transmission Line Pilot contemplates two underground electric transmission projects to further the Company's understanding of underground electric transmission lines. The purposes of these programs differ from the Grid Transformation Plan and the Battery Storage Pilot Program, and any potential benefits to the overall resource plan are indirect.

9.3 GTSA Mandates

Figure 9.3.1 provides a list of "mandates" from the GTSA and the accompanying citation to the GTSA. The sections that follow outline these mandates and detail the Company's plans related to each one. Several provisions of the GTSA encourage specific public policies, such as greater deployment of renewable energy, without taking the form of a mandate.

Figure 9.3.1 – GTSA Mandates

Mandate	Citation
Evaluate in future Plans: (i) electric grid transformation projects, (ii) energy efficiency measures, and (iii) combined heat and power or waste heat to power	Va. Code § 56-599; EC 12; EC 18
Adjust rates to reflect the reduction in corporate income taxes	EC 6; EC 7
Provide one-time, voluntary bill credits	EC 4; EC 5
Offer Manufacturing and Commercial Competitiveness Retention Credit	EC 11
File triennial review	Va. Code § 56-585.1; Va. Code § 56-585.1:1
Report on potential improvements to renewable programs	EC 17
Report on economic development activities	EC 16
Report on the feasibility of providing broadband using utility infrastructure	EC 13
Report on energy efficiency programs by an independent monitor	EC 15 Va. Code § 56-596.2
Fund energy assistance and weatherization pilot program	Va. Code § 56-585.1:2
Propose a plan to deploy 30 MW of battery storage under new pilot program	Va. Code § 56-585.1:6 (EC 9; EC 10)
Propose a plan for electric distribution grid transformation projects	Va. Code § 56-585.1 A 6
Propose a plan for energy conservation measures with a projected cost of no less than $870 million	Va. Code § 56-596.2 (EC 15)

Note: "EC" = Enactment Clause

9.3.1 Plan-Related Mandates

This 2020 Plan includes all of the analyses required by Va. Code § 56-599, including long-term planning related to the distribution grid and energy efficiency measures. In this Plan, the Company considered combined heat and power as a possible generation resource as required by Enactment Clause 12 of the GTSA, as discussed in Section 5.5. Finally, Section 6.6 provides the analysis related to energy efficiency measures required by Enactment Clause 18 of the GTSA.

9.3.2 Rate-Related Mandates

The GTSA contained a number of mandates related to customer rates. The Company has complied or will comply with each of these provisions:

- The Company reduced its rates for generation and distribution services by $182.574 million to reflect the reduction in corporate income taxes under the federal Tax Cuts and Jobs Act of 2017 consistent with Enactment Clauses 6 and 7 of the GTSA. See SCC Case No. PUR-2018-00055.

- The Company issued one-time, voluntary generation and distribution services bill credits totaling $200 million consistent with Enactment Clauses 4 and 5 of the GTSA. See SCC Case No. PUR-2018-00053.

- The Company began offering a Manufacturing and Commercial Competitiveness Retention Credit, designated Rider CRC, to eligible customers consistent with Enactment Clause 11 of the GTSA. See SCC Case No. PUR-2018-00133.

- The Company will make a triennial review filing by March 31, 2021.

9.3.3 Mandated Reports

The GTSA mandated a list of reports for the Company to file with the SCC and others. The Company has filed the following reports:

- Solar Energy Report (Nov. 1, 2018) (EC 17);
- Economic Development Report (Dec. 1, 2018) (EC 16);
- Broadband Feasibility Report (Dec. 1, 2018) (EC 13); and
- The Report of the Independent Monitor on the Status of the Energy Efficiency Stakeholder Process (Jun. 28, 2019) (EC 15, Va. Code § 56-596.2).

9.3.4 Pilot Program Mandates

The GTSA contained two mandates related to pilot programs. First, under the amended language in Va. Code § 56-585.1:2, the Company must continue its pilot program for energy assistance and weatherization for low income, elderly, and disabled individuals "at no less than $13 million for each year the utility is providing such service." The Company has continued this pilot program and has met the required funding.

Second, the GTSA required the SCC to establish a pilot program for storage batteries. The SCC established guidelines for this pilot program on November 2, 2018, in Case No. PUR-2018-00060. The SCC approved the Company's first application to participate in the pilot program on February 14, 2020, allowing for the deployment of three BESS projects totaling 16 MW.

9.3.5 Mandate Related to Electric Distribution Grid Transformation Projects

The GTSA mandated that the Company petition the SCC for approval of a plan for electric distribution grid transformation projects. Section 8.3 provides details on the Company's Grid Transformation Plan.

9.3.6 Mandate Related to Energy Conservation Measures

The GTSA directed the Company to develop a proposed program of energy conservation measures with a proposed cost of no less than $870 million by July 1, 2028, and established an energy efficiency stakeholder process. See Chapter 6 for more details on the Company's DSM initiatives.

9.4 Economic Development Rates

As of March 1, 2020, the Company has seven unique customers located in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 154 MW. As of March 1, 2020, the Company has no customers in North Carolina receiving service under economic development rates.