Date of Meeting: January 18, 2022

8

BOARD OF SUPERVISORS
BUSINESS MEETING
ACTION ITEM

SUBJECT: **Review of Power Purchase Agreements and Community Choice Aggregation**

ELECTION DISTRICTS: Countywide

CRITICAL ACTION DATE: At the pleasure of the Board

STAFF CONTACTS: Dennis Cumbie, Department of General Services
Marc Aveni, Department of General Services
Ernest N. Brown, Department of General Services
Erin McLellan, County Administration

PURPOSE: To provide the Board of Supervisors (Board) with the results of staff's investigation of Power Purchase Agreements (PPA), and the recently completed Community Choice Aggregation (CCA) Feasibility Study, and to request approval of recommended next steps for both items.

RECOMMENDATION: Staff recommends that the Board of Supervisors direct staff to develop Loudoun specific guidelines for PPAs and to refer the Community Choice Aggregation (CCA) Feasibility Study to the Finance/Government Operations and Economic Development Committee (FGOEDC) for additional discussion, and that the FGOEDC provide recommendations to the Board for future action.

BACKGROUND: At the December 1, 2020, Board of Supervisors (Board) Business Meeting, staff was directed (9-0) to investigate the potential for executing Power Purchase Agreements (PPA) as a potential method to expand the local use of renewable energy sources such as solar and the ability to sell any excess power generated back to the power supply for the region or "grid." At the December 15, 2020 Board Business meeting, the Board reiterated direction for staff on PPA investigation, and approved (8-0-1: Kershner absent) $200,000 of fund balance to evaluate how the County could establish Community Choice Aggregation (CCA), also known as Municipal Aggregation in the State Code, which would allow the County to aggregate power supply needs and buy directly from power supply providers rather than as a bundled customer of an Investor-Owned Utility (IOU) such as Dominion. Under a Municipal Aggregation model, local governments such as Loudoun can purchase and manage their community's electric power supply

from a preferred mix of traditional and renewable energy sources while the IOU continues to provide distribution, billing services, and outage management.

The purpose of the feasibility study was to estimate Municipal Aggregation operating costs and if projected rates could cover estimated operating costs and whether projected rates are comparable or even lower than IOU rates. The study suggests that Municipal Aggregation could provide a power supply that has a higher percentage of renewable energy than is currently offered by Dominion at a lower cost to rate payers. However, there are significant questions that still need to be answered regarding financial, legal, and staffing issues with Municipal Aggregation.

ISSUES:

Power Purchase Agreements. A Power Purchase Agreement (PPA) is a contract for the sale of electric generation. Electric utilities can obtain the power necessary to serve customers through PPAs or from generation facilities they own and operate.

A renewable energy power purchase agreement (RPPA) is a financial agreement where a "developer" arranges for the design, permitting, financing and installation of a renewable energy generating system (typically solar, but can be wind) on a customer's property at little to no cost to the customer. A developer under an RPPA is an entity that has the ability and capacity to design, permit, finance and install the renewable energy generation system. The developer sells the power generated to the host customer at a fixed rate that is typically lower than the local utility's retail rate. This lower electricity price serves to offset the customer's purchase of electricity from the grid while the developer receives the income from the sales of electricity as well as any tax credits and other incentives generated from the system. RPPAs typically range from 10 to 25 years and the developer remains responsible for the operation and maintenance of the system for the duration of the agreement. At the end of the RPPA contract term, a customer may be able to extend the RPPA, have the developer remove the system or choose to buy the renewable energy system from the developer.

Renewable PPAs can be found with other contractual constructs, but not all types are available to municipalities under State Code. Staff has done some initial research on the various types of PPAs, the State Code governing the use of PPAs in Virginia, and examples of PPA use among municipalities. This information is included as Attachment 1, which outlines the benefits and challenges associated with PPAs.

The benefits of entering a PPA include:

a) No/low upfront capital costs,
b) Potential for reduced energy costs,
c) Limited operational risk,
d) Better leverage of available tax credits,
e) Potential increase in property value, and
f) Economy of Scale through Virtual and Large Scale RPPAs.

The challenges associated with PPAs include:

a) Lack of historical precedent,
b) Complex contract negotiations,

c) Negotiation of Renewable Energy Credits (RECs),
d) RPPA structure vs. ownership,
e) Cost of site upgrades, and
f) Potential increase in property taxes.

The use of an RPPA as described above is limited to RPPA's for County Owned facilities. A separate issue is the many County residents who have been approached by RPPA developers proposing to install solar arrays at little to no cost and buy any excess energy produced. These inquiries may appear to be PPA solicitations in that they may offer the property owner purchasing rights to a portion of the power provided. However, under State Code, these are considered utility-scale solar developments constructed to generate power that is in turn sold to the power grid.

To assist property owners with navigating solicitations as described above, staff recommends that a set of "Solar PPA Fact Sheets" be produced to provide guidance to residents and businesses looking to enter into PPAs that address risks and concerns, legal and zoning issues, and State Code requirements while at the same time allowing for expanded renewable energy generation which reduces fossil fuel dependance.

Community Choice Aggregation: The Board has shown interest in the potential to provide constituents with the benefits of Community Choice Aggregation (CCA), also known as Municipal Aggregation in § 56-577 (A)(3) and § 56-589 of the Virginia State Code. State Code allows local governments to aggregate power supply needs and buy directly from power supply providers rather than as a customer of an Investor-Owned Utility (IOU) such as Dominion. Under a Municipal Aggregation model, local governments such as Loudoun can purchase and manage their community's electric power supply from a preferred mix of traditional and renewable energy sources while the IOU continues to provide distribution, billing services, and outage management. A CCA could allow a locality such as Loudoun to decide on the power generation mix it desires as a community to meet climate and energy goals on a potentially accelerated timeline.

With funding provided by the Board, staff procured the services of GDS Associates (GDS) and Best, Best & Krieger (BB&K) to perform the requested CCA Feasibility Study. The final report, titled "Municipal Aggregation Technical Feasibility Study" (Study) and dated December 2, 2021, is provided as Attachment 2. The Study was designed to:

1. estimate municipal aggregation operating costs (including power supply, labor, consultants, regulatory, legal, financing),
2. calculate anticipated municipal aggregation customer generation rates,
3. determine if projected rates can cover estimated operating costs, and
4. establish whether projected municipal aggregation generation rates are comparable to or lower than projected IOU generation rates.

The study results, while encouraging, are detailed and complex with legal, financial, and operating concerns. It provides a detailed account of assumptions considered, including an "opt-out" model where all customers are assumed to be included unless they take action to remove themselves from participation, and that the CCA will operate under an Enterprise Governance model where the

County operates its own municipal aggregation as a County department/enterprise fund. CCA performance projections are based on three separate energy portfolios as shown in Table 1 below. Of note is the ability to reach carbon neutrality goals at a much-accelerated rate with portfolios three or four.

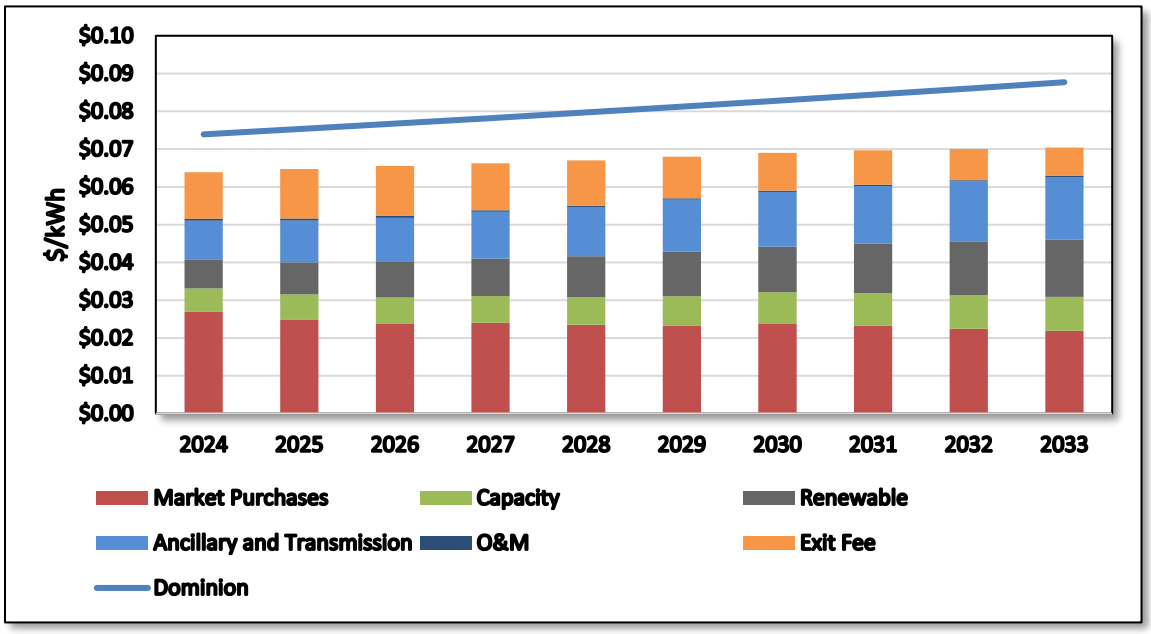
TABLE 1-1. LOUDOUN COUNTY MUNICIPAL AGGREGATION RESOURCE PORTFOLIOS

	% Renewable[1] at Launch (2024)	% Renewable at 10 Yrs. (2033)
Scenario 1: 25% Renewable by 2033 (Low Case) Portfolio	10%	25%
Scenario 2: 50% Renewable by 2033 (Base Case) Portfolio	23%	50%
Scenario 3: 75% Renewable by 2033 (Mid Case) Portfolio	50%	75%
Scenario 4: 100% Renewable Portfolio (High Case)	100%	100%

[1]Renewable includes only RPS eligible resources. For this Study, all eligible renewable resources are also greenhouse gas (GHG) free. Where renewables don't meet the Commonwealth's GHG-free definition, GHG-free attributes are purchased through a $/MWh adder.

The Study also provides analysis of current generation costs that a CCA customer would pay in comparison to the current and projected Dominion generation rates. Figure 1 illustrates the costs under the Base municipal aggregation portfolio, which is 23% renewable in 2024 and increases to 50% renewable by 2033.

FIGURE 1. GENERATION RATE COMPARISON: BASE CASE PORTFOLIO



In Figure 1, the stacked columns represent the additive costs that will be incurred by the CCA to provide electrical services to the aggregated costumers. "Market Purchases" and "Renewable" stacks refer to the actual costs of generated energy purchased to meet customer demand, "Capacity" refers to the costs associated with ensuring capacity is met by the PJM (the regional

electrical grid organization (originally included only Pennsylvania, New Jersey and Maryland, thus PJM)), "Ancillary and Transmission" costs are those paid to Dominion to continue electrical service, "O&M" are the operational and maintenance costs incurred directly by the CCA, and "Exit Fees" represent stranded costs that Dominion may be able to charge the CCA customers in order to cover investment costs in generation facilities incurred prior to CCA establishment.

The State Corporation Commission (SCC) has so far been silent on the ability for Dominion to charge exit fees to customers who opt in to a CCA construct. Based on previous experiences in other states, GDS has included exit fees into the expenses stack to provide a conservative financial outlook.

The solid line in Figure 1 represents the current and projected rates that Dominion will charge existing customers. The difference between the Dominion rate and the stacked CCA expenses represents the potential rate difference between CCA customers and Dominion. The Study has referred to this difference as "savings", but the reality is that the difference reflects only a change in the rate required to cover all CCA costs.

Table 2 summarizes some of the key financial results of the Study, including the total electrical load served in Gigawatt hours (GWh).

Table 2. Key Financial Results

Power Supply Portfolio Scenario:	2024 Loudoun County Municipal Aggregation Base Case Renewable Portfolio	2033 Loudoun County Municipal Aggregation Base Case Renewable Portfolio
Operating Expenses (Accrual Basis), $ million	$647	$1,324
Revenues (Cash Basis), $ million	$679	$1,612
Load Served, GWh	13,400	23,000
Working Capital), $ million	$80M	--
Startup Loan Repayment, years	5	--
Initial Generation Rate Discount, %	4.0%	4.0%
Start-Up Capital Requirements	$3.7M	--
Total Bill Discount if All Funds Go to Rate Discounts	4%	10%

Operating Expenses are defined further in Section 5 of the Study and include power purchases, capacity fees to PJM, payments to Dominion for ancillary and transmission costs along with billing fees, and costs associated with the enterprise governance model (staff, payments to consultants, legal fees). Working capital is assumed by the Study to be roughly three months of capacity purchases and is assumed to be financed through a 5-year loan. The initial generation rate discount is the rate discount offered initially to all customers as a benefit for participation. Start-up capital requirements include initial staffing, legal review, and deposits for PJM capacity.

Risks: While the Study shows that forming a CCA model is financially feasible under a wide range of scenarios, doing so is not without risk. The feasibility of a County CCA (maintaining customer rates competitive with Dominion and maintaining positive net revenues) primarily depends on power supply costs, which make up over 95% of the overall CCA operating budget. Other factors impacting CCA financial feasibility include costs Dominion directly passes through to all customers (including an assumed exit fee), market supply of renewable power, availability, and cost of financing, and legislative and regulatory actions.

To assess the magnitude of risk imposed on a potential municipal aggregation program by these factors, the Study includes a Sensitivity and Risk Analysis section (Section 8). Section 8 establishes a wide range of high and low scenarios of prices for CCA-procured market power, Dominion's forecasted customer rates, municipal aggregation financing costs, CCA customer participation rates, and the level of a possible Dominion exit fee.

The results of the sensitivity and risk analysis indicate under what scenarios the CCA's generation rates may exceed Dominion's customer rates and suggest actions the CCA entity can take to manage these risks. Risk mitigation actions consist of standard industry best practices and strategies employed by other established municipal aggregation models—including conservative power procurement strategies, utilization of market risk management policies, development of a cash reserve fund, and engagement on State regulatory and legislative issues.

Legal Review: The Study included a legal review of the State Code that establishes the authority for municipal aggregation. Additionally, the legal team of BB&K reviewed several issues that were included in the project scope of work, including;

- The County is eligibility to participate in municipal aggregation,
- Municipal aggregation may use either an opt-in or opt-out structure,
- Circumstances requiring SCC licensure,
- Collection of taxes under a CCA model,
- Can the IOU charge exit fees, and if so, how are they calculated, and
- the current Renewable Portfolio Standards (RPS) for the IOUs.

BB&K's legal review was successful in providing clear answers to most questions except for the stranded costs (exit fees). As mentioned previously, the SCC has so far been silent on the ability of Dominion or other IOUs to charge exit fees.

Another legal issue that arose during the study has to do with the ability for a municipality to aggregate all classes of loads within an electric cooperative's service territory. This question is important to a potential Loudoun CCA considering that a large portion of the County is within the Northern Virginia Electric Cooperative (NOVEC) service area. State Code establishing municipal aggregation refers specifically to investor-owned utilities and is silent on electric cooperatives. This issue will require additional review on the part of the County Attorney's Office before municipal aggregation could be implemented.

Data Centers and Other Users: Energy usage data for Loudoun County show that increased energy consumption relative to other localities is driven by increasing consumption in the

commercial sector. The main driver of commercial consumption in Loudoun is the large population of data centers whose energy consumption per commercial floor area ratio is higher than many other types of industry.

The increased loads of data centers will theoretically enable a CCA to provide more economy of scale leverage toward energy generation purchases on the wholesale market. However, due to the size of data center loads, some data centers have been able to negotiate directly with the incumbent utilities to provide lower rates. In some cases, the negotiated rates may be lower that rates that could be achieved through CCA wholesale market purchases. Therefore, it may be a difficult decision for data centers with already low negotiated rates to participate in a CCA. If many data centers were to opt-out of CCA participation, the impact would be to lower the economy of scale leverage available to the CCA for market purchases.

It should be noted that a significant number of Loudoun County's data centers are in the NOVEC service area, so the loads from those customers were not included in the rate and pro forma calculations found in the Study. If data centers choose to opt-out of CCA participation to preserve already low negotiated rates, they will be constrained to the renewable energy generation portfolio of the incumbent utility. CCA participation would enable the data centers to secure a renewable energy mix that may be more favorable to their own Company declared renewable goals.

Of note with a CCA is the economic development potential to negotiate rates for certain uses, as well as promote and attract certain industries that want to use mainly renewable sources like "green breweries" and others.

Findings and Conclusions: Based on the analysis conducted in this Study, the following findings are made:

- The pursuit of a municipal aggregation can be financially feasible and could yield benefits for all participating residents and businesses.
- Financial benefits include generation rates that could be 15% lower compared with Dominion generation rates, or a total bill reduction of 10% if all financial surpluses are used to reduce rates.
- Benefits are also achieved through local decision-making on power supply, rates, and customer programs. Specific programs could include economic development incentives, and targeted energy efficiency and demand response programs. Municipal aggregation start-up costs could be fully recovered within the first three years of municipal aggregation operations.
- After this cost recovery, revenues that exceed costs could be used to finance a rate stabilization fund, new local renewable resources, economic development projects, and/or further reduced rates.
- The sensitivity analysis shows that the ranges of prices for different market conditions will, in most cases, not negatively impact municipal aggregation generation rates compared to Dominion generation rates. Where negative impacts may exist, risks can be mitigated.
- Municipal aggregation could be a means to achieve local control of energy supply and to help the municipal aggregation member jurisdictions achieve GHG reduction goals.

- There are risks associated with County municipal aggregation. If formed, this will be a new and competitive effort for the County. New skill sets and strong policy guidance will be needed for a County municipal aggregation to succeed.

Since the final study was provided to staff in early December, staff has provided copies to several Departments including the Department of Finance & Budget (DFB) and the County Attorney's Office (CAO), along with the Office of the County Administrator. Various members of the Board appointed Environmental Commission, other local governments, and the public have also requested copies through the Freedom of Information Act (FOIA).

Based on the complexity of issues presented by the study and in discussion internally, staff is recommending that further investigation into budget and legal concerns be conducted prior to bringing recommendations to the Board for implementation of Community Choice Aggregation in Loudoun.

Department of Finance & Budget (DFB): While the Study provided a detailed pro forma on the financial performance of a County CCA, there were several assumptions that were made regarding growth of commercial and residential sectors within the County. A more detailed look at financial performance based on growth factors modelled by knowledgeable financial experts would provide a better level of certainty than what was developed by GDS based on their assumptions. Assumptions around customer participation (90%), minimal County staffing and operating costs, and start up and operating capital needs also need in depth analysis. Subject matter expert financial consultants should be engaged to evaluate assumptions, review the model, and propose options for County risk mitigation. This analysis is expected to take 6-12 months to complete. DFB has also identified the need to further evaluate operating and staffing issues outlined in the report.

County Attorney's Office: As mentioned in the Study, there are some outstanding legal issues related to CCA's in Virginia that warrant further review by the CAO. These issues include: 1) Dominion's potential to charge exit fees, and how those fees will be calculated, 2) whether there is a Code of Conduct that will govern municipal aggregators and the IOUs, and 3) whether electric cooperative service areas are subject to municipal aggregation.

FISCAL IMPACT: At this time, staff does not have an estimate for the cost of procuring a consultant to complete the necessary financial analysis of this proposal; however, should the Board direct staff to pursue this matter further, DFB will work to identify funding in existing FY 2022 appropriations. There is no anticipated fiscal impact associated with the staff recommendations. If the Board in the future were to direct staff to either explore Power Purchase Agreement solicitation, or to implement Community Choice Aggregation, staff would come back to the Board with more specific fiscal impact information.

ALTERNATIVES:

1. The Board may choose to direct staff to develop Loudoun specific guidelines for PPAs refer the CCA discussions to the Finance/Government Operations and Economic Development Committee for further study and discussion.
2. The Board may choose to direct staff to develop Loudoun specific guidelines for PPAs and develop a CCA implementation work plan that would include further financial and legal investigation.
3. The Board may choose to direct staff to develop Loudoun specific guidelines for PPAs and to discontinue efforts toward CCA implementation.
4. The Board may choose to not direct staff to develop Loudoun specific guidelines for PPAs and to discontinue efforts toward CCA implementation.

DRAFT MOTIONS:

1. I move that the Board of Supervisors forward the Community Choice Aggregation Feasibility Study findings to a future Finance/Government Operations and Economic Development Committee meeting for further discussion and return to the Board at a future business meeting with recommendations.

   I further move that the Board of Supervisors direct staff to develop Loudoun specific guidelines to assist property owners in navigating Power Purchase Agreements.

OR

2. I move an alternate motion.

ATTACHMENTS:

1. Power Purchase Agreement Review
2. Municipal Aggregation Technical Feasibility Study

December 28, 2021

REVIEW - POWER PURCHASE AGREEMENTS

PREPARED FOR THE LOUDOUN COUNTY BOARD OF SUPERVISORS BY STAFF FROM THE DEPARTMENT OF GENERAL SERVICES

1. PURPOSE

At the December 1, 2020, Board of Supervisors (Board) Business Meeting, the Board directed staff (9-0) to investigate the potential for executing Power Purchase Agreements (PPA) as a tool for expanding use of renewable energy sources.

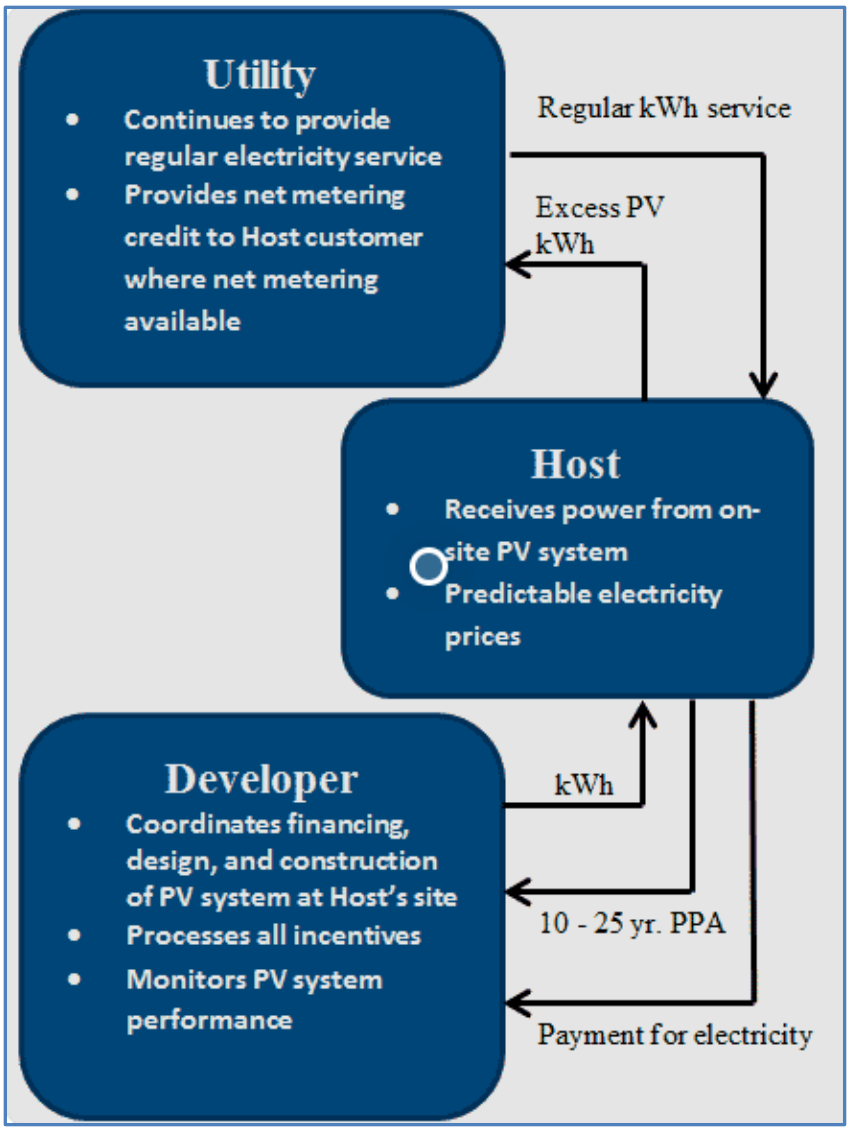
The purpose of this review is to provide the Board with the information requested, including definitions of the various types of PPAs, a review of Virginia State Code related to PPA use, and to provide context of PPA potential relative to the Board's current initiative to investigate the feasibility of Community Choice Aggregation (CCA).

2. BACKGROUND

In general, a Power Purchase Agreement (PPA) is contract for the sale of electric generation. Electric utilities can obtain the power necessary to serve customers through PPAs or from generation facilities they own and operate. Virginia electric utilities recover PPA costs through their fuel factor, with no rate of return markup applied.

A renewable energy power purchase agreement (RPPA) is a financial agreement where a developer arranges for the design, permitting, financing and installation of a renewable energy generating system (typically solar, but can be wind) on a customer's property at little to no cost. The developer sells the power generated to the host customer at a fixed rate that is typically lower than the local utility's retail rate. This lower electricity price serves to offset the customer's purchase of electricity from the grid while the developer receives the income from the sales of electricity as well as any tax credits and other incentives generated from the system. RPPAs typically range from 10 to 25 years and the developer remains responsible for the operation and maintenance of the system for the duration of the agreement. At the end of the RPPA contract term, a customer may be able to extend the RPPA, have the developer remove the system or choose to buy the renewable energy system from the developer.

How a PPA Works:



Another type of PPA is a Virtual Power Purchase Agreement (VPPA). A VPPA is similar the RPPA construct, but instead of the energy physically flowing from the developer project to the customer, it takes the form of a financial contract that allows the energy to be sold on the wholesale market where anyone can use it. Simply put, a VPPA contract is a financial transaction (commonly referred to as a fixed-for-floating swap) that guarantees that the project developer will receive the fixed PPA for every megawatt hour of energy sold at market and in return, the customer receives energy at a fixed price, along with the unbundled Renewable Energy Credits (RECs) generated by the renewable energy system. RECs are the accepted legal instrument through which renewable energy generation and use claims are substantiated in the U.S. renewable energy market.

Most often in RPPAs, RECs are owned by the developer. When entering into a PPA, it is important for a customer to clearly understand who owns and can sell the RECs generated from the system, the risks attendant to REC ownership, and the tradeoffs with respect to PPA price.

A third type of RPPA is an off-site Large Scale Power Purchase Agreement. An off-site RPPA is strictly a financial tool - a wholesale contract between an electricity end-user (customer) and a renewable energy developer. The customer commits to buying all or part of the electricity output from the renewable energy plant for a specific duration and at a predetermined price per kilowatt hour (kWh). The electricity output is then sold into the wholesale electricity market. The customer is credited with the difference between the RPPA price paid by the customer to the developer and the net revenue from the electricity sale into the wholesale market. The credited savings can be applied to the customers actual energy invoices. In addition, the customer will receive the RECs from the sale of the renewable energy as proof that the customer has contributed emissions-free electricity to the regional electric grid and thus has mitigated some of its GHG emissions.

3. BENEFITS/CHALLENGES WITH RPPAS

3.1 Benefits:

a) **No/low upfront capital costs:** The developer handles the upfront costs of sizing, procuring and installing the renewable energy system. Without any upfront investment, the customer can adopt renewable energy and begin realizing savings as soon as the system becomes operational.

b) **Potential for reduced energy costs:** Renewable PPAs provide a fixed, predictable cost of electricity for the duration of the agreement and are structured in one of two ways.
   i. A fixed escalator plan, where the customer price rises at a predetermined rate, typically between 2% - 5%. This is often lower than projected utility price increases, although lower rates cannot be guaranteed.
   ii. A fixed price plan, where a constant price is maintained throughout the term of the RPPA. This structure can save the customer more as utility prices rise over time.

c) **Limited operational risk:** The developer is responsible for system performance and operating risk.

d) **Better leverage of available tax credits:** Developers are typically better positioned to utilize available tax credits to reduce system costs. For example, municipal hosts and other public entities with no taxable income would not otherwise be able to take advantage of the Section 48 Investment Tax Credit.

e) **Potential increase in property value:** A renewable energy system has been shown to often increase residential property values. The long-term nature of these agreements allows RPPAs to be transferred with the property and thus provides customers a means to invest in their home at little or no cost.

f) **Virtual and Large Scale RPPAs:** These types of RPPAs can be used simply as a financial tool with no on-site construction of renewable systems necessary. In return for financial investment of a renewable system, the purchaser will be provided energy at a set price over

a set period, while the actual energy produced is sold by the developer on the wholesale market. The agreement can also be structured to provide unbundled RECs to the purchaser.

3.2 Challenges:

a) **Historical precedent:** In most states, Virginia included, the availability of Renewable Power Purchase Agreements is relatively new, with no extensive historical data on RPPA effectiveness.

b) **Complex contract negotiations:** In addition to negotiating an acceptable rate and escalator, negotiations must also include maintenance costs, charges for disruption of service, and contract term. For non-jurisdictional municipal customers, such as Loudoun, whose rates are determined by direct negotiation with the utility, it may be difficult for a renewable developer to guarantee a rate lower than the negotiated utility rate.

c) **RECs:** Typically, the RECs generated by any renewable energy system are owned by the developer. However, RPPAs can be structured to allow REC ownership by the customer. Currently, Virginia has no established market for RECs, although one is anticipated to be established as part of the VCEA, therefore trends in REC valuation are difficult to predict.

d) **RPPA structure vs. ownership**: In an RPPA, ownership of the energy system stays with the developer. At the end of the RPPA term, the energy system may be sold to the customer, removed by the developer, or a new RPPA with a new term may be executed. The cost of the RPPA and the desire for system ownership should be carefully considered when deciding between an RPPA or investing in owner installation and operation.

e) **Site upgrades**: The RPPA system developer may not be required to do any site development, such as grading or roof structural enhancement prior to system installation. The cost for such upgrades may fall to the customer.

f) **Increase in property taxes**: Although not an issue for local governments as RPPA customers, residential and commercial customers may see a rise in property taxes coincident with higher property values.

4. POWER PURCHASE AGREEMENTS IN VIRGINIA

In Virginia, the State Corporation Commission (SCC) regulates the sale of energy to Virginia customers. The SCC accepts notices of intent by non-utility owners of solar or wind-powered generation who are interested in selling electricity to utility customers through a RPPA. Under a RPPA, a non-utility developer installs a solar or wind generating facility on a customers' property and then sells the electricity generated by them back to that customer at a price that is usually less than electricity provided by the utility company.

As authorized by the General Assembly in 2013, the SCC has administered a pilot program with Dominion Energy and Appalachian Power to allow certain classes of customers to enter into third party RPPAs. The pilot program previously established a cap of 50 megawatts (MW) total generation capacity for all Dominion customers, and a cap of seven MW total for Appalachian customers. By fall 2019, the Dominion cap had been reached and solar PPA projects, such as a large contract entered into by Fairfax County, were forced to cease.

In July of 2020, as part of the Virginia Clean Economy Act (VCEA), the SCC updated the pilot program regulations and the 50 MW Dominion cap was raised to 1,000 MW, allowing all non-residential customers (including municipal governments) more availability to access RPPAs. The 1,000 MW Dominion customer cap established a 500 MW cap for jurisdictional customers (those customers with rates subject to SCC approval) and 500 MW for non-jurisdictional customers (customers who negotiate rates directly with Dominion, such as through the Virginia Electricity Purchasing Government Association (VEPGA)). The Pilot Program also limits the aggregated capacity to 6% of each utility's adjusted Virginia peak load forecast for the previous year. The estimated 2021 peak capacity is 15,604 MW; thus, the legislative limit would be 837.37 MW.

To initiate an RPPA through the Pilot Program, renewable energy developers must coordinate with prospective customers to provide the SCC with a letter of intent to participate. Each letter of intent must at minimum include the following information:

1. Name of Owner-Operator (the Developer)
2. Eligible Customer-Generator (the host)
3. Pilot Utility (either Dominion or APCO)
4. Utility Account No. (Confidential)
5. Customer Type: Jurisdictional or Non-Jurisdictional (County is non-Jurisdictional)
6. Location of Project
7. Renewable Energy Source
8. Generation Capacity: kW Alternating Current (AC)
9. Expected In-Service Date
10. Duration of PPA: ____ years
11. Proof of 501(c)3 (if applicable)
12. Expected Project Installation Cost (Confidential) $____/watt AC

The SCC will review each letter of intent and notify participants of generation capacity availability.

The VCEA calls for the SCC to perform a biennial review of the Pilot Program and will determine if the limitations above require expansion. As of October 12, 2021, a total of 13 owner-operators have entered into pilot RPPAs with 114 Customers for a total of 68.5 MW of generation capacity within the Dominion service area. The average duration of the existing RPPAs is 20.17 years.

The VCEA limits the generating capacity for renewable energy systems to 3 MW, with a minimum of 50 kilowatts (kW). The minimum generation capacity is lifted for certain non-profit and low-income entities. These RPPAs are structured so that a school district, municipality or any commercial or non-profit customer can have a solar array installed at no cost, paying just for the energy produced at prices set within the agreement. Additional limitations in the state code are that a generation facility subject of to third party RPPA under the pilot program shall serve only one customer, and a third party RPPA shall not serve multiple customers.

Net Metering:

Net metering is the policy that allows renewable energy generation systems to get a credit on their electric bill for the energy produced by the system. In Virginia, the rules for net metering for solar generating systems are established in Virginia State Code §56-594 and allows a one-to-one retail rate credit for solar energy output to the grid for residential systems up to 25 kW, or non-residential

systems up to 3,000 kW. The code also allows for credits for agricultural aggregated capacity up to 500 kW. Net metering rules are important considerations when negotiating terms of a PPA.

5. MUNICIPAL RPPA EXPERIENCES

Since non-profits such as schools, churches and local governments are tax exempt, the benefit of federal tax credits for solar installation have not been available as renewal energy incentives. Instead, RPPAs have become more popular with tax exempt customers, since the third-party installer is eligible for the tax credits, with savings passed on to the tax-exempt customer as part of the agreement. Such was the case for the Fairfax County when they issued an RFP for 44 MW of solar installations at 130 County facilities, including 113 of their schools.

Public School Systems:
Albemarle County Public Schools (ACPS) became the first public school district in Virginia to use solar energy under an RPPA at six of the district's schools. The 1.1 MW solar photovoltaic system meets 22% of the six schools' annual electricity requirements. ACPS entered into a contract with Solar Futures in May of 2015; Solar Futures owns and operates the project and sells the electricity to ACPS. Over the 20-year contract period, ACPS expects to realize $80,000 in savings.

Similar to the Fairfax County contract, Henrico County and the Henrico County School Board entered into a contract with Sun Tribe Solar, LLC in March of 2020 for the installation of solar generating systems at two County facilities, the Libbie Mill Library, and the Mental Health East Center. The contract also allows for investigation of solar generating potential at additional sites as requested by Henrico County. In addition to the estimated $1M in up-front capital cost savings, the County estimates that the RPPA will save an additional $475,000 in electrical costs over the 25-year contract period.

Smaller School Systems and Government Participants:
Many smaller districts such as Mineral County, Orange County and Northumberland have also realized savings. By early 2020, every school in rural Middlesex County on the Middle Peninsula was entirely powered by solar installed as part of an RPPA. The district is anticipating savings of $2.4M over the life of the 25-year agreement.

In addition to the RPPA participants mentioned above, many any existing Pilot RPPAs reported within the Dominion service area are government entities. These include Arlington Public Schools, Manassas City Public Schools, Virginia Union University, Staunton Public Schools, Norfolk Academy, Westmoreland County Public Schools, and the University of Virginia. A full list of current Dominion Pilot RPPA participants can be found in Appendix 1.

Arlington County Government and Amazon have recently entered into a joint large-scale RPPA with Dominion Energy, where Amazon will purchase 70% and Arlington County 30% of the output of a large solar farm located in Pittsylvania County in Southern Virginia. As a non-jurisdictional Dominion customer, Arlington County has made the arrangement as an addendum to the existing contract negotiated through VEPGA. The load purchased through the contract is anticipated to be just over 79 MW annually.

This RPPA is a "contract for differences". Specifically, the difference between the fixed price of power specified in the agreement and the variable wholesale price of power. The renewable

electricity generated at the solar farm site will be sold into the wholesale power market. The difference between the hourly wholesale power price received and the fixed price of the agreement will lead to a credit (or expense) to the County.

Loudoun County Public Schools:
In August of 2019, the Loudoun County Public School District (LCPS) issued a request for proposals (RFP) for an RPPA for solar generating systems to be installed at 14 schools. After receiving multiple proposals, LCPS hired an engineering firm to analyze each proposal from a technical standpoint with the intent of understanding how technical differences could/would affect savings achieved. LCPS also solicited an Energy Savings Contractor (ESCO) through a cooperative procurement agreement contract through the Virginia Department of Mines, Minerals, and Energy (now Virginia Energy), a model where LCPS finances the installation with a guaranteed savings.

LCPSs analysis of RPPA proposals and the ESCO model revealed that the ESCO model provides guaranteed savings through a bonded contract, while the RPPA savings are subject to market changes in power rates with no guarantee. While LCPS has not discarded potential RPPAs, they have decided to move forward with moving 9 of the 14 planned RPPA solar installations to the ESCO model. Also, as return on investment has become more favorable, LCPS has also constructed two new schools with on-site LCPS owned solar systems.

6. USE OF RPPAs RELATIVE TO COMMUNITY CHOICE AGGREGATION:
In addition to the December 1, 2020, Board request for staff to investigate the potential for executing PPAs, at the December 8, 2020, Business meeting, the Board provided $200,000 of fund balance to fund a study that would evaluate if and how the County could establish a Community Choice Aggregation (CCA), also known as Municipal Aggregation in the State Code. Staff entered into a contract with GDS Associates (GDS) and Best, Best & Krieger (BB&K) in April 2021 to perform the requested CCA Feasibility Study. The results of the Study are to be presented to the Board coincident with this report.

A CCA allows a jurisdiction, or multiple jurisdictions under a joint agreement, to aggregate the electrical load of all classes of customers within its jurisdiction and purchase the required load on the wholesale market at their behalf. In Virginia, a CCA must purchase from Competitive Service Provider (CSP) registered through the SCC. If a jurisdiction has entered into a CCA agreement with a CSP, then a renewable PPA would be available if part of the energy portfolio offered by the CSP. Any CSP with a CCA contract can purchase renewable energy through large-scale PPAs. Although the County would not be able to directly enter into an RPPA under a CCA model, the CSP providing the energy purchases would undoubtedly employ the use of renewable PPAs. Conversely, if the County were not part of a CCA, then RPPAs through a CSP would be available as a tool for providing renewable energy to County facilities provided that a petition with the SCC is approved and that the County's aggregated load is more than 5MW (§ 56-577.A.3).

Additionally, Virginia Code § 56-577 also provides opportunity for customers may purchase "100 percent renewable energy" from competitive suppliers if the customer's electric utility does not offer an SCC-approved 100% renewable energy tariff. No utility, including Dominion, currently offers an SCC-approved 100% renewable tariff. In all the scenarios provided in this section, the use of RPPAs would only involve the aggregated load of County facilities within the Dominion

service area. RPPAs for facilities within the NOVEC area would be contracted separately since state code only allows aggregation within the same incumbent utility service area.

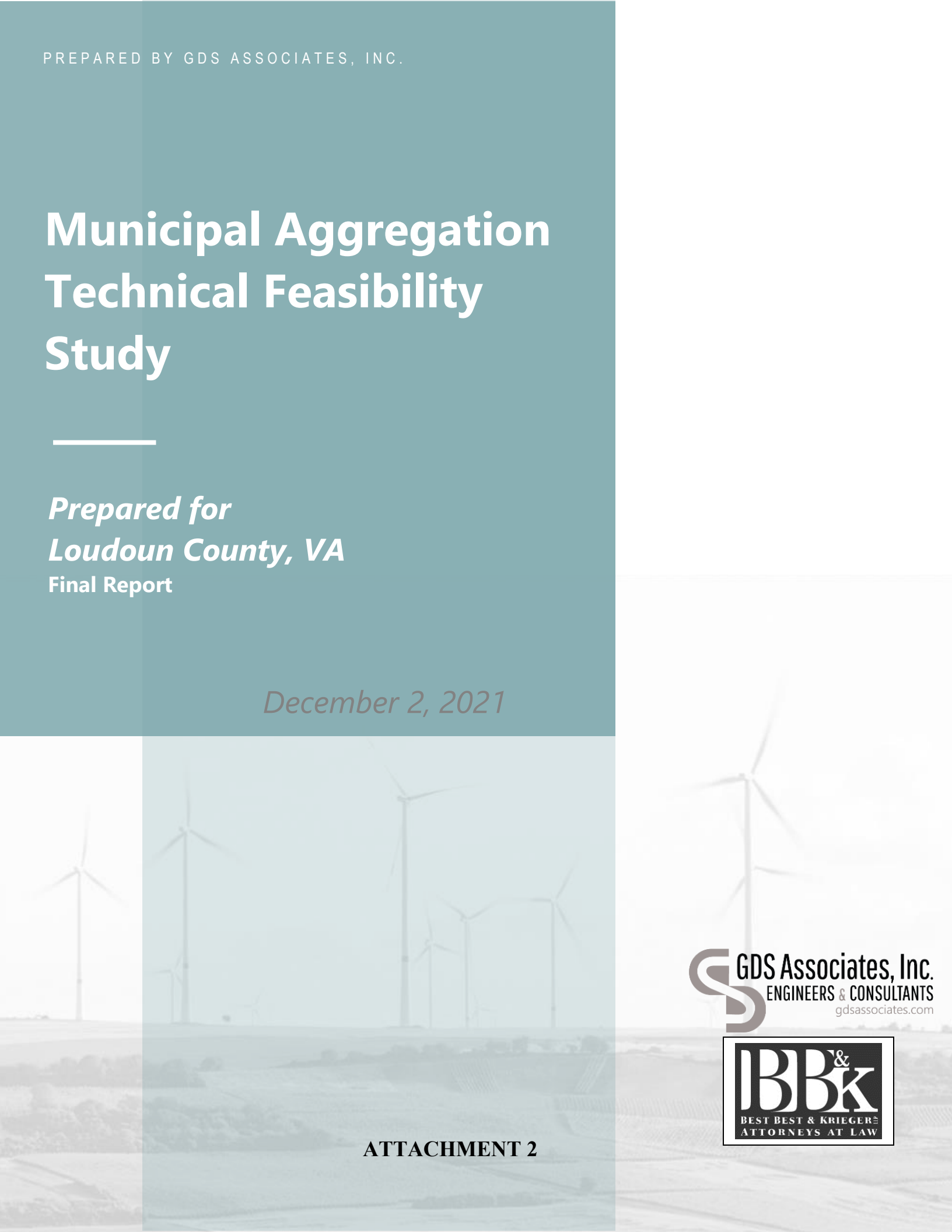
NEXT STEPS: If the County is interested in pursuing a Power Purchase Agreement using the third party PPA model, staff will need to begin the process of evaluating specific County-owned properties to assess PPA potential. This process will include evaluating each property for adequate space for installation of solar arrays, whether ground-mounted or roof-mounted, and whether or not a long-term PPA would interfere in any future plans for each property. A complete list of potential locations should be assembled and ranked prior to finalizing a proposal. In order to maximize the value of the PPA, it may be prudent to develop a single proposal before solicitation of third-party providers.

PREPARED BY GDS ASSOCIATES, INC.

Municipal Aggregation Technical Feasibility Study

Prepared for
Loudoun County, VA
Final Report

December 2, 2021



GDS Associates, Inc.
ENGINEERS & CONSULTANTS
gdsassociates.com

BB&K
BEST BEST & KRIEGER LLP
ATTORNEYS AT LAW

ATTACHMENT 2

GDS Associates, Inc.
ENGINEERS & CONSULTANTS
gdsassociates.com

Gary Saleba, Executive Consultant.
gary.saleba@gdsassociates.com
cell 425-260-6678

December 2, 2021

Mr. Dennis Cumbie
Water & Environmental Programs Division Manager
Department of General Services
801 Sycolin Road, Suite 300
P.O. Box 7100
Leesburg, VA 20177

SUBJECT: Municipal Aggregation Technical Feasibility Study – Final

Dear Mr. Cumbie:

Please find attached the final Municipal Aggregation Technical Feasibility Study (Study) for the County of Loudoun, VA (County). This Study was completed by GDS Associates, Inc. (GDS) and the law firm of Best, Best & Krieger (BB&K).

We very much appreciate all the effort your project team has spent on the Study, and we hope it is useful for the County's evaluation of a municipal aggregation business model.

Very truly yours,

Gary S. Saleba
EXECUTIVE CONSULTANT
425.260.6678

Garrett D. Cole, P.E.
PRINCIPAL
770.799.2393

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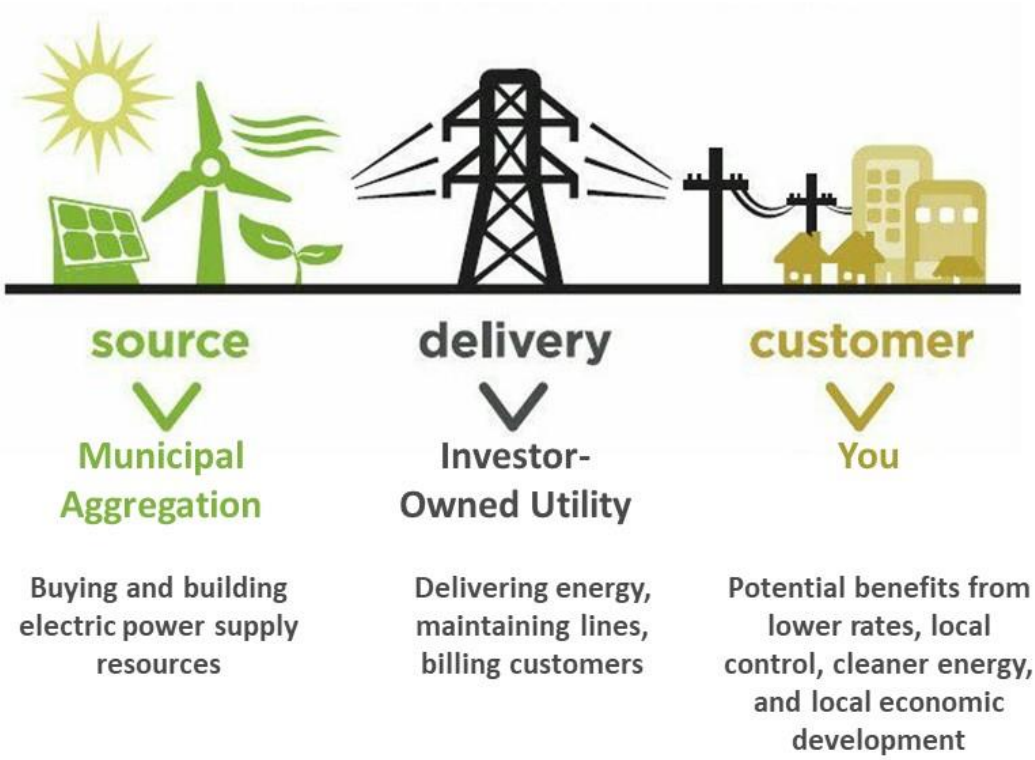
1 Executive Summary

The Commonwealth of Virginia (Commonwealth) enacted municipal aggregation legislation in 2003 allowing cities and counties to aggregate power supply needs and buy directly from power supply providers rather than as a bundled customer of the incumbent investor-owned utility (IOU). Under the municipal aggregation business model, local governments purchase and manage their community's electric power supply by sourcing power from a preferred mix of traditional and renewable energy sources, while the IOU continues to provide distribution and billing service. Under the municipal aggregation business model, responsibility for the distribution for electricity, billing and outage management remains with the incumbent IOU. Figure 1-1 illustrates how municipal aggregator's function within the traditional electric utility industry supply infrastructure.

FIGURE 1-1. MUNICIPAL AGGREGATION BUSINESS MODEL CONSTRUCT



Since 2003, the City of Fairfax applied for, and was approved by the Virginia State Corporation Commission (SCC), an aggregation program license. The City of Fairfax did not move forward with its aggregation program and let its license expire in 2009. There are currently no municipal aggregation business models operating in the Commonwealth.

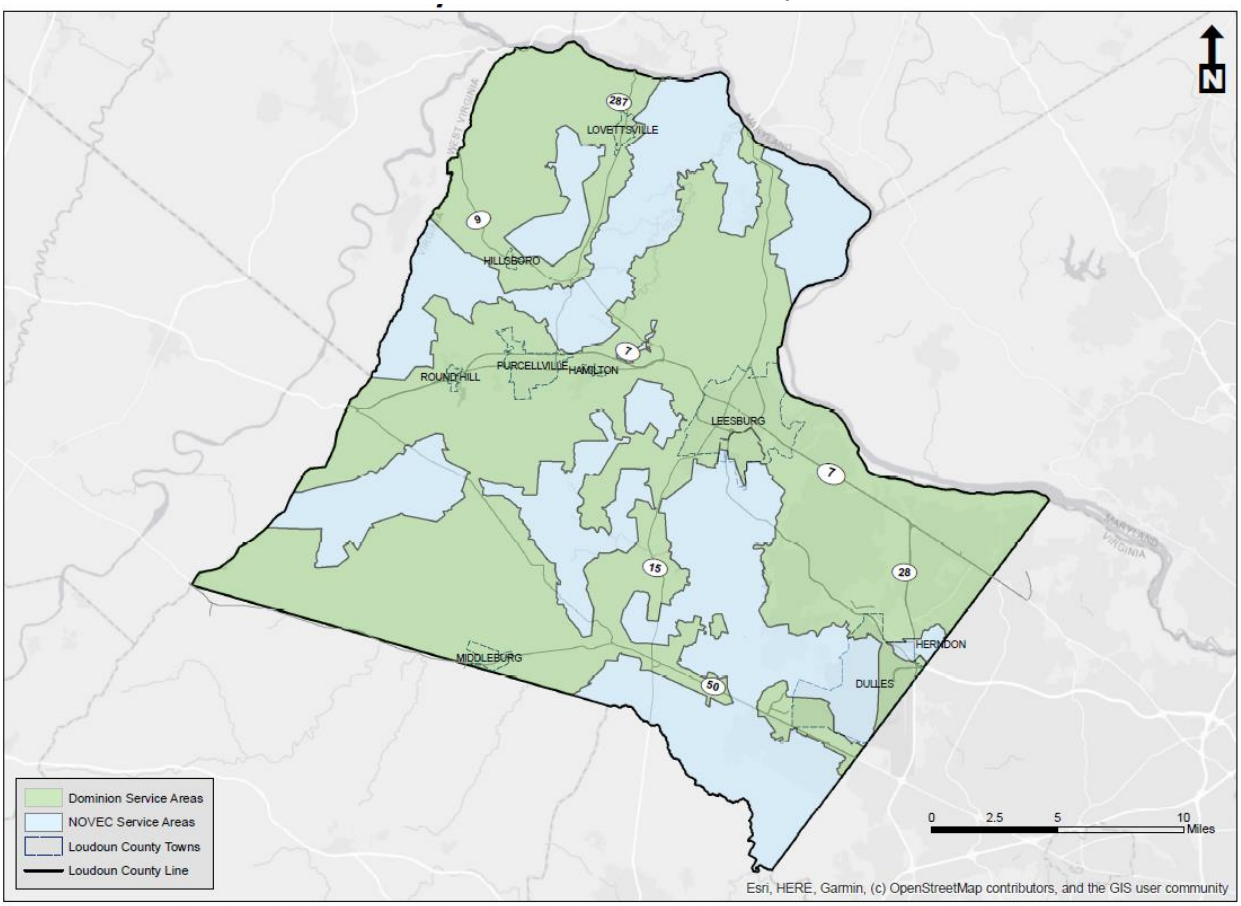
To better understand the benefits and risks associated with municipal aggregation programs, Loudoun County (County) selected GDS Associates, Inc. (GDS) and Best, Best & Krieger (BB&K) to prepare this Study that assesses the technical and financial feasibility of municipal aggregation as a mechanism to provide choice to customers, potentially lower their electricity rates, and contribute toward achieving the County's greenhouse gas reduction goals. This Study relies on information taken from previous

aggregation attempts within the Commonwealth, the incumbent IOU rates and power supply portfolio mix, and municipal aggregation programs operating in other parts of the country.

1.1 OVERVIEW OF STUDY PURPOSE AND ANALYTICAL CONSTRUCT

The purpose of this Study is to estimate municipal aggregation operating costs (including power supply, labor, consultants, regulatory, legal, financing), calculate anticipated municipal aggregation customer generation rates, determine if projected rates can cover estimated operating costs and whether projected municipal aggregation generation rates are comparable to or lower than projected IOU generation rates. County residents and businesses are currently served by Dominion Energy Virginia (Dominion) and Northern Virginia Electric Cooperative (NOVEC). The NOVEC territory in the map below is excluded from this Study. Risks are assessed through a sensitivity analysis on key input variables. The Study also looks at various governance options. The Study concludes with a discussion of potential regulatory issues that may need resolution at the SCC.

DOMINION AND NOVEC SERVICE TERRITORIES, LOUDOUN COUNTY



The geographic data layers produced by the Government of Loudoun County, Virginia ("Loudoun County"), and any associated maps and applications, are provided as a public resource. While every reasonable effort is made to ensure the accuracy and completeness of the data, Loudoun County makes no warranties, expressed or implied, concerning the accuracy, completeness or suitability of its data, and it should not be construed or used as a legal description.
Created 10/18/2021 by Loudoun County Department of General Services - Stormwater Division.

In order to determine the financial feasibility of municipal aggregation, this Study compares Dominion generation rates with projected municipal aggregation generation rates. If a municipal aggregation business model can provide electricity at an equal or lower price than Dominion, the municipal aggregation business model is deemed to be financially feasible. Within this Study, a forecast of Dominion and municipal aggregation generation rates is performed. The details of this comparison are provided within this Study. This Executive Summary contains the highlights of the Study. The balance of this Study discusses the details of this generation rate comparison and then continues with a review of potential municipal aggregation's environmental, economic, governance and operational issues. A Glossary of Terms is available in Appendix A.

1.2 AGGREGATION SERVICE AREA TO BE ANALYZED IN THIS STUDY

The Study's analysis, findings and recommendation address the residential and business electric accounts currently served by Dominion, the investor-owned electric utility (IOU) in the County. Electric accounts within the County served by the Northern Virginia Electric Cooperative (NOVEC) have been excluded from the Study's analysis, findings and recommendations. This exclusion is made as nationally, the municipal aggregation business model has been applied only to IOU electric accounts.

Municipal aggregation was established by statute in 1999, section 56-589, as part of deregulation under the Virginia Electric Utility Restructuring Act. In 2007, Virginia re-regulated the electric utility industry under the Electric Utility Regulation Act imposing new laws on the State's two largest IOUs, Dominion and Appalachian Power Company (APCO). The 2007 Act, along with section 56-589, is governed under Chapter 23, while NOVEC is a regulated electrical cooperative regulated under Chapter 9.

1.3 STUDY ASSUMPTIONS AND SCENARIOS

Because municipal aggregation programs in the Commonwealth have not yet been established, the construct for this Study relies on constructs from other states as well as historical Commonwealth law and statutes. The following key assumptions are made in order to evaluate financial feasibility of a municipal aggregation business model for the County:

- An exit fee would be paid by municipal aggregation customers to Dominion to recover stranded generation costs incurred by load departure. The exit fee is calculated as the difference in Dominion's cost to provide power less its market value. The exit fee is intended to hold harmless remaining bundled customers from any lost revenues or increased costs attributable to customers leaving Dominion to join a municipal aggregator. The legality of exit fees is discussed later but they are assumed to be payable to maintain a conservative posture throughout the Study.
- Operating expenses for currently functioning municipal aggregators and similar organizational structures are applied to develop the cost of service for perfecting a County municipal aggregation business model.
- Generation costs are estimated based on four different resource portfolios with varying levels of renewable energy.
- Financing for working capital is available to a new municipal aggregator through third party lending institutions.
- Customer participation rates of 90% are based on an opt-out structure where customers must elect to opt out in order to remain under Dominion bundled service (i.e., assume that only 10% opt out). Opt-out is an important assumption, as the economic feasibility of municipal aggregation hinges on aggregating enough load to justify the expenses of mobilizing the utility operation for

the benefit of local consumers. Economic feasibility would be difficult in another structure where customers have to choose to make the shift to municipal aggregation (i.e., opt-in), as a very small percentage of customers track these considerations.

- The analysis is prepared over a 10-year forecast period.

1.3.1 Loads

Dominion provided annual loads for the Unincorporated County area by rate class for the period of 2015-2019. The commercial sector has experienced significant load growth in the past five years. In discussions with the County, it was determined that much of this growth is expected to continue over the 10-year Study period. Figure 1-2 illustrates historic and forecasted loads by customer class. Figure 1-3 shows the number of service accounts eligible for municipal aggregation service in the Dominion service territory within the County.

FIGURE 1-2. FORECAST MUNICIPAL AGGREGATION SERVICE AREA LOAD

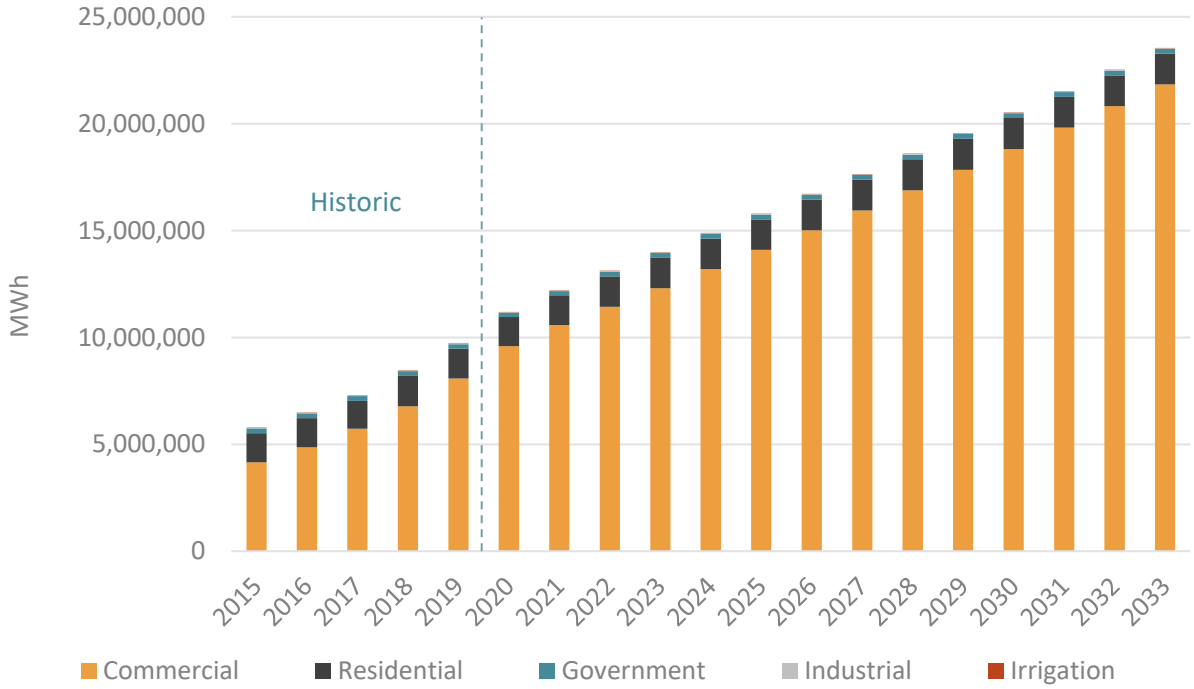
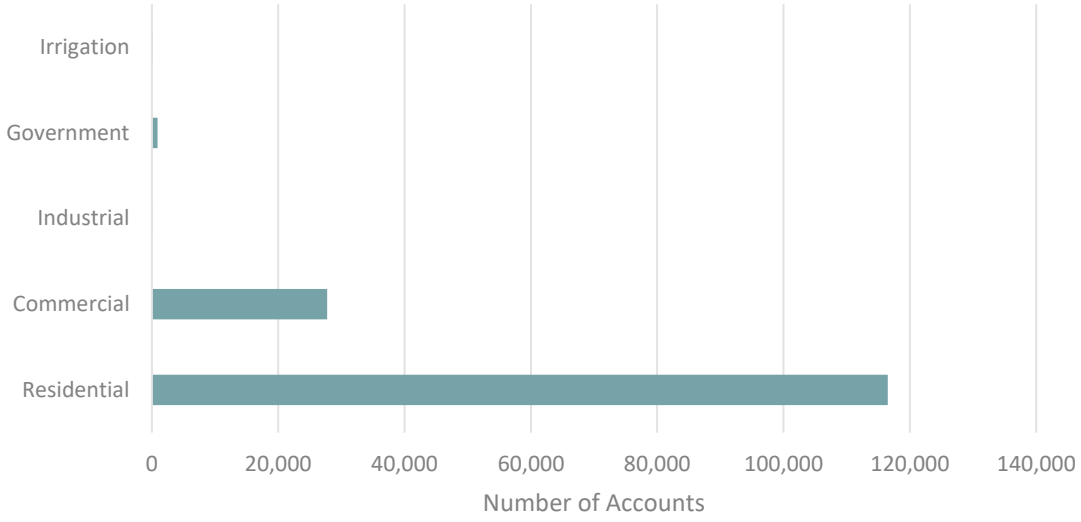


FIGURE 1-3. 2024 FORECAST SERVICE ACCOUNTS



1.3.2 Power Supply

To provide information about cost differences among renewable resource portfolios, this Study analyzes four power supply scenarios detailed in Table 1-1.

TABLE 1-1. LOUDOUN COUNTY MUNICIPAL AGGREGATION RESOURCE PORTFOLIOS

	% Renewable[1] at Launch (2024)	% Renewable at 10 Yrs. (2033)
Scenario 1: 25% Renewable by 2033 (Low Case) Portfolio	10%	25%
Scenario 2: 50% Renewable by 2033 (Base Case) Portfolio	23%	50%
Scenario 3: 75% Renewable by 2033 (Mid Case) Portfolio	50%	75%
Scenario 4: 100% Renewable Portfolio (High Case)	100%	100%

[1]Renewable includes only RPS eligible resources. For this Study, all eligible renewable resources are also greenhouse gas (GHG) free. Where renewables don't meet the Commonwealth's GHG-free definition, GHG-free attributes are purchased through a $/MWh adder.

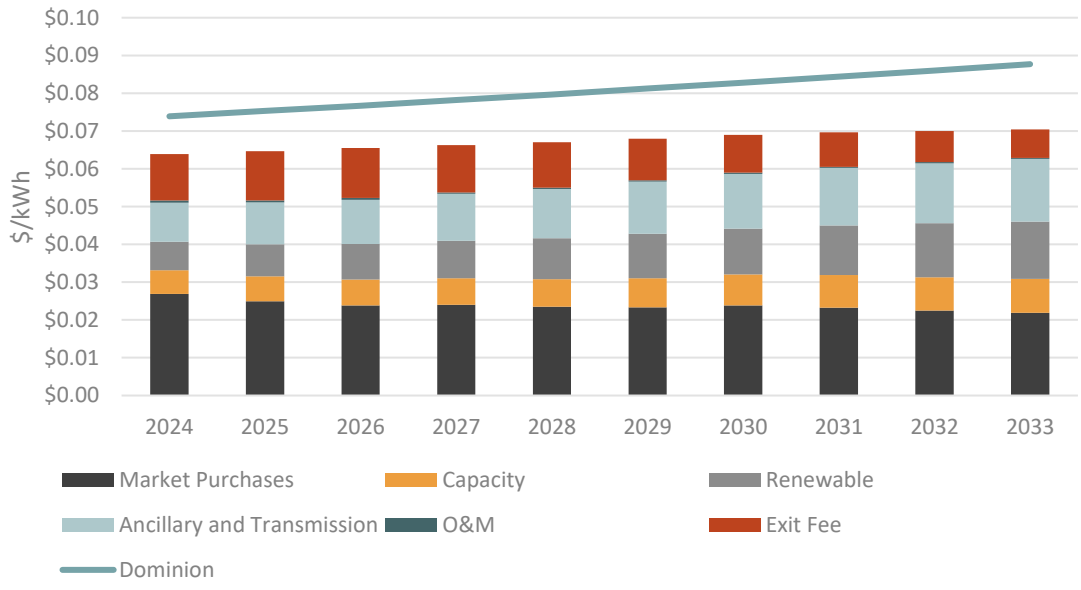
The resource portfolios are developed to include both utility-scale and local-scale renewable resources as well as unbundled renewable energy credit (REC) purchases. Figure 1-4 compares the blended cost of each portfolio. The costs below include energy, load balancing, capacity requirements, ancillary services, and Dominion transmission costs. Individual resource prices are shown for comparison, including local distributed solar, utility-scale solar and the wholesale market.

FIGURE 1-4. POWER COST COMPARISON

1.4 RATE COMPARISON

Figure 1-5 illustrates this breakdown of generation costs that a municipal aggregation customer would pay in comparison to the Dominion generation rate. Figure 1-5 illustrates the costs under the Base municipal aggregation portfolio, which is 23% renewable in 2024 and increases to 50% renewable by 2033.

FIGURE 1-5. GENERATION RATE COMPARISON: BASE CASE PORTFOLIO



1.5 KEY FINDINGS

The Study results show that a County municipal aggregation is financially feasible under all resource portfolio options and can provide the following benefits:

- Based on projected Dominion generation rates and assumed exit fees, a County municipal aggregation model is economically feasible. Municipal aggregation could provide power supply that has a higher percentage of renewable energy than Dominion, while offering rates that are lower.

- County municipal aggregation could reduce greenhouse gas (GHG) emissions by up to 3.1 million short tons/year by 2035 under the Base Case scenario compared to the forecast GHG emissions in Dominion's rates. This reduction in GHG emissions is equivalent to taking roughly 600,000 gasoline-fueled cars off the road.

- After initial working capital is repaid, prudent cash reserves are collected and an initial 4% generation rate discount is offered, a significant amount of net income or additional savings compared to paying Dominion rates ($150 million/year) is available for other related purposes such as further lowering generation rates, local renewable energy development, energy efficiency, assist low-income customers and/or local economic development. If all of this additional savings went to further lower generation rates for municipal aggregation customers, total generation rate discounts of 15% are achievable when compared to Dominion or savings off the total Dominion retail rates of 10%. Details on the financial pro formas can be found in Appendix B at the end of this Study.

- The municipal aggregation model would provide policymakers with full control over power supply purchases and could create a power supply mix that meets other, specific goals.

Table 1-2 shows Key Operating Figures for a County municipal aggregation model.

TABLE 1-2. LOUDOUN COUNTY MUNICIPAL AGGREGATION KEY OPERATING FIGURES

Power Supply Portfolio Scenario:	2024 Loudoun County Municipal Aggregation Base Case Renewable Portfolio	2033 Loudoun County Municipal Aggregation Base Case Renewable Portfolio
Operating Expenses (Cash Basis), $ million	$647	$1,324
Revenues (Cash Basis), $ million	$677	$1,603
Load Served, GWh	13,400	23,000
Working Capital, $ million	$80M	--
Startup Loan Repayment, years	5	--
Initial Generation Rate Discount, %	4.0%	4.0%
Start-Up Capital Requirements	$3.7M	--
Total Bill Discount if All Funds Go to Rate Discounts	4%	10%

1.6 RISKS

While the Study shows that forming a municipal aggregation model is financially feasible under a wide range of scenarios, doing so is not without risk. The feasibility of a County municipal aggregation model (maintaining customer rates competitive with Dominion and maintaining positive net revenues), primarily depends on power supply costs, which make up over 95% of the overall municipal aggregation operating budget. Other factors impacting the financial feasibility of municipal aggregation include: costs Dominion directly passes through to all customers (including an assumed exit fee), market supply of renewable power, availability and cost of financing, and legislative and regulatory actions.

To assess the magnitude of risk imposed on a potential municipal aggregation program by these factors, the Study includes a Sensitivity and Risk Analysis section. This section establishes a wide range of high and low scenarios of prices for municipal aggregation-procured market power, Dominion's forecasted customer rates, municipal aggregation financing costs, municipal aggregation's customer participation rates, and especially the level of a possible Dominion exit fee.

The results of the sensitivity and risk analysis indicate under what scenarios the municipal aggregation's generation rates may exceed Dominion's customer rates, and also suggest actions the municipal aggregation entity can take to manage these risks. The risk mitigation actions consist of standard industry best practices and strategies employed by other established municipal aggregation models—including conservative power procurement strategies, utilization of market risk management policies, development of a cash reserve fund, and engagement on State regulatory and legislative issues.

1.7 GOVERNANCE

If the County chooses to implement a municipal aggregation model, it must select an appropriate governance structure. This Study evaluated the following two governance options:

- Enterprise Municipal Aggregation – County operates its own municipal aggregation as a County department/enterprise fund.
- Service District Aggregation Model – The County would partner with other local governments to form a single municipal aggregation entity governed by partnership agreements.

Start-up costs for these governance options are presented in Table 1-3.

TABLE 1-3. START-UP COST ESTIMATES

Security Deposit	$150,000
PJM Deposit	$500,000
Staffing + Admin & General	$1,166,217
Customer Notification	$600,000
Legal/Regulatory	$408,000
Consultants	$917,575
Total	**$3,741,792**

Enterprise Municipal Aggregation – A County-only Enterprise municipal aggregation retains the greatest amount of local control for programs, organization and power supply. Surplus revenues above what is needed to run the municipal aggregation program remain under the County's direct control. Power supply choice, rate discounts, customer program designs, marketing, and outreach are customized to the County's needs. The Enterprise municipal aggregation option is well-suited for jurisdictions that are large enough to operate individually, or may not find partners with similar goals and demographics. Various mechanisms are available to shield the County General Fund from liability associated with an Enterprise municipal aggregation, including fund segregation, contractual protections and insurance, which can be addressed in more detail by the County Counsel and staff. This option also requires the County to secure or provide the $3.7 million in start-up funding. A municipal aggregation's ongoing working capital is typically financed externally, and options for financing the start-up costs are also available.

Service District Municipal Aggregation – The County could form a municipal aggregation entity with other jurisdictions under a service district construct. This could include jurisdictions in the region that do not want to pursue their own municipal aggregation. Under this option, the governing body of each member would pass an ordinance to approve joining a County-developed service district municipal aggregation model. The service district operates as its own entity and typically is governed by a Board consisting of one elected official from each member jurisdiction. Voting requirements would be documented in the service district agreement. Under a service district model, the municipal aggregation would have a larger customer base and could possibly offer lower rates compared with the enterprise municipal aggregation model. The start-up costs would typically be shared among the service district members, and each member would pay a prorated portion of the startup costs. The working capital financing would be funded externally and repaid via customer rates. The power supply mix for a service district would be determined by its Board, and the default power supply option for each service district member could be selected independently to meet individual member power supply goals. This service district option provides the greatest level of General Fund protection.

1.8 LEGAL/REGULATORY ISSUES

As noted earlier, there is no functioning municipal aggregation in the Commonwealth. Accordingly, there are numerous regulatory and legal issues to be resolved or addressed. A summary of these legal/regulatory issues is provided below. Detail regarding these legal and regulatory issues is provided in Appendix C to this Study.

Municipal Aggregation Eligibility. Virginia Code § 56-589 allows counties, cities, towns, and other political subdivisions of the Commonwealth including special districts, upon a majority vote of their governing bodies, to aggregate electrical energy and demand requirements. Aggregation can include residential, commercial, industrial and/or municipal customers. The statute appears to allow municipal aggregation on a non-contiguous basis without a city having to be a neighbor of or contiguous with another city.

Customer Opt-In vs. Opt-Out. Virginia Code § 56-589 expressly allows a municipal aggregator to enroll customers on either an opt-in or opt-out basis. In other words, the municipal aggregator can automatically enroll customers into the program (opt-out), or it can implement a program whereby customers have to expressly join (opt-in). The Study assumes an opt-out scenario will be implemented.

State Corporation Commission Approval. Virginia Code § 56-588 requires an aggregator of electrical energy, normally a company, to obtain a license from the State Corporation Commission ("SCC"). Municipal aggregators that seek to aggregate only their municipal load are exempt from licensing requirements, while those municipalities seeking to aggregate residential, commercial, and industrial load are not exempt. SCC staff has informally indicated to the drafters of the Study that a license is not required for municipal aggregation; however, the City of Fairfax did obtain one in 2006. Therefore, it is recommended that SCC staff clarify this issue.

It does not appear that the SCC further regulates municipal aggregators regarding their rates, terms of service, or other planning efforts.

Tax Obligations. Virginia Code §§ 58.1-2900 and 58.1-2901 impose a consumption tax that is required to be billed, collected, and passed through by any "provider of billing services." Therefore, the municipal aggregator, or its contracted-for billing provider, will be obligated to collect the tax. Municipal usage would be exempt. It is suggested that the County request Dominion to collect all of this tax and remit to the Commonwealth.

Stranded Costs. In some statewide aggregation regulatory schemes, the customer of the municipal aggregator pays a monthly charge for the costs remaining to the incumbent utility for power purchased or generation constructed on that customer's behalf. Such charges or "exit fees" are established to protect the remaining incumbent customers from paying for the costs of the departing load. Neither Commonwealth law nor SCC regulations appear to provide for the recovery of stranded costs due to municipal aggregation. The SCC, however, has denied companies like Costco and Wal-Mart from commercially aggregating on the basis that stranded costs would be too high for the remaining customers and against the public interest, but it has not formulated a methodology to calculate them. This Study assumes for the payment of stranded costs or "exit fees" and recommends that more clarification is needed.

Renewable Portfolio Standard (RPS). The Virginia Clean Economy Act of 2020 established mandatory RPS program requirements for Dominion and APCO where the utilities must meet annual goals for the sale of renewable energy to retail customers. Beginning in 2024, the utilities must procure 23% of power from renewable sources with a sliding scale through 2033 of 52%. The Act does not yet apply to municipal aggregation, but the Study suggests that the County decide on the baseline amount of renewables it desires to offer to itself or its customers. The Study's Base Case assumes 23% renewable in 2024 and 50% in 2033.

1.9 CONCLUSIONS

The Study results suggest that municipal aggregation programs are financially feasible for County municipal aggregation. These findings are based on the mentioned governance options and under current market conditions. The economies of scale for all options are sufficient for stable municipal aggregation operation under a wide range of financial assumptions and sensitivities. From a regulatory standpoint, there are still several outstanding issues in need of resolution before the County can commence operation of the municipal aggregation business model.

1.10 NEXT STEPS

There are many governance, regulatory and technical tasks that need to be resolved before a municipal aggregation business model can become functional. A summary of these tasks follow:

- Governance Tasks
  - Choose a governance structure such as the enterprise or service district models.
  - Determine which local governmental units should participate such as County only, County and towns within the County or seek local governments outside of County.
  - Develop a strawman governance document.

- Regulatory Tasks
  - The SCC should be contacted to appraise them of the County's desires and intentions, and to solicit SCC staff feedback on the merits of the County pursuing the municipal aggregation business model.
  - The SCC staff should also be asked about the regulatory status of exit fees in the Commonwealth and any technical input on this Study's input assumptions. Also discuss the opt-in/opt-out assumptions and licensing requirements.
  - Determine what customer notice requirements will be needed.

- Technical Tasks
  - Confirm that Dominion will continue to read all meters, prepare all bills, and collect revenues then rebate the market aggregator's portion to the market aggregator.
  - Develop a timeline for key activities in forming a municipal aggregation business model that includes the tasks noted above as well as staffing requirements.

The aforementioned tasks can be used by the County as a scope of work for further municipal aggregation working activities.

2 Introduction

The Commonwealth of Virginia (Commonwealth) enacted municipal aggregation in 2003 allowing cities and counties to aggregate its constituents' power supply needs and buy directly from power supply providers rather than as a bundled customer of an investor-owned electric utility (IOU). Under the municipal aggregation business model, local governments purchase and manage their community's electric power supply by sourcing power from a preferred mix of traditional and renewable energy sources, while the IOU continues to provide distribution and billing service.

Since 2003, the City of Fairfax applied and was approved by the State Corporation Commission (SCC), for an aggregation program license. The City of Fairfax did not move forward with its aggregation program and let its license expire in 2009. There are currently no municipal aggregators operating in the Commonwealth.

To better understand the benefits and risks associated with the municipal aggregation business model, the County selected GDS Associates, Inc. (GDS) and Best, Best & Krieger (BB&K) to prepare this Study. This Study assesses the technical and regulatory feasibility of municipal aggregation operations as a mechanism to provide choice to customers, potentially lower electricity rates, and contribute toward achieving the County's greenhouse gas (GHG) reduction goals and stimulate the local economy. This Study relies on previous aggregation attempts within the Commonwealth, the incumbent IOU rates and portfolio mix, and municipal aggregation programs operating in other parts of the country to develop the financial forecasts needed to determine potential feasibility.

2.1 SERVICE AREA TO BE ANALYZED IN THIS STUDY

The Study's analysis, findings and recommendation address the residential and business electric accounts currently served by Dominion, the incumbent investor-owned utility (IOU) IOU in the County. Electric accounts within the County served by the Northern Virginia Electric Cooperative (NOVEC) have been excluded from the Study's analysis, findings and recommendations. This exclusion is made as nationally, the municipal aggregation business model has been applied only to IOU electric accounts, and the Project Team is specifically not able to comment on the impacts of municipal aggregation on cooperative service territories.

Municipal aggregation was established by statute in 1999, Virginia State Code § 56-589, as part of deregulation under the Virginia Electric Utility Restructuring Act. In 2007, Virginia re-regulated the electric utility industry under the Electric Utility Regulation Act imposing new laws on the State's two largest IOUs, Dominion and APCO. The 2007 Act, along with § 56-589, is governed under Chapter 23, while NOVEC is a regulated electrical cooperative regulated under Chapter 9. In 1896, the Virginia Supreme Court adopted the Dillon Rule, which is a legal principle that local governments have limited authority and can pass ordinances only in areas where the General Assembly (which meets in the state capitol in Richmond) has granted clear authority. Since regulated electrical cooperatives are not explicitly included in § 56-589, and after consultation with County staff and other industry experts, municipal aggregation is not assumed for NOVEC electric accounts within the County.

2.2 STUDY METHODOLOGY

This Study evaluates the estimated costs and resulting generation rates of operating a municipal aggregation model for the residents and businesses within the County and currently served by Dominion

and compares the generation rates for Dominion and a municipal aggregator for the years 2024 through 2033. This pro forma financial analysis models the following cost components:

- Power Supply Costs:
  - Wholesale Purchases
  - Renewable Purchases
  - Local and Regional Solar
  - Battery Storage
  - Procurement of Reliability Pricing Model (RPM) or "Performance" Capacity
  - Ancillary Services
- Non-Power Supply Costs:
  - Start-Up Costs
  - Municipal Aggregation Staffing and Administration Costs
  - Consulting Support
  - Dominion billing and Regulatory Charges
  - Financing Costs
- Pass-Through Charges from Dominion:
  - Transmission and Delivery Charges
  - Potential Stranded Generation Costs/Exit Fee

The information above is used to determine the projected generation rates for County municipal aggregation. The County municipal aggregation generation rates are then compared to the Dominion generation rates for the municipal aggregation service area. After these rate comparisons are completed, economic development and GHG emission comparisons are made. Operational and governance options are discussed, including a sensitivity analysis of the key variables contained in the Study. Finally, a list of potential legal and regulatory issues is outlined with an attendant strategy to resolve all regulatory issues.

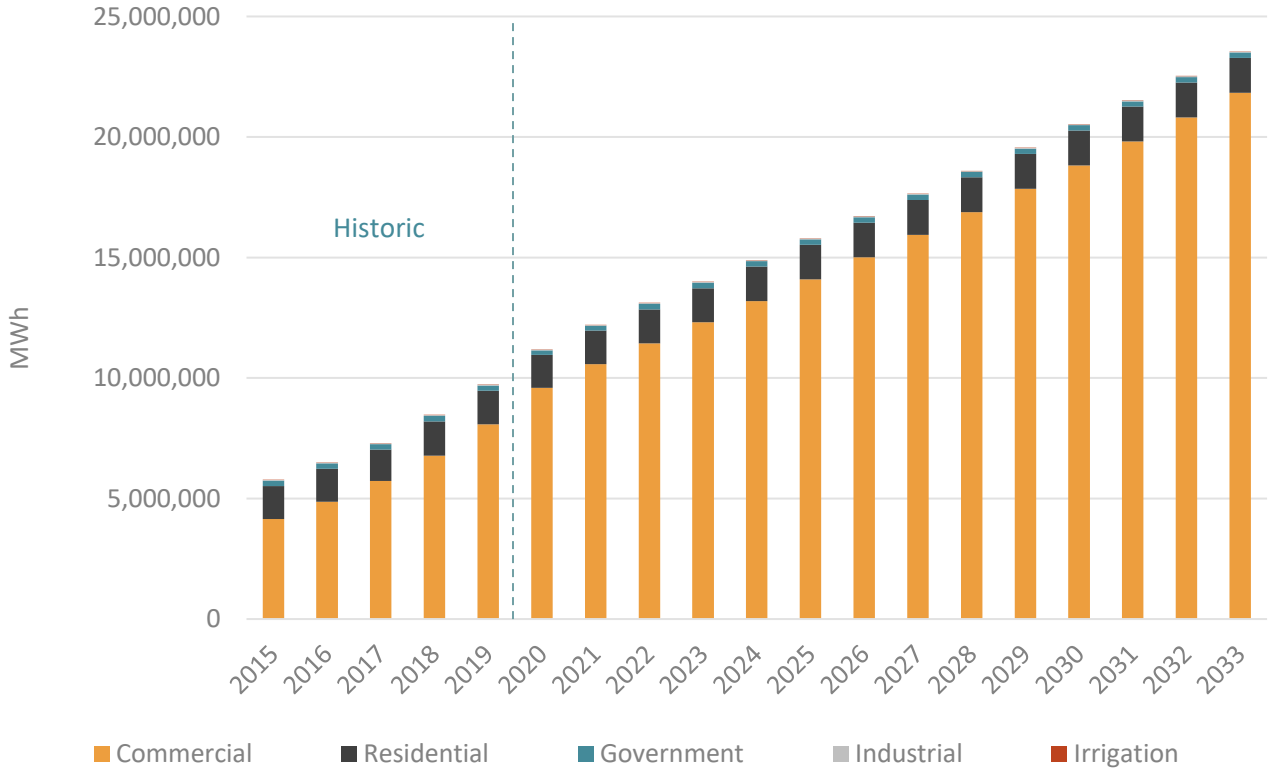
3 Load Requirements

One indicator of the viability of a municipal aggregation model for the County is the number of customers that participate in the municipal aggregation as well as the quantity and timing of energy these customers consume. This section of the Study provides an overview of these projected values and the methodology used to estimate them.

3.1 HISTORICAL CONSUMPTION

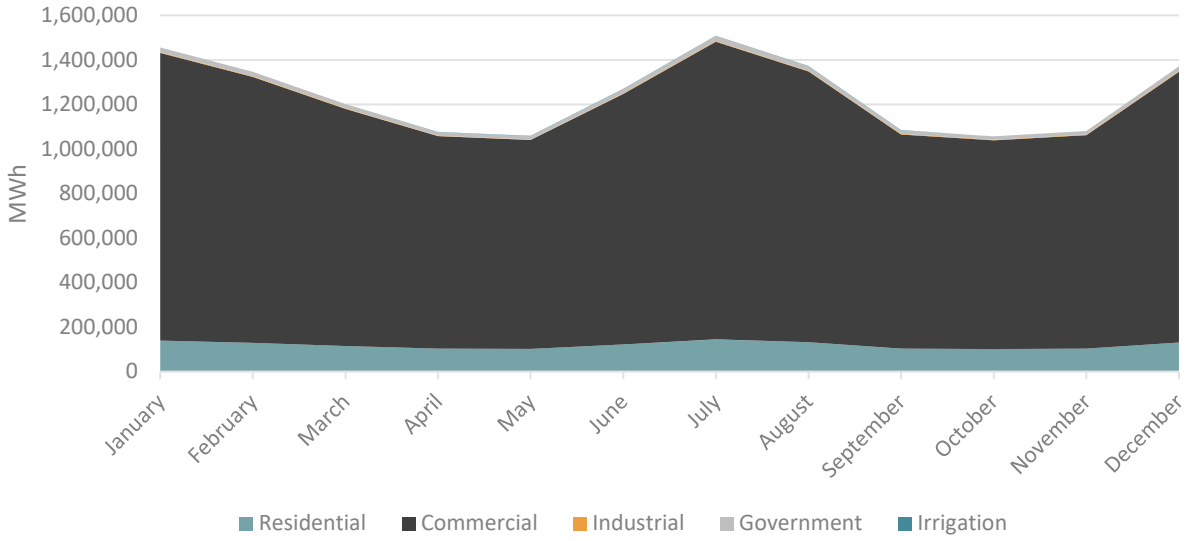
Dominion provided historic retail sales from 2015 through 2019 by customer class. Utilizing this historical annual energy consumption by class, an annual load forecast was developed for 2024 through 2033. Due to the expected continued growth of data centers in the County, the commercial class is projected to continue a steep growth pattern. The continuous operation of data center load has resulted in an annual projected load factor ranging between 65-70% over the 10-year forecast period. Figure 3-1 summarizes the annual energy load forecast for each customer class.

FIGURE 3-1. FORECAST MUNICIPAL AGGREGATION SERVICE AREA LOAD



To develop detailed peak and hourly shaped load profiles, load profiles and customer mix for utilities near the County were reviewed. These loads include other municipalities and cooperatives with similar climate and customer mix. The County's annual load forecast was shaped into monthly energy and peak demand based on the load data from these similar utilities. Similar to the utilities surveyed, County loads are expected to be summer peaking. Monthly loads are shown in Figure 3-2. The timing of energy usage is important for estimating generation costs to the municipal aggregation entity .

FIGURE 3-2. MONTHLY AGGREGATED LOAD



For the purposes of generation cost estimation, the monthly loads are disaggregated into an hourly shape. The hourly shape allows for more precise power cost estimation as resources such as solar and battery are added into the municipal aggregation generation mix.

3.2 MUNICIPAL AGGREGATION PARTICIPATION RATES

This Study assumes that the municipal aggregation program will be an "opt-out" program. An opt-out program means customers in the municipal aggregation service territory will automatically be enrolled into the municipal aggregation entity unless they proactively opt-out. Opt-out programs typically have higher participation rates than opt-in programs. With higher participation rates, the municipal aggregation model is more likely to be financially feasible.

Before customers are served by a municipal aggregation entity, it is assumed that the municipal aggregator will provide two notices enclosed with their Dominion monthly energy bills 60 and 30 days before the municipal aggregation's launch and another two notices 30 and 60 days after the municipal aggregation launches. These notices provide information needed to understand the terms and conditions of service from the municipal aggregator and explain how customers can opt-out, if desired. Notices typically provide a rate comparison between the municipal aggregation and the incumbent IOU. All customers that do not follow the opt-out process specified in the customer notices are automatically enrolled into the municipal aggregation entity.

As such, a municipal aggregator would typically provide a minimum of four opt-out notices to customers to notify and educate them about the municipal aggregator's product offerings and their option to opt-out. Customers automatically enrolled would continue to have their electric meters read and billed for electric service by Dominion. The municipal aggregation billing would also continue to be processed by Dominion, showing separate charges for power supply procured by the municipal aggregator, all other charges related to the delivery of the electricity by Dominion and other charges that would continue to be assessed.

This Study anticipates an overall customer participation rate of 90% for all accounts. This participation assumption is conservative based on participation rates in other opt-out municipal aggregation programs.[1]

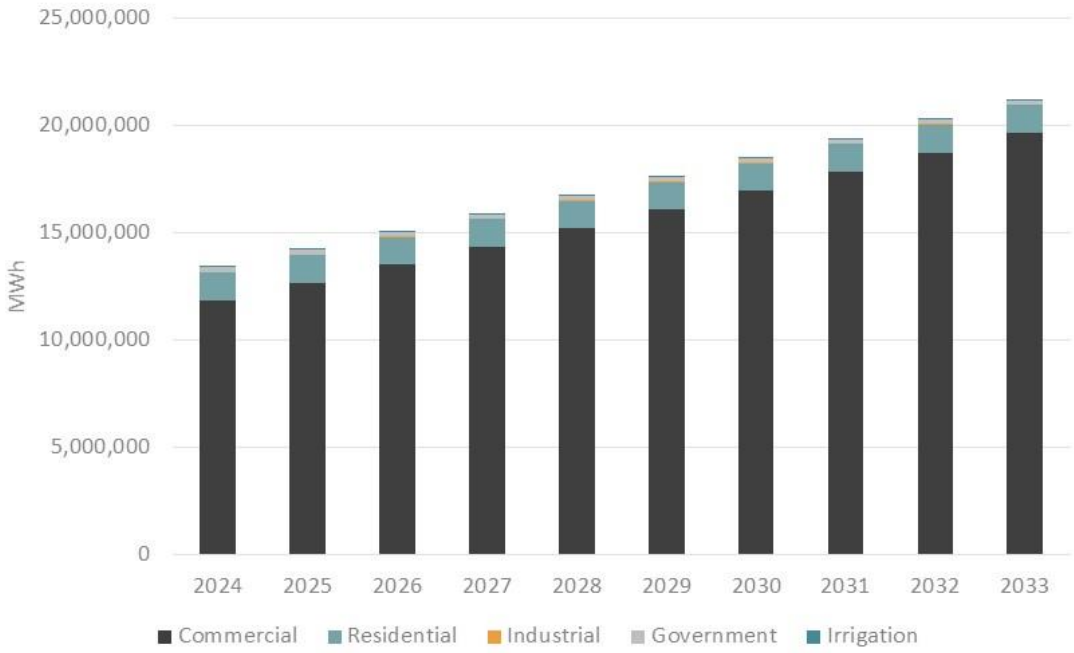
3.3 CONCEPTUAL MUNICIPAL AGGREGATION LAUNCH

For simplicity, it is assumed that the municipal aggregator will begin serving all loads on January 1, 2024. If the municipal aggregation program is feasible, alternative launch strategies can be analyzed to determine the best time to launch each customer class based on retail rate structures and seasonal power supply costs.

3.4 FORECAST CONSUMPTION AND CUSTOMERS

The number of customers enrolled in the municipal aggregation are assumed to increase at the same growth rate as their loads are expected to increase. The forecast of load served by a municipal aggregator over the next ten years is shown in Figure 3-3. The municipal aggregation forecast of GWh sales in Figure 3-3 reflects the single-phase roll-out and customer enrollment and participation percentages discussed above.

FIGURE 3-3. PROJECTED PARTICIPATING LOAD BY SECTOR



3.5 LOAD SUMMARY

The load projected within the County is significant compared with currently operating municipal aggregation programs in other parts of the country. County municipal aggregation also has a large number of customers that can support the administrative costs for municipal aggregation operation. The County municipal aggregation service territory will have an estimated 130,700 accounts in 2024 and increase to

[1] Opt-out programs typically observe participation rates of 95% or greater depending on customer class.

an estimated 162,000 accounts by 2033. Aside from the number of accounts, the total retail sales would make the County municipal aggregation one of the largest municipal aggregators in the country.

4 Power Supply Strategy and Costs

Long-term resource planning involves load forecasting and power supply planning on a 10- to 20-year time horizon. This Study focuses on a 10-year study period. Prior to launch, the municipal aggregation planners would develop Integrated Resource Plans (IRPs) that meet their supply objectives and balances cost, risk, and environmental considerations. IRPs also consider demand-side energy efficiency, demand response programs, and non-renewable supply options. Municipal aggregation would require staff or a consultant to oversee planning even if the day-to-day supply operations are contracted to third parties. This staff or consultant would ensure that local preferences regarding the future composition of power supply and demand-side resources are planned, developed, and implemented.

4.1 RESOURCE STRATEGY

This Study assumes that the County municipal aggregation entity would be interested in minimizing overall community energy bills, stimulating local economic development, achieving goals that reduce GHG emissions, and meeting or exceeding the State's renewable energy requirements. As discussed in greater detail below, municipal aggregation's electric portfolio would be guided by the municipal aggregation's policymakers with input from its stakeholders, portfolio manager, scheduling coordinator, and other power supply experts. The scheduling coordinator would obtain enough resources each hour to serve all the municipal aggregation customer loads. The municipal aggregation policymakers would guide the power supply acquisition philosophy to achieve the municipal aggregation's policy objectives.

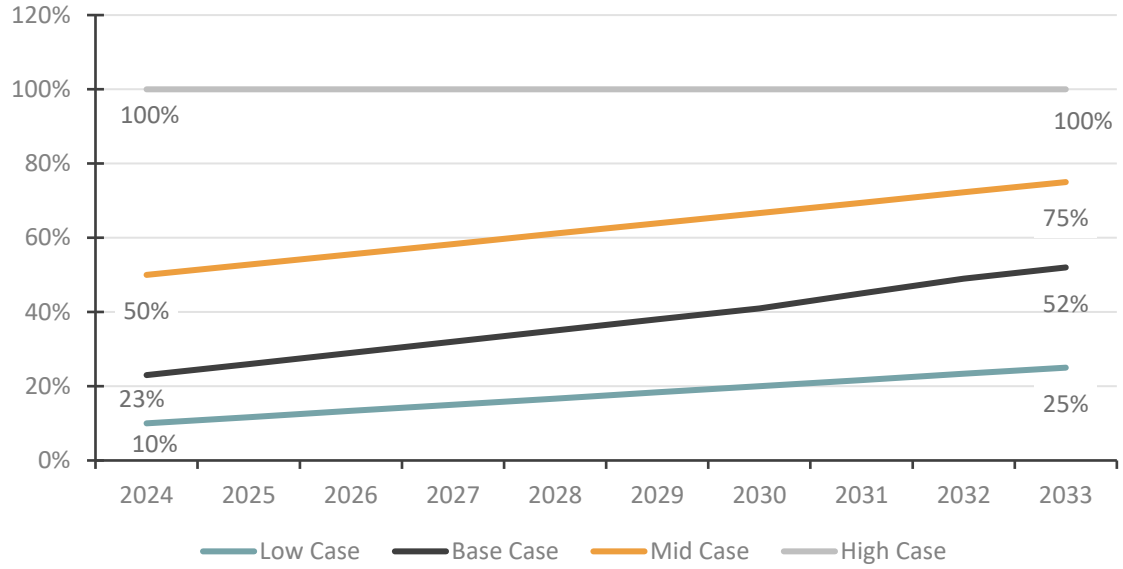
4.1.1 Municipal Aggregation Power Portfolios

Four power portfolios are analyzed for the County within the feasibility analysis:

- **Scenario 1** *25% Renewable by 2033 Portfolio (Low Case)*: Renewable Portfolio increases linearly from 10% in 2024 to 25% in 2033, recognizing that the municipal aggregation will not be bound by the Virginia Clean Economy Act (VCEA) and may be able to provide a discounted rate compared to Dominion IOU by balancing an optimized portfolio and a renewable option.
- **Scenario 2** *52% Renewable by 2033 Portfolio (Base Case)*: Following VCEA's renewable timeline for Dominion IOU, Renewable Portfolio will increase from 23% in 2024 to 52% by 2033.
- **Scenario 3** *75% Renewable by 2033 Portfolio (Mid Case)*: Renewable goal increases linearly from 50% in 2024 to 75% in 2033, providing a higher renewable standard than the VCEA for Dominion.
- **Scenario 4** *100% Renewable by 2033 Portfolio (High Case)*: 100% of retail loads are served with RPS-qualifying renewable resources or Renewable Energy Credits in all years.

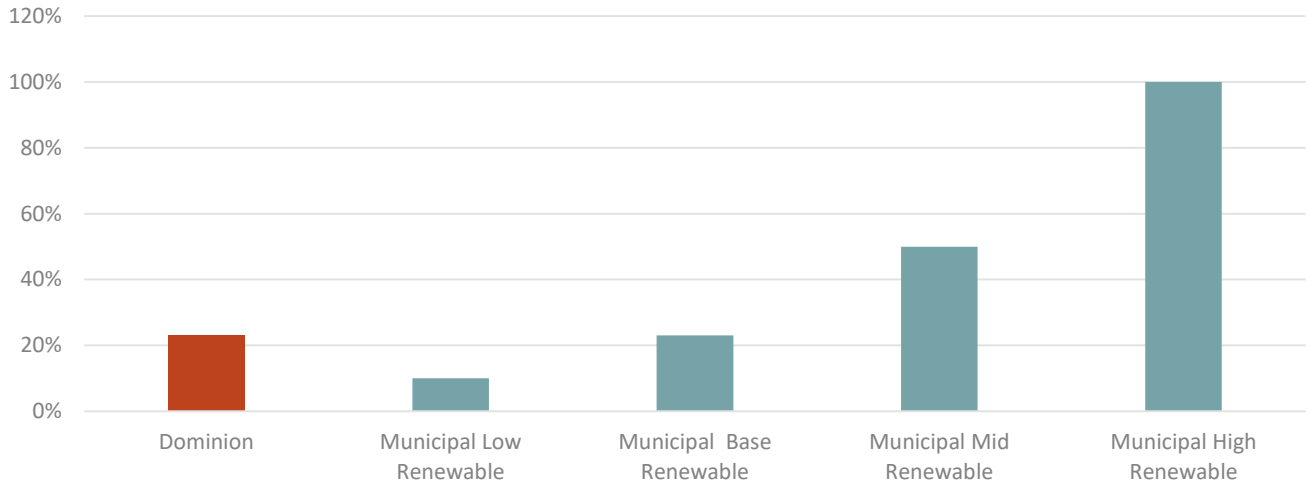
It should be noted that while municipal aggregation policymakers may opt for other resource portfolios, those selected above should give the County a sound basis for evaluating other resource portfolio options. The renewable energy targets of the four portfolios included in the power cost model are shown below in Figure 4-1.

FIGURE 4-1. PORTFOLIO RENEWABLE ENERGY SHARE



Dominion's resource mix is compared with the portfolios analyzed to determine how competitive municipal aggregation's resource offerings could be. Dominion's current resource mix is over 95% non-renewable as of 2019. In its 2020 IRP, Dominion provides several alternative plans to meet or exceed the VCEA RPS requirements through 2035. Figure 4-2 compares the 4 municipal aggregation portfolios to Dominion's projected power content label for 2024. Dominion's renewable resource additions consist primarily of wind and solar.

FIGURE 4-2. PROJECTED RENEWABLE SHARE COMPARISON IN 2024



Dominion has generators set to retire in the next seven years, including over 3,000 MW of coal, oil, natural gas, and biomass. At the same time, Dominion is developing least cost alternatives to meet the VCEA RPS requirement of 100% renewable by 2045.

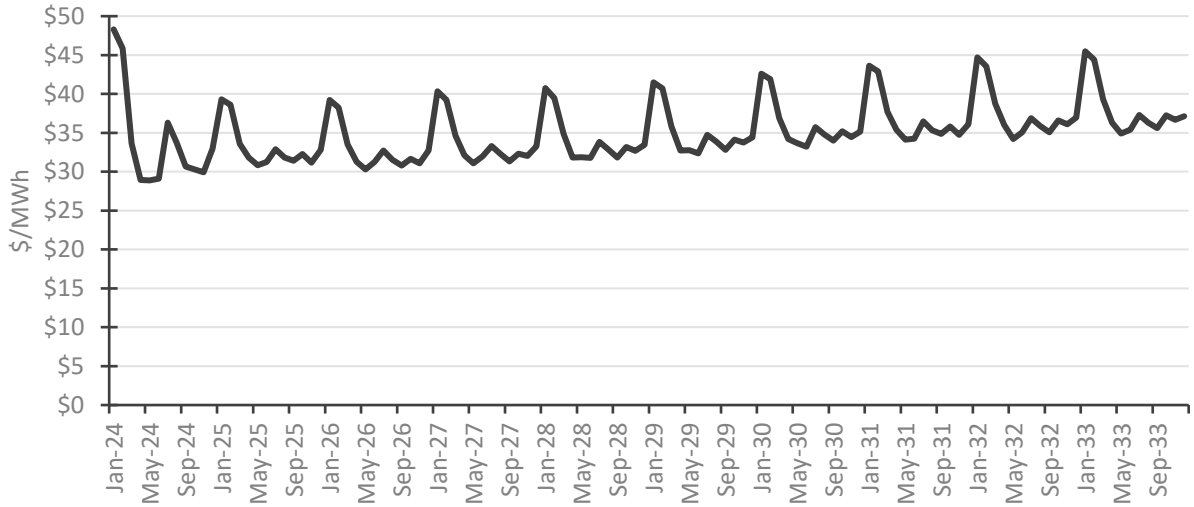
4.2 PROJECTED POWER SUPPLY AND GENERATION COSTS

This Study presents the costs of renewable and non-renewable generating resources as well as Power Purchase Agreements (PPAs) based on current and forecasted local wholesale market conditions, recently transacted power supply contracts, and a review of the applicable regulatory requirements. In summary, a County municipal aggregation model would need to procure market purchases, renewable purchases, ancillary services, PJM capacity, and power management/schedule coordinator services. The Study determines the base case assumption for each of these cost categories and establishes a high and low range for each, to be used for the risk analysis later in the Study.

4.2.1 Market Purchases

Hourly market price curves for the Dominion service area were developed to evaluate market exposure based on the County municipal aggregation entity load shape. Dominion area market price projections were developed through 2026 based on market price forward data, which represents a high liquidity, and high-volume market measuring point near Dominion Hub or service area.[2] Historical congestion trends between the County and Dominion Hub are included as an adder to develop the Dominion Hub price forecast. The market price forecast is then escalated at the same rate as the monthly central (Henry Hub) gas index over the remainder of the Study period (2027-2033). Figure 4-3 shows forecasted monthly Dominion Hub wholesale electric market prices. The levelized value of market purchase prices over the 10-year study period is $35.29/MWh ($2021) assuming a 3% discount rate. Figure 4-3 shows the clear seasonal variability in prices each year, as well as the overall trend in prices.

FIGURE 4-3. FORECAST OF DOMINION HUB WHOLESALE MARKET PRICES



Wholesale market power prices are used to value balancing market purchases and sales. When the municipal aggregator's loads are greater than its resource capabilities, the PJM market would provide balancing purchases. When the municipal aggregator's loads are less than its resource capabilities, the PJM market would provide for sales and the municipal aggregator that would receive market sales revenue.

[2] S&P Global Market Intelligence.

4.2.2 Renewable Energy

Various renewable energy resources were reviewed and incorporated into the municipal aggregation generation mix based on their relative benefits to peak demand and energy needs.

4.2.2.1 Local (Distributed) Generation

Distributed solar and battery storage interconnected behind retail meters can provide future peak shaving benefit to decrease capacity and transmission billing demands. Capacity billing demand is based on coincident load during PJM's 5 summer peak load hours (June-September). Dominion transmission billing demand utilizes a monthly zonal peak allocation factor to determine annual billing demand. Solar could offset capacity billing demands, and associated reserve margins, and transmission billing demands dependent on the generation output during these peak hours. Solar is anticipated to provide ~56% of capacity billing demand offset and 31% of transmission billing demand offset based on expected generation during peaks. Battery storage offset will depend on the duration of the battery and probability of predicting the peak day and time. Battery durations of 2 of more hours are projected to provide peak shaving benefits of 80% or more of the nameplate capacity value.

Distributed generation, especially for retail load, is limited by several factors, including land availability, minimum substation loading, pricing, and policy thresholds. Land availability is a key limiting factor. When considering solar development, approximately 10 acres of land is required per 1 MW of solar installation. For maximum solar output, a flat area of land with minimal obstructions is recommended. Battery storage requires less laydown area and is easier to accommodate.

4.2.2.2 Transmission-Interconnected Solar PV

Transmission-interconnected solar projects are typically much larger (Utility-Scale) projects that accrue economies of scale and can be used to achieve renewable portfolio goals. The municipal aggregation can issue an RFP to contract for an allocation of one of these larger projects located throughout VA and PJM. Since these projects are not interconnected behind the retail meter, they cannot be used for capacity and transmission peak shaving purposes, however, the capacity can be bid into the PJM capacity auction to receive capacity credit at the prevailing auction prices. Because Solar PV is an intermittent resource, the capacity accreditation that it receives in the PJM capacity market is subject to the newly approved Effective Load Carrying Capability (ELCC), which decreases over time as more solar is installed on the grid. The PJM ELCC rates are shown below in Table 4-1. Additionally, the municipal aggregation may receive the RECs associated with the projects.

TABLE 4-1. PJM CURRENT SOLAR ELCC ASSUMPTIONS

Solar Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032*	2033*
ELCC	52%	48%	44%	42%	39%	36%	31%	26%	26%	26%

*PJM's current solar ELCC curve only goes out until 2031. Assume flat 26% ELCC for 2032 and 2033.

4.2.2.3 Battery Storage

The Study also evaluates the potential inclusion of battery storage technology. Battery technology continues to improve, and future cost declines are expected. As the penetration of solar and wind variable resources increases, battery storage is expected to offset some of the open capacity requirements. Short-term lithium-ion batteries are a widely available technology that is expected to grow at an exponential pace in the next two years. These storage resources are typically short-term resources providing 4-6 hours of energy daily. These resources provide very little energy (negative net energy), but they may be used to meet capacity requirements and could provide

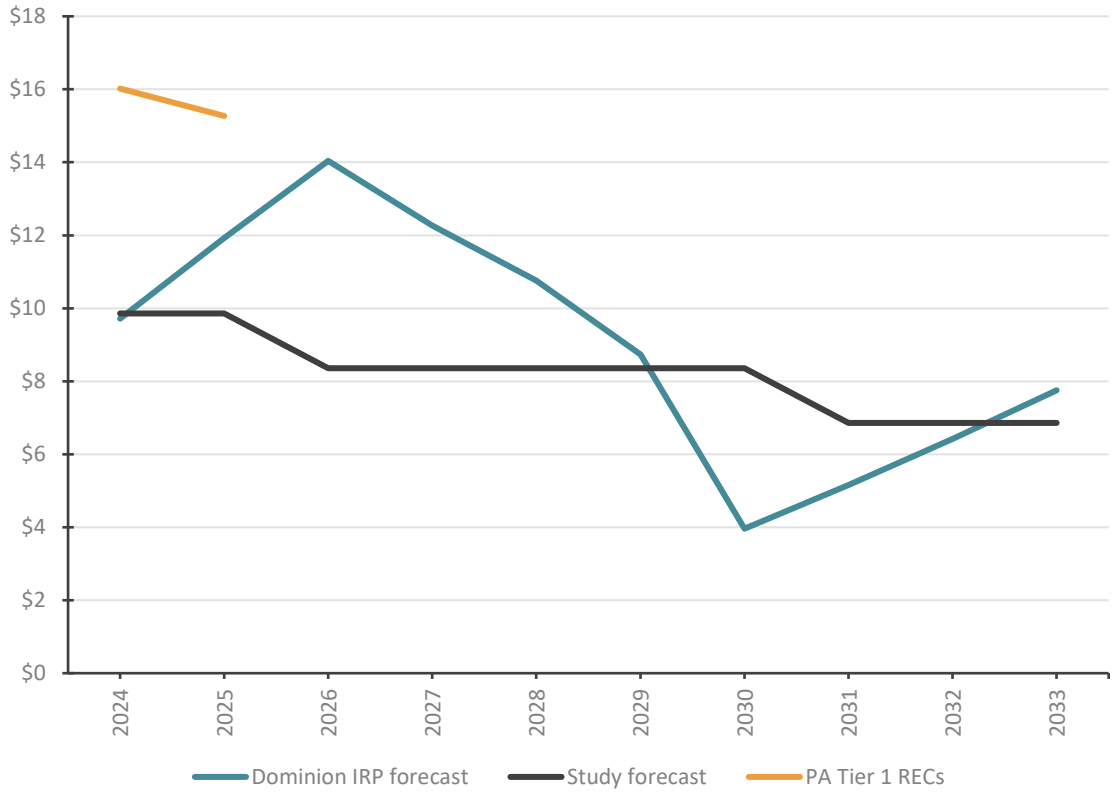
significant peak shaving benefits if located behind the distribution meter. Other storage options may become available to the municipal aggregation, including pumped storage and long-term storage technologies. Because the current PJM capacity benefit alone does not outweigh the current pricing for interconnected 4-hour battery storage, this type of resource was excluded from the analysis in each case as it only adds incremental cost to the overall power supply.

4.2.3 Renewable Energy Credits (RECs)

In addition to direct purchases of renewable power, renewable energy credits (RECs) are an alternative for meeting short-term RPS requirements. Currently, the Commonwealth does not have a REC market, however, RECs can be purchased from PJM or from other state markets surrounding the Commonwealth. For the Study, RECs are assumed to average $8.21/REC for the study term of 2024-2033. For each of the four portfolio scenarios reviewed, RECs will be used to achieve any remaining renewable requirement that is not served by a contracted renewable resource.

Due to the VCEA, it is anticipated that the Commonwealth will develop a REC market within the Study term. Although it is difficult to project a new REC or solar REC market and associated prices in an evolving market, it is anticipated that the prices could closely follow those in other neighboring states such as Pennsylvania, where the market is limited to renewable resource RECs located within the state boundaries. It is important to consider the value of these RECs when planning and evaluating future renewable projects and associated value and/or the investment associated with REC purchases to achieve future renewable goals. Please reference Figure 4-4 for a REC price forecast.

FIGURE 4-4. REC PRICES AND FORECASTS



4.2.4 Ancillary Service Costs

The municipal aggregation model would need to pay PJM for transmission congestion and ancillary services associated with its power supply purchases. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion charges are accrued in the day-ahead and real-time markets. These congestion charges are incorporated into the market price projection.

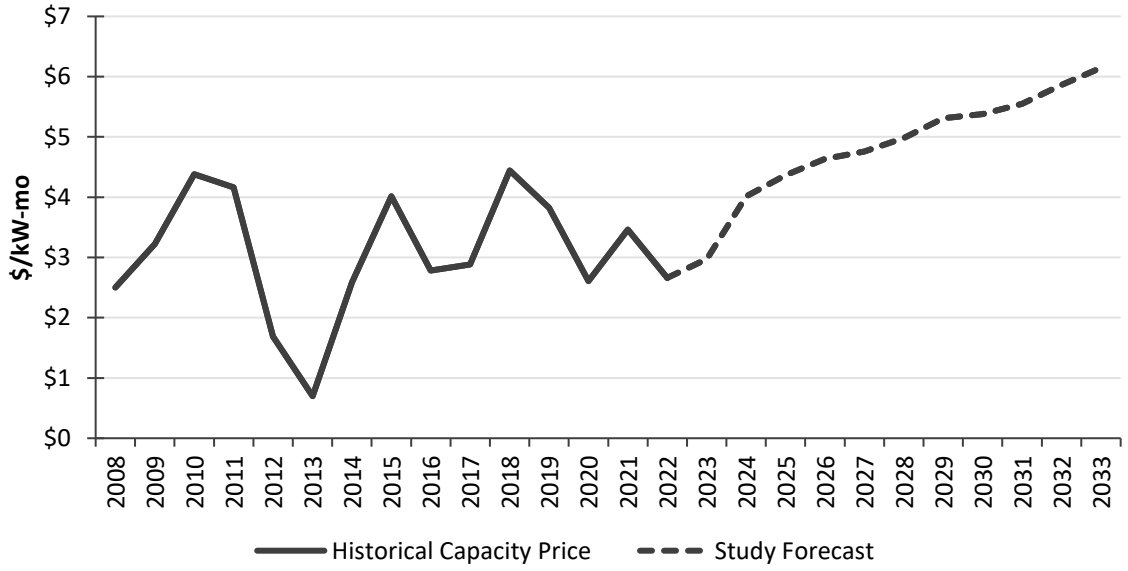
In addition, because generation is delivered as produced and can be intermittent, deliveries need to be firmed using ancillary services to meet the municipal aggregator's load requirements. Ancillary services and products need to be purchased from PJM based on the municipal aggregator's total load requirement. Based on a survey of ancillary service costs currently paid by PJM participants, the municipal aggregation entity's ancillary service costs are estimated to be approximately $0.77/MWh.

4.2.5 PJM Capacity

All utilities that are participants in PJM, including any municipal aggregators, are required to participate in the PJM Reliability Pricing Model (RPM). The RPM ensures long-term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted demand on the system in the future. PJM conducts RPM auctions annually to develop capacity market prices for planning years three years in advance.

For the Study, capacity billing units were projected based on a projected summer peak coincident with PJM's summer peak. Any behind the meter retail capacity from solar or battery resources is deducted from these billing units. A reserve margin of 20% is assumed based on internal forward PJM Capacity price forecast. PJM capacity prices have fluctuated from year to year based on supply and demand curves and changes in regulation. In the Study's base cases, capacity prices are projected to be between $4.01-6.15/kW-mo., however, capacity prices could change based on on-going restructuring in the PJM capacity market. Figure 4-5 illustrates these capacity pricing forecast.

FIGURE 4-5. PJM HISTORICAL AND FORECAST CAPACITY PRICES



Transmission-interconnected solar and battery storage may provide additional capacity credit if bid into the PJM capacity auction. Due to the intermittent nature of solar, solar paired with battery storage may provide additional capacity value, especially with the recent adoption by PJM of ELCC. ELCC is a method of determining capacity credit based off a probabilistic model that compares the ability to reliably serve load with and without certain

resources. Going forward, PJM will update the ELCC to determine capacity credit associated with intermittent resources instead of evaluating an individual resource's capabilities. Table 4-2 provides an example of the ELCCs associated with various resources.

TABLE 4-2. ELCC CROSS RATINGS FOR 2023/2024 BRA

ELCC Class Ratings for 2023/2024 BRA

ELCC Class	ELCC Class Rating for 2023/2024 BRA
Onshore Wind	15%
Offshore Wind	40%
Solar Fixed Panel	38%
Solar Tracking Panel	54%
4-hr Storage	83%
6-hr Storage	98%
8-hr Storage	100%
10-hr Storage	100%
Solar Hybrid Open Loop - Storage Component	82%
Solar Hybrid Closed Loop - Storage Component	82%
Hydro Intermittent	42%
Landfill Gas Intermittent	59%
Hydro with Non-Pumped Storage*	96%

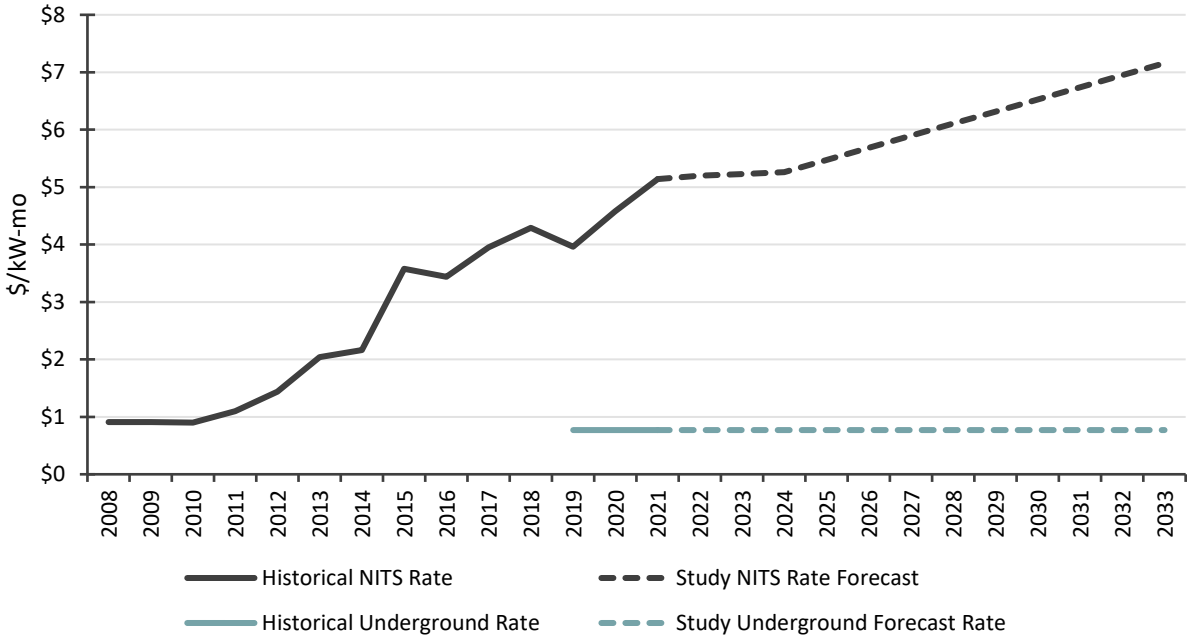
* PJM performs an ELCC analysis for each individual unit in this class. The value shown in the table is a representative value provided for informational purposes

4.2.6 Dominion Zonal Transmission

As a PJM LSE under Dominion's formula rate or as a municipal aggregator, the County would be responsible for the PJM Zonal Transmission costs. Transmission billing units in most PJM zones are based on load coincident with annual zonal peak load. For the Dominion Zone, this holds true when developing the zonal Network Integration Transmission System (NITS) rate and developing the Annual Transmission Revenue Requirements (ATRR). In October 2019, FERC permitted Dominion to adopt a new allocation of the ATRR to LSEs based on the utilization of load coincident to the Dominion Zone's monthly peaks for the applicable 12-month period.

The NITS rate is based on Dominion's ATRR and the annual zonal coincident peak. NITS rates have shown significant increases in recent years due to transmission system upgrades and replacements to respond to aging infrastructure, integration of renewable and gas generation, and system resiliency, security and protection. The Study continues to assume a steady increase in the NITS rate, assuming 3% increase annually. Figure 4-6 illustrates these costs.

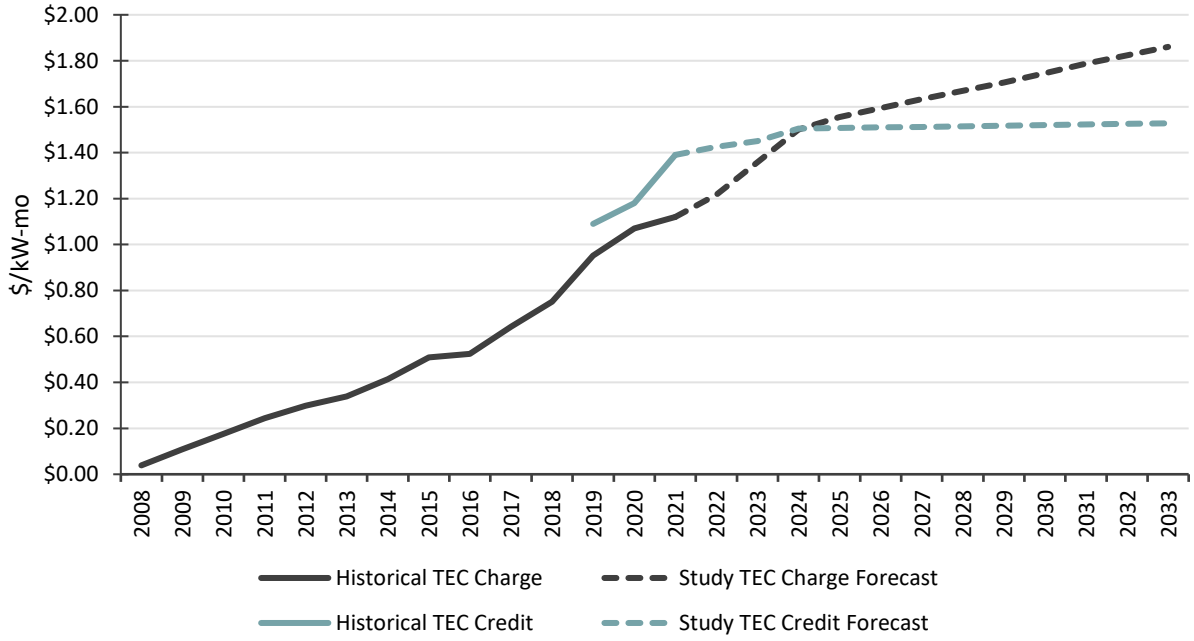
FIGURE 4-6. DOMINION HISTORICAL AND FORECAST ZONAL NITS AND UNDERGROUND RATES



The Underground Transmission Service rate is a sub-set rate of the NITS and is only applicable to the Dominion Zone. This rate was developed to recover costs associated with three underground transmission line projects located within the Dominion territory. The projects were developed to ensure higher reliability in areas that experienced a high rate of outages. The charges have been in place since Jan 2019 and are projected at a consistent rate of $0.14/kW-month for the term of the project.

Transmission Enhancements rates apply to specific transmission projects associated with Schedule 12 of the PJM Tariff. Network customers pay transmission owners based on zonal cost responsibilities. In certain zones, such as the Dominion Zone, there may be a cost and a credit associated with this rate. Historically, the Dominion Zone Transmission Enhancement Rate has been a net credit at ($0.27)/kW-mo., and it may change at any point in the year based on new transmission projects and costs. Based on recent years of Transmission Enhancement Charges escalation, the pro forma assumes an average escalation of 11.8% in the first 3 years for the charges and an average escalation of 2.2% thereafter. Based on the most recent year of Transmission Enhancement Credit escalation, the pro forma assumes an average escalation of 0.1% thereafter since the Transmission Enhancement Credits have increased at a slower rate than the Transmission Enhancement Charges. Figure 4-7 illustrates these costs.

FIGURE 4-7. DOMINION HISTORICAL AND FORECAST ZONAL TEC RATES



4.2.7 Power Management/Scheduling Coordinator

Given the likely complexity of a municipal aggregator's resource portfolio, the municipal aggregator would want to engage an experienced scheduling coordinator to efficiently manage the municipal aggregator's power purchases and wholesale market transactions. The municipal aggregation's resource portfolio would ultimately include market purchases, shares of some relatively large power supply projects, as well as shares of smaller, renewable resources with intermittent output. Managing a diverse resource portfolio with metered loads that can be heavily influenced by distributed generation may be one of the most important and complex functions of municipal aggregation.

The municipal aggregator should initially contract with a third party possessing the necessary experience (proven track record, longevity, and financial capacity) to perform most of the municipal aggregator's portfolio operation requirements. This would include the procurement of energy, scheduling coordinator services, day-ahead and real-time trading and any long-term capacity management activities. Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of municipal aggregation customers.
- *Risk Management* – standard industry risk management techniques would be employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.
- *Load Forecasting* – develop accurate load forecasts, both long-term for resource planning, and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.
- *Scheduling Coordination* – scheduling and settling electric supply transactions with PJM, with related back-office functions to confirm Dominion billing to customers.

A municipal aggregation should approve and adopt a set of protocols that would serve as the risk management tools for the municipal aggregation entity and any third-party involved in the municipal aggregation portfolio

operations. Protocols would define risk management policies and procedures, and a process for ensuring compliance throughout municipal aggregation. During the initial start-up period, the chosen electric suppliers would bear most of the risk and be responsible for managing those risks. The protocols that cover electricity procurement activities should be developed before operations begin.

Based on conversations with scheduling coordinators currently working within the PJM footprint, the estimated cost of scheduling services is $85,000 per year. Portfolio management services are estimated at $250,000 per year.

4.3 RESOURCE PORTFOLIOS

Projected generation costs were developed for four representative resource portfolios. For each of the resource portfolios, a combination of resources has been assumed to meet the renewable energy and GHG-free targets, capacity requirement targets, and ancillary and balancing requirements. The mixes of resources included in each portfolio are for analytical purposes only. Municipal aggregation should be flexible in its approach for obtaining the renewable and non-renewable resources necessary to meet these requirements.

Figure 4-8 shows the levelized resource costs used in this Study. It compares the costs of wholesale market power prices, a PPA tied to either utility-scale solar or distributed solar resources and the four portfolios evaluated in the Study.

FIGURE 4-8. 10-YEAR LEVELIZED RESOURCE COSTS ($2021/MWH)

The levelized resource costs shown above include ancillary services, capacity, and RECs. Scheduling services and other costs are not included. These costs would not change significantly due to different portfolio choice. Figure 4-9 below illustrates the annual generation cost for each resource portfolio, demonstrating that in the short-term, the resource portfolios with higher renewable requirements have a higher cost, but the increased reliance on fixed rate solar PPAs helps hedge against the increasing market prices in future years.

FIGURE 4-9. ANNUAL POWER SUPPLY COSTS ($/MWH)

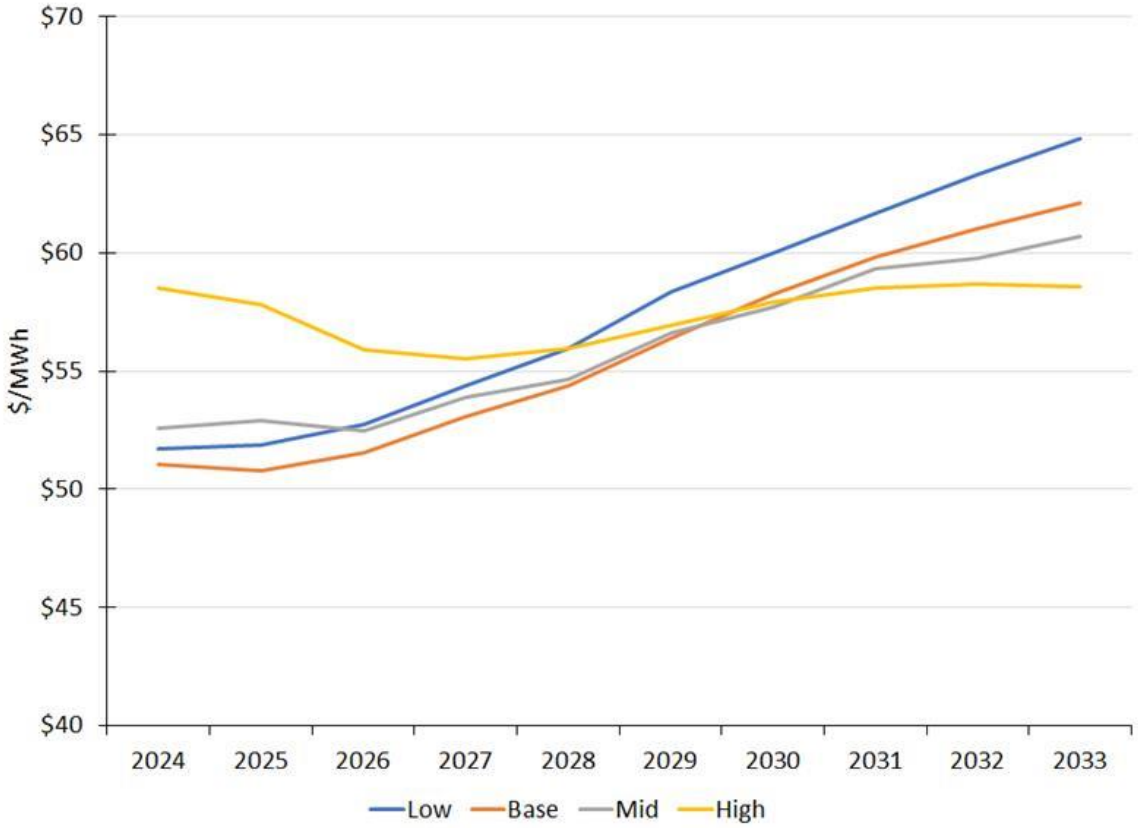
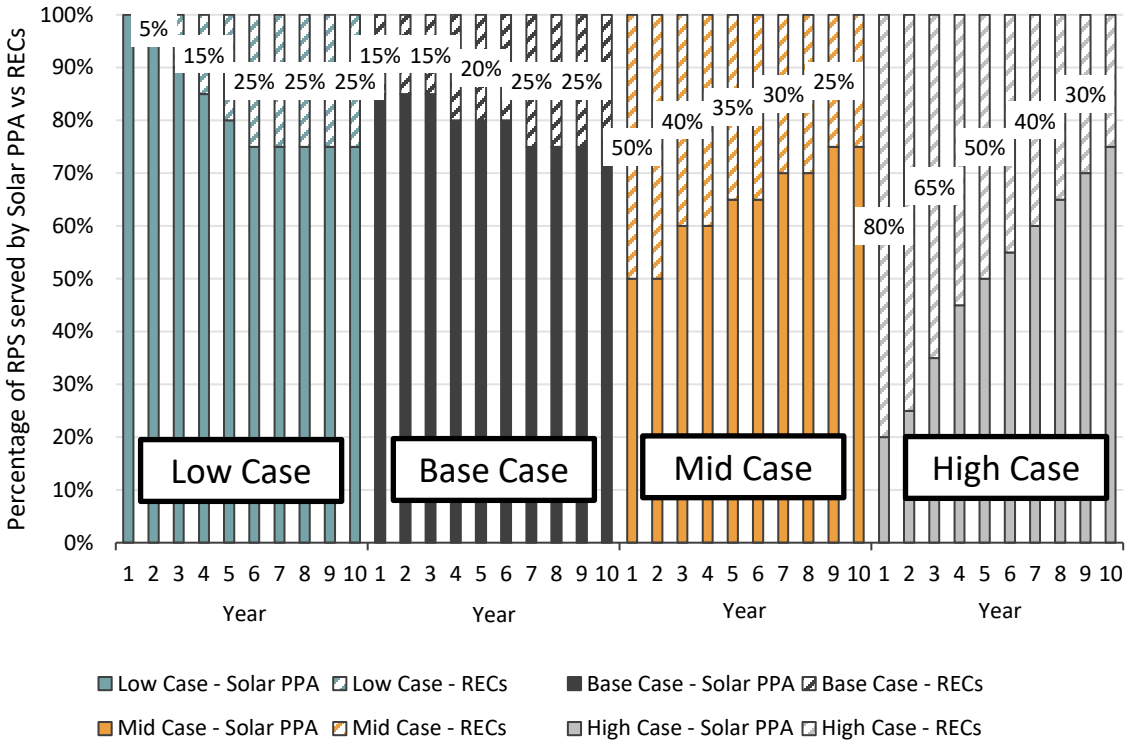


Figure 4-10 shows the annual breakdown of each portfolio's reliance on RECs and solar PPAs to meet that year's corresponding RPS goal. In 2024, the Low and Base Case portfolios begin with a small reliance on RECs (0-15%), while the Mid and High Cases rely on RECs to serve 50-80% of the RPS goal. By the end of the term, all four resource portfolios have a 25% reliance on RECs, while the other 75% is met by long-term solar PPAs.

FIGURE 4-10. RPS BREAKDOWN – SOLAR PPA VS RECS



4.4 RESOURCE STRATEGY

A third-party vendor may manage a municipal aggregator's electric portfolio, at least during the initial implementation period. Through a power services agreement, a municipal aggregation entity can obtain full-service requirements electricity for its customers, including providing for all electric, ancillary services and the scheduling arrangements necessary to provide delivered electricity. The contracted power services manager would assist the municipal aggregator in meeting resource portfolio requirements, such as the requirements for long-term renewable energy contracts and energy storage requirements. The costs for these resources are factored into the Study.

After operations have begun, a municipal aggregator could decide to sign long-term PPAs, which could minimize the municipal aggregator's exposure to market prices and provide the ability to increase the renewable percentage over time. A portfolio manager or schedule coordinator could actively track the municipal aggregator's portfolio and implement energy source diversification, monitor trends and changes in economic factors that may impact load, and identify opportunities for dispatchable energy storage systems or automatic controls for managing energy needs in real-time with PJM.

5 Cost of Service

This section of the Study describes the financial pro forma analysis detailed in Appendix B and cost of service for a municipal aggregation entity. It includes estimates of staffing and administrative costs, consultant costs, generation costs, uncollectable charges and Dominion charges. In addition, it provides an estimate of start-up costs and longer-term external financing requirements.

5.1 COST OF SERVICE FOR MUNICIPAL AGGREGATION OPERATIONS

The first category of the pro forma analysis is the cost of service for a municipal aggregator. To estimate the overall costs associated with municipal aggregation operations, administration costs are estimated and added to the generation cost estimates. Once the costs of municipal aggregation operations have been determined, the total costs can be compared to Dominion's projected generation rates.

5.1.1 Non-Generation Costs

While generation costs would make up most costs associated with operating the municipal aggregation (generation costs are roughly 95% total operating expenses), there are additional cost components that must be considered in the pro forma financial analysis. These additional non-generation costs are summarized in Table 5-1 and then described below.

TABLE 5-1. ANNUAL NON-POWER SUPPLY COSTS

		Pre-Launch	First Year of Operation	
		2023	**2024**	**2025**
PJM Deposit		$500,000		
Dominion Security Deposit		$150,000		
Customer Notification		$600,000		
Data Management and Customer Service Call Center		$0	$1,674,472	$1,750,070
Power Management Consultant		$255,000	$260,100	$265,302
Schedule Coordinator/Dispatch		$50,575	$88,434	$90,203
Technical Consultants		$306,000	$312,120	$318,362
Marketing & Outreach		$306,000	$312,120	$318,362
Legal/Regulatory		$408,000	$416,160	$424,483
Dominion Fees, Billing		$0	$167,447	$175,007
General & Administrative expenses		$1,166,217	$1,884,789	$1,922,484
Total O&M and A&G		**$3,741,792**	**$5,115,642**	**$5,264,274**

Pre-launch costs in 2023 can be variable depending on how quickly the municipal aggregator wants to begin outreach and if there are additional requirements from the SCC before the municipal aggregator begins providing service.

5.1.2 Estimated Staffing Costs

Staffing is a key component to operating a successful municipal aggregation entity. The County municipal aggregation entity would have discretion to distribute operational and administrative tasks between internal staff and external consultants. For this Study, a limited staffing scenario is modeled. This minimum staff scenario relies initially on a few dedicated full-time staff members and the use of technical consultants for support. If the

municipal aggregator finds that there are cost savings for increasing the number of internal staff, the feasibility of this business model scenario would improve.

Based on the minimal staffing plan, the municipal aggregator would initially rely on internal staff and hire a Chief Administrative Officer (CAO) in 2023. Once municipal aggregation begins commercial operations, it is anticipated that internal staffing would increase within the first year of operation. Internal staff will be needed to oversee power management activities and consultants, customer service functions and the attendant vendor, and the overall financial status and reporting for the municipal aggregator.

5.1.3 General and Administrative Costs

Overhead needed to support the organization includes computers and other equipment, office furnishings, office space, utilities, and miscellaneous expenses. These expenses are estimated at $220,000/ year and escalated at 2%.

5.1.4 Outside Consultant Costs

Consultant costs would include outside assistance for legal and regulatory work, power supply management, communication and marketing, data management, financial consulting, technical consulting, and implementation support.

Municipal aggregation data management providers supply customer management system software and oversee customer enrollment and service, as well as payment processing, accounts receivable, and verification services. The cost of data management is charged on a per account basis and has been estimated based on existing contracts for similarly sized municipal aggregators. For this Study, the cost for data management is estimated at $1.00 per account per month.

In addition, estimated funding for other consulting support (such as human resources, legal, customer service, etc.) is provided. These costs have been estimated based on the experience of start-up consulting costs for other municipal aggregators. Consultant costs are increased by inflation every year.

5.1.5 Dominion Fees

Dominion would provide billing and metering services to the municipal aggregator. The estimated costs payable to Dominion for services related to the municipal aggregation start-up include costs associated with initiating service with Dominion, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing and billing fees.

5.1.6 Uncollectible Costs

As part of its operating costs, the municipal aggregator must account for customers that do not pay their electric bill. While Dominion would attempt to collect outstanding funds, approximately 0.3% of revenues are estimated as uncollectible.[3] This cost is removed from the revenue projection in the pro forma. It should be noted that uncollectible revenues will increase during economic downturns. The assumption in this Study reflects long-term averages.

5.2 FINANCIAL RESERVES

The municipal aggregator is assumed to receive external financing during its start-up through full operation. After successful commercial operations begin, a municipal aggregator should build up a reserve fund that is available to address contingencies, cost uncertainties, rate stabilization, or other risk factors faced by municipal aggregation.

[3] Based on 2019 uncollectible expenses Dominion South Carolina, Inc. FERC Form 1. Filed April 17, 2020.

This Study assumes that a municipal aggregator would begin building its reserves immediately upon commencement of commercial operations. After three full operating years, it is estimated that municipal aggregation will have accumulated enough reserves to cover three months of expenses. This level of reserves represents the industry standard for electric utilities and would provide financial stability to assist in obtaining favorable interest rates if additional financing is needed. After that point, revenues that exceed costs could be used to fund lower rates, procure new local renewable resources, fund customer programs and pursue economic development projects. Table 5-2 provides an estimate of the net revenues available for local programs, rate stabilization or additional generation rate discounts in excess of the initially assumed 4%.

TABLE 5-2. RESERVES AND NEW PROGRAM ACCOUNT BALANCES, MILLIONS

	Reserve Fund Balance*	Operating Reserve Target (3 months O&M)	Net Revenue for: New Programs or Further Rate Reduction
2023	$61.7	$155.1	$0.0
2024	$29.6	$155.1	$0.0
2025	$116.9	$179.1	$0.0
2026	$192.3	$192.3	$23.9
2027	$209.0	$209.0	$98.7
2028	$225.6	$225.6	$132.1
2029	$245.5	$245.5	$146.2
2030	$267.0	$267.0	$161.4
2031	$287.3	$287.3	$187.8
2032	$306.8	$306.8	$222.7
2033	$326.8	$326.8	$258.1

** Includes cash available from external financing*

5.3 FINANCING COSTS

In order to estimate financing costs, a detailed analysis of working capital needs and start-up capital is undertaken. Each component is discussed below.

5.3.1 Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that would be required until full operation of the municipal aggregation is achieved. For the purposes of this Study, it is assumed that the municipal aggregation pre-operations begin in January 2023. This date provides 12 months for the municipal aggregator to complete start-up activities, including hiring initial staff and the team of consultants, developing a power supply strategy and entering into contracts. The cash flow analysis identifies and provides monthly estimates for each cost category. A key aspect of the cash flow analysis is to identify the timing of the monthly operating expenses and revenues.

The cash flow analysis also provides estimates for revenues generated from municipal aggregation operations. In determining the level of revenues, the cash flow analysis assumes that all customers are enrolled at the same time. The results of the cash flow analysis provide an estimate of the level of working capital required for the municipal aggregation to move through the pre-operations period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues minus cost of operations) based on payment terms, along with the timing of customer payments and power supply bill payments.

The cash flow analysis assumes that customers will make payments within 60 days of the service month, and that the municipal aggregator would make payments to power suppliers within 30 days of the service month. It is

assumed that payments for all non-power supply expenses would need to be paid within 30 days. Customer payments typically begin to come in soon after the bill is issued, and most are received before the due date; however, some customer payments are received well after the due date. The 30-day net lag in payment is therefore a conservative assumption for cash flow purposes.

For purposes of determining working capital requirements related to power purchases, the municipal aggregator would be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, the municipal aggregator would be obligated to meet working capital requirements related to program management, a potential program reserve of $150,000 and $500,000 security deposit to become a market participate within PJM.[4]

The Study finds that the municipal aggregator will need no more than $80 million in working capital and start-up funds. This amount of working capital can be reduced by staggering the commercial operation dates for customers. Municipal aggregation may also need additional funds for power supply contract collateral. Rather than collateral, it is assumed that power suppliers require a "lockbox" arrangement in lieu of collateral payments. A lockbox arrangement requires the municipal aggregator to place revenues into a "lockbox" which power suppliers can access in order to get paid first before the funds are transferred to the municipal aggregator. This lockbox construct is fairly common in the electric utility industry.

5.3.2 Municipal Aggregation Funding Landscape

A review of the current options for obtaining funds for the long-term line of credit needed for operations is detailed below. It is assumed the start-up capital equal to $3.7M is funded internally but external options may also be available if desired by the County.

Direct Loan from the County – The County could loan funds from its General Fund for all or a portion of the pre-launch through launch needs. Start-up funding provided by the County would be secured by the municipal aggregator's revenues once launched. The County would likely assess a risk-appropriate interest rate for such a loan. This rate is estimated to be 4.0% per annum.

Collateral Arrangement from the County – As an alternative to a direct loan from the County, the County could establish an escrow account to backstop a lender's exposure to municipal aggregation. The County would deposit funds into an interest-bearing escrow account, which the lender could tap should the municipal aggregator revenues be insufficient to pay the lender directly. The County's obligations would be secured by municipal aggregation revenues collected once municipal aggregation is launched.

Loan from a Financial Institution without Support – In California, Silicon Valley Clean Energy Authority (SVCEA) CCA was able to use this option to fund ongoing working capital. After member agencies funded a total of $2.7 million in start-up funds, SVCEA obtained a $20 million line of credit without collateral. This is the most common financing option used by emerging municipal aggregators. This arrangement typically requires a "lockbox" approach with the power providers. This arrangement reduces the required reserves and collateral required of municipal aggregators.

Vendor Funding – A municipal aggregator could negotiate with its power suppliers or other vendors to eliminate or reduce the need for supplemental start-up and operating capital. However, the vendor funding approach can

[4] The financial reserve amount assumes an upfront payment made by the municipal aggregator in the event that the program becomes insolvent and customers are returned to Dominion. Additional research may be required to determine the financial reserve requirement, if any, in the Commonwealth. PJM minimum capitalization requirement is $500,000 per credit overview and supplement to the PJM Credit Risk Management Policy. Version 3.41. April 1, 2021. Page 12.

be less transparent as the vendor controls expenses and activities, and the associated cost may outweigh the benefit of eliminating or reducing the need for bank financing.

Revenue Bond Financing by Municipal Aggregator – This financing option becomes feasible only after the municipal aggregator is fully operational and has established a credit rating.

6 Generation Rate Comparisons

Utility rate design typically features a "generation" rate and "distribution/wires" rate, the sum of which equals the total electric bill to a customer. This section provides a comparison of generation rates between Dominion and County municipal aggregation. Rates are evaluated based on the municipal aggregator's total generation rates as compared to Dominion's total generation rates. "Distribution wires" rates are not addressed as they will remain equal for all customers regardless of who provides the actual electricity.

6.1 GENERATION RATES PAID BY DOMINION BUNDLED CUSTOMERS

6.1.1 Background on Dominion Rates

Dominion must receive approval from the SCC before implementing rate adjustments. Dominion's current application requests are for no rate adjustment but a rebalancing of rates among customers and function (delivery vs. generation).[5] Dominion is requesting that generation rates be decreased and delivery rates increased to rebalance the return on equity received through each function. In 2019, the SCC determined that Dominion received a 14.56% return on generating assets and only a 1.38% return on distribution assets.[6]

Additionally, Dominion is seeking an increase in its approved rate of return. Currently a 9.2% return on equity (ROE) is approved by the SCC. Dominion is now asking for this amount to increase to 10.8%. [7] This request is based on the utility's review of neighboring IOU ROE rates, which are much higher compared with Dominion's ROE rate.

One consideration as the County considers implementing municipal aggregation is that Dominion's approved ROE has been subject to investigation by the SCC in recent years. The SCC has found that Dominion has over-collected over $500 million system-wide over the two-year period 2017-2018.[8] This overcollection was paid in part by the County businesses and residents. Rather than return the overcollection to its ratepayers, Dominion has chosen to invest the overcollection into renewable resources.[9] As a result, municipal aggregation customers have overpaid through historic rates and the overcollection is not being returned through rate reductions; and these new renewable resources could be included in cost stranding calculations paid for by municipal aggregation customers. These decisions directly impact the rate savings available to potential municipal aggregation customers. The County should monitor this segment of Dominion's regulatory activities.

6.1.2 Study Assumptions for Generation Rate Comparisons

Customers served by Dominion will pay a bundled rate that includes Dominion's generation and distribution/wires charges. Dominion's current rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the Dominion rate forecast.

The average Dominion distribution/wires rate, which is paid by both Dominion bundled customers and municipal aggregation customers, has been calculated based on the forecasted customer mix for a County municipal aggregation entity. The Dominion generation and distribution/wires rates have been projected to increase 2% per

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[5] https://www.tdworld.com/utility-business/article/21161809/virginia-to-hold-public-hearing-on-dominions-rate-case-in-september

[6] Commonwealth of Virginia State Corporation Commission. Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant s 56-596 B of the Code of Virginia. August 18, 2020. https://scc.virginia.gov/getattachment/bef130f2-2e42-4c45-b128-f796ab2fa444/2020veur.pdf "SCC Status Report"

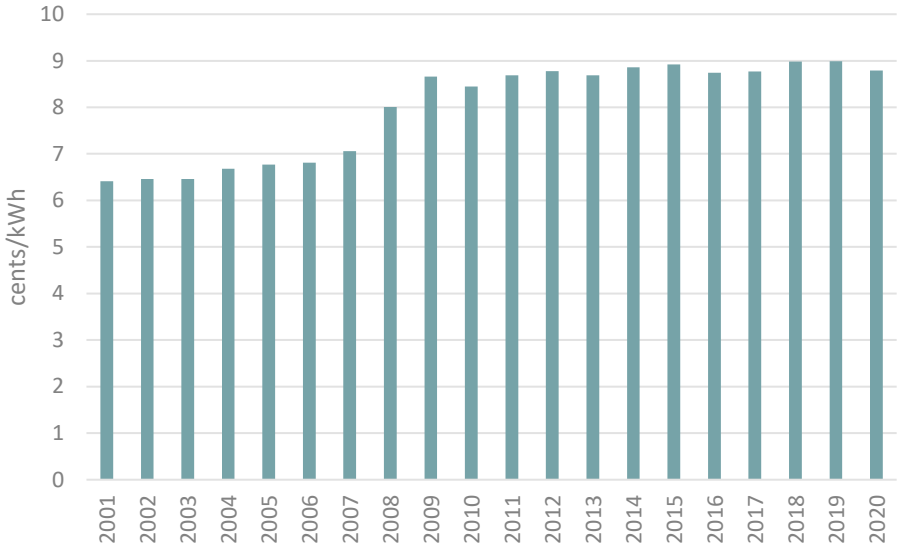
[7] "Daily Press" https://www.dailypress.com/business/consumer/dp-nw-dominion-review-20210401-7qnh3gddg5cuvb4xgmmy2fh6gy-story.html

[8] SCC Status Report

[9] Daily Press.

year. These cost projections are consistent the average historic Dominion retail rate increase of 2%. Figure 6-1 shows the average retail rate for Dominion retail customers since 2001.[10]

FIGURE 6-1. DOMINION HISTORIC RETAIL RATE (BUNDLED)



6.2 RATES PAID BY MUNICIPAL AGGREGATION CUSTOMERS

The Study assumes that County municipal aggregation rate designs would initially mirror the structure of Dominion's rates so that similar rates can be provided to municipal aggregation customers and bill comparisons can be made on an apples-to-apples basis. The Study assumes all customers are enrolled at the same time and that start-up costs are financed via start-up loans.

In addition to paying the municipal aggregator's generation rate, municipal aggregation customers would pay the Dominion delivery rate and non-bypassable charges. These non-bypassable charges include the Rider CE (Solar Energy) and an exit fee. The Rider CE is also charged to Dominion's bundled customers. As such, the only additional non-bypassable charge that is payable to Dominion by a County municipal aggregation customer is the exit fee.

6.2.1 Generation Exit Fee (Stranded Costs)

An exit fee is typically a $/kWh charge that is added to municipal aggregation customer's bill to cover an IOU's stranded costs associated with energy purchases anticipated but unrealized from departing municipal aggregation customers. IOUs enter power contracts anticipating load growth; however, when load departs IOU service, excess energy purchased will need to be resold in the wholesale market.

There is a legal question about whether the SCC can impose an exit fee on municipal aggregation customers. Note legal analysis in the Study's Appendix C. But to be conservative, this Study assumes an exit fee will be imposed on departing municipal aggregation customers.

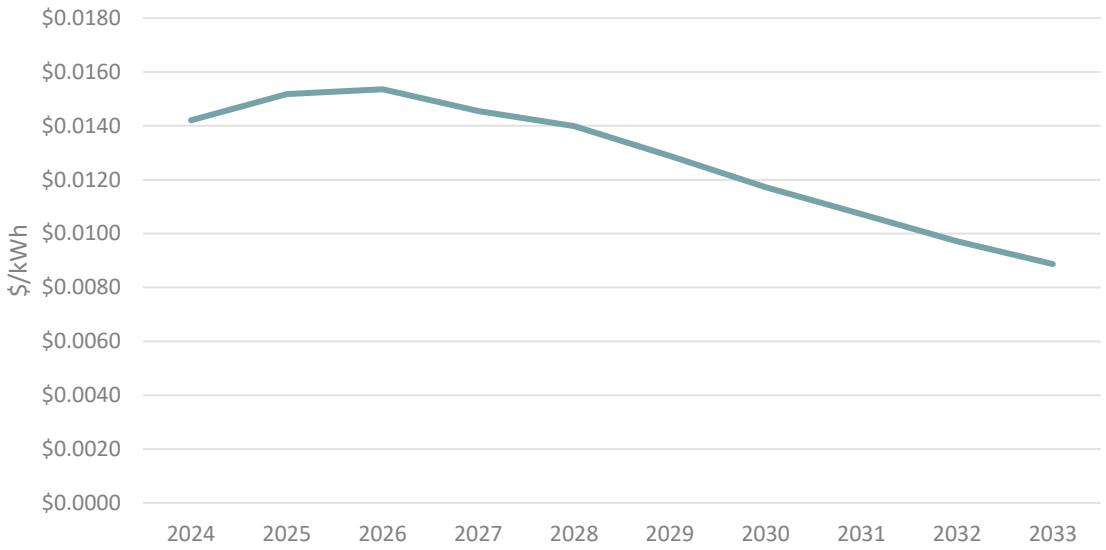
This Study assumes that once the County notifies Dominion of its plans to aggregate, future resource additions by Dominion are no longer included in the exit fee calculation. Assuming notification is provided by the end of 2022, County municipal aggregation customers would not be responsible for resources contracted after that date. Additionally, as current Dominion resources are retired, the exit fee should be reduced to reflect retired assets will no longer attract cost recovery for these resources. This methodology is conservative. Nationally, there has

[10] S&P Global Market Intelligence. Data is sourced from FERD Form 1/1-F, FERC Form 3/3-A or EIA 861 Filings.

been debate over whether resources prior to renewable portfolio standard requirements could be included in stranded cost estimates. This Study allows for their inclusion resulting in a higher exit fee estimate.

The exit fee is estimated based on forecasted Dominion generation costs. When load departs Dominion bundled service, the excess generation is sold at market rates. A forecast of PJM prices values the excess generation. Estimated generation costs are adjusted in forecast years based on Dominion's retirement schedule for resources provided in the most recent IRP. This method effectively removes retired resources from Dominion rate recovery. Figure 6-2 illustrates the Study's exit fee forecast.

FIGURE 6-2. DOMINION EXIT FEE FORECAST



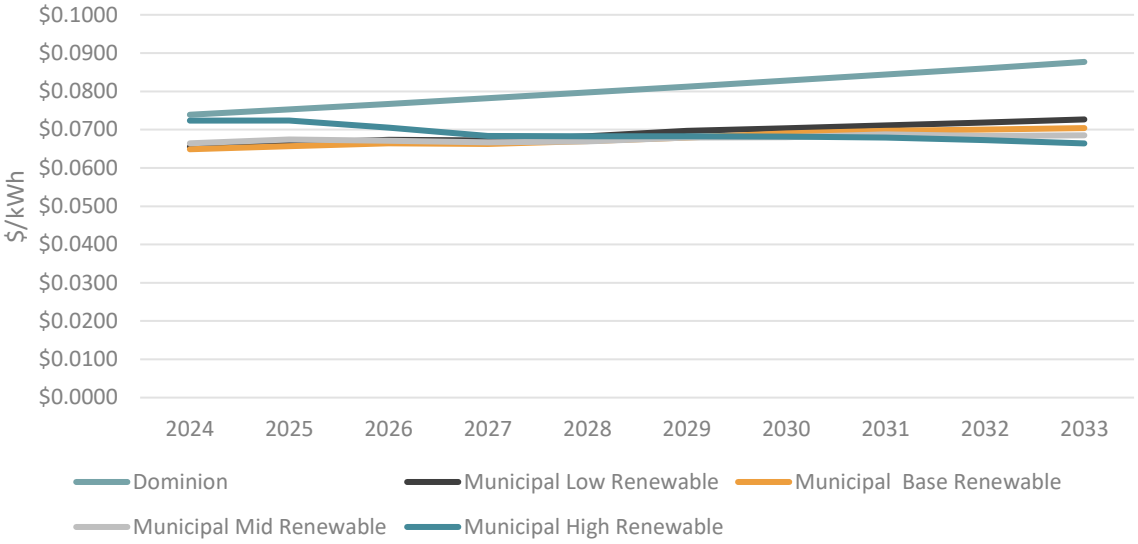
The above methodology values generation cost stranding at only market value. The value of capacity, ancillary services or renewable portions of the stranded assets is not included. These value adders were excluded from the calculation since these values are likely a small portion of the total value, and the methodology and assumptions for determining exit fees in the Commonwealth are not well defined. Therefore, the exit fee assumptions in this Study are conservative. Lower exit fees would result in increased financial feasibility for municipal aggregation. It is important to note that exit fees will likely be the source of ongoing debate and can significantly affect financial feasibility.

6.3 GENERATION RATE COMPARISON

Based on the municipal aggregation's projected generation costs, exit fees, operating costs and Dominion's generation and delivery costs, forecasts for municipal aggregation and Dominion generation rates are developed.

The analysis balances the rate discount, collection of reserves, and the share of renewable and GHG-free resources purchased. Figure 6-3 compares the forecasted Dominion generation rate with generation costs for the municipal aggregator under each power supply portfolio option plus the exit fee. Figure 6-3 illustrates that, regardless of the power supply portfolio, there is an opportunity for municipal aggregation to offer lower rates while collecting reserves, offering valuable customer programs and increasing the customer's amount of renewable energy.

FIGURE 6-3. AVERAGE GENERATION COST COMPARISON



A financial pro forma in support of these rates is available in Appendix A. As noted above, there is a viable business case for County municipal aggregation. Overall total bill discounts of 10% are achievable under the municipal aggregation business model. Given this feasibility, the balance of this Study will address the environmental, economic, risk, and governance options associated with County municipal aggregation.

7 Environmental and Macroeconomic Impacts

This section provides an overview of the potential environmental and macroeconomic impacts to the County from the implementation of County municipal aggregation. In addition, potential future programs that could be offered by a County municipal aggregation are outlined.

7.1 IMPACT OF RESOURCE PLAN ON GREENHOUSE GAS (GHG) EMISSIONS

According to Dominion's 2019 power content label, Dominion's current resource mix is 5% renewable.[11] VCEA requires that Dominion meet 23% RPS by 2024. Dominion can meet this requirement through existing renewable projects (5%), new projects (9% energy from planned solar projects per Plan B in the Dominion 2020 IRP), imported renewable energy or RECs. Resources that directly serve load, such as solar or solar plus battery, reduce GHG emissions since these resources reduce output needed from non-renewable resources.

GHG reduction estimates are calculated for each municipal aggregation portfolio option assuming Dominion pursues Plan B in its IRP and meets the remainder of the VCEA requirement through unbundled REC purchases. Market purchases for PJM are associated with an emissions rate of 0.61 tons CO2e/MWh, which is consistent with the assumptions in the Dominion IRP. For comparison, the share of renewable energy in the municipal aggregator's 2033 portfolio is assumed constant through 2035. Table 7-1 illustrates the GHG reductions.

TABLE 7-1 GREENHOUSE GAS REDUCTION ESTIMATES

	Dominion	Municipal Aggregation Low RPS Portfolio	Municipal Aggregation Base RPS Portfolio	Municipal Aggregation Mid RPS Portfolio	Municipal Aggregation High RPS Portfolio
Projected Annual GHG Emissions in 2035 million short tons CO2e	11.0	10.5	7.9	5.7	3.2
GHG Reductions relative to Dominion Portfolio, Million short tons CO2e		0.5	3.1	5.3	7.8
Difference expressed as Number of Cars[1]		98,623	614,714	1,054,347	1,532,208

1. Assumes one gasoline-fueled car emits 4.6 metric tons/CO_2e per year at 11,500 miles per year and 22 mpg per the EPA.[12]

7.2 LOCAL RESOURCES/BEHIND THE METER MUNICIPAL AGGREGATION PROGRAMS

Municipal aggregation would have the option to implement in a range of programs to expand renewable energy use and enhance economic development in the County. Increased renewable energy use can be accomplished by supporting customers wishing to install small renewable generation facilities (net energy metering), purchasing from small local for-profit renewable generators (feed-in tariffs), purchasing renewable resources directly and supporting electric vehicle use. The County can identify other program goals in the areas of building energy efficiency and electrification, energy efficient construction, clean energy transportation enhancement and energy storage. Municipal aggregation is a viable mechanism for developing and implementing these types of programs using funding from a variety of sources, including municipal aggregation net operating revenues.

[11] 2018 Dominion information.

[12] United States Environmental Protection Agency. https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle#:~:text=typical%20passenger%20vehicle%3F-,A%20typical%20passenger%20vehicle%20emits%20about%204.6%20metric%20tons%20of,8%2C887%20grams%20of%20CO2.

Each of these programs also yields economic development benefits by stimulating spending locally and reducing costs for local customers. Economic development can also be accomplished by providing additional support for low-income customers or extra support for new or growing businesses. The following sections discuss these programs in further detail.

7.3 ECONOMIC DEVELOPMENT RATE INCENTIVE

There are several programs that municipal aggregation can offer to stimulate local economic development in their service area. One is a special economic development rate to encourage job providers to locate within the municipal aggregation's jurisdiction.

Another type of program that promotes economic development is one that provides incentives for businesses to locate in the service area, remain there or expand. For instance, municipal aggregation could offer rebate programs or fund infrastructure costs for a business to target the business sectors of interest to its service area. For example, if a large industrial customer would like to locate within the municipal aggregation service area, increased sales may result in decreased costs to all other customers due to overhead cost sharing.

7.4 NET ENERGY METERING (NEM) PROGRAM

Municipal aggregation could establish a net energy metering (NEM) program for qualified customers in their service territory to encourage wider use of distributed energy resources (DER) such as rooftop solar, energy storage, demand-side management, energy efficiency, demand response and electric vehicle charging.

Dominion currently offers a NEM program for solar generation in which customers receive credit for excess generation and must sign over the green attributes of the project to Dominion. This program closed on August, 2018.

NEM programs typically true up net excess generation annually. This allows customers to balance credits earned in summer months (when solar energy generation is highest) with charges accrued in the winter (when solar generation is lower). Additionally, municipal aggregators often choose to offer NEM programs that provide credit for excess generation that is larger than the credit offered by the incumbent IOU. This has the benefit of increasing the supply of renewable resources available to municipal aggregation as well as encouraging high participation rates among current and potential NEM customers. County municipal aggregation would have the option to implement a NEM program and the ability to stimulate local economic development in the form of new DER system investments and associated business activity.

7.5 FEED-IN TARIFFS

Feed-in tariffs (FIT) offer terms by which electric service providers such as IOUs and municipal aggregation purchase power from small-scale renewable electricity projects within their service territory. In contrast with NEM programs, which typically target owners of homes and small businesses who wish to install a rooftop photovoltaic (PV) system, FIT programs target owners of larger generation projects, in the range of 0.5-3 MW. These could be larger rooftop photovoltaic (PV) systems located at industrial sites or ground-mounted solar shade structures in parking lots. In developing a FIT program of its own, County municipal aggregation could incentivize customers in their service area to develop local renewable resources.

7.6 LOCAL GENERATION RESOURCES DEVELOPMENT

A final option to drive investment in local renewable generation resources within the municipal aggregation service area is for the municipal aggregator itself to build or acquire generation resources. This model of municipal aggregation-owned resources provides municipal aggregation with a guaranteed renewable power source as well as local economic stimulus. This Study assumes local solar is included in each of the portfolio options.

7.7 LOW INCOME PROGRAMS

Dominion offers some low-income assistance to customers in the way of billing options such as payment plans or budget billing. Dominion also forgave arrears accumulated during the first part of the COVID-19 pandemic.

The municipal aggregation could offer additional rate discounts, bill assistance or energy efficiency programs targeted at hard-to-reach customers. Municipal aggregations in other parts of the country have offered low-income electric vehicle programs, zero cost energy efficiency upgrades and other programs to improve energy efficiency within their service territories.

7.8 ECONOMIC IMPACTS IN THE COMMUNITY

The analyses contained in this Study for the formation of County municipal aggregation have focused only on the direct economic effects of this formation. However, in addition to direct effects, indirect macroeconomic effects are also expected.

The indirect effects of creating municipal aggregation include the effects of increased commerce and disposable income. Within this Study, an input-output (IO) analysis is undertaken to analyze these indirect effects. The IO model estimated the impact on the economy of municipal aggregation that would lead to lower energy rates for municipal aggregation customers. Three types of indirect impacts are analyzed in the IO model. These are described below.

Local Investment – The municipal aggregation may choose to implement programs to incentivize investments in local distributed energy resources (DER). The municipal aggregation may choose to invest in local DER generation projects in the form of behind the meter or community projects where several customers participate in a centrally located project (e.g., "community solar"). Demand for local renewable resources resulting from these projects would lead to an increase in the manufacturing and installation of DER, along with an increase in employment in the related manufacturing and construction sectors.

Increased Disposable Income – Establishing a municipal aggregation could lead to reduced customer rates for energy, more disposable income for individuals and greater revenues for businesses. These cost savings would then lead to more investment by individuals and businesses for personal or business purposes. Increases in spending would in turn lead to increased employment for multiple sectors such as retail, construction, and manufacturing.

Environmental and Health Impacts – With the creation of municipal aggregation, other indirect effects would occur. These may be environmental, such as improved air quality or improved human health due to the municipal aggregation utilizing more renewable energy sources, versus continuing use of traditional energy sources. While a change in GHG emissions is not modeled directly in economic development models used in this Study, reductions in these emissions are captured in indirect effects projected by the model to the extent that carbon prices are accounted for in the IO matrix.[13]

Input-Output Modeling (IO Modeling) – County-wide electric rate savings and growth in manufacturing jobs and other energy intensive industries are expected to spur economic development impacts. Table 7-2 shows the effect of $35 million in rate savings could have on the County economy as estimated in the County IMPLAN model.[14] The

[13] Decreased health care costs have been modeled to make a major contribution to the local economy. e.g., DT Shindell, Y. Lee & G. Faluvegi, Climate and health impacts of US emissions reductions consistent with 2 °C; *Nature Climate Change* **volume 6**, pages 503–507 (2016)

[14] http://www.implan.com/

$35 million rate savings represents the minimum annual bill savings projected to occur once municipal aggregation has achieved full operation if all of the load is included (DOMINION-Equivalent Renewable portfolio or 90% Renewable by 2030). These rate savings will increase to $200M - $300M per year in the later years of the Study period and economic impacts will increase proportionately. The IMPLAN model is an IO model that estimates impacts to an economy due to a change to various inputs such as industry income, supply costs or changes to labor and household income. Both positive and negative impacts can be measured using IO modeling. IO modeling produces results broken down into several categories. Each of these is described below:

- Direct Effects – Increased purchases of inputs used to produce final goods and services purchased by residents. Direct effects are the input values in an IO model, or first round effects.
- Indirect Effects – Value of inputs used by firms affected by direct effects (inputs). Economic activity that supports direct effects.
- Induced Effects – Results of Direct and Indirect effects (calculated using multipliers). Represents economic activity from household spending.
- Total Effects – Sum of Direct, Indirect and Induced effects.
- Total Output – Value of all goods and services produced by industries.
- Value Added – Total Output less value of inputs or the Net Benefit/Impact to an economy.
- Employment – Number of additional/reduced full time employment resulting from direct effects.

This Study uses value added and employment figures to represent the total additional economic impact of the generation rate savings associated with municipal aggregation.

The projected generation rate savings are modeled for residential, commercial, industrial and agricultural sectors. For residential, the rate savings are modeled at different household income levels to estimate the impact on the economy from reduced bills. Estimated household income distribution is based on the income percentiles from the County-wide statistical atlas. The change in household income assumes that all households are impacted proportionately; however, in practice lower income households typically see the most significant benefit due to the disproportionate amount of total household income that goes to costs associated with household electricity use. Generally, lower income families are not able to reduce their utility bills as easily through efficiency upgrades or modified behavior due to lack of disposable income. Therefore, the Study's overall impacts of rate savings are likely underestimated.

Table 7-2 details the macroeconomic impacts anticipated from the generation rate savings after forming municipal aggregation. The total increase in local economic activity with County municipal aggregation for one year is valued at $50.3 million. In addition, the rate savings are estimated to produce an additional 421 full time jobs. Again, this macroeconomic analysis is predicated on rate savings of only $35M per year. Actual rate savings may be many times this amount and macroeconomic benefits will increase proportionately.

TABLE 7-2. POTENTIAL ECONOMIC IMPACTS FROM RATE SAVINGS, MILLIONS[1]

Impact Type	Employment, Jobs	Labor Income	Total Value Added	Output
Direct Effect	194	$9.5	$9.7	$17.8
Indirect Effect	37	$2.5	$4.0	$6.7
Induced Effect	179	$8.8	$16.0	$25.8
Total Effect	**421**	**$20.7**	**$29.7**	**$50.3**

1. Based on $35 million in rate savings per year. The full impact to the County is estimated, though, it can be expected that a large share of these impacts would be realized across the entire County municipal aggregation service territory.

These savings are based on the economic construct that households would spend some share of the increased disposable income on more goods and services. This increased spending on goods and services would then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. Increases in wages or additional hires would in turn give new or existing employees a larger disposable income, which they would then presumably spend on goods and services, thus repeating the cycle of increased demand. In addition, reduced inputs to production for non-residential electric customers would allow companies to invest in other areas to promote growth such as hiring new employees, offering additional training and purchasing upgraded equipment.

8 Sensitivity and Risk Analysis

The economic analysis provides a Base Case scenario for pursuing municipal aggregation. The Base Case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Study will provide considerations for the range of impacts that could result from changes in the most significant variables for the portfolios described in the Power Supply Strategy and Cost of Service sections of this Study. In addition, this section will address uncertainties that should be addressed and mitigated to the maximum extent possible.

8.1 MUNICIPAL AGGREGATION RISK ANALYSIS

The following analysis is an overview of risks and their relative severity, followed by a discussion of each factor. For variables where uncertainty is quantified, key assumptions are discussed, and a reasonable range of outcomes is established. The range in variable assumptions is meant to reflect probable futures, but do not demonstrate the full scope of possible outcomes. The municipal aggregation's generation rate impacts are estimated using a range of likely outcomes and presented in a scenario analysis. Figure 8-1 illustrates this breakdown of municipal aggregation costs. Table 8-1 provides detail of each risk factor.

FIGURE 8-1. GENERATION RATE COMPARISON BASE RENEWABLE PORTFOLIO

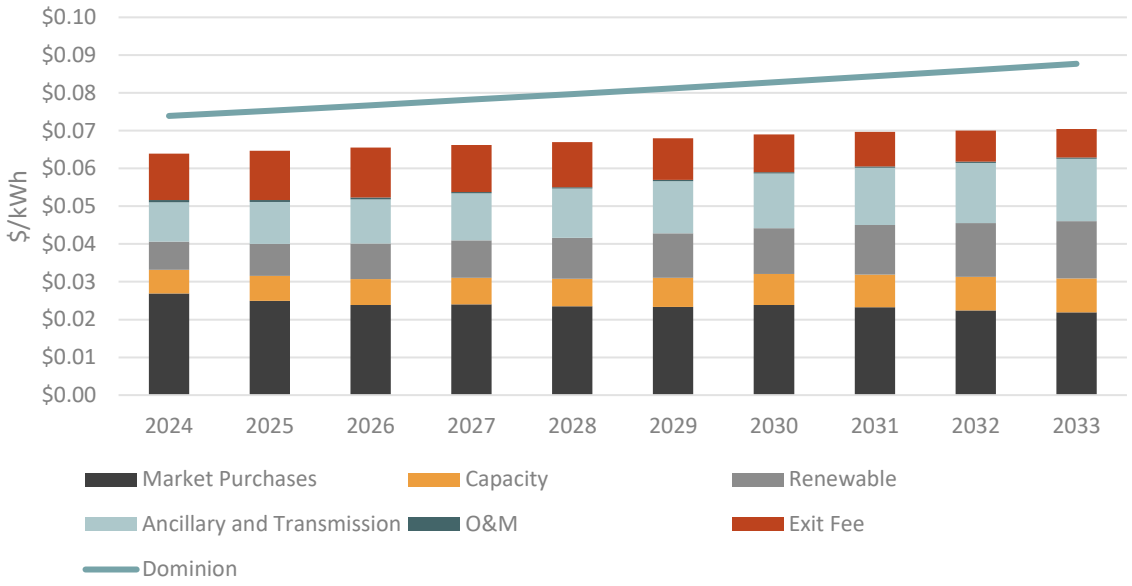


TABLE 8-1. UNCERTAINTY AND MITIGATION STRATEGIES

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "Suspend" municipal aggregation
1	Dominion Rates and Surcharges	Dominion's energy supply rates decrease, or its exit fee charges increase	• Municipal aggregation rates exceed Dominion • Increased customer opt-out rate	• Establish Rate Stabilization Fund • Invest in a balanced energy supply portfolio to remain agile in power market • Emphasize the value of programs, local control, and environmental impact in marketing	High – Most operating municipal aggregations have undergone short periods of rate competition from the incumbent IOU.	Medium - Municipal aggregations have been able to buffer rate impacts using financial reserves, then adjust power supply to regain rate advantage.	Medium – Municipal aggregations may need to rely on reserves to manage short-term fluctuations.
2	Regulatory Risks	Energy policy is enacted that compromises municipal aggregation competitiveness or independence	• New costs incurred • Reduced authority	• Coordination with municipal aggregation community on regulatory involvement • Hire lobbyists and regulatory representatives to advocate for municipal aggregation	Low – Existing regulatory precedent and a growing market share makes the likelihood of state policies that severely disadvantage municipal aggregations low.	High – A worst-case scenario regulatory legislative decision limiting municipal aggregation autonomy or enforcing additional costs could hinder municipal aggregation viability.	Medium – Energy policy severe enough to make municipal aggregation infeasible is not likely.
3	Power Supply Costs	Power prices increase at crucial time for municipal aggregation	• Municipal aggregation rates exceed Dominion rates • Increased customer opt-out rate	• Long-term contracts • Hedge 100% of energy supply • Draw on municipal aggregation reserves to stabilize rates through price spike	Low – Market prices are unlikely to spike enough to make municipal aggregation financially infeasible prior to municipal aggregation launch. From that point on, the municipal aggregation can limit its exposure through contract selection.	Medium –A poorly timed price spike combined with poor power supply contract management could require municipal aggregation to dig into reserves or delay launch.	Low – Municipal aggregation and IOU face the same market for power.
4	Dominion RPS Share	Dominion's RPS or GHG-free power portfolio grows to match or exceed	Increased customer opt-out rate	• Increase renewable power portfolio • Emphasize rates and local programs in marketing	Medium – Dominion's power portfolio is dynamic and could change rapidly if	Low – Municipal aggregation would have capability to increase renewable energy	Very Low – Municipal aggregation is likely to

	Risk	Description	Problem	Mitigation Strategy	Likelihood of Problem	Severity of Problem	Potential to "Suspend" municipal aggregation
		municipal aggregation's			municipal aggregation were to dramatically expand in Virginia	purchases to match or exceed Dominion. In addition, municipal aggregation would promote other benefits of its service to customers.	respond effectively if this occurs.
5	Availability of RPS/GHG- free power	Unexpectedly high market demand or loss of supply of renewable resources	• municipal aggregation unable to provide target power products	• Shift emphasis to GHG-free or RPS resources depending on availability • Secure long-term contracts • Invest in local renewable resources	Low – power procurement providers are projecting a plethora of RPS and GHG-free bids available on the market.	Medium – If municipal aggregation were unexpectedly unable to procure enough RPS or GHG-free power, it could emphasize other program strengths to retain customers until new resources came online.	Low – negligible chance of occurring.
6	Financial Risks	Municipal aggregation is unable to acquire desired financing or credit	• Slower or delayed program launch • Unable to build generation projects	• Adopt gradual program roll-out • Establish Rate Stabilization Fund • Minimize overhead costs	Low – The municipal aggregation business model has become established in other parts of the Country and, as a result, the number of potential banking partners has increased.	Medium – In the event municipal aggregation is limited in financing options, it can adopt a more conservative program design and gradual roll-out.	Low
7	Loads and customer participation	Unprecedented opt-out rate reduces competitiveness Net Zero homes	• Excess power contracts • Poor margins	• Increase marketing • Reduce overhead • Expand to new customer markets • Consider merging with existing municipal aggregation • Consistent municipal aggregation rate review	Low – Opt-out programs in other states have experienced participation rates upwards of 90%	Low – Municipal aggregation would have numerous viable options in the event they suffer unexpectedly low participation.	Low

The various sensitivities are discussed below followed by the results of the sensitivity analysis.

8.2 DOMINION RATES AND SURCHARGES

Sensitivity analyses were conducted for two components of Dominion operations: generation rate and the exit fees. Delivery rates are paid by both the municipal aggregation and Dominion bundled customers. As such, changes in delivery rates impact all customers equally and are not considered in this sensitivity analysis.

8.2.1 Generation Rate

Dominion generation rates are projected to increase on average by 2% per year over the next 10 years based on the projected market prices, Dominion's current resource mix and future requirements. To explore the impact that Dominion's generation rates change significantly relative to the municipal aggregator's cost of power, Dominion's generation rates and power costs are modeled in the high and low case by incorporating higher (3%) and lower (-1%) generation rate growth rates.

8.2.2 Exit Fees (Stranded Costs)

The level of the exit fee, if applicable, impacts the cost competitiveness of County municipal aggregation. In order to be competitive, the municipal aggregator's generation costs plus exit fee and other surcharges must be at or lower than Dominion's generation rates. Many factors influence the exit fee, but primarily the exit fee is determined by the cost of power contracts and the cost to Dominion from departing load. Uncertainties surrounding the exit fee include methodology assumptions unique to Dominion, as well as to what degree previously acquired power contracts can be retired. The potential for the exit fee to increase sharply occurs when Dominion must sell previously contracted power at times when wholesale power prices are much lower. The exit fee also has potential to decrease since it reflects Dominion's own resources and signed contracts obtained prior to load departure. Once these contracts expire, the related exit fee would disappear. The exit fee would therefore vary over time, but it is expected that it would decline as market prices increase and grandfathered contracts expire. Because no clear precedence exists for Dominion exit fee calculations, exit fees are a critical variable of potential sensitivity, and any developments regarding the exit fee calculation or their legality must be considered closely as it relates municipal aggregation's financial feasibility.

8.3 REGULATORY UNCERTAINTIES

There are numerous factors that could impact Dominion's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements, inflation and gas prices could all impact Dominion's rates in the future. Additional regulatory issues may arise that may impact the competitiveness of County municipal aggregation, but these issues are difficult to assess and model quantitatively.

8.4 FINANCIAL RISKS

Starting a new venture carries financial risks that will have to be considered and mitigated before proceeding with municipal aggregation. Depending on the organizational structure, a third-party may take on the financial obligations of municipal aggregation. These include establishing start-up financing, working capital funding such as lines of credit and entering into contracts with suppliers and consultants. Other cities and counties have protected their General Funds by establishing special districts or "lockbox" arrangements with vendors.

County municipal aggregation could manage many of the financial risks associated with the uncertainty surrounding a municipal aggregation start-up. While the goal is to provide clean power competitively with Dominion, the most important consideration to the third-party financier is that the municipal aggregator can increase rates if needed to ensure sufficient revenues are collected to meet costs. In addition, the municipal aggregation can plan carefully by minimizing staff initially and only growing as fast as the size of municipal aggregation can support. This approach minimizes the fixed costs of operating municipal aggregation.

County municipal aggregation would need to manage the financial risk associated with generation costs by managing power market and load exposure through prudent hedging and power portfolio management. In addition, the establishment of rate stabilization reserves and sufficient working capital can mitigate financial risks to the third-party financier and to customers. The success of existing municipal aggregators in managing the financial challenges of a start-up and setting rates that are competitive with Dominion and the other IOUs can be a valuable guide for County municipal aggregation staff and policymakers.

8.5 LOADS AND CUSTOMER PARTICIPATION RATES

The Study bases the load forecasts on expected load growth, load profiles, and participation rates. In order to evaluate the potential impact of varying loads, low, medium, and high load forecasts have been developed for the sensitivity analysis.

Another assumption that can impact the costs of municipal aggregation is the overall municipal aggregation customer participation rates. This Study uses a conservative participation rate of 90% as its base case. A higher participation rate has been experienced by many operating municipal aggregations. On the other hand, a reduced participation rate would increase the fixed costs per customer for County municipal aggregation.

Sensitivity to changes in projected loads has been tested for the high and low load forecast scenarios. For the sensitivity analysis, the high case assumes an additional 5% participation rate, while the low case assumes the participation rate is reduced by 10% for all customers.

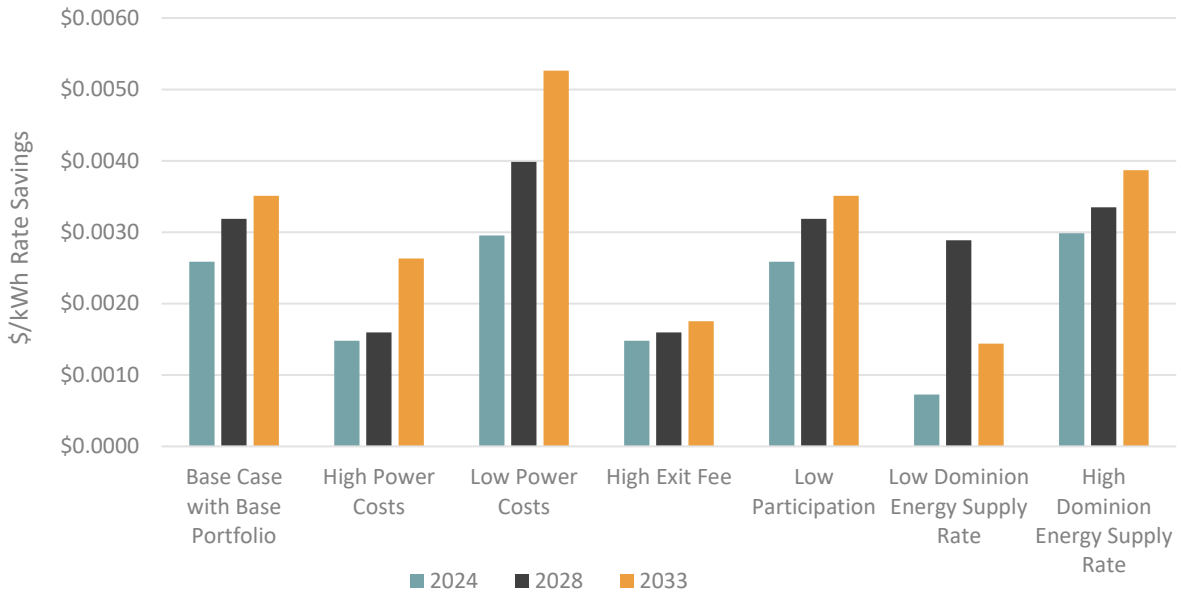
8.6 SENSITIVITY RESULTS

Figure 8-2 provides the results of the sensitivity analysis for the Base Case Portfolio. The scenarios assume the following:

- High Generation Costs: 15% increase in total power supply costs
- Low Generation Costs: 10% lower than forecast
- High Exit Fee: 50% higher than base case
- Low Participation: Program Participation is 80% (vs. 90%)
- Low Dominion Generation Rate: -1% annual change in 2022 and 0% after
- High Dominion Generation Rate: 3% annual change from 2022

Figure 8-2 illustrates that the viability of a generation rate discount is most sensitive to the exit fee and Dominion generation rates.

FIGURE 8-2. BASE CASE PORTFOLIO SENSITIVITY



While municipal aggregation would not be able to impact Dominion's generation rates, municipal aggregation does have the opportunity to monitor and actively opine on the costs and methodology used to allocate generation cost stranding to municipal aggregation customers.

This Study assumes a relatively high customer opt-out percentage (10% for non-residential customers) compared to the lower opt-out rates experienced by actively operating municipal aggregations, which is closer to 2-5% overall. While there is a possibility that County municipal aggregation does not reach the projected participation rates, careful monitoring and planning can reduce the potential impact of low loads through flexible generation contracts, and regular monitoring of administrative and general expenses.

Municipal aggregation should also implement a rate stabilization fund so that short-term events that result in lower Dominion rates, or higher exit fees, can be mitigated with reserves rather than by rate changes. Reserves would help municipal aggregation remain competitive and provide rate stabilization for customers.

9 Municipal Aggregation Governance Options

This section of the Study discusses the two governance options that may be available to the County – enterprise option and service district option. Rate impacts, timing of launch, staffing organization and local control aspects of these options are explored. Each municipal aggregation governance option is discussed below.

9.1 ENTERPRISE MUNICIPAL AGGREGATION

With this governance option, the County forms a municipal aggregation entity that functions as a department within the County's government structure subject to the direct control of the Board of Supervisors.

- *Financial Viability*: Based on the analysis in this Study, a County-only municipal aggregation is financially feasible.
- *Governance*: Municipal aggregation operates as a County department and is governed by the County Board of Supervisors.
- *Local Control*: Decision-making is totally focused on the needs of the County's constituents.
- *Other Attributes*: Operating an Enterprise municipal aggregation will require specific measures to protect County General Funds from municipal aggregation obligations.

9.2 COUNTY SERVICE DISTRICT MUNICIPAL AGGREGATION

Under the County service district municipal aggregation option, the County would establish a municipal aggregation entity that includes one or more other jurisdictions such as other towns, cities or other counties. This option implies shared decision-making rights in accordance with a specified voting structure. Additionally, under a service district municipal aggregation model, administrative and consultant costs are pooled and covered by the collective service district municipal aggregation revenues.

- *Financial Viability*: This option would likely improve the financial feasibility as the customer base is larger providing more opportunity for shared costs.
- *Governance*: The County and other members would establish the governing board. Having a limited number of board members helps to enable flexible governance and maintain focus on local control.
- *Local Control*: The County would share decision making with other members.
- *Other Attributes*: Potential partners should share the County's intentions for municipal aggregation goals, local programs and operations design. Operational savings on non-generation costs (administration, legal, regulatory, and other services) would likely occur due to economies of scale. A service district agreement provides express financial protection of each member's General Funds from municipal aggregation contractual obligations.

9.3 SUMMARY OBSERVATIONS ON GOVERNANCE OPTIONS

If the County moves toward municipal aggregation adoption, it should further investigate each of these governance options. It is recommended that the County further discuss the options and consider the respective pros and cons. The County should develop a more detailed assessment of adding member organizations or developing a County-only municipal aggregation.

9.4 MUNICIPAL AGGREGATION OPERATIONAL OPTIONS

If the County operates as a service district with other members, there are several staffing options available. One option would be to operate the municipal aggregation entity with minimal staff, such as a Chief Administrative Officer, Director of Power Management, Director of Customer Service and Director of Finance to oversee consultants that would perform all necessary technical tasks. Another option is to minimize the use of outside consultants and hire sufficient staff in-house to manage all necessary tasks. Most operating municipal aggregators have started with minimal staffing and then transitioned over time to additional staff in-house. A third option is to have an independent third party completely operate municipal aggregation through a "turnkey" option.

For this Study, it is assumed that the County would operate municipal aggregation with limited staff supported by consultants. If the County decides to transition some administrative and operational responsibilities to internally staffed positions, municipal aggregation could reach a full-time staff of approximately four employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing, and customer service. Technical functions associated with managing and scheduling power suppliers and those related to retail customer billing would likely still be performed by an experienced third-party consultant.

10 Major Legal and Regulatory Issues

While there is a basic municipal aggregation framework in place in the Commonwealth, there are legal and regulatory issues that will need to be considered and resolved. The following is a summary of the Study's findings on legal and regulatory issues and the issues that remain outstanding.

Municipal Aggregation Eligibility. Virginia Code § 56-589 allows counties, cities, towns, and other political subdivisions of the Commonwealth including special districts, upon a majority vote of their governing bodies, to aggregate electrical energy and demand requirements. Aggregation can include residential, commercial, industrial and/or municipal customers. The statute appears to allow municipal aggregation on a non-contiguous basis without a city having to be a neighbor of or contiguous with another city.

Customer Opt-In vs. Opt-Out. Virginia Code § 56-589 expressly allows a municipal aggregator to enroll customers on either an opt-in or opt-out basis. In other words, the municipal aggregator can automatically enroll customers into the program (opt-out), or it can implement a program whereby customers have to expressly join (opt-in). The Study assumes an opt-out scenario will be implemented.

State Corporation Commission Approval. Virginia Code § 56-588 requires an aggregator of electrical energy, normally a company, to obtain a license from the State Corporation Commission ("SCC"). Municipal aggregators that seek to aggregate only their municipal load are exempt from licensing requirements, while those municipalities seeking to aggregate residential, commercial, and industrial load are not exempt. SCC staff has informally indicated to the drafters of the Study that a license is not required for municipal aggregation; however, the City of Fairfax did obtain one in 2006. Therefore, it is recommended that SCC staff clarify this issue.

It does not appear that the SCC further regulates municipal aggregators regarding their rates, terms of service, or other planning efforts.

Tax Obligations. Virginia Code §§ 58.1-2900 and 58.1-2901 impose a consumption tax that is required to be billed, collected, and passed through by any "provider of billing services." Therefore, the municipal aggregator, or its contracted-for billing provider, will be obligated to collect the tax. Municipal usage would be exempt. It is suggested that the County request Dominion to collect all of this tax and remit to the Commonwealth.

Stranded Costs. In some statewide aggregation regulatory schemes, the customer of the municipal aggregator pays a monthly charge for the costs remaining to the incumbent utility for power purchased or generation constructed on that customer's behalf. Such charges or "exit fees" are established to protect the remaining incumbent customers from paying for the costs of the departing load. Neither Commonwealth law nor SCC regulations appear to provide for the recovery of stranded costs due to municipal aggregation. The SCC, however, has denied companies like Costco and Wal-Mart from commercially aggregating on the basis that stranded costs would be too high for the remaining customers and against the public interest, but it has not formulated a methodology to calculate them. This Study assumes for the payment of stranded costs or "exit fees" and recommends that more clarification is needed.

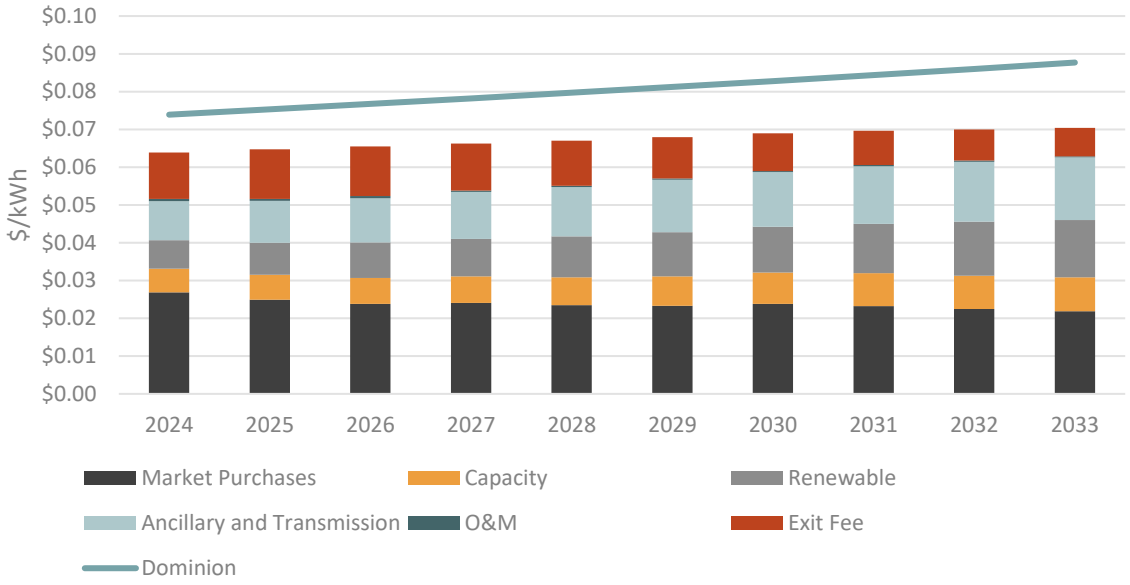
Renewable Portfolio Standard (RPS). The Virginia Clean Economy Act of 2020 established mandatory RPS program requirements for Dominion and APCO where the utilities must meet annual goals for the sale of renewable energy to retail customers. Beginning in 2024, the utilities must procure 23% of power from renewable sources with a sliding scale through 2033 of 52%. The Act does not yet apply to municipal aggregation, but the Study suggests that the County decide on the baseline amount of renewables it desires to offer to itself or its customers. The Study's Base Case assumes 23% renewable in 2024 and 50% in 2033.

11 Summary and Conclusions

The first impact associated with forming a County municipal aggregation entity would be lower electricity bills for County customers. Municipal aggregation customers should see no changes in electric service other than the lower price and more renewable power procurement. Customers would pay the generation charges set by the municipal aggregator and no longer pay the costs of Dominion generation but would still pay the costs of Dominion distribution services or wires rates.

Given this Study's findings, municipal aggregation can establish a goal of providing rates that are lower than the equivalent rates offered by Dominion even under all four portfolio options. The projected Base Case municipal aggregation and Dominion generation rates are illustrated in Figure 11-1.

FIGURE 11-1. RATE COMPARISON – BASE CASE



The Base Case assumes that municipal aggregation rates initially are 4% less than comparable Dominion generation rates. Even with this initial generation rate discount, the Base Case model produces another $150M in surplus funds which can be used for additional rate discounts, new customer programs and/or development of new renewable energy projects. If all of the surplus funds are dedicated to rate discounts, the municipal aggregation generation rate would be 15% less than the comparable Dominion generation rate. This reduced generation rate translates into a 10% reduction in the municipal aggregation customers total electricity bill.

11.1 LOCAL CONTROL

A second outcome of pursuing a municipal aggregation is that municipal aggregation can enjoy local control over rates, generation mix and its customer programs. Nationally, municipal aggregators have become innovators in the energy supply space. Their relatively smaller size compared with IOUs and progressive goals have led to significant investment in local resources and innovative technologies, all resulting in local control and economic development.

11.2 CUSTOMER PROGRAMS

A third outcome of forming a municipal aggregation entity would be an increase in customer energy efficiency program investments and activities. The existing energy efficiency programs administered by Dominion are not expected to change as a result of forming a municipal aggregation. The municipal aggregation customers would continue to pay Dominion distribution (wires) rates, which fund energy efficiency programs for all customers, regardless of generation supplier. The customer energy efficiency programs ultimately planned for municipal aggregation would be in addition to the level of investment that would continue in the absence of a municipal aggregation. Thus, the municipal aggregation has the potential to increase energy investment and savings while further reducing emissions through expanded energy efficiency and renewable resource programs.

11.3 FINDINGS AND CONCLUSIONS

Based on the analysis conducted in this Study and the assumptions used herein, the following findings and conclusions are made:

- The pursuit of a municipal aggregation is financially feasible and could yield benefits for all participating residents and businesses.
- Financial benefits include generation rates that could be 15% lower compared with Dominion generation rates, or a total bill reduction of 10% if all financial surpluses are used to reduce rates.
- Benefits are also achieved through local decision-making on power supply, rates and customer programs. Specific programs could include economic development incentives, and targeted energy efficiency and demand response programs. Municipal aggregation start-up costs could be fully recovered within the first three years of municipal aggregation operations.
- After this cost recovery, revenues that exceed costs could be used to finance a rate stabilization fund, new local renewable resources, economic development projects, and/or further reduced rates.
- The sensitivity analysis shows that the ranges of prices for different market conditions will, in the majority of cases, not negatively impact municipal aggregation generation rates compared to Dominion generation rates. Where negative impacts may exist, risks can be mitigated.
- Municipal aggregation could be a means to achieve local control of energy supply and to help the municipal aggregation member jurisdictions achieve GHG reduction goals.
- There are risks associated with County municipal aggregation. If formed, this will be a new and competitive effort for the County. New skill sets and strong policy guidance will be needed for a County municipal aggregation to succeed.

11.4 SUMMARY

This Study concludes that the pursuit of County municipal aggregation is financially feasible and could yield benefits in excess of costs for all participating residents and businesses. The base metrics for a County municipal aggregation entity are summarized in Table 11-1 below.

TABLE 11-1. KEY MUNICIPAL AGGREGATION STATISTICS

Power Supply Portfolio Scenario:	2024 Loudoun County Municipal Aggregation Base Case Renewable Portfolio	2033 Loudoun County Municipal Aggregation Base Case Renewable Portfolio
Operating Expenses (Cash Basis), $ million	$647	$1,324
Revenues (Cash Basis), $ million	$676	$1,603
Load Served, GWh	13,400	23,000
Working Capital, $ million	$80M	--
Startup Loan Repayment, years	5	--
Initial Generation Rate Discount, %	4.0%	4.0%
Start-Up Capital Requirements	$3.7M	--
Total Bill Discount if All Funds Go to Rate Discounts	4%	10%

11.5 NEXT STEPS

Table 11-2 provides a high-level timeline of next steps. This schedule could apply to any new municipal aggregation (enterprise or service district structure).

TABLE 11-2. NEXT STEPS OVERVIEW

Answer Regulatory Questions	2022: Approach SCC to Resolve Relevant Issues
Select Governance	2022: Form Enterprise Fund or Service District with Other Members
File Application	2022: File Application with SCC
Hire Staff	2023: Hire Potential Staff to Begin Pre-Start-Up Operations • Chief Administrative Officer • Director of Power Supply • Director of Customer Service • Director of Finance
Secure Financing	2023: Have Financing in Place to Facilitate Contracting for Power and Services
Contract for Power and Data Management Services	2023: Build and Contract Team of Consultants • Data Management and Customer Call Services • Scheduling Coordinator • Portfolio Manager • Technical Consultants (Financial and Other) • Rate Setting and Regulatory • Risk Management and Other Policies • Power Supply Contracts for Deliveries Beginning in 2024
Commence Commercial Operations	2024: Begin Serving Customers

There are many governance, regulatory and technical tasks that need to be resolved before a municipal aggregation business model can become functional. A summary of these tasks follow:

- Governance Tasks
  - Pick a governance structure such as the enterprise or service district models.
  - Determine which local governmental units should participate such as County only, County and towns within the County or seek local governments outside of County.
  - Develop a strawman governance document.
- Regulatory Tasks
  - The SCC should be contacted to appraise them of the County's desires and intentions, and to solicit staff feedback on the merits of the County pursuing the municipal aggregation business model.
  - The SCC staff should also be asked about the regulatory status of exit fees in the Commonwealth and any technical input on this Study's input assumptions. Also discuss the opt-in/opt-out assumptions.
  - Determine what customer notice requirements will be needed.
- Technical Tasks
  - Confirm that Dominion will continue to read all meters, prepare all bills, and collect revenues then rebate the market aggregator's portion to the market aggregator.
  - Develop a timeline for key activities in forming a municipal aggregation business model that includes the tasks noted above as well as staffing requirements.

The aforementioned tasks can be used by the County as a scope of work for further municipal aggregation working activities.

12 Appendix A – Glossary

Ancillary Services: Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.

Baseload Resources: Base load power generation resources are resources such as coal, nuclear, hydropower, and geothermal heat that are cheapest to operate when they generate approximately the same output every hour.

Basis Difference (Natural Gas): The difference between the price of natural gas at the Henry Hub natural gas distribution point in Erath, Louisiana, which serves as a central pricing point for natural gas futures, and the natural gas price at another hub location (such as for Virginia).o

Bundled Customers: Electricity customers who receive all their services (transmission, distribution and supply) from the Investor-Owned Utility.

Bundled and Unbundled RECs: Unbundled Renewable Energy Credits (RECs) are those that have been disassociated from the electricity production originally represented and are sold separately from energy. Bundled RECs are delivered with the associated energy.

Capacity Factor: The ratio of an electricity generating resource's actual output over a period of time to its potential output if it were possible to operate at full nameplate capacity continuously over the same period. Intermittent renewable resources, like wind and solar, typically have lower capacity factors than traditional fossil fuel plants because the wind and sun do not blow or shine consistently.

Climate Zone: A geographic area with distinct climate patterns necessitating varied energy demands for heating and cooling.

Coincident Peak: Demand for electricity among a group of customers that coincides with peak total demand on the system.

Community Choice Aggregation (CCA): Method available through Virginia law to allow cities and Counties to aggregate their residents and become their electric generation provider.

Community Choice Energy: A City, County, or Joint Powers Agency procuring wholesale power to supply to retail customers.

Congestion Charges: When there is transmission congestion, i.e. more users of the transmission path than capacity, PJM charges all users of the congested transmission path a "Usage Charge".

CO_2e: Carbon dioxide equivalent.

Demand Side Resources: Energy efficiency and load management programs that reduce the amount of energy that would otherwise be consumed by a customer of an electric utility.

Demand Response (DR): Electric customers who have a contract to modify their electricity usage in response to requests from a utility or other electric entity. Typically, will be used to lower demand during peak energy periods, but may be used to raise demand during periods of excess supply.

Departing Load: Electric customer loads that were previously served by an investor-owned utility but are now served through direct access, municipalization, or municipal aggregation.

Dominion Hub: Represents the electric market location where Loudoun County market energy purchases are expected to be delivered

Direct Access: Large power consumers which have opted to procure their wholesale supply independently of the IOUs through an Electricity Service Provider.

EEI (Edison Electric Institute) Agreement: A commonly used enabling agreement for transacting in wholesale power markets.

Electric Service Providers (ESP): An alternative to traditional utilities. They provide electric services to retail customers in electricity markets that have opened their retail electricity markets to competition.

Electric Tariffs: The rates and terms applied to customers by electric utilities. Typically have different tariffs for different classes of customers and possibly for different supply mixes.

Enterprise Model: When a City or County establishes a municipal aggregation by themselves as an enterprise within the local government entity.

Federal Tax Incentives: There are two Federal tax incentive programs. The Investment Tax Credit (ITC) provides payments to solar generators. The Production Tax Credit (PTC) provides payments to wind generators.

Feed-in Tariff (FIT): A tariff that specifies what generators who are connected to the distribution system are paid.

Firming: Firm capacity is the amount of energy available for production or transmission that can be (and in many cases must be) guaranteed to be available at a given time. Firm energy refers to the actual energy guaranteed to be available. Firming refers to the financial instrument to change non-firm power to firm power.

Forward Prices: Prices for contracts that specify a future delivery date for a commodity or other security. There are active, liquid forward markets for electricity to be delivered at a number of electricity trading hubs, including PJM Western Hub, which corresponds closely to the price location that the County will pay to supply its load.

FTE: Full Time Equivalent.

Greenhouse Gas (GHG): Refers mainly to carbon dioxide.

GWh: Gigawatt Hour, 1,000 MWh.

Henry Hub: Located in Erath, Louisiana, Henry Hub is a nexus of several natural gas interconnections and provides ready access to pipelines serving markets across the United States. Henry Hub is typically used as a central location that local markets across the United States use to base the price of their natural gas

IMPLAN: IMPLAN Group LLC's Input-Output Model.

Implied Heat Rate: A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

Integrated Resource Plan: A utility's plan for future generation supply needs.

Investor-Owned Utility (IOU): For profit regulated utilities. For example, IOUs within Virginia are American Electric Power and Virginia Electric Power Company (Dominion).

ISDA (International Swaps and Derivatives Association): Popular form of bilateral contract to facilitate wholesale electricity trading.

Joint Powers Agency (JPA): A legal entity comprising two or more public entities. The JPA provides a separation of financial and legal responsibility from its member entities.

kW: Kilowatt, equal to 1,000 watts, is measure of electric demand.

kWh: Kilowatt Hour.

Load Forecast: A forecast of expected load over some future time horizon. Short-term load forecasts are used to determine what supply sources are needed. Longer-term load forecasts are used for budgeting and long-term resource planning.

Marginal Unit: An additional unit of power generation to what is currently being produced. At an electric power plant, the cost to produce a marginal unit is used to determine the cost of increasing power generation at that source.

Metric Tons (MT): 2,000 lbs.

MW: Megawatt equal to 1,000 kW.

MWh: Megawatt Hours equal to 1,000 kWh.

Net Energy Metering (NEM): The program and rates that pertain to electricity customers who also generate electricity, typically from rooftop solar panels.

Non-bypassable Charges: Charges applied to all customers receiving service from an Investor-Owned Utilities, but which are separated into a separate charge for departing load customers, such as Community Choice Aggregation and Direct Access Customers.

Non-Coincident Peak: Energy demand by a customer during periods that do not coincide with maximum total system load.

Non-Renewable Power: Electricity generated from non-renewable sources or a source that does not come with a Renewable Energy Credit (REC).

On-Bill Repayment (OBR): Allows electric customers to pay for financed improvements such as energy efficiency measures through monthly payments on their electricity bills.

Operate on the Margin: Operation of a business or resource at the limit of where it is profitable.

Opt-Out: Community Choice Aggregation is, by law, an opt-out program. Customers within the borders of a municipal aggregation are automatically enrolled within the municipal aggregation unless they proactively opt-out of the program.

Opt-Up: The portion of municipal aggregation customers selecting 100% renewable portfolio content energy.

Photovoltaic (PV): Solar PV.

Power Purchase Agreement (PPA): The standard term for bilateral supply contracts in the electricity industry.

Pricing Nodes: The ISO wholesale power market prices electricity based on the cost of generating and delivering it from particular grid locations called nodes.

Renewable Energy Credits (RECs): The renewable attributes from RPS-qualified resources that must be registered and retired to comply with RPS standards.

Renewable Portfolio Standard (RPS): The state-based requirement to procure a certain percentage of load from RPS-certified renewable resources.

Scheduling Coordinator: An entity that is approved to interact directly with PJM to schedule load and generation. All PJM participants must be or have a Scheduling Coordinator. A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services.

Scheduling Agent: A person or service that forecasts and monitors short term system load requirements and meets these demands by scheduling power resources to meet that demand.

Shaping: Function that facilitate and supports the delivery of energy generation to periods when it is needed most.

Spark Spread: The theoretical growth margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. All other costs (capital, operation and maintenance, etc.) must be covered from the spark spread.

Supply Stack: Refers to the generators within a region, stacked up according to their marginal cost to supply energy. Renewables are on the bottom of the stack and peaking gas generators on the top. Used to provide insights into how the price of electricity is likely to change as the load changes.

System Resource Adequacy: System requirements are determined based on the utility's load forecast plus a 15% planning reserve margin.

Time-of-Use (TOU): Electric rate design where prices vary by time of electricity usage where on-peak periods are priced higher than off-peak periods.

Wholesale Power: Large amounts of electricity that are bought and sold by utilities and other electric companies in bulk at specific trading hubs. Quantities are measured in MWs, and a standard wholesale contract is for 25 MW for a month during heavy-load or peak hours (7 am to 10 pm, Mon-Sat), or light-load or off-peak hours (all the other hours).

13 Appendix B – Base Case Pro Forma Analysis

In order to gauge the financial feasibility of the municipal aggregation business model for the County, a 10-year forecast of this model's financial pro forma was undertaken and summarized in Table 13-1 below.

Table 13-1 presents a cash basis income statement for municipal aggregation within the County from 2022 to 2033 with an assumed commercial operations date of 2024. This income statement starts with projected municipal aggregation revenues. These revenues assume municipal aggregation customers pay Dominion generation rates less an initial 4% discount.

Next expenses for the municipal aggregation option are forecast for the Base Case resource portfolio as described on Table 1-1. Power supply costs are functionalized by product to include block energy purchases, renewable energy, capacity/resource adequacy, ancillary services and transmission. A full description of these products can be found in Section 4 of this Study. Next a list of all operating and administrative costs (excluding power supply) is forecast. These cost estimates come from other similarly situated electric utilities doing only aggregation service. These costs are detailed in Section 5 of this Study. The sum of power supply and operation/administrative expenses quantifies the total expenses (budget) for a municipal aggregator.

Expenses are subtracted from revenues to determine annual net income through 2033. Net income is then used to repay initial loans and build a cash reserve fund. After these two requirements are satisfied, any additional net income can be used to develop customer programs, build renewable resources or reduce generation rates more than the initially assumed 4% in this Base Case.

TABLE 13-1. BASE CASE PORTFOLIO ANNUAL PRO FORMA (CASH BASIS), $MILLIONS

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Revenues												
Retail Rate Revenues	$0.0	$0.0	$678.7	$834.1	$899.7	$982.0	$1,067.8	$1,164.7	$1,269.0	$1,377.1	$1,490.7	$1,607.8
Uncollectible	$0.0	$0.0	-$1.8	-$2.3	-$2.4	-$2.7	-$2.9	-$3.2	-$3.4	-$3.7	-$4.0	-$4.4
Total Rate Revenue	$0.0	$0.0	$676.8	$831.9	$897.2	$979.3	$1,064.9	$1,161.6	$1,265.6	$1,373.4	$1,486.6	$1,603.4
Expenses												
Power Supply												
Block Energy Purchases	$0.0	$0.0	$323.4	$352.8	$357.1	$379.0	$390.9	$407.3	$437.3	$447.1	$452.3	$461.4
Renewable Energy	$0.0	$0.0	$96.3	$119.6	$140.4	$156.5	$180.3	$205.8	$222.7	$252.8	$288.0	$319.5
Capacity/Resource Adequacy	$0.0	$0.0	$76.8	$93.3	$102.6	$111.0	$121.4	$135.2	$151.0	$166.8	$178.2	$189.2
Ancillary Services	$0.0	$0.0	$9.4	$10.9	$11.5	$12.2	$12.8	$13.5	$14.2	$14.8	$15.5	$16.2
Transmission	$0.0	$0.0	$118.0	$144.7	$162.9	$183.6	$203.7	$227.8	$251.4	$277.4	$304.0	$332.4
Total Power Supply	**$0**	**$0**	**$624**	**$721**	**$774**	**$842**	**$909**	**$990**	**$1,077**	**$1,159**	**$1,238**	**$1,319**
Operating and Administrative												
Data Management and Customer Service Call Center	$0.0	$0.0	$1.5	$1.7	$1.8	$1.9	$2.0	$2.1	$2.2	$2.3	$2.4	$2.5
Power Management Consultant	$0.0	$0.2	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Schedule Coordinator/Dispatch	$0.0	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Technical Consultants	$0.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.4	$0.4	$0.4	$0.4
Marketing & Outreach	$0.0	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.4	$0.4	$0.4	$0.4
Legal/Regulatory	$0.0	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5
Dominion Fees, Billing	$0.0	$0.0	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
General & Administrative expenses	$0.0	$1.4	$2.1	$1.9	$2.0	$2.0	$2.0	$2.1	$2.1	$2.2	$2.2	$2.2
Total O&M and A&G	**$0.0**	**$2.6**	**$5.2**	**$5.3**	**$5.4**	**$5.6**	**$5.7**	**$5.9**	**$6.1**	**$6.2**	**$6.4**	**$6.6**
Debt Service Payment on Financing	$0.0	$2.1	$18.1	$18.1	$18.1	$16.0	$1.3	$0.0	$0.0	$0.0	$0.0	$0.0
Total Expenses	$0.0	$4.7	$647.2	$744.7	$798.0	$863.8	$916.2	$995.5	$1,082.7	$1,165.2	$1,244.4	$1,325.4
Net Income	$0.0	-$4.7	$29.6	$87.2	$99.3	$115.5	$148.7	$166.1	$182.9	$208.2	$242.2	$278.0
Cash From Operations and Financing												
Net Income From Operations	$0.0	-$4.7	$29.6	$87.2	$99.3	$115.5	$148.7	$166.1	$182.9	$208.2	$242.2	$278.0
Cash from Financing	$10.0	$70.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Change in Cash Available	$10	$65	$30	$87	$99	$115	$149	$166	$183	$208	$242	$278
Net Income Allocation												
Reserve Fund Contribution	$0.0	$61.7	$29.6	$87.2	$75.4	$16.8	$16.5	$19.9	$21.5	$20.3	$19.5	$20.0
Start-up Funding Payments + Collateral	$0.0	$3.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Discretionary Programs/Additional Rate Discounts	$0.0	$0.0	$0.0	$0.0	$23.9	$98.7	$132.1	$146.2	$161.4	$187.8	$222.7	$258.1
Total Cash Outlays	$0	$65	$30	$87	$99	$115	$149	$166	$183	$208	$242	$278
Rate Stabilization Reserve Balance	$0.0	$61.7	$29.6	$116.9	$192.3	$209.0	$225.6	$245.5	$267.0	$287.3	$306.8	$326.8
Reserve Balance Target	$0.0	$155.1	$155.1	$179.1	$192.3	$209.0	$225.6	$245.5	$267.0	$287.3	$306.8	$326.8

14 Appendix C – Legal/Regulatory Analysis

Memorandum

To: Dennis Cumbie
Water & Environmental Programs Division Manager
Loudoun County Department of General Services

From: Ryan M. F. Baron

Date: September 16, 2021

Re: Legal/Regulatory Review for Loudoun County, Virginia Municipal Aggregation Feasibility Study

This memorandum expands on the legal and regulatory issues identified in the Study. The following questions are identified as priority to address for CCA formation and operation in Virginia. Our respective responses follow.

1. Which local governments are eligible to participate in municipal aggregation?

Municipalities including counties, cities, and towns, as well as other political subdivisions of the State may, upon majority votes of their governing bodies, aggregate electrical energy and demand requirements subject to the provisions of Virginia Code § 56-589 (municipal and state aggregation). This would include special districts.[15] Therefore, most local governments within Loudon County would be eligible for municipal aggregation. In addition, the statute does not contain a geographical limitation, which would allow for the ability to aggregate on a non-contiguous basis and across county jurisdictional boundaries. Although there has not been a local government that has formed a municipal aggregator to date or that has participated in an approved State Corporation Commission ("SCC" or "Commission") pilot program, six local governments have previously participated in a feasibility study. These include the Cities of Charlottesville, Fairfax, and Hampton, and the Counties of Charles City, Chesterfield, and York.[16] The City of Fairfax is the only Virginia municipality that obtained a license for municipal electric aggregation from the SCC.[17] The license was subsequently terminated by the SCC at the request of the City of Fairfax which did not implement a municipal aggregation program or elect to renew its license.[18]

[15] Virginia Code § 15.2-2403.

[16] See *First Annual Report of Dominion Virginia Power on Status of the Retail Access Pilot Programs*, PUE-2003-00118, at 12 (May 25, 2005); *Second Annual Report of Dominion Virginia Power on Status of the Retail Access Pilot Programs*, PUE-2003-00118, at 1 (May 25, 2006).

[17] State Corporation Commission, License A-24, City of Fairfax (Apr. 18, 2006).

[18] State Corporation Commission, *Dismissal Order*, PUE-2006-00018 (July 14, 2009); Ltr from Robert Sisson, City Manager City of Fairfax, to Office of the City Clerk, State Corporation Commission (June 19, 2009).

Municipal aggregation would not be available to entities that were not formed as a city, county, town or political subdivision of the State. Virginia Code § 56-577 sets forth the criteria by which other residential, commercial, or industrial customers may aggregate electric load.[19]

2. Is the municipal aggregator required to offer an opt-in or opt-out structure?

Virginia Code § 56-589 allows municipal aggregation on either an opt-in or opt-out basis. Section 56-589 reads as follows:

> "Any municipality or other political subdivision of the Commonwealth may aggregate the electric energy load of residential, commercial, and industrial retail customers within its boundaries *on an opt-in or opt-out basis*."[20]

Based on the plain language of the statute, the municipal aggregator has discretion to structure customer enrollment. Customers can be automatically enrolled into an aggregation program upon formation and implementation of the municipal aggregation program, or the municipality can allow customers to voluntarily elect to participate.

Neither the Code nor SCC regulations specify procedures for how customers are notified of enrollment. In other state aggregation programs, there are specific rules for how customers are notified and the time period by which they may opt-out, with no charge from the incumbent utility or aggregator.[21] In this case, absent specific rules, the municipal aggregator appears to have broad discretion to fashion either an opt-in or opt-out program.

3. What is the licensing process for a municipal aggregator?

Section 56-588 requires each person seeking to be an aggregator to obtain a license from the Commission. As a condition to obtaining the license, the applicant must provide background information, demonstrate financial responsibility, post a bond, pay an annual fee, and pay all applicable taxes and fees.[22] The Commission may also impose certain reasonable and nondiscriminatory requirements as well as technical capability requirements.[23] In addition to its licensing authority, the Commission may establish a period by which a retail customer can cancel a contract entered into with a licensed aggregator.[24]

State licensing laws, however, appear to govern municipal aggregation differently than commercial aggregators depending on the class of customers served. Under section 56-589, a municipality or other political subdivision of the state seeking to aggregate the electric load of governmental buildings, facilities, and other operations does not require SCC licensing.[25] Similarly, two or more municipalities or other political subdivisions seeking to aggregate the electric load of governmental buildings, facilities, and other government operations also do not need a license if they are acting jointly to negotiate energy needs with licensed suppliers or

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[19] This class is limited to (a) individual retail electric customers whose demand exceeds 5 MW subject to certain limitations, (b) two or more individual non-residential retail customers whose demand does not exceed 5 MW, and (c) individual retail customers that desire to purchase 100 percent renewable energy.

[20] Emphasis added.

[21] See, e.g., Cal. Pub. Util. Code § 366.2 (specifying that aggregation is an opt-out program whereby customers receive three notices during enrollment and have the opportunity to opt-out and stay with the incumbent utility at no charge).

[22] Virginia Code § 56-588(B).

[23] *Id.*

[24] *Id.* at § 56-588(D).

[25] Virginia Code § 56-589(A)(2) ("Any municipality or other political subdivision of the Commonwealth may aggregate the electric energy load of its governmental buildings, facilities, and any other governmental operations requiring the consumption of electric energy. *Aggregation pursuant to this subdivision shall not require licensure pursuant to § 56-588*.") (Emphasis added).

aggregators.[26] If the municipality or political subdivision, or groups thereof, seek to aggregate the load of residential, commercial, and industrial customers, however, a license appears to be required.[27] Section 56-589 explicitly states when a license is not required for the aggregation of municipal load; however, the statute is silent on the aggregation of residential, commercial, and industrial load. Thus, a plain and general reading of the statute in conjunction with section 56-588 suggests that if the municipality or political subdivision seeks to aggregate more than just its governmental buildings, licensing is required.

In recent correspondence with SCC staff, they indicated that municipal aggregation is not required to obtain a license from the Commission and that there is no statutory authority for the SCC to impose licenses. It should be noted, however, that the City of Fairfax in February 2006 applied for and was granted a license "for electricity energy supply service for the Dominion Virginia Power customers within its geographic boundaries."[28] We believe a license would be required for residential, commercial, and/or industrial aggregation, but suggest further clarification from Commission staff.

In the event a license is required to aggregate the residential, commercial, and industrial load within the municipal boundaries, the SCC appears to have a process in place that was utilized by the City of Fairfax. The City filed a lengthy application providing some of the following information to the Commission:

1. A description of its "business structure;"
2. The name and address of the Mayor, Councilmembers and other city staff;
3. The location and phone number of its customer service department;
4. A comprehensive annual financial report, including information regarding its investment credit rating;
5. The City's experience in operating similar utilities, such as water and sewer; and
6. A description of the billing services options, *e.g.*, bill ready, rate ready.

Within three weeks of filing the application in April 2006, and payment of a $250 fee, the Commission issued a notice and comment period in which Dominion Resource Services, Inc. publicly supported the City's application noting that the two entities had been working cooperatively. The Commission granted the City's application and issued a license in just two months of the filing. The Commission did not propose any conditions on the license, such as cost recovery. We note, however, that there is no other information in Commission records discussing the licensing process or any rules promulgated by the SCC. In June 2009, the City sent a one sentence letter to the Commission indicating that it was not renewing its license. In July 2009, the SCC terminated the license with no other discussion or orders.

[26] *Id.* at § 56-589(A)(3).
[27] *Id.* at § 56-589(A)(1).
[28] City of Fairfax, *License Application of the City of Fairfax to Become a Municipal Aggregator of Electricity Pursuant to the Rules Governing Retail Access to Competitive Energy Services 20 VAC 5-312-40*, PUE-2006-00018 (Feb. 10, 2006).

Dominion Energy has established a registration process for competitive energy suppliers, which includes aggregators.[29] The registration requests a copy of the SCC license, an affidavit, a service provider agreement,[30] member status and standing information, a certification checklist, and a security administrator form.[31]

4. What taxes will a municipal aggregator be required to pay or collect?

The municipal aggregator, or its contracted competitive service provider, may be required to collect and pass through a consumption tax in accordance with Virginia Code § 58.1-2900. State law requires all consumers of electricity to pay a tax based on their monthly consumption subject to a legislative formula expressed in kWh. Electric utilities owned or operated by a municipal utility do not have to collect the tax if an amount equivalent to the tax is included in the rates of customers. The tax does not apply to municipalities' own use or to use by its government agencies.[32]

The statute does not discuss imposition or collection by municipal aggregators. Section 58.1-2901, however, imposes the duty of collecting the text on any "provider of billing services," which is defined as "the person who bills a customer for electric services rendered."[33] Therefore, either the municipal aggregator operating as the billing and collections entity or its contracted provider would have an obligation to collect the tax on residential, commercial, and industrial usage. Municipal usage would be exempt.

5. Are the customers of the municipal aggregator obligated to pay stranded costs through exit fees? If so, how are stranded costs calculated?

In some regulatory schemes where electric service has been deregulated allowing for choice in service other than from the monopoly provider, stranded costs are allowed to be recovered by the incumbent utility from the departing customers through a charge or exit fee.[34] The stranded cost is justified on the grounds that the incumbent has acquired or built generation assets or entered into power purchase agreements on behalf of all of its customers with approval by the regulators. The basic premise is that would be unfair to and discriminate against those remaining bundled customers to pay for the costs left by the departing customers which assets or contracts have been acquired or let on their behalf, *i.e.*, cost-shifting.

Virginia Code does not provide for the recovery of stranded costs by the incumbent utility from the municipal aggregator or their customers. Furthermore, the Commission does not appear to have the authority to establish stranded cost recovery or set an "exit fee" that a customer has to pay as part of taking service from a municipal aggregator. The only stranded cost formula is under the Virginia Electric Utility Regulation Act, which established competitive service providers and aggregation generally. Section 56-584 allows incumbent

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[29] Dominion Energy, *Aggregation Registration Form*, available at https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/supplier/supplier-pdf/aggregator-registration-form.pdf?la=en&rev=a42aa9081caf46c1b797de63d6a8f43b&hash=8718A15F7960681B82EFD1D3BC4B40AE.

[30] Dominion Energy, *Aggregator Agreement*, available at https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/supplier/supplier-pdf/csp-aggregator-agreement.pdf?la=en&rev=b9fa3957f8d440f8800b8886f424a47b&hash=834DD0F651F22C40B7227B6C1B4EF27B.

[31] Dominion Energy, *Competitive Energy Suppliers*, available at https://www.dominionenergy.com/virginia/rates-and-tariffs/competitive-energy-suppliers.

[32] Virginia Code § 58.1-2900(B).

[33] *Id.* at § 58.1-2901(E).

[34] Under federal law when the open access transmission tariff was established, wholesale transmission was deregulated allowing the recovery of stranded costs to prevent customers from stranding transmission assets. FERC Order No. 888-A, § II. Under California law, the customer of the municipal aggregator pays an exit fee to the utility so that the remaining bundled customers are not charged for the generation assets or contracts acquired or purchased on behalf of the departing customers. Cal. Pub. Util. Code § 366.2.

utilities to recover "just and reasonable net stranded costs" from their remaining bundled customers, subject to capped rates as established by the Commission pursuant to section 56-582 and the incumbents' rate case proceedings. Therefore, it appears that if a municipal aggregator is formed, it can do so without having to factor in the payment of stranded costs by it or its customers.

In the event the law is changed or the Commission promulgates rules or guidelines on stranded costs, a few proceedings shed light on how the Commission might calculate them. We note, though, that the stranded cost determinations in the aggregation context are inconsistent and there does not appear to be one methodology used or adopted by the SCC.

The Commission has addressed stranded costs in the context of three applications for aggregation made by commercial and industrial customers. Section 56-577(A)(4) allows two or more non-residential customers whose load does not exceed 5 MW to aggregate their demand upon a petition to the Commission to purchase electricity from a licensed supplier. Applications have been filed by Reynolds company, Wal-Mart and Costco.

In the *Reynolds* proceeding,[35] the company was granted the right to aggregate. The Commission did not establish a stranded cost methodology, but based its findings on Reynolds aggregated peak demand of its retail customers as compared with Dominion's peak demand. The Commission found that there were no adverse effects to the remaining Dominion customers since Reynolds peak demand was 0.06% of Dominion's system peak. Dominion did not put forth evidence of adverse effects, though, in the proceeding.

In the *Wal-Mart* proceeding,[36] Appalachian and Dominion proffered testimony that was accepted by the Commission that significant cost-shifting would result if Wal-Mart was allowed to aggregate a number of its stores. Appalachian estimated that its customers would be subject to $4 million in stranded costs while Dominion estimated that such costs would be approximately $65 million. Customer monthly bills would increase by $0.05 and $0.13, respectively. RAC rates and base rates would also be higher. Ultimately, the Commission reviewed both generation[37] and transmission cost shifting[38] and denied Wal-Mart's application on public interest grounds. It did not adopt a particular stranded cost formula.

In the *Costco* proceeding,[39] Dominion provided a calculation of the non-fuel generation revenue that would no longer be recovered from Costco ($1.57 million annually), and would be shifted to Dominion retail customers in order for Dominion to maintain the same rate of return. Dominion testified that its calculation

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[35] *Petition of Reynolds Group Holdings, Inc.*, Opinion, PUR-2017-00109 (May 16, 2018) (*Reynolds*).

[36] *Petition of Wal-Mart Stores East, LP and Sam's East, Inc.*, Final Order, PUR-2017-00174 (Feb. 25, 2019) (*Wal-Mart*).

[37] "When this customer shops, it realizes a large non-fuel generation cost savings but will use the same amount of the Company's generation capacity on average. The difference is that the Company and its non-shopping customers are paying for the shopping customer's non-fuel generation cost savings…Some of the shifted non-fuel generation costs will be captured in almost real time through the monthly Dresden G-RAC deferral accounting process. Others that relate to base rate non-fuel generation costs will be shifted to the Company's shareholders until base rates are reset. In the Company's next triennial review filing, non-shopping customers may bear those shifted costs."

[38] "Virginia shopping does affect the APCo jurisdictional transmission allocation factors because APCo is no longer incurring the PJM LSE OATT expense from shopping customers in Virginia so PJM bills the CSPs directly. As APCo no longer incurs the PJM OATT LSE expense associated with shopping customers, it makes sense to remove those shopping customers' loads from the total Virginia retail and APCo loads used to calculate the allocation factors used to allocate the total APCo PJM LSE OATT expense to the West Virginia and Virginia retail jurisdictions. This results in a lower Virginia retail jurisdictional allocator for transmission function costs only. The lower Virginia retail jurisdictional allocator is offset by the loss of retail transmission rate adjustment clause ^ (T-RAC) revenue and the fact that roughly half of the PJM LSE OATT cost savings from a customer shopping is allocated away from the Virginia retail jurisdiction. . . . The $1.35 million cost shift to non-shopping customers is captured in real time through the monthly T-RAC deferral accounting."

[39] *Petition of Costco Wholesale Corporation*, Final Order, PUR 2018-00088 (May 30, 2019) (*Costco*).

included the reallocation of production plant, cost, and related non fuel expenses. Because $1.57 million of additional costs could be shifted annually to non-shopping customers, the Commission found that approving the aggregation was not consistent with the public interest.

In sum, the Commission has not established a stranded cost charge and it has not adopted a consistent methodology for determining stranded costs. It has, instead made public interest findings based on a case-by-case formula generally provided for by the incumbent utilities through individual testimony.

6. What are the renewable targets for a municipal aggregator for 2024-2033?

Virginia passed the Virginia Clean Economy Act in 2020, establishing mandatory renewable portfolio standards ("RPS") program requirements for Dominion and APCo. The RPS requirements are codified under Virginia Code § 56-585.5(C) and (D). The legislation does not apply to aggregators, competitive service providers, electric cooperatives, or municipal utilities. We do, however, discuss the renewable targets that apply to the incumbent utilities as earlier drafts of the bill included all licensed energy providers. Therefore, if the Act is amended, it could be extended to aggregators or those service providers through which the aggregator procures energy from.

Dominion is required to attain 100% renewables by 2045. Dominion must meet annual goals for the sale of renewable energy to retail customers in its service territory. The schedule for 2024-2033 is as follows:

Year	Percentage of total electric energy sold in previous calendar year
2024	23%
2025	26%
2026	29%
2027	32%
2028	35%
2029	38%
2030	41%
2031	45%
2032	49%
2033	52%

Compliance with the RPS program is determined by Dominion's procurement and retirement of renewable energy certificates (RECs) originating from eligible sources as defined by Virginia law.

For the 2024 compliance year, Dominion may use RECs from any renewable energy facilities located in Virginia or physically located within the PJM Interconnection, LLC ("PJM") region. "Renewable energy" includes solar, wind, hydro, biomass, "sustainable or otherwise," waste-to-energy, landfill gas, municipal solid waste, wave motion, tides, and geothermal power, as well as the proportion of thermal or electric energy from a facility that results from the co-firing of biomass.

From 2025 and onward, RECs may be used from RPS eligible sources only. RPS eligible sources include facilities that generate electric energy derived from solar and wind, certain hydro, certain waste-to-energy and landfill gas, and certain biomass located in Virginia or physically located within the PJM region. Specific definitions follow:

(a) **Solar and Wind**. Electric-generating resources that generate electric energy derived from solar or wind located in Virginia or off Virginia's Atlantic shoreline or in federal waters and interconnected directly into Virginia or physically located within the PJM region;

(b) **Hydro (utility-owned or contracted)**. Falling water resources located in Virginia or physically located within the PJM region that were in operation as of January 1, 2020, that are owned by APCo or Dominion or for which APCO or Dominion has entered into a contract prior to January 1, 2020 to purchase the energy, capacity, and renewable attributes of such falling water resources;

(c) **Hydro (Non-utility owned)**. Non-utility-owned resources from falling water that (1) are less than 65 megawatts, (2) began commercial operation after December 31, 1979, or (3) added incremental generation representing greater than 50% of the original nameplate capacity after December 31, 1979, provided that such resources are located in Virginia or are physically located within the PJM region;

(d) **Waste-to-energy or landfill gas-fired** generating resources located in Virginia and in operation as of January 1, 2020, provided that such resources do not use waste heat from fossil fuel combustion or forest or woody biomass as fuel; or

(e) **Biomass-fired** facilities in operation in Virginia and in operation as of January 1, 2020 that supply no more than 10% of their annual net electrical generation to the electric grid or no more than 15% of their annual total useful energy to any entity other than the manufacturing facility to which the generating source is interconnected.

In addition to the annual requirements, Dominion must meet 1% of the RPS program requirements in any given compliance year with solar, wind, or anaerobic digestion resources of one megawatt or less located in Virginia.[40] For 2025 and onward, at least 75% of all RECs used by Dominion in a compliance period shall come from RPS eligible resources located in Virginia.

In any year, if Dominion is unable to meet the RPS program compliance obligations, or if the cost of RECs necessary to comply exceeds $45 per megawatt hour, the utility must pay a deficiency payment equal to $45 per megawatt hour ("MWh") shortfall for the year of noncompliance. The deficiency payment for any shortfall in procuring RECs for solar, wind, or anaerobic digesters located in Virginia shall be $75 MWh for resources one MW and lower.

7. Is there a code of conduct that restricts the incumbent utilities from advocating against municipal aggregation or any other code of conduct rules that apply?

In certain states, the incumbent utilities are prohibited from marketing against a municipal aggregation program unless the marketing is done through an independent marketing division that is funded solely by utility shareholders and does not use ratepayer funds.[41] The rules prohibit lobbying against the formation or implementation of a program. rules do not restrict factual answers about utility rate programs or analyses or questions from government agencies.

No such rules exist in Virginia or have been promulgated by the Commission. Virginia Code § 5-12-330 does include code of conduct rules that apply to the incumbent utilities and their affiliates with respect to advertising and solicitation materials. The rules do not include conduct or marketing restrictions regarding aggregators or other competitive service providers. Therefore, it appears that the incumbent utilities could legally market or lobby against the formation of a municipal aggregation program absent legislation or Commission rules to the contrary.

[40] With not more than 3,000 kilowatts at any single location or at contiguous locations owned by the same entity or affiliated entities and, to the extent that low-income qualifying projects are available, then no less than 25% of such 1% shall be composed of low-income qualifying projects.

[41] Cal. Pub. Util. Code § 707(a). California Public Utilities Commission Decision (D.) 12-12-036.

8. Who is the provider of last resort?

There does not appear to be an established provider of last resort under the existing Virginia regulatory framework. The Virginia Administrative Code provides rules for switching service to and from competitive service providers ("CSPs").

20VAC5-312-80 governs the rules for enrollment and switching to and from CSPs, and notice requirements for CSPs and local distribution companies when customer service is terminated. Generally, if service is cancelled at the request of the customer or by the CSP, the local distribution company is notified of the service termination.[42] The local distribution company informs the customer of the customer's opportunity to select a new supplier.[43] If the customer does not select another CSP, the local distribution company will provide the customer's electricity supply service pursuant to the prices, terms, and conditions of its tariffs approved by the SCC.[44]

9. What role, if any, will the Commission play in regulating municipal aggregation?

As discussed in Question 1, above, the Commission has certain licensing oversight delegated to it pursuant to Virginia Code §§ 56-588 and 56-589. In addition, the Commission has approval oversight over commercial and industrial aggregation pursuant to section 56-577 where retail electricity aggregation is authorized in three narrow categories. Two of the categories are *by right*, and SCC has no discretion to approve or reject retail choice: (1) large customers with a demand exceeding five MW, and (2) all customers seeking 100% renewable energy if the customer's incumbent utility does not offer the same. The third category applies to nonresidential customers that desire to aggregate less than 5 MW where Commission approval is required with findings that the aggregation is in the public interest.

It does not appear that Virginia Code addresses Commission regulation other than the limited licensing structure contemplated in section 56-589. There is no other statute addressing municipal aggregation or authorizing the Commission to regulate other aspects of an aggregation program. The SCC Division of Public Utility Regulation only regulates investor-owned utilities and member-owned electric cooperatives. A search of Commission decisions regarding municipal aggregation revealed orders limited to the approval of a municipal aggregation pilot program by Dominion[45] and the licensing of the City of Fairfax. There are no other orders or regulations that have been issued or promulgated. This opinion has been confirmed by Commission staff who indicated that it does not have the authority to issue rules or guidelines regarding municipal aggregation.

[42] 20VAC5-312-80(K)–(N).
[43] 20VAC5-312-80(N).
[44] 20VAC5-312-80(N).
[45] State Corporation Commission, *Application of Virginia Electric and Power Company D/B/A Dominion Virginia Power*, PUE-2003-00118 (Jan. 18, 2005).

PREPARED BY GDS ASSOCIATES, INC.

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GDS Associates, Inc.
ENGINEERS & CONSULTANTS
gdsassociates.com

BB&K
BEST BEST & KRIEGER LLP
ATTORNEYS AT LAW