Comments of the Public Staff

2023 Biennial Integrated Resource Plan
of Dominion Energy North Carolina

and

2023 REPS Compliance Plan
of Dominion Energy North Carolina

Docket No. E-100, Sub 192

January 29, 2024

Contents

EXECUTIVE SUMMARY

The Public Staff has investigated the 2023 Integrated Resource Plan (IRP) filed by Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (Dominion or the Company). Overall, the Public Staff believes Dominion's IRP complies with Commission Rule R8-60. However, the Public Staff has concerns about (1) the modeling utilized being overly constrained and (2) the large amount of total capacity and energy imports the Company is relying upon as part of its base case assumptions.

These issues are exacerbated by the fact that PJM Interconnection LLC (PJM) increased its planning reserve margin in October 2023. As the Company's analysis predates this increase, it is not reflected in Dominion's filed capacity expansion plans. While an IRP is a snapshot in time, the Company's proposed portfolios now underforecast the new capacity expansion requirements and underestimate the costs and challenges associated with providing reliable electric service to its North Carolina customers.

Dominion's 2023 IRP, depending on which capacity expansion plan is utilized for future system planning, includes additional capacity and energy from natural gas, nuclear, wind, and solar resources, as well as increases in energy storage. Dominion's plans for these new resources represent a continuation of prior trends toward greater amounts of renewable generation. Given the long-term scope of impacts and uncertainties inherent in any IRP, these comments highlight general Public Staff concerns with the IRP inputs and make recommendations regarding the capacity expansion plans and production cost modeling to be utilized in the Company's 2024 IRP cycle. Although the IRP filing is compliant with Commission Rule R8-60, the Public Staff recommends that the Commission order that Dominion, in its next filed IRP, address the Public Staff's concerns listed herein.

DOMINION IRP

Dominion serves approximately 2.7 million customers across approximately 30,000 square miles. Dominion's North Carolina territory accounts for approximately 5% of Dominion's total electric load and has limited dispatchable generating capacity. The remaining load, and most of the Company's dispatchable generation, is located in Virginia.[1] Dominion is also a member of the regional transmission organization (RTO) PJM Interconnection, LLC (PJM).

Dominion's IRP is, unsurprisingly, largely driven by standards set by Virginia and PJM. In April 2020, the Virginia Clean Economy Act (VCEA) became law in Virginia, and, among other things, requires Dominion to procure 100% of its electricity from carbon free resources by 2045, with the caveat that fossil resources may be retained as needed to maintain system reliability.

As part of its IRP modeling analysis, Dominion submitted to the Commission five alternative plans (Plans A through E) designed to meet customers' needs

[1] An exception to this is Dominion's Mt. Storm Power Station, which has a peak capacity of approximately 1,600 megawatts (MW) of coal-fired generation and is located in West Virginia but interconnected to Dominion's transmission system that serves both Virginia and North Carolina customers.

under various scenarios. Plan A, which is a least-cost scenario, is not compliant with the applicable VCEA requirements and is designed for cost comparison purposes only. Plans B, C, D, and E evaluate various pathways and are discussed in detail below. Plans C and E are least-cost dispatch variations from Plans B and D. The Public Staff highlights two plans – Plans D and B. Dominion's Plan D includes significant development of nuclear, solar, wind, and energy storage resources, and is compliant with the VCEA's renewable energy requirements within its study period (2024 to 2048). The Public Staff believes Plan B represents pathways similar to Plan D over the next 15 years, but there are potential modeling restrictions and constraints that make each plan sub-optimal. Dominion also projects each individual plan's net present value (NPV) ranging from $109.7B for Plan A to $140.9B for Plan D. Table 1 below compares the rate impacts of Dominion's Plan B with Plan D. Dominion only presented the bill projections for Plan B in their initial filing and provided Plan D upon request of the Public Staff. The values are derived using the Company's methodology for computing bill projections, which includes load growth, relative to customer bills based on rates in effect on May 1, 2020.

Table 1: Dominion Residential Bill Projection 2020 to 2035 (15-year impact)[2]

Portfolio	Annual Average Increase	Average Total Increase in Monthly Residential Bill by 2035
Plan B	2.6%	$57.97
Plan D	3.0%	$69.41

[2] IRP at 34, Figure 2.5.1. Based on 1,000 kWh per month assumption.

AREAS OF CONCERN

The Public Staff highlights several concerns for the Commission's consideration.

First, the Company artificially limited the model's ability to select new natural gas generation by requiring that all be built in Virginia. Future generation resources are non-designated resources that can be built in either Virginia or North Carolina, but it appears that the Company assumes that any new natural gas generation[3] would be built in Virginia based on the discussion of hydrogen firing these units in 2045, thus limiting its ability to build carbon-emitting resources while achieving compliance with the VCEA.

Second, each plan relies on import capacity to meet system planning requirements. In certain of the 2023 capacity expansion plans, the Company is relying on nearly 11 gigawatts (GW) of import capacity to serve system needs by 2045.

Third, for Plans B and D, the Company "forced in" a second tranche of offshore wind by requiring the model to select this resource in 2033. This second tranche of offshore wind equates to 2,600 MW, at a presumed 42% annual capacity factor.[4] It is unreasonable to force the model to select a resource of this magnitude

[3] Scarcity warrants consideration in planning, but the Williams Company is in the process of completing the Transcontinental Gas Pipeline's Southside Reliability Enhancement project, an expansion of a pipe lateral that originates in southern-central Virginia (Pittsylvania County, VA) and ends in northeast North Carolina (Hertford County, NC).

[4] 2022 EIA lists the generic costs for offshore wind base overnight costs at $4,833/kW. A 2,600 MW facility using general EIA data results in the Company's "forced in" resource costing $12.6B.

of capacity, energy, and overnight total costs for purposes of an unquantified target for resource diversity.[5]

Fourth, the Company limited the amount of solar and battery storage resources that could be selected by the model. While only a certain amount of resources can be built and interconnected each year, this limit is unknown and theoretical. Depending on the circumstances and assumptions made, this limit can change year to year.

Fifth, PJM updated its reserve margin after the Company filed its 2023 IRP. This change in the reserve margin limits the planning value of the long-term portfolios as filed. The impact of the increased reserve margin, coupled with the Public Staff's other findings and concerns, raises concerns regarding the breadth of the Company's proposed short-term action plan and its ability to ensure system reliability.

Last, and more generally, there is uncertainty around the ultimate impact of state[6] and federal[7] regulations. In addition, the adoption of energy storage, increase in the number of electric vehicles, and large load customer trends (in particular, data centers) are impacting Dominion's load forecast models, and appear to be accelerating.

[5] See Dominion IRP p. 67, "the Company forced the model to select the second tranche of offshore wind in 2033, to diversify its carbon-free generation resources."

[6] For example, Virginia's Regional Greenhouse Gas Initiative (RGGI).

[7] For example, those that may be proposed by the Environmental Protection Agency under Section 111(d) of the Clean Air Act (42 U.S.C. § 7411(d)) regarding existing and new fossil resources.

The Public Staff believes that policy assumptions regarding long-term planning – particularly those pertaining to carbon regulation – involve a level of uncertainty, and failure to account properly for this uncertainty can result in sub-optimal plans and create the risk of unnecessarily high rates for customers. The policy of North Carolina is to "promote adequate, reliable and economical utility service to all of the citizens and residents of the State," and long-term forecasts raise inherent risks that must be considered and taken into account.

PUBLIC STAFF RECOMMENDATIONS

In other IRP proceedings, the Public Staff likely would have recommended that the Commission require the Company to refile its IRP Portfolios to address the concerns stated above prior to the Public Staff making its final recommendation on the IRP. However, given recent changes in Virginia law[8] requiring Dominion to file a full IRP again in 2024,[9] the Public Staff makes the following recommendations to the Commission based upon its review of Dominion's 2023 IRP:

1. That the Commission find Dominion's short-term action plan is reasonable for planning purposes.

2. That the Commission not accept Dominion's Plans A through E, as the modeling restrictions placed on the proposed plans raise significant concerns about their reasonableness for long term planning purposes.

[8] Va. Code § 56-599.

[9] Assuming the Commission grants the Company's proposed revisions to Commission Rule R8-60, which are pending in Commission Docket No. E-100, Sub 195 and supported by the Public Staff, Dominion will be required to file its next full IRP on October 15, 2024.

3. That the Commission require Dominion, in its development of the 2024 IRP and all future IRPs, to:

   a. continue to review its load forecasting methodology to ensure that assumptions and inputs remain current and that the methodology employs appropriate models quantifying customers' responses to weather, particularly abnormally cold winter weather events;

   b. continue to review its capacity options for addressing the winter peak;

   c. identify any changes in energy efficiency (EE) related technologies, regulatory standards, or other drivers that would impact future projections of EE savings;

   d. model new natural gas generation, applying reasonable modeling constraints such as fuel supply limitations or a maximum number of units that can be built in a year as non-designated resources that can be built in Dominion's service territory of Virginia or North Carolina;

   e. allow its model to select advanced class combustion turbines (CTs);

   f. model an alternative plan that does not rely on any import capacity to solve energy or capacity needs;

   g. not force undesignated resources into the capacity expansion plan;

h. continue to include at least one plan that retires all carbon-emitting resources located in Virginia by 2045 while complying with the VCEA and other applicable law;

i. to the extent that Dominion asserts that reliability would be impacted by retirement of all its carbon-emitting resources by 2045, provide clear evidence that a reliability concern is present or imminent;

j. model a plan that progressively increases the number of distributed resources that can be interconnected each year (the Company should enable the model to increase interconnection amounts year over year in the planning period (i.e., the next 15 years) rather than holding interconnection limits to a relatively static level);

k. increase the amount of solar and battery storage resources that can be selected by the model each year;

l. incorporate any updates to PJM's reserve margin; and

m. incorporate all Public Staff recommendations into at least one single aggregated portfolio and provide the NPV amounts and a corresponding bill impact analysis focused on North Carolina customers.

4. That the Commission encourage Dominion to optimize use of its DSM resources to reduce fuel costs (especially when marginal costs of energy are high) and ensure reliability.

5. That due to the increasing reliance upon energy storage in Dominion's IRP, the Commission initiate a generic rulemaking proceeding to evaluate whether, and under what circumstances, an electric supplier should be required to receive Commission approval prior to construction of a battery energy storage facility in North Carolina.[10]

6. That the Commission approve Dominion's 2023 North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Plan for purposes of this proceeding.

BACKGROUND

Pursuant to N.C. Gen. Stat. § 62-2(b), the Commission is vested with the duty to regulate public utilities and their expansion in relation to long-term energy conservation and management policies. North Carolina General Statute § 62-2(a)(3a) declares it to be the policy of North Carolina:

> [t]o assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as

[10] The Public Staff made this request in its 2020 IRP Comments, and the Commission stated it would take the recommendation under advisement and address the suggestion at a later time. *See* Comments of the Public Staff at 15 and 109, filed February 26, 2021, in Docket No. E-100 Sub 165. *See also* Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning at 21, issued November 19, 2021.

> additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills.

Similarly, N.C.G.S. § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis is required to include (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). *Id.*

North Carolina General Statute § 62-110.1 further requires the Commission to consider this analysis in acting upon any petition for construction of a generating facility. In addition, that statute requires the Commission to submit annually to the Governor and appropriate committees of the General Assembly (1) a report of the Commission's analysis and plan, (2) the progress in carrying out such plan, and (3) the Commission's program for the ensuing year in connection with such plan.

North Carolina General Statute § 62-15(d) requires the Public Staff to assist the Commission in this analysis and plan. Commission Rule R8-60 provides the Commission's specific requirements for the IRPs. Commission Rule R8-60 parts

(c) through (i) describe the requirements for Dominion's IRPs.[11] The Public Staff has reviewed the IRP filed by Dominion, as well as recent Commission orders regarding IRPs. Dominion has met all filing requirements of Commission Rule R8-60.

2023 PROCEDURAL HISTORY

On May 1, 2023, Dominion filed its 2023 IRP and REPS Compliance Plan. On May 22, May 31, June 12, July 6, August 8, and September 15, 2023, Dominion filed corrected pages. Pursuant to Commission Rule R8-60(m), Dominion met with the Public Staff on June 13, 2023, to discuss the IRP as filed at that time.

In addition to the Public Staff, whose intervention is recognized by statute, the Carolina Utility Customers Association, Inc., and the Carolina Industrial Group for Fair Utility Rates I have also intervened in this docket.

EVOLUTION OF THE IRP

Over the past 15 years, resource planning has changed significantly. Instead of focusing on large, centralized, thermal generation units, current IRPs must consider the addition and operational impacts of distributed energy resources (DERs), including intermittent generation such as wind and solar, and energy storage systems, as well as legislative policies that influence the types of generation resources that can and should be built. IRPs have also taken on greater significance due to the influence they have on directing and guiding public policies

[11] On November 13, 2019, the Commission repealed R8-60(i)(10) and R8-60.1 regarding smart grid impacts and smart grid technology plans.

associated with energy consumption, environmental impacts, and the economy. Federal, state, and executive initiatives, including the implementation of PURPA,[12] NC Senate Bill 3,[13] the VCEA,[14] NC House Bill 589,[15] NC EO80,[16] NC House Bill 951,[17] NC EO246,[18] and VA SB 1166,[19] and the interests of investor-owned utility (IOU) shareholders have all impacted the direction, scope, and determination of a reasonable least-cost plan. Consideration of the early retirement of fossil (thermal) generation and the replacement of that generation with less carbon intensive generation has taken on a more prominent role in Dominion's IRP, driven by the passage of the VCEA and Dominion's corporate goal of net zero emissions by 2050. Promotion and further development of cost-effective EE and demand response programs are a necessary part of reducing CO_2 emissions in a least-cost manner in light of existing plant obsolescence and retirements. As a result, the IRP has become an increasingly complex planning document, and the process that produces the IRP is integral to, and intertwined with, many other proceedings, including Certificate of Public Convenience and Necessity (CPCN) applications, the determination of avoided capacity and energy costs and values, the North

[12] 16 U.S.C. § 824a-3, enacted November 9, 1978.

[13] N.C. Session Law 2007-397, enacted August 20, 2007.

[14] Va. House Bill 1526, 2020 Session Chapter 1193, enacted April 11, 2020.

[15] N.C. Session Law 2017-192, enacted July 27, 2017.

[16] N.C. Executive Order 80, North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy, signed October 29, 2018.

[17] N.C. Session Law 2021-165, enacted October 13, 2021.

[18] N.C. Executive Order 246, North Carolina's Transformation to a Clean, Equitable Economy, signed January 7, 2022.

[19] Va. Senate Bill 1166, 2023 Session, Chapter 753, enacted April 12, 2023.

Carolina Interconnection Procedures (NCIP), and the evaluation and approval of demand-side management (DSM) and EE programs.

LEGISLATIVE, EXECUTIVE, AND CORPORATE ACTION INFLUENCING 2023 IRP

Since Dominion's last IRP update, there have been significant energy policy actions that influence the 2023 IRP, as summarized below.

VIRGINIA CLEAN ECONOMY ACT

The VCEA was signed into law on April 11, 2020, and became effective July 1, 2020. The VCEA is major comprehensive energy legislation that mandates a renewable energy portfolio standard (RPS) reaching 100% of total electricity sold to retail customers in the Commonwealth of Virginia by 2045. Beginning in 2025 the law requires that 75% of all renewable energy credits (RECs) used to comply with the RPS program must come from resources located in the Commonwealth.[20]

Further, the VCEA requires the Company to seek approval from the Virginia State Corporation Commission (SCC) by the end of 2035 for the construction, acquisition, or purchase of 16,100 MW of generation capacity from solar and onshore wind resources located in the Commonwealth; and 5,200 MW of offshore wind resources, which is to be located in the Commonwealth or located either off the Commonwealth's Atlantic shoreline or in federal waters and interconnected into

[20] *See* Va. Code Ann. § 56-585.5(C). Prior to 2025, the Company may rely on RECs from resources located in either Viriginia or PJM.

the Commonwealth.[21] Additionally, the VCEA requires the Company to seek approval for the construction or acquisition of 2,700 MW of energy storage resources by the end of 2035 from the SCC.[22] The VCEA also sets a target of 5% EE savings (based on 2019 jurisdictional electricity sales) by 2025.

The VCEA also mandates the retirement of all carbon-emitting generating resources located in the Commonwealth by 2045 but allows the Company to petition for relief from the SCC from the obligations "on the basis that the requirement would threaten the reliability or security of electric service to customers."[23] Lastly, the VCEA directed Virginia's participation in a carbon trading program through 2050.

The VCEA is an important reference in the five plans filed by the Company. As discussed below, Alternative Plan A of Dominion's IRP does not achieve compliance with the VCEA and is for cost comparison purposes only. Alternative Plans B through E are presented by Dominion as being compliant with the VCEA. The Public Staff, however, does not believe Plans B and C are compliant with the VCEA; notably, while they do not adequately demonstrate reliability concerns, Plans B and C do not retire all carbon-emitting resources by 2045. Dominion states that meeting the VCEA targets for procuring solar in Plans B through E will present challenges going forward, specifically in land acquisition, permitting, and supply chain for both equipment suppliers and construction contractors. Dominion also

[21] Va. Code Ann. § 56-585.5(D). Lower targets are set at earlier dates.

[22] Va. Code Ann. § 56-585.5(E).

[23] Va. Code Ann. § 585.5(B)(3).

states that Plans D and E will severely challenge the ability of the transmission system to meet its customers' reliability expectations.[24]

VIRGINIA AND THE REGIONAL GREENHOUSE GAS INITIATIVE

The Clean Energy and Community Flood Preparedness Act was also enacted by the Virginia legislature in 2020 and became effective April 22, 2022.[25] This Act authorized Virginia to join the Regional Greenhouse Gas Initiative (RGGI) and the Commonwealth became eligible to participate in RGGI auctions beginning on January 1, 2021.

RGGI is a market-based program organized by several Northeast and Mid-Atlantic states to reduce greenhouse gas emissions. RGGI is a state-implemented (as opposed to a utility-implemented) program that requires member states to cap carbon dioxide (CO_2) emissions from power plants 25 MW or larger and further requires those plants to purchase allowances for all CO_2 they emit.[26] However, Dominion has explained that on June 7, 2023, the Virgina Air Pollution Control Board repealed the rule enabling Virginia to join RGGI, which went into effect on December 31, 2023.[27] The Company stated that, with the repeal of the rule, Virginia does not qualify for RGGI participation and the pending litigation stays or overturns the repeal, Virginia will no longer be a RGGI participant.[28] The

[24] IRP at 110 (found at Page 119 of 283 in the September 15, 2023, filing).

[25] Va. 2020 Session, Chapter 1280, Article 4, enacted April 22, 2020.

[26] https://www.rggi.org/

[27] *See* Docket No. E-100, Sub 194, Update to Initial Statement of Dominion Energy North Carolina at 1, filed January 9, 2024.

[28] *Id.*at 2.

Alternative Plans A through E provided in the IRP reflect the assumption that Virginia will exit the RGGI and therefore no longer be subject to its obligations. The Company's RGGI sensitivity results[29] suggest an average increase to plan implementation costs of 1.35% were Virginia to remain in RGGI. The effect of Virginia's membership in RGGI on Dominion's future operations and resource planning is uncertain. Further uncertainty stems from the potential establishment of a mandatory federal CO_2 compliance standard applicable to electric utilities since this could significantly influence the RGGI market as a whole.

As an electric generator in Virginia, Dominion must pay an allowance for each ton of CO_2 it emits. Dominion does not have to pay for RGGI allowances for CO_2 emitted from its electric generating plants located in North Carolina (Rosemary) and West Virginia (Mt. Storm).

RGGI returns a significant portion of auction proceeds back to its member states. Virginia law requires that 50% of the revenues received from the auction proceeds it receives be used for low-income EE programs, 45% for assisting localities and residents affected by flooding and sea-level rise, and 5% for administration and planning. These programs are administered by the Commonwealth of Virginia and are not directed specifically to Dominion ratepayers who ultimately pay for Dominion's RGGI allowances.

[29] IRP at 35.

Although RGGI exit efforts are facing political and legal challenges, the Company believes "Virigina's December 31, 2023 exit from RGGI will stand."[30]

UTILITY NET ZERO POLICIES

On February 11, 2022, Dominion announced an expansion of its Corporate Net Zero Commitments, by expanding the 2050 goals to include all Scope 2 emissions and also certain material categories of Scope 3 emissions. Scope 2 emissions are those emitted from electricity the Company consumes but does not generate. Scope 3 emissions are generated downstream of Company operations by customers and upstream by suppliers.[31] In its 2020 IRP, Dominion stated that the net zero CO_2 and methane emissions commitment parallels the requirement in the VCEA.[32]

IRP PORTFOLIOS

As discussed above, Dominion presented several portfolios, or alternative plans, in its IRP, demonstrating the impact of various policies and carbon reduction goals. Plan A is representative of an unconstrained least-cost plan. While not compliant with the VCEA, it is presented for cost comparison purposes only.[33] All other plans put forth by Dominion, as well as the planning assumptions that drive them, are discussed in more detail below.

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[30] Update to Initial Statement of Dominion at 1, Docket No. E-100, Sub 194.

[31] https://news.dominionenergy.com/2022-02-11-Dominion-Energy-Broadens-Net-Zero-Commitments.

[32] Dominion 2020 IRP at 22.

[33] IRP at 2.

PLANNING ASSUMPTIONS

Certain variables in the resource planning process significantly affect the determination of least-cost resource scenarios. Four of these variables significantly affect the Present Value of Revenue Requirement (PVRR) for the alternative resource scenarios and, ultimately, the potential costs that customers will pay:

- Projected price of natural gas.
- Capital cost and operating characteristics of new generation.
- Planned unit retirements over the planning horizon.
- The allowable amounts and types of resources that can be built in each year (e.g., modeling constraints).

NATURAL GAS PRICE

The Mountain Valley Pipeline (MVP) mainline project is a 303-mile interstate pipeline currently under construction which is expected to provide up to two million dekatherms per day (or two billion cubic feet (Bcf) per day) to Virginia and North Carolina with firm transportation access from the low-cost Marcellus and Utica Shale natural gas production. After numerous delays, MVP is now scheduled to enter service in early- to mid-2024.[34] Currently, the growth of natural gas production in the Appalachian basin is constrained by the lack of available takeaway pipeline capacity to move it to the Southeast demand markets, a situation that would be partially alleviated by the completion and operation of MVP.

[34] https://www.mountainvalleypipeline.info/overview/.

The base case natural gas price forecast currently forecasts a premium for Henry Hub natural gas compared to Zone 5 Delivered starting in 2026. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

<u>CAPITAL COST OF NEW GENERATION AND OPERATING PARAMETERS</u>

Dominion's projected capital cost per kilowatt (kW) of new generation ($/kW) is one variable used in determining the optimal least-cost capacity expansion plan. The capital cost per kW is combined with the projected cost of fuel, unit heat rates, operating and maintenance (O&M) costs, service life, and other inputs in Dominion's busbar[35] screening. IRP models minimize total costs of meeting future load by finding the least-cost mix of new and existing resources given capital costs for new units and upgrades to existing units, O&M costs, and operating characteristics for all units.

Table 2 below shows important capital and operating characteristics for select new generation units evaluated by Dominion:[36]

[35] "The busbar results show the levelized cost of power generation 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 operation and maintenance costs, expected service life, overnight construction costs, and applicable REC investment or tax credits." IRP at 95.

[36] Figures derived from Dominion response to a Public Staff Data Request.

Table 2: Comparison of Key Variables for New Generation – Dominion

	CTs	Combined Cycle 2x1	Solar	Offshore Wind	Battery*	Pumped Storage
Capacity (MW) (summer rating)	485	~1,100	60	2,600	30	300
Heat Rate (MMbtu/MWh)	8,880	5,400	NA	NA	NA	NA
Investment**($/kW)	$1,179	$1,215	$2,006	$3,965	$2,863	$9,667
Book Life (years)	36	36	35	30	10	50

Notes: See Dominion IRP, Appendix 5N

* a 4-hour battery.

** installed cost in 2023 dollars.

RENEWABLES

Solar and offshore wind resources can either be forced into the capacity expansion model or economically selected. The VCEA dictates certain target MWs of solar and offshore wind procurement to be in the public interest. Renewables that were economically selected were chosen by the model as the optimal generation source to meet load and energy requirements, even with the Company placing annual interconnection limits on them.

The economic selection of solar depends on several input assumptions, including capital and operating costs, expected capacity factor, and capacity value. The capacity expansion models used by the Company must solve multiple constraints over the time horizon, such as meeting hourly load, peak load, and reserve margin requirements, all while minimizing costs.

Subsequent License Renewal (SLR) of Existing Nuclear Plants

As discussed in past Public Staff IRP comments, a significant issue facing Dominion is the pending expiration of operating licenses for nuclear energy resources in the next 20 to 30 years. Dominion is pursuing SLRs for its existing four-unit nuclear generation fleet of approximately 3,500 MW.

The Public Staff recommends that the Commission continue to direct Dominion in future IRPs to include a discussion and evaluation of SLRs for each of its existing nuclear units, including an anticipated schedule for SLR application submission and review, and an evaluation of the risks and required costs for upgrades if required by the SLR approval, or any new industry trends.

Unit Retirements

Within the confines of the 2023 IRP, Dominion has not identified any retired generation other than that which was previously scheduled. Dominion has retired Yorktown 3, Chesterfield 5, and Chesterfield 6 since the last IRP. These resources represented 1,781 MW of summer capacity and 1,824 MW of winter capacity. However, in 2039, just outside the current planning period, Plans D and E recognize the retirement of other carbon-emitting resources until they are all retired in 2045. Table 3 below shows all future unit retirements identified in Plans D and E.

Table 3: Units Slated for Retirement

Year	Retirements
2039	Chesterfield Unit 7
2039	Chesterfield Unit 8
2039	South Anna
2040	Clover Unit 1
2040	Clover Unit 2
2040	Rosemary
2041	Darbytown CT
2041	Elizabeth River CT
2041	Gravel Neck CT
2042	Possum Point 6
2042	Bear Garden
2043	Ladysmith CT
2044	Mt. Storm
2045	3x1 (Greensville, Brunswick, Warren)
2045	Virginia City Hybrid Energy Center
2045	Remington

PLANNED GENERATION

DOMINION'S EXPANSION PLANS

For the purposes of this section, resource additions are for the near-term Planning Period (2024-2038). The five alternative plans presented by Dominion in its 2023 IRP are described below:

- Plan A (Least-Cost) is a base case plan that considers only pre-VCEA carbon regulations and Virginia RPS Program requirements and, as such, is not compliant with the VCEA. It consists of 5,905 MW of new natural gas generation, 10,800 MW of new solar PPAs (power purchase agreements), 3,040 MW of new wind (on- and off-shore), 1,050 MW of new storage, and annual capacity purchases ranging from 1,300 MW in 2024 to 2,000 MW in 2038 (for a 15-year total of 27,100 MW).

- Plan B (Base with units forced in) is the least-cost plan that accounts for all current Virginia and North Carolina laws. The plan forecasts lower additions of natural gas generation than Plan A (only 2,910 MW of future natural gas fired generation would be added). In addition, the plan calls for 6,396 MW of Company-built solar, 3,444 MWs of solar PPAs, and 1,035 MW of solar DER (distributed energy resources). The plan includes 3,040 MW of new wind (on- and off-shore) and 2,370 MW of battery storage. Finally, Plan B calls for 804 MW of Small Modular Reactors (SMR) and annual capacity purchases ranging from 1,100 MW in 2028 to 2,600 MW in 2038 (for a 15-year total of 21,900 MW).

- Plan C (Plan B – Least-cost optimization with constraints) disregards the development targets set forth by the VCEA for solar, wind, and energy storage. Plan C procures 75 fewer MW of solar (all solar is PPA or Cost of Service under Plan C) and 150 fewer MW of storage, and annual capacity purchases ranging from 1,100 MW in 2024 to 2,700 MW in 2038 (for a 15-year total of 28,200 MW, which is 6,300 MW more in capacity purchases as compared to Plan B).

- Plan D (No Company-owned carbon after 2045 and units forced in) requires the retirement of all carbon-emitting generation by the end of 2045. However, for the purposes of a 15-year evaluation, Plan D does not call for any retirements until 2039. The difference between Plan D and Plan B is that Plan D constructs only 970 MW of new natural gas generation (versus 2,910 MW), which is assumed to burn 100% hydrogen by 2046, 1,608 MW of Nuclear SMR (small modular reactor) (Plan B calls for 804 MW), and annual capacity purchases ranging from 1,100 MW in 2024 to 3,800 MW in 2038 (for a 15-year total of 25,100 MW).

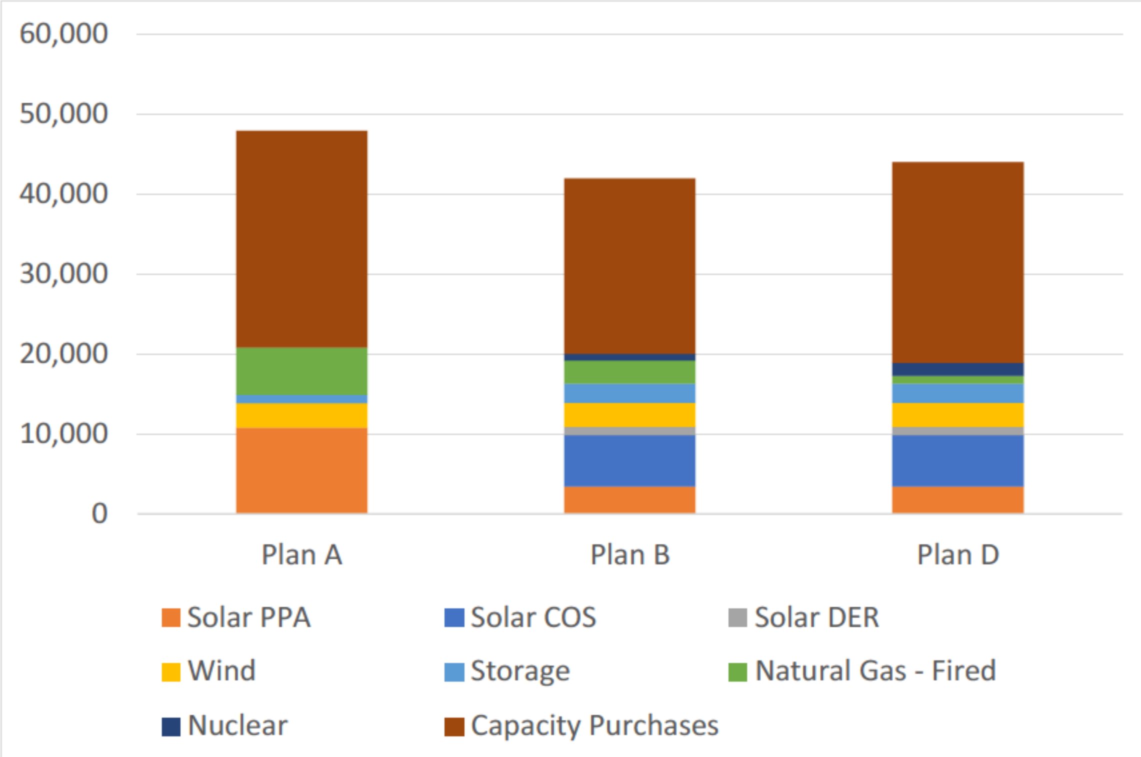
- Plan E (No carbon w/ least-cost optimization) is similar to Plan C with the least-cost optimization ignoring the prescriptive procurements of the VCEA while retiring all fossil resources by 2045, resulting in the procurement of 219 MW of incremental solar relative to Plan B, 540 MW of incremental storage, the same 970 MW of hydrogen capable natural gas turbines, and 268 MW of incremental SMR capacity. Plan E requires 7,200 MW of incremental capacity purchases relative to Plan B, which is achieved from capacity purchases ranging from 1,100 MW in 2024 to 3,800 MW in 2038 (for a 15-year total of 29,100 MW).

A comparison of the new capacity planned in portfolios A, B, and D from 2024-2038 is displayed in Table 4 below.

Table 4: Dominion Portfolio Cumulative Resource Comparison of Select Plans (2024-2038)			
	Plan A (Least-Cost)	**Plan B** (Base)	**Plan D** (2045 Retirements)
Company-Built Solar (MW)	-	6,396	6,396
Solar PPA (MW)	10,800	3,444	3,444
Solar DER (MW)		1,035	1,035
OSW (MW)	2,660	2,600	2,600
On-Shore Wind (MW)	380	440	440
Battery Storage (MW)	1,050	2,370	2,370
Natural Gas (MW)	5,905	2,910	970
Nuclear SMR (MW)	-	804	1,608
Capacity Purchases (MW)	27,100	21,900	25,100
Total (MW)	47,895	41,899	43,963

Table 4 shows that the new generation forecasted in Plan B and Plan D does not significantly diverge during the 2024-2038 planning period except for decreased natural gas resources and doubling of new nuclear generation in Plan D. The magnitude of capacity purchases is substantially larger than all other new resources in Plans A, B, and D, and exceeds 50% of total resource additions in all three Plans. New capacity planned in each Portfolio from 2024-2038 is displayed in Figure 1 below.

Figure 1: Planned Capacity by Portfolio



COMMENTS ON DOMINION'S EXPANSION PLANS

The Public Staff has reviewed the alternative plans presented by Dominion. As noted by the Company, Plan A is not a realistic path forward due to its inability to satisfy the requirements of the VCEA. Plans B and D are almost identical in procured resources until 2034 when Plan B procures additional natural gas and Plan D procures additional nuclear.

It should be noted that the least-cost dispatch runs of Plans C and E delay the selection of 2,600 MW of offshore wind from 2033 to 2035. In addition, the 970 MW of new natural gas fired CTs are delayed from 2028 to 2033 (Plan C) or 2034

(Plan E). Reliability concerns could justify selection of natural gas or offshore wind resources earlier.

As noted above, the cumulative quantity of capacity purchases necessary to fill the Company's PJM Reliability Requirement is significant. The model's determination that purchasing capacity is optimal to building additional resources concerns the Public Staff and bears further discussion. As it stands, the Company has forecast PJM's Capacity Price to increase from a current value of $43.85/MW-Day to $265.37/MW-Day in 2038, or a compound annual growth rate of 12.8%.[37] Such a compound annual growth rate (CAGR) of capacity prices would likely drive significant capacity expansion, whether in Dominion's territory or in the rest of PJM. Future NPVs calculated by the Company would incorporate these capacity prices by building additional transmission to access the supply via imports or the market value of Company-owned resources. Dominion should evaluate in the 2024 IRP the reasonableness of this forecast.

In addition to the above issues, PJM is currently engaged with FERC to modify the existing capacity market rules. These changes could potentially adjust the economics of the Fixed Resource Requirement (FRR) alternative that Dominion currently utilizes to satisfy its PJM Reliability Requirements. As noted by the Company, the EPA has proposed a new rule for regulating GHG emissions that is expected to be finalized during the second quarter of 2024. There has been additional guidance from the Internal Revenue Service relating to Production Tax

[37] Appendix 4N: Commodity Price Forecast, PJM RTO Capacity

Credits, Investment Tax Credits, and other impacts of the Inflation Reduction Act that were not clear at the beginning of 2023. Additionally, the Company is a member of the Mid-Atlantic Hydrogen Hub, which was selected by the US Department of Energy for award negotiations in October 2023. On top of those provisions, PJM has approved a new Regional Transmission Expansion Plan called Window 3, which calls for the construction of approximately $5 billion of green- and brownfield transmission lines to support data center load growth in Northern Virginia and Maryland.[38] Incorporating the results of this new information received since the May 1, 2023 filing will be important to understanding the reasonableness of Dominion's next IRP.[39] Due to changes in Virginia law that impact its IRP filing cadence, the Company will file a full IRP again on or before October 15, 2024, in Virginia, and has petitioned the NCUC to modify Commission Rule R8-60(h)(1) and (2) to allow for a similar filing schedule in North Carolina.[40] The Public Staff has recommended against the approval of any plan in this IRP and believes that this revision can be captured in the Company's 2024 IRP filing.

Dominion allowed the model to select simple cycle CTs (i.e., peaking CTs) in certain plans, and in some cases forced the resources into specific years.

[38]https://www.pjm.com/-/media/committees-groups/state-commissions/isac/2023/20231218/20231218-rtep-window-3-2022.ashx

[39] On December 8, 2023, the SCC Senior Hearing Examiner issued the Report on the 2023 IRP including various recommendations relating to future IRPs filed by Dominion. Pursuant to Virginia state law, the SCC must determine whether Dominion's IRP is reasonable and in the public interest. The Hearing Examiner found that she could not conclude that Dominion's 2023 IRP is reasonable and in the public interest. This conclusion was supported primarily by the Short-Term Action Plan item to continue development of 970 MW of new natural gas-fired CTs. In prior years, the SCC has ordered the Company to refile the IRP with changes; however, the hearing examiner does not recommend that outcome in this case if the SCC agrees with her conclusion.

[40] *Supra* Footnote 9.

However, the Company excluded the ability for the model to select new advanced gas CTs. Advanced class turbines are generally more efficient (lower heat rates) than older turbines (higher heat rates) and add flexibility via superior ramping capabilities compared to certain CT technology, which can help maintain system reliability as intermittent generation deployment levels increase. Given the significant energy and capacity needs in Dominion's load projections, and the amount of renewable generation being selected, the Company should include advanced class CTs (e.g., H and J frames, or equivalent) for selection. These assets will also serve as reliable generation units with spinning reserve capabilities while providing synchronous reserves and ancillary services.

The Company constrained the number of new resources that could be selected in a single year (i.e., an annual limit) and the maximum number of resources that could be selected over the entirety of the planning period. Generally, imposing modeling constraints is reasonable due to physical limits on the level of resources that can be built and interconnected each year. However, overly constraining a model may result in a sub-optimal resource portfolio. Listed below are the modeling constraints the Company imposed in Portfolios B through D, as presented to the Public Staff in response to a data request.

Table 5: Portfolios B – D Modeling Constraints

Asset	Annual Limit	Maximum Unit Limit
Battery Storage	300 MW Total	None
Utility Scale Solar	900 MW	None
DG Solar	120 MW	None
Generic On Shore Wind	1-unit/60 MW	1-unit every 3 years
Offshore Wind	1-unit/2,600 MW	1 unit
SMR	1-unit (268 MW)/2-years	8 Total units
3x1 CC	2 units	2 units
1x1 CC & 2x1 CC	1 unit	1 unit
2X CT	1 set	1 set
2X CT Chesterfield	1 set	1 set
1X CT (Aero)	4 units (Every 4 years)	24 units
Pump Storage	1 unit/300 MW	1 unit

As Table 5 above illustrates, the Company imposed constraints on generation units on both an annual and maximum build amount. For example, a 300 MW annual limit on energy storage is artificially imposed by the Company and is reflected in certain portfolios that build up to that exact maximum amount. This same behavior is observed with utility-scale solar as well. Given how the portfolios have maximized certain resources up to their imposed limits, the Company should relax such constraints in the next IRP filing. The Public Staff gives substantial weight to the resources selected in Plan D, while noting that Plan E more accurately emulates VCEA compliance while allowing the resources to be selected economically (e.g., a delay in the second tranche of offshore wind occurred in Plan E compared to Plan D). Utility-scale solar and storage resources are added at their model-imposed maximum amount, evidenced by the fact that the model selected 100% of all the available resource types for 2030 through 2047. Even though solar and battery storage are selected at maximum levels over much of the planning horizon, the Company remains deficient of capacity to meet system energy and capacity planning requirements by almost 11 GW. To put that amount of import capacity in perspective, 11 GW would be approximately one third of the capacity needed to meet Dominion's projected Load Serving Entity (LSE) load.[41] The Company has not demonstrated a plan to locate and build out the required transmission infrastructure to import that level of firm and dependable capacity to, and within, the Dominion Zone. It is also not certain if a future capacity market will be able to serve as a backstop for Dominion's capacity needs as well as other utilities who may also make similar capacity import assumptions.

The Public Staff recommends that Dominion increase the annual and maximum limit of resources available to be selected in the model, gradually increasing year over year, thus mitigating concerns of the model being overly constrained. For example, solar additions may start at 900 MW, but be allowed to increase by 100 MW each year until the 1600 MW annual interconnection limit is reached. Energy storage additions should also increase, starting at 300 MW and increasing at an interval of 60 MW each year until the initial value doubles. The Company should also relax the IRP limit constraint on new nuclear generation, allowing the model to determine the number of total units to be built to solve for energy and capacity requirements. In addition, Dominion should limit the level of import capacity to the current level of 1,100 MW in future North Carolina IRP filings

[41] See Dominion IRP, Figures 2.2.4, at 28 and Figure 4.1.1.1, at 44. Dominion LSE equivalent MW in 2046 is 29,767 MW.

in at least one portfolio.[42] Finally, Dominion should provide a North Carolina specific bill impact analysis for each alternative plan.

TRANSMISSION

Transmission planning and investment has taken on greater significance than in previous IRPs for a variety of reasons, including recent and unexpected load growth, generation interconnections coupled with PJM queue reform, and the magnitude of GW of imported capacity needed to support the Company's proposed portfolios. Depending on which portfolio the Company relies upon for planning purposes, Dominion is expecting to import up to nearly 11 GW of capacity by 2045. The sources of firm import capacity to be procured to meet system needs are uncertain, and even if Dominion is able to procure the capacity, incremental transmission will be required. Large scale transmission projects typically take a decade or longer to identify need, plan, build, and become commercially operable. A review of Plan D indicates that the Company is anticipating 3.8 GW of capacity purchases by 2038 (i.e., the end of the 15-year planning horizon), with the amount increasing to nearly 11 GW by 2045.[43] Notably, the capacity purchases in 2039 through 2048 appear to be linked to unit retirements as the model will be able to import the equivalent capacity amount up to the capacity of the retired unit. The Company's planning assumptions, in addition to the modeling constraints discussed previously, raise concerns as to whether the Company's proposal is least cost (much less executable) given siting uncertainty for new high-voltage

[42] See Dominion IRP Figures 2.2.2 thru 2.2.5. Each Figure's present import amounts in 2024 was set to 1,100MW.

[43] IRP at 28.

transmission that will likely be needed in the northern and northwestern parts of Virginia based on the existing transmission network and the Company's participation in PJM. Dominion projects that for Plan D, an additional approximate 11,000 MW of transmission import capacity may be required, at an incremental cost of $10.9 billion relative to Plan A.[44] The total transmission investment for Plans A through E ranges from $22.2 billion to $33.1 billion (NPV). Note that this total transmission investment is inclusive of transmission upgrades to interconnect new system generation facilities as well as to enable capacity imports to meet system needs.

SHORT-TERM ACTION PLAN

Dominion's Short-Term Action Plan (STAP) includes new generation capacity to be built as well as other actions to occur over the next five years.[45]

Table 6: Cumulative Generation Additions and Retirements (2024-2029)

Utility	Offshore Wind	CT	CC	Utility Scale Solar	Storage
Dominion	2,587	970	0	2,388[46]	210[47]

NON-UTILITY GENERATION

Commission Rule R8-60(i)(2)(iii) requires Dominion to provide in its biennial IRP report a list of all non-utility electric generating facilities (NUGs) in its service

[44] IRP at 31-32.

[45] IRP at 37.

[46] The amount of Utility Scale Solar procured varies between the different Plans from 1,920 to 2,700 MW. Appendix 3A designates 654 MW of solar.

[47] Storage is selected by Plans B, D, and E within the STAP Window.

areas, including customer-owned and stand-by generating facilities. Dominion provided a list of Power Purchase Agreement Units in Appendix 5B in the original filing.

Table 7 below provides a breakdown of all the Dominion PPAs presented.

Table 7: Dominion PPAs

Fuel Type	VA	VA (MW)	NC	NC (MW)	Total	Total (MW)
Municipal Solid Waste	1	21	0	0	1	21
Hydro	6	7.428	0	0	6	7.428
Methane	1	3.28	0	0	1	3.28
Coal/Biomass	2	143.5	1	9	3	152.5
Solar	12	258.03	88	661.315	100	919.345
Biomass	0	0	2	0.4	2	0.4

COSTS

The cost of each capacity expansion plan consists of many components and can be expressed in several ways. In the sections below, the Public Staff discusses the primary metrics by which the Company evaluated its plans, as well as the cost risk associated with carbon legislation uncertainty.

PRESENT VALUE REVENUE REQUIREMENTS

One of the primary metrics used by Dominion to compare its various capacity expansion plans is the Present Value of Revenue Requirement (PVRR) metric. This methodology represents the total revenue collected from customers to compensate the utility and its investors for all expenditures of capital associated with each generation portfolio. The capacity expansion model converts the anticipated annual future nominal expenditures into one single figure that is reflective of the approximate present value of the revenue requirements necessary to fund each plan. The annual future nominal expenditures from the capacity expansion model are also used to estimate future rate impacts, as discussed in the next section.

Dominion presents a PVRR analysis for each of its Plans A through E in its IRP.[48] This information, along with cost premiums calculated for each plan relative to Plan A (least cost), is presented in Table 8 below.

Table 8: PVRR through 2050 for Dominion ($ values in Billions)

2023 $B	Plan A	Plan B	Plan C	Plan D	Plan E
Total System Costs	**$ 88.5**	**$ 100.2**	**$ 99.7**	**$ 108.8**	**$ 105.8**
Grid Transformation Plan (Net of Benefits)	$ (1.6)	$ (1.6)	$ (1.6)	$ (1.6)	$ (1.6)
Strategic Underground Program	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7
Transmission	$ 22.2	$ 28.4	$ 28.4	$ 33.1	$ 33.1
Total Plan NPV	**$ 109.7**	**$ 127.7**	**$ 127.2**	**$ 140.9**	**$ 138.0**

The Public Staff notes that while the VCEA has a requirement that all carbon-emitting generation be offline by 2045, there is a provision that allows Dominion to petition the Virginia SCC to keep certain carbon-emitting plants online if the "requirement would threaten the reliability or security of electric service to customers."[49] If such a petition is made, the Virginia SCC must "consider in-state

[48] IRP p. 32, Figure 2.4.1.

[49] *See* VA Code § 56-585.5(B)(3).

and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition."[50]

In its IRP, Dominion recommends a path forward that substantially aligns with the first 15 years of Alternative Plans B through E; it also recommends Plan B over the longer term in its avoided cost filing.[51] However, the SCC Staff noted concerns with the addition of new natural gas CTs without comprehensive analysis to justify their inclusion.[52] The Public Staff agrees with Dominion that there are no significant differences in the aggregate of resources between Plans B through E in the next 15 years. However, given the modeling constraints the Company imposed, ultimately limiting the ability of the model to select a true least-cost plan, the Public Staff is concerned that the NPV results reported by the Company do not accurately reflect the full costs of the plans.

RATE IMPACTS

Dominion's approach to calculating the bill impacts represented in its Table 2.5.1[53] is similar to that of the Duke utilities in their recent IRPs. However, there are a few notable differences. First, Dominion's approach focuses only on the residential rate impacts of the Virginia jurisdiction, including the allocation of

[50] *Id.*

[51] Dominion's 2023 NC Biennial Avoided Cost Initial Statement and Exhibits, filed November 1, 2023 in Docket No. E-100, Sub 194.

[52] "Given the 2023 IRP's focus upon the imminent addition of new natural gas CTs, and because the Company failed to provide more comprehensive information and/or analysis with the 2023 IRP concerning its ability to overcome 56-585.1 A 5 of the Code's presumption against new carbon-generating unit approvals, I find Dominion failed to establish the 2023 IRP is reasonable and in the public interest." – Report of A. Ann Berkebile, Senior Hearing Examiner at 160.

[53] IRP at 34.

revenue requirement among the various Virginia retail customer classes using the average and excess cost of service methodology, as approved by the SCC. Second, Dominion indicates that it established a cost baseline that predates the VCEA. In other words, the rate impact analysis focused on the impacts associated with system costs resulting from the VCEA. Dominion also does not include any costs associated with the Commonwealth of Virginia's participation in RGGI but did provide a sensitivity that indicates an average increase to NPV of 1.57% across all plans.

The Public Staff has concerns regarding Dominion's calculations and the results shown in its Table 2.5.1 for residential bills. It is important to note that such calculations are always subject to several assumptions and should never be interpreted in absolute terms. However, the data in the tables provide a good representation of the differences in the bill impacts of each portfolio. The use of consistent supporting inputs for each portfolio provides a reasonable snapshot and comparison between plans. Dominion has included its residential bill impact analysis for several IRP cycles. However, the Company has not provided an analysis of how its expansion plans will affect North Carolina ratepayer bills. The majority of Dominion's North Carolina territory is categorized by the North Carolina Department of Commerce as Tier 1,[54] which is the most distressed, and the rate

[54]The North Carolina Department of Commerce annually ranks the state's 100 counties based on economic well-being and assigns each a Tier designation. This Tier system is incorporated into various state programs to encourage economic activity in the less prosperous areas of the state. The 40 most distressed counties are designated as Tier 1, the next 40 as Tier 2 and the 20 least distressed as Tier 3. County Tiers are calculated using four factors: average unemployment rate, median household income, percentage growth in population, and adjusted property tax base per capita.

increases that the Company has presented for its Virginia customers are substantial and may be difficult for many of its North Carolina customers to bear. The Public Staff recommends that the Company provide North Carolina-specific bill impacts in future IRP filings to contextualize the residential impacts to North Carolina. The Public Staff will continue to work with Dominion to understand the sensitivities of the various inputs to ensure that the analyses are capturing all the incremental changes to revenue requirements resulting from each plan.

DOMINION'S INTEGRATED DISTRIBUTION PLANNING

In its IRP, Dominion recognizes the need for an evolution of the distribution grid to support increasing deployment of DERs and the electrification of transportation. In September 2019, Dominion filed with the SCC a white paper providing a detailed overview of its Integrated Distribution Planning (IDP) process.[55] Since that time, Dominion has deployed its IDP roadmap[56] to focus on near-term goals based on load growth, reliability needs, DER growth, new technology adoptions, and other changes on the distribution system over the planning horizon. Dominion identified areas where it has made progress, including centralizing the distribution-related modeling and data analysis team, improving technologies through development and implementation of Grid Transformation Plan investments, and instituting new processes such as the development and deployment of DER hosting capacity maps. Dominion has deployed three hosting

[55] Dominion Petition for approval of a plan for electric distribution grid transformation projects, PUR-2019-00154.

[56] IRP Appendix 8A.

capacity tools: one for customers and developers to identify sections of the distribution system that may be suitable for new generation, one that identifies distribution level behind the meter generation opportunities, and one that identifies hosting capacity for transportation electrification.[57] The IDP process relies upon the investments proposed as part of the Grid Transformation Plan, as well as technologies available to Dominion. Some aspects of Dominion's IDP share characteristics with Duke Energy Progress, LLC's (DEP) and Duke Energy Carolinas, LLC's (DEC) (together, Duke) Integrated System and Operations Planning or ISOP,[58] including enhanced feeder-level forecasting, a standardized screening process to consider non-wire alternatives (NWAs), and the integration of operational organization structures as needed. The timeframe for development and deployment of the supporting technology for the IDP begins in 2024 for DER Interconnection, NWAs, Distribution System Analysis, and development of a methodology to increase hosting capacity.

ECONOMIC DEVELOPMENT

In its Order dated November 28, 1994, issued in Docket No. E-100, Sub 73, the Commission ordered North Carolina utilities to review the combined results of existing economic development rates within the approved IRP process and file the results in their short-term action plans.

[57] IRP Appendix 8A, at 1.

[58] https://www.duke-energy.com/our-company/isop

Dominion offers one Commission-approved economic development rate, Rider EDR Economic Development (Rider EDR). Rider EDR is available to new non-residential load associated with initial permanent service to new establishments or the expansion of existing establishments. As of March 31, 2023, Dominion had ten customers receiving service on Rider EDR in Virginia, representing 226 MW of load, and one customer in North Carolina on Rider EDR, representing 2 MW of load.

PEAK LOAD AND ENERGY FORECASTS

The Public Staff has reviewed the 15-year peak demand and energy forecasts (2024–2038) of Dominion. The CAGRs for the forecasts are within the range of 0.7% to 1.5%. In its IRP, Dominion used accepted econometric and end-use analytical models to forecast its peak and energy needs. With any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

In assessing the reasonableness of Dominion's forecasts, the Public Staff first compared the utility's most recent peak loads to those forecasted in its 2020 IRP. The Public Staff then analyzed the accuracy of the utility's peak demand and energy sales predictions in its 2018 IRP by comparing them to actual peak demands and energy sales. A review of past forecast errors can identify trends in forecasting and assist in assessing the reasonableness of the utility's forecasts.

The Company's 15-year forecast (2024-2038) is based on PJM's peak load and energy sales forecast, scaled down for the Dominion LSE. However, unlike prior PJM forecasts, PJM incorporated an independent consultant's analysis review of its modeling process to more accurately reflect the data center load growth that lacked historic precedent.[59] This stems from the fact that the Company "serves the largest data center market in the world."[60] The vast majority of data centers served by the Company (approximately 80%) are in Loudoun County in northern Virginia. The data centers are substantial consumers – in fact, the data center industry in Virigina achieved a peak metered load of almost 2.8 GW in 2022.[61] Dominion does not forecast the growth of data centers as it does the growth of other traditional customer groups, for which it uses forecasts of the number of houses, predicted manufacturing growth, and other forecast drivers. Rather, the Company utilizes executed customer contracts for new service as one basis for the projection of its new data centers. The Public Staff views this approach as reasonably conservative given (1) the lack of historical data on data center-type loads and (2) the size of such loads. These facts, together with Dominion's historical experience with the growth of data centers over the last ten years, lends further credence to the Company's forecasts.

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[59] "These changes included replacing annual/quarterly end-use indices with monthly/daily indices, replacing daily models with hourly models, and incorporating a data center forecast covering fifteen years, instead of just five…." IRP at 6.

[60] IRP at 55.

[61] *Id*.

The graphs below illustrate the predicted growth of the Company's summer peak load and energy sales forecasts with a CAGR of 3.0%, as compared to a growth rate of 0.9% in the 2020 Plan[62] and 0.7% in the 2018 Plan.[63] Dominion's energy sales after adjusting for EE programs are projected to grow annually at 4.2% over the next 15 years. Similar growth rates have not been observed over the last 40 years or more. Dominion's projected load from data centers alone increases from approximately 3,000 MW in 2023 to over 12,000 MW in 2038. As a result, on average, the Company will need an additional 638 MW of supply each year over the 15-year forecast to serve all load, including data center load, and this is not inclusive of the updated PJM Reserve Margin requirements. In comparison, Dominion's data center load increased an average of 205 MW from their 2020 Plan[64] and 267 MW from its 2018 Plan.[65]

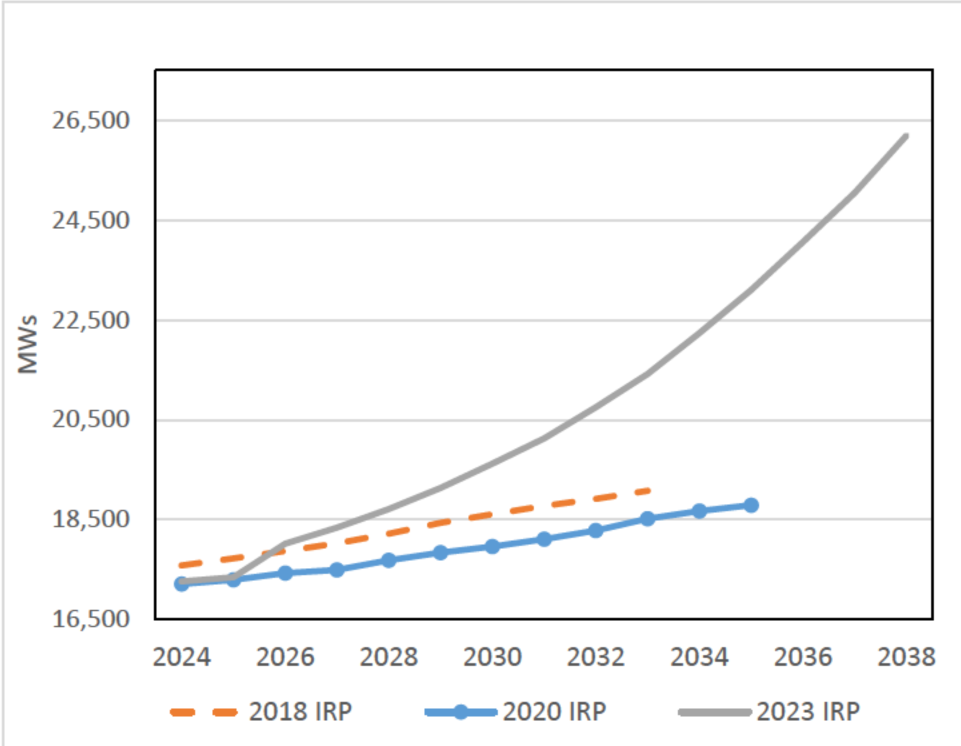
[62] 2020 IRP Plan filed in Docket No. E-100, Sub 165.

[63] 2018 IRP Plan filed in Docket No. E-100, Sub 157.

[64] 2020 IRP.

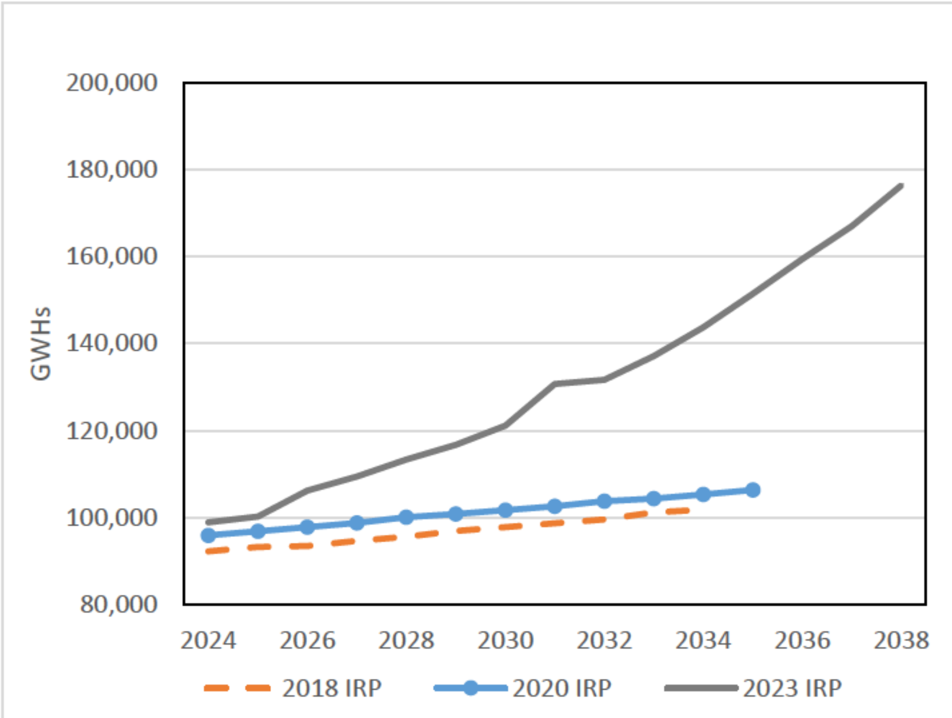
[65] 2018 IRP.

Figure 2: Dominion's Summer Peak Load Forecasts



The winter peak is also forecasted to grow at a CAGR of 3.0%; however, the summer peak will remain the dominant annual peak by approximately 3,000 MW by 2038. Dominion's EE programs are predicted to provide between a 3% and 4% reduction of the summer and winter peaks. As noted, the Company's annual energy sales are predicted to grow at a CAGR of 4.2%, which includes a higher level of reduced sales as a result of EE programs of 2% and 3% through 2038. The below graph illustrates the increased growth and level of energy sales in this IRP as compared to prior forecasts that annually grew at approximately 1.0% to 1.5%.

Figure 3: Dominion's Energy Sales Forecasts



The Public Staff's review of Dominion's actual peak load forecasting accuracy for 2022 and 2023 shows that its 2022 IRP update underpredicted the Company's 2022 and 2023 summer peak loads by an average rate of 4% and the energy forecasts reflected a 2% error rate. While the Public Staff evaluates the one- and two-year forecasts, its review of Dominion's peak load forecasting accuracy is largely based on the 2018 IRP forecasts for 2019 – 2023, as five years is a reasonable window for planning adjustments. The five-year review indicates that all the predicted annual peak demands were greater than the actual peaks. This overprediction generated a mean forecast error of 7% and an average annual overestimation of 1,112 MW of load. Likewise, the energy forecasts from the 2018

IRP reflected an average 5% error rate. The following table provides an overview of Dominion's annual peak load forecasts:

Table 9: Accuracy Analysis of Dominion's 2018 IRP

Yr.	Date	Actual	2018 IRP	Difference	%Difference	Absolute Difference	Absolute
2019	31-Jan-19	16,842	17,674	832	4.9%	832	5%
2020	20-Jul-20	16,356	17,766	1,410	8.6%	1,410	9%
2021	12-Aug-21	16,462	18,026	1,564	9.5%	1,564	10%
2022	9-Aug-22	17,131	18,284	1,153	6.7%	1,153	7%
2023	28-Jul-23	17,957	18,559	602	3.4%	602	3%
					Average	1,112	7%

Note:

The absolute difference or error is the absolute difference between the actual peak load and the forecasted peak.

CONCLUSIONS ON PEAK LOAD FORECASTS

The Public Staff continues to support the use of the PJM constructed peak demand forecast for Dominion as previously ordered by the SCC.[66] However, the Public Staff also notes that in 2022, PJM made changes to its load forecasting methodology based on data from the Company and Northern Virginia Electric Cooperative.[67] While the Public Staff is concerned with the added degree of

[66] Virginia SCC Case No. 2018-00065, December 7, 2018, pages 6 – 8.

[67] "In its 2022 PJM Load Forecast, PJM incorporated changes to its load forecasting methodology and utilized the latest data center forecast provided by the Company and Northern Virginia Electric Cooperative, which resulted in a significant increase in the load forecast compared to 2021. PJM's forecasting adjustments addressed the Company's concerns with PJM's utilization of a long-term trend variable as discussed in the 2021 Update. PJM also adjusted its method of incorporating data center forecasts into the overall forecast. Previously, the data center forecast was "implicitly" incorporated into the DOM Zone forecast by way of adjusting an input variable; by contrast, the 2022 PJM Load Forecast isolated the non-data center forecast from the data center forecast, thereby incorporating the data center forecast explicitly. These changes provide more forecast transparency." 2022 IRP, Section 1.1, at 8, Docket No. E-100, Sub 182.

uncertainty associated with data centers, which have relatively large loads and relatively little history as compared to other customers, the Public Staff finds that the Company has considerably more experience than others with data centers and has combined this knowledge with various statistical analyses to better understand its current and future energy requirements. Therefore, the Public Staff concludes that Dominion's peak load and energy sales forecasts are reasonable for planning purposes.

SUMMARY OF GROWTH RATES

The following table summarizes the growth rates for Dominion's system peak and energy sales forecast in the IRP Compliance filing:

Table 10: 2024-2038 Growth Rates (After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
Dominion	3.0%	3.0%	4.2%	638

DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

OVERVIEW

The Public Staff has reviewed Dominion's portfolio of DSM and EE programs. Dominion's portfolio relies heavily on the programs primarily implemented in its Virginia jurisdiction and the decisions made by the SCC regarding those programs. Dominion continues to work with the Public Staff to evaluate which, if any, of the programs cancelled in Virginia can be cost effectively offered on a North Carolina-only basis. In the past, when such a program could be offered in a cost-effective manner, even in the short term, Dominion has requested approval from the Commission.

Legislation such as the VCEA has had a major influence on Dominion's DSM and EE portfolio in Virginia, with corresponding impacts in its North Carolina service territory, as it is difficult to offer North Carolina-specific programs that are cost effective. While this legislation is an expansion of the Grid Transformation and Security Act of 2018 (GTSA), the VCEA provides further guidance on future DSM and EE and the general deployment direction that Dominion will pursue.

Dominion's 2023 IRP includes the impacts of all the programs in its portfolio; however, not all are available in its North Carolina service territory because certain programs that are considered DSM and EE programs by definition in Virginia or that are required by Virginia general statute do not meet North Carolina’s definition of DSM or EE or are not explicitly required by North Carolina general statute. Such programs generally involve the incentivization of renewables and electric vehicle programs.

The Public Staff notes that Dominion continues to host an EE stakeholder process as required by the GTSA. Stakeholder meetings have been held regularly to date, and are likely to continue for the foreseeable future, with the intent of bringing interested parties, including the Public Staff, together to discuss EE implementation in Virginia and North Carolina.

The Public Staff has concerns regarding the long-term achievability of the VCEA's requirement that Dominion achieve 5% EE savings by 2025 relative to a 2019 jurisdictional baseline. Dominion has incorporated this requirement as a modeling assumption. Based on responses to Public Staff data requests, the Company achieved 1,224,836 megawatt-hour (MWh) gross EE in 2022 relative to the 68,231,332 MWh baseline set in 2019, which equates to 1.80% savings. In order to achieve the legislatively required 5% EE savings, Dominion will have to aggressively increase its current level of EE savings by 178% relative to 2022 by 2025. As such, the Public Staff agrees with Recommendation #12 of the SCC Senior Hearing Examiner to utilize only Category 1 EE Programs for future model runs.[68] The inclusion of Category 2 is appropriate for a sensitivity analysis.[69]

Regarding DSM, the Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the inconvenience associated with the use of DSM are all important considerations in determining which DSM resources should be deployed and how often. Because the use of DSM is largely dependent on circumstances such as weather, grid conditions, and seasonal availability of resources, it cannot be dispatched at all times. Nevertheless, utilities should seek to maximize the use of DSM to reduce

[68] Report of A. Ann Berkebile, Senior Hearing Examiner at 161 "12. The Commission should direct the Company to run model sensitivities with only Category 1 DSM program savings for Alternative Plans B and E." https://www.scc.virginia.gov/docketsearch/DOCS/7w5801!.PDF

[69] IRP at 50 "The first category ("Category 1 Programs") consists of previously approved EE programs that remain effective (*i.e.*, that are still producing savings), along with programs that were approved by the SCC in Case No. PUR-2021-00247. The second category ("Category 2 Programs" or "generic" EE) represents unidentified EE programs and measures designed to meet legislative directives."

fuel costs, particularly when marginal energy costs are high. Based on the evidence from Docket No. E-22, Sub 676, Dominion reasonably activated its DSM resources throughout the summer of 2022 to achieve an average demand reduction of 33.294 MW. Table 11 below summarizes Dominion's DSM activation during three seasonal peaks. Dominion's 2023 annual system peak of 17,957 MW occurred on July 28, 2023, at the hour ending 5:00 p.m. and at a system-wide average temperature of 95 degrees. Dominion's winter system peak of 17,813 MW occurred on December 24, 2022, at the hour ending 8:00 a.m. and at a system-wide temperature of 9 degrees.[70]

Table 11: DOM Zone DSM Peak Activation Information

	2021 Summer Peak Demand	2022 Winter Peak Demand	2022 Summer Peak Demand
Date and Hour Ending	8/12/2021 1800	12/24/2022 0800	8/9/2022 1700
MW Load	20,406	22,219	21,156
MWs Reduced by DSM	41.04	5.66	43.13
Operating Reserve (%)	14.36%	11.94%	9.05%
Dom Zone LMP $ per MWH	$129	$2,073	$970

<u>RESERVE MARGINS AND RESOURCE ADEQUACY</u>

The reserve margin is designed to ensure that adequate generation capacity is planned to meet the system's needs at peak load, in light of scheduled and unscheduled maintenance, higher than expected load growth, operational limitations based on environmental constraints, variance in load due to extreme weather, transmission availability, and disruptions in power supply resulting from

[70] The data in Table 11 represent system peaks for the DOM Zone of PJM, which include loads not served by Dominion.

noncompliance with PPAs. Once a reserve margin target has been established, utilities build enough capacity to meet the forecasted peak demand plus the reserve margin. Typically, the reserve margin focuses on either winter or summer, depending on the characteristics of the system.

A reserve margin is generally defined as:

Reserve Margin = (Resources – Demand) / Demand

Different methods are used to estimate appropriate reserve margins. One of the more common methodologies is a Loss of Load Expectation (LOLE) analysis, whereby the utility's system is modeled in a particular year or over a range of years. The model inputs include load forecasts, expected load forecast error (LFE), expected weather, generator outages (planned, maintenance or unplanned), assistance from neighboring utilities, and expected output from intermittent energy sources, among others. The model then simulates system operations – often thousands of times – to determine when, and how often, a firm load shed event is likely to occur.

The reserve margin can be adjusted by adding or removing projected peaking resources (such as CTs) until the overall probability of a firm load shed event (referred to as the LOLE) is, for example, 0.1 events per year. The 0.1 figure is a common industry standard and is also known as one event in ten years. While not as common, the 0.1 LOLE standard can also be expressed as 2.4 hours per year, assuming the LOLE model can also calculate Loss of Load Hours (LOLH).

Both LOLE and LOLH standards are sometimes referred to as a physical reliability reserve margin, as the LOLE standard of 0.1 events per year is fixed and thus is not based on evaluating tradeoffs between the cost of adding new generation and the cost of a firm load shed event.

In its 2023 IRP, as in past IRPs, Dominion relies upon PJM's annual reserve requirement study (PJM Reserve Study), which estimates required reserve margins to maintain summer reliability.[71] Dominion is required to maintain sufficient long-term capacity to meet its target level of reliability, which is defined by the industry standard of a LOLE of one event in ten years discussed above. Dominion's target reserve margin from the PJM Reserve Study is 14.9% in delivery year 2023/2024, 14.8% for 2024/2025, and 14.7% for 2025 through 2027. In applying these reserve margin requirements to its IRP, Dominion uses a reserve margin target of 14.9% throughout its Study Period. It should be noted that PJM, as well as Dominion individually, is still considered summer peaking and summer planning (in contrast to DEP and DEC, both of which are winter planning). Dominion forecasts winter reserve margins greater than 29% throughout the Study Period for Plan B.[72]

The Public Staff also notes that Dominion filed its 2023 IRP based upon the 2022 PJM Reserve Study; however, after Dominion's filing, PJM released its 2023 Reserve Study on October 3, 2023, which calls for an increase to target reserve

[71] Dominion bases its 2023 reserve margin targets on the 2022 PJM Reserve Requirement Study.

[72] *See* Appendix 4I.

margins.[73] The recommended reserve margin from the 2023 Reserve Study is approximately 17.7%.[74] PJM recommended the new reserve margin be applicable staring with the 2024/2025 Delivery Year (June 2024-May 2025).[75] The Public Staff does not know how it will impact future Dominion IRPs, but all else being equal, an increase in the reserve margin will result in an increase in resources needed to meet Dominion's load forecast. While the Public Staff recognizes that IRPs are inherently a snapshot in time and there will be some staleness to any reviewed plan, an updated reserve margin of this magnitude, coupled with Dominion's expected load forecast and modeling resource constraints, casts uncertainty over the usefulness of the 2023 IRP results as filed. Dominion will file another full IRP in October 2024, which should address this adjustment to the reserve margin.

The minimum reserve margins from the PJM Reserve Study are applied to the peak system load, and in some cases the actual reserve margin is significantly higher than the target reserve margin, due to the timing and discrete sizes of future resource additions, load growth, and unit retirements. For the planning period of 2023 to 2038, the range of reserve margins reported by Dominion continues to be like those seen in previous IRPs. Planned reserves are presented below in Table 12. Under Plan B, Dominion expects that its reserve margin will fall to 2.7% in 2026. The high reserve margins in the winter do not necessarily indicate

[73] The 2023 PJM Reserve Study, https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20231025/20231025-item-02---2-2023-pjm-reserve-requirement-study-report-final.ashx.

[74] *Id.* at 9, Table I-1.

[75] *Id.* at 19

overbuilding, but rather the fact that Dominion has near equal if not higher winter peaks than summer peaks, and solar resources contribute less to winter peaks than summer peaks. The use of peak system load for system planning is not new but is relevant in the context of the capacity value of solar and storage resources.

Table 12: Reserve Margins

Electric Utility	Target Reserve	Minimum Reserve over Planning Horizon	Maximum Reserve over Planning Horizon
Dominion[76]	14.9%	2.7% (summer 2026)	31.1% (winter 2028)

The Public Staff also tracks the actual operating reserves on the peak day each week for each utility. Figure 4 below shows this data for 2023. In 2023, Dominion's average estimated operating reserve was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[77]

[76] Plan B. See Appendix 4I.

[77] Dominion's operating reserves occasionally fall below 0% throughout the year, as spot capacity purchases are not included in the calculation. In these situations, Dominion relies on imports from PJM to meet load.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

<u>CAPACITY VALUES</u>

In estimating the existing generation and reserve capacity necessary to meet load and account for uncertainty, the seasonal net dependable capacity of traditional thermal resources is entirely counted towards the necessary generation capacity – i.e., a 1,224 MW natural gas combined cycle (CC) plant will provide 1,224 MW of capacity to meet the winter planning reserve margin requirements, representing a capacity value of 100%.[78] Note that this definition is not meant to imply that the resource will always be available at times of peak demand – as evidenced by generator performance during historic winter storms, some generation fails to start or is forced into an outage during peak demand hours. The recognition of the likelihood of traditional thermal generation unavailability is captured in the model through forced outage rates for existing and new thermal resources, and in the determination of the target reserve margin.[79]

However, intermittent and energy-limited resources (such as wind, solar, and battery storage) are known to be unable to provide 100% of their capacity during peak-demand periods or certain reliability events. This "de-rating" of nameplate capacity for intermittent resources reflects the reality that utilities cannot rely on the full capacity of intermittent resources. For example, the typical winter morning peak load in North Carolina is from 7 am – 8 am, when solar resources are generating only a small fraction of their nameplate capacity. This concept is referred to as the capacity value of the resource.

There are multiple ways to estimate a resource's capacity value. Prior to 2018, PJM conducted an analysis to determine what fraction of a particular resource was actually available during historic peaks and used this average across

[78] The capacity value is different from the capacity factor of a resource. The former represents the percentage of a resource's nameplate capacity available during peak demand or reliability events. The latter is the ratio of actual energy produced to maximum energy that could be produced.

[79] Studies that determine the target reserve margin include outage rates for thermal resources, which affect the availability of those resources during the study period. Generally, a higher forced outage rate assigned to resources will result in a higher target reserve margin to maintain the same 0.1 LOLE.

a resource type as the capacity value. Since 2018, PJM has developed a probabilistic analysis referred to as Effective Load Carrying Capability (ELCC). An ELCC study will perform thousands of model runs in a Monte Carlo simulation[80] to evaluate the LOLE over a large number of possibilities. Each model run draws from different weather years, load profiles, and renewable output profiles, and may result in different LOLE values. To determine a resource's capacity value, the ELCC study will run a base case and a change case with incremental load. The addition of this incremental load in the change case will ultimately increase the LOLE from the base case. Then, a particular resource or combination of generation resources will be added until the LOLE returns to the same level as the base case. The capacity value is determined by dividing the amount of incremental load by the amount of the resource that was added to lower the LOLE back to the base case level.

Dominion relied upon PJM's 2022 ELCC Study to establish the capacity values for solar, onshore wind, offshore wind, and energy storage.[81] This resulted in a capacity value of 55% for tracking solar, 43% for offshore wind, 18% for onshore wind, and 82% for four-hour battery storage. As more of each of these resources are added to the system, the capacity value will decline because of declining marginal utility. This is due to the fact that as more of a particular resource is added, it provides less capacity value to the system. Consider 4-hour energy

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[80] A Monte Carlo simulation is a model used to predict the probability of a variety of outcomes when the potential for random variables is present. Monte Carlo simulations help to explain the impact of risk and uncertainty in prediction and forecasting models.

[81] The 2022 PJM ELCC Study is available at https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx.

storage deployed to meet a 2-hour peak – the capacity value may be 100%. But as enough 4-hour energy storage is deployed, the peak will flatten and lengthen to the point where it may be a 5-hour peak, which results in 4-hour energy storage being assigned a capacity value of less than 100%. Other factors may also contribute to this phenomenon.

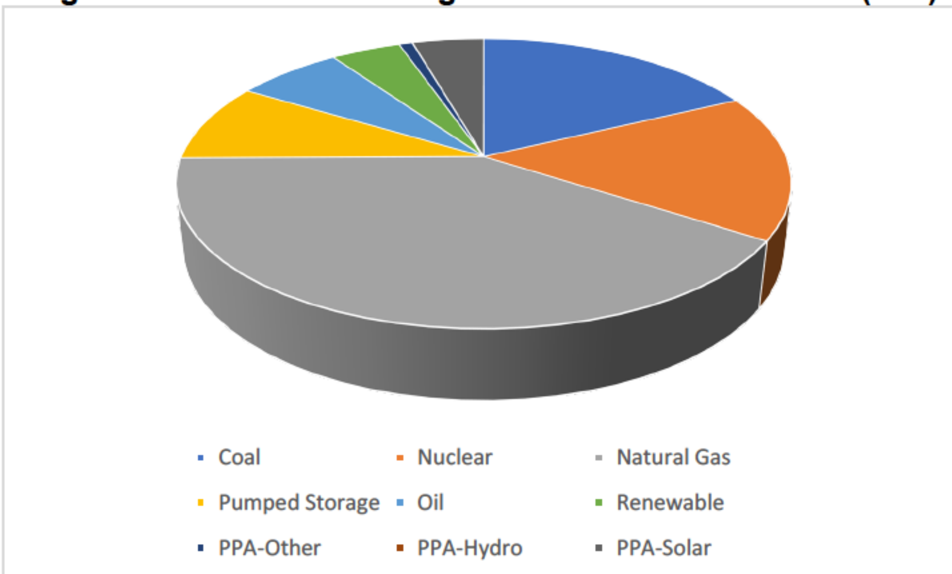
Generally, the Public Staff supports the use of an ELCC study to determine capacity values for intermittent and energy-limited resources and recommends that Dominion's capacity values be approved as reasonable for planning purposes.

EXISTING SYSTEM RESOURCES

GENERATION AND TRANSMISSION

Dominion currently meets electric demand through a diverse portfolio of utility-owned generation assets, long-term PPAs, and open-market purchases of energy and capacity. Figure 5 below is a pie chart showing the current generation mix, including utility-owned assets as well as non-utility generation (NUG) and wholesale purchases.

Figure 5: Dominion Existing Generation Resource Mix (MW)



<u>FIRST CAPACITY NEED</u>

On May 1, 2023, Dominion filed its Statement of Capacity Need as Addendum 5 to its 2023 IRP. This document states that Dominion's first undesignated capacity need is in 2024 in accordance with Figure 2.1.1 of its IRP.[82] This capacity need is determined inclusive of DSM and EE measures. Generators under construction are included as existing resources. Dominion has identified a system-wide capacity gap of 1,019 MW in 2024.

[82] IRP at 19.

CONCLUSIONS AND RECOMMENDATIONS ON DOMINION’S IRP

After reviewing Dominion’s IRP in its entirety, conducting discovery, and meeting with the Company, the Public Staff believes the short-term action plan presented is sufficient for planning purposes. The Public Staff also finds that the load forecast is reasonable given the relatively nascent data center load growth and how Dominion is attempting to forecast such growth. However, the Public Staff believes that the long-term planning included in Expansion Plans A through E raise enough concerns that it cannot recommend that the Commission should accept those plans as reasonable for planning purposes.

Therefore, the Public Staff recommends the following:

1. That the Commission find Dominion’s short-term action plan is reasonable for planning purposes.

2. That the Commission not accept Dominion’s Plans A through E, as the modeling restrictions placed on the proposed plans raise significant concerns about their reasonableness for long term planning purposes.

3. That the Commission require Dominion, in its development of the 2024 IRP and all future IRPs, to:

    a. continue to review its load forecasting methodology to ensure that assumptions and inputs remain current and that the methodology employs appropriate models quantifying customers’ responses to weather, particularly abnormally cold winter weather events;

b. continue to review its capacity options for addressing the winter peak;

c. identify any changes in EErelated technologies, regulatory standards, or other drivers that would impact future projections of EE savings;

d. model new natural gas generation, applying reasonable modeling constraints such as fuel supply limitations or a maximum number of units that can be built in a year as non-designated resources that can be built in Dominion's service territory of Virginia or North Carolina;

e. allow its model to select advanced class CTs;

f. model an alternative plan that does not rely on any import capacity to solve energy or capacity needs;

g. not force undesignated resources into the capacity expansion plan;

h. continue to include at least one plan that retires all carbon-emitting resources located in Virginia by 2045 while complying with the VCEA and other applicable law;

i. to the extent that Dominion asserts that reliability would be impacted by retirement of all its carbon-emitting resources by 2045, provide clear evidence that a reliability concern is present or imminent;

j. model a plan that progressively increases the number of distributed resources that can be interconnected each year (the Company should enable the model to increase interconnection amounts year over year in the planning period (i.e., the next 15 years) rather than holding interconnection limits to a relatively static level);

k. increase the amount of solar and battery storage resources that can be selected by the model each year;

l. incorporate any updates to PJM's reserve margin; and

m. incorporate all Public Staff recommendations into at least one single aggregated portfolio and provide the NPV amounts and a corresponding bill impact analysis focused on North Carolina customers.

4. That the Commission encourage Dominion to optimize use of its DSM resources to reduce fuel costs (especially when marginal costs of energy are high) and ensure reliability.

5. That due to the increasing reliance upon energy storage in Dominion's IRP, the Commission initiate a generic rulemaking proceeding to evaluate whether, and under what circumstances, an electric supplier should be required to receive Commission approval prior to construction of a battery energy storage facility in North Carolina.

Given the recent changes in Virginia law, requiring the Company to file another full IRP in 2024, the Public Staff does not believe it is prudent, given past procedural schedules in IRP dockets, to recommend that the Commission require Dominion to refile its IRP with the Public Staff recommended revisions in this docket. The Company is likely to begin its modeling for its 2024 IRP in the next few months, and requiring it to delay that process in an effort to comply with the Public Staff's recommendations in this docket would not be an efficient use of time. Therefore, the Public Staff requests that the Commission order Dominion to incorporate the Public Staff modeling recommendations in its 2024 IRP filing.

REPS COMPLIANCE PLAN REVIEW

REPS COMPLIANCE REQUIREMENTS

N.C.G.S. § 62-133.8 sets forth North Carolina's REPS, which requires all electric power suppliers in North Carolina to meet specified percentages of their North Carolina retail (NC Retail) sales using renewable energy. Electric public utilities may comply with REPS by generating renewable energy at their own facilities, purchasing RECs, or purchasing RECs bundled with renewable energy from a renewable energy facility. One REC represents one MWh of renewable energy. Nuclear energy was added as a REPS compliance option in 2023 as described more fully below.

Electric membership corporations (EMCs) and municipalities may comply with REPS using the methods described above but may also comply through an agreement with a wholesale power supplier or partially comply using their allocations from the Southeastern Power Administration (SEPA).

The REPS statute requires various types of RECs, as shown in the table below:

TABLE 13: Various Laws

REPS Section	Types of RECs
N.C.G.S. § 62-133.8(b)	General requirement[83] for electric public utilities
N.C.G.S. § 62-133.8(c)	General requirement for EMCs and municipalities
N.C.G.S. § 62-133.8(d)	Solar energy set-aside
N.C.G.S. § 62-133.8(e)	Swine waste energy set-aside
N.C.G.S. § 62-133.8(f)	Poultry waste energy set-aside

Alternatively, an electric power supplier may comply partially by reducing energy consumption through implementation of EE measures or electricity demand reduction[84] (or through DSM measures, in the case of EMCs and municipalities). Electric public utilities may use EE measures to meet up to 40% of the total REPS requirement. One MWh of savings from DSM, EE, or electricity demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. EMCs and municipalities may use DSM and EE to meet the requirements of N.C.G.S. § 62-133.8(c) without any limit on the maximum percentage allowed.

All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of their total requirements, except for Dominion, which may use out-of-state RECs to meet its entire requirement. The total number of RECs and

[83] The REPS requirements of N.C.G.S. § 62-133.8(b) and (c), net of the requirements of the three set-asides established by N.C.G.S. § 62-133.8(d), (e) and (f), are frequently referred to as the "general requirement."

[84] "Electricity demand reduction," as used herein, is defined in N.C.G.S. § 62-133.8 (a)(3a).

EECs that electric public utilities must provide each year is equal to 12.5% of their NC Retail sales for the preceding year. For the EMCs and municipalities, the total amount is 10%.

The solar energy set-aside requires that 0.2% of the previous year's NC Retail sales must be met with solar energy. The solar energy sources can be a combination of solar electric facilities and metered solar thermal energy facilities.

The electric power suppliers of North Carolina were initially required to meet the swine and poultry waste energy set-asides beginning in 2012. However, by orders issued in Docket No. E-100, Sub 113, beginning in 2012 and continuing through 2023, the Commission has delayed or modified the swine and/or poultry waste set-aside requirements as allowed by N.C.G.S. § 62-133.8(i)(2). On December 20, 2022, the Commission issued an order setting the poultry waste energy set-aside at 900,000 MWh per year (the statutory requirement) on a state-wide basis for 2023 and thereafter. On December 11, 2023, the Commission issued an order reducing the swine waste energy set-aside requirements for electric public utilities to 0.05%, 0.14%, and 0.20% of NC Retail sales for 2023, 2024, and 2025, respectively. For the EMCs and municipalities, this order eliminated the swine waste set-aside requirement for 2023 and reduced it to 0.07% of NC Retail sales for 2024 and 2025.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. The electric power suppliers must file their Plans on or before September 1 of each year and explain how they will meet the requirements of

N.C.G.S. § 62-133.8(b), (c), (d), (e), and (f). The REPS Compliance Plans must cover the current year and the next two calendar years, or in this case 2023, 2024, and 2025 (the Planning Period). REPS Compliance Plans filed by EMCs and municipalities are for information only. An electric power supplier may have its REPS compliance requirements met by a utility compliance aggregator as defined in Commission Rule R8-67(a)(5).

The passage of Session Law 2023-138 on October 10, 2023, revised N.C.G.S. § 62-133.8, and REPS became the Clean Energy and Energy Efficiency Portfolio Standard (CEPS), and nuclear energy became an eligible resource for compliance. Because Dominion filed its REPS Compliance Plan prior to the effective date of S.L. 2023-138, the Public Staff uses the term REPS in this docket instead of CEPS.

COMPLIANCE BY DOMINION AND THE TOWN OF WINDSOR

Dominion provides REPS compliance for the Town of Windsor (Windsor) and filed a REPS Compliance Plan for both itself and Windsor.

Dominion has contracted for and banked sufficient resources to meet the REPS requirements through the Planning Period for itself and for Windsor. Dominion plans to use EE, purchased in-state and out-of-state RECs, and company-generated RECs to meet the general requirement for its retail customers. For Windsor, Dominion will use biomass RECs and Windsor's allocation of energy from SEPA. Dominion has purchased or plans to purchase solar RECs to meet the solar energy set-aside and has executed contracts with in-state solar facilities to satisfy Windsor's portion of the in-state solar energy set-aside. Dominion's total costs are the same as its incremental costs because it currently plans to purchase only unbundled RECs to meet its REPS requirements instead of RECs that are bundled with renewable electric energy.

Dominion expects that the REPS compliance costs for itself and Windsor will be well below the cost caps set forth in N.C.G.S. § 62-133.8(h)(3) and (4) for the Planning Period.

REPS COMPLIANCE SUMMARY TABLES

The following tables are compiled from data submitted in the Company's REPS Compliance Plan. Table 14 shows the projected annual MWh sales upon which Dominion's and Windsor's REPS obligations are based. It is important to note that the figures shown for each year are the MWh sales for the preceding year; for instance, the sales for 2023 are MWh sales for calendar year 2022. The Public Staff presents the totals in this manner because REPS obligations are determined as a percentage of the electric power supplier's MWh sales for the preceding year. Table 15 presents a comparison of the projected annual incremental REPS compliance costs with the annual cost caps.

Table 14: Projected Annual Sales (MWh)

Compliance Year	Dominion	Windsor	Total
2023	4,078,059	45,229	4,123,288
2024	3,832,880	45,540	3,878,420
2025	3,864,529	45,600	3,910,129

Table 15: Comparison of Incremental Costs to the Cost Cap

		Dominion	**Windsor**
2023	Incremental Costs	$1,371,355	$27,379
	Cost Cap	$5,751,206	$96,553
	Percent of Cap	24%	28%
2024	Incremental Costs	$1,763,536	$30,843
	Cost Cap	$5,400,578	$96,745
	Percent of Cap	33%	32%
2025	Incremental Costs	$2,216,091	$35,012
	Cost Cap	$5,510,618	$97,180
	Percent of Cap	40%	36%

CONCLUSIONS ON REPS COMPLIANCE PLAN

The Public Staff's conclusions regarding the REPS Compliance Plan for Dominion and Windsor are as follows:

1. Dominion and Windsor should be able to meet their general, solar energy set-aside, and poultry waste energy set-aside requirements in the Planning Period without exceeding their cost caps.

2. Dominion and Windsor should be able to meet their swine waste energy set-aside requirements as modified by the Commission in the Planning Period without exceeding their cost caps.

3. The Public Staff recommends that the Commission approve the 2023 REPS Compliance Plan for Dominion.

WHEREFORE, the Public Staff prays that the Commission take these comments and recommendations into consideration in reaching its decision in this proceeding.

Respectfully submitted this the 29th day of January, 2024.

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CERTIFICATE OF SERVICE

I certify that I have served a copy of the foregoing Comments on all parties of record, the attorneys of record of such parties, or both, in accordance with Commission Rule R1-39, by United States mail, postage prepaid, first class; by hand delivery; or by means of facsimile or electronic delivery.

This the 29th day of January, 2024.

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