STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Tariff filing of Green Mountain Power Corporation requesting a change in rates, effective October 1, 2022	)))	Case No. 21-____-TF
Petition of Green Mountain Power for approval of its new multi-year regulation plan pursuant to 30 V.S.A. §§ 209, 218, and 218d.	)))	Case No. 21-3707-PET

PREFILED DIRECT & SUPPLEMENTAL TESTIMONY OF MARIA FISCHER ON BEHALF OF GREEN MOUNTAIN POWER

January 18, 2022

Summary of Testimony

Ms. Fischer presents GMP's power supply costs during the Rate Year, Fiscal Year 2023, describing GMP's power supply portfolio and primary drivers of recent changes in power supply and transmission costs. Ms. Fischer also explains how GMP developed power supply cost forecasts for the following three years of the proposed New Plan.

Exhibit List

Exhibit GMP-MF-1	Power Supply Cost Summary - Test Year
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PREFILED DIRECT & SUPPLEMENTAL TESTIMONY OF MARIA FISCHER ON BEHALF OF GREEN MOUNTAIN POWER

I. Introduction

Q1. Please state your name and occupation.

A1. My name is Maria Fischer. I am the Lead Power Supply Analyst for Green Mountain Power ("GMP").

Q2. Please summarize your educational background and pertinent professional experience.

A2. I have worked for over 13 years in the electric industry, focusing on power supply portfolio planning, wholesale and retail power transactions, and Renewable Energy Credit ("REC") trading. I hold a Bachelor of Arts degree with majors in Mathematics and Economics from Lafayette College.

Starting in 2008 I worked in the power supply departments at Green Mountain Power for seven years and then at Vermont Public Power Supply Authority ("VPPSA") for three years as an Analyst and Trader for energy, capacity, and RECs. In 2018, I joined the Vermont Department of Public Service (the "Department" or "DPS") as a Utilities Economic Analyst. Working within the Department's Planning and Energy Resources Division, I supported the development of state energy policy and implementation of the Renewable Energy Standard ("RES"), reviewed rate cases, and evaluated utility integrated resource planning for electric and natural gas utilities, among other responsibilities.

I rejoined GMP in May 2021 in my current role as Lead Power Supply Analyst. In this capacity, I am responsible for forecasting, tracking, and reporting GMP's power costs. I also helped develop GMP's 2021 Integrated Resource Plan ("IRP") submitted this past December.

Q3. Have you previously testified before the Public Utility Commission ("Commission" or "PUC")?

A3. Yes, I have testified before the Public Utility Commission on numerous occasions, on topics that include resource planning, rate case review, and energy efficiency utility efficiency screening. Most relevant to this proceeding, I provided testimony on behalf of the Department of Public Service in the proceeding for GMP's existing Multi-Year Regulation Plan, Case No. 18-1633-PET ("Current Plan"), Vermont Electric Cooperative's 2020 Rate Case, Case No. 19-4585-TF, Washington Electric Cooperative's 2020 Rate Case, Case No. 19-4576-TF, The Village of Hyde Park's 2019 Rate Case, Case No. 19-3020-TF, and the Village of Stowe's 2018 Rate Case, Case No. 18-2372-TF.

Q4. What is the purpose of your testimony?

A4. Sections II–IV of my testimony provide the details of GMP's power supply costs in the context of the traditional rate case filing, summarizing these costs in the upcoming Rate Year (Fiscal Year 2023, or "FY23," beginning in October 2022) and explaining how these costs were developed in response to many power supply cost drivers.

I also present in Section V GMP's forecasts for power supply and revenue expected for the fiscal years of 2024–2026 ("FY24–26") as supplemental testimony to

Douglas Smith's testimony in the GMP's concurrent new regulation plan proceeding (Case No. 21-3707-PET) ("New Plan"). In that section, I also briefly describe a revised attachment to the proposed New Plan.

II. Overview of Traditional Rate Filing and Power Portfolio

Q5. Can you please quantify GMP's Rate Year power costs relative to the Test Year at a high level?

A5. For the Rate Year, total power supply-related costs, which include purchased transmission, are $438M, an increase of about $13M from the Test Year (FY21), which include many areas out of GMP control.

Q6. What are the key changes in GMP's net power costs for the Rate Year, relative to the Test Year?

A6. Mr. Smith's prefiled direct testimony submitted in the New Plan proceeding summarized the overall trends driving power supply costs leading into, and during the New Plan period. The key changes in GMP's net power costs between the Test Year and the Rate Year include:

- Higher forward prices for electricity in New England driven by post-pandemic natural gas price recovery and increase. This has led to higher expected costs for GMP's projected ISO-New England ("ISO-NE") spot purchases and higher power purchase agreement ("PPA") prices for GMP energy contracts with indexed pricing features, such as the Hydro-Quebec U.S. ("HQUS") PPA.

- Higher rates of inflation in the Interim Year (FY22), which directly impacts PPAs with inflation-based escalation, such as the Seabrook contract.
- Increasing REC revenues due to stronger REC market prices that have resulted from regional requirements increasing faster than renewable supply additions.
- Continued robust deployment of net-metering projects, a more expensive resource for non-participating customers. As more solar generation has been deployed in Vermont and ISO-NE as a whole, the capacity, transmission, and distribution cost savings through peak shift provided by additional solar have diminished.
- Drought conditions persisted through much of the Test Year leading to lower-than-average hydroelectric generation. Rather than using the single Test Year generation output, expected Rate Year generation is based on a 20-year average to better account for hydrological conditions over time, adjusted for known upgrades and outages.
- Various expirations and starts of new contracts. For example, GMP will begin receiving deliveries of energy and RECs from its long-term PPA from Great River Hydro's Connecticut River and Deerfield River plants during the Rate Year.
- Increasing transmission expense due to costs associated with the regional bulk grid. These are primarily cost increases from Vermont Electric Power Company ("VELCO").[1] These are changes from the Test Year to the Rate Year, though I

[1] References to VELCO costs in this testimony also include costs associated with VELCO's affiliate Vermont Transco, LLC which holds most bulk transmission assets in Vermont.

note that the year-over-year changes (FY22 to FY23) for this item result in a $3.8M decrease.

These cost changes, many from economic factors outside of GMP's control, reflect a period of national and local economic disruption. These pressures also highlight the benefits of our energy transformation work advanced during the Current Plan, and that GMP will continue in the New Plan, as described in the testimony of Mr. Castonguay. As we continue to seek, develop, and implement innovative solutions, we are generating new value streams that directly benefit customers by reducing costs. This has been demonstrated, for example, by the successful implementation of residential battery storage that, in combination with our own storage resources, helps reduce peak demand.

Q7. Can you explain how GLOBALFOUNDRIES has been handled in your power supply modeling for the Rate Year?

A7. Yes. As described further in Mr. Ryan and Mr. Bingel's testimony, in this case we have modeled both power supply costs and revenues related to serving GLOBALFOUNDRIES U.S. 2 LLC ("GF") consistent with GF's proposal to become its own utility starting in FY23. This proposal is before the PUC in Case No. 21-1107-PET and related Case No. 21-1109-PET. GF's proposal includes a four-year transition period starting in FY23, during which GMP would provide power to GF through a PPA, and would receive revenue through the PPA, plus an additional transition fee from GF, which both benefit customers. Mr. Ryan and Mr. Bingel explain how the revenue and transition fee would be booked during the transition period. On the power supply side, the four-year PPA means that costs associated with procuring power to serve GF are still included in our power supply costs in FY23 (and through the New Plan period). However, under the GF proposal, GF would be responsible for its own transmission costs. As a result, transmission costs associated with the GF load are not included in our power supply forecast as modeled for FY23 or beyond. However, if GF were to remain a customer in FY23 such that GMP would incur the transmission expense and GF would pay for these costs, the result would largely net out. On a total basis, when the transition fee is accounted for, we do not expect a material difference in FY23 regardless of GF's status as a customer or separate utility, as explained further by Mr. Ryan and Mr. Bingel.

It is important to note that GF's proposal is still pending before the Commission. To address this fact, GMP sought, and the PUC recently approved, an extension of up to one year of the existing term contract between GMP and GF. This limited extension of the term contract would be in place through FY23 in the event the GF utility proposal is not resolved in time to implement during FY23. Although our power supply model assumes implementation of GF's utility proposal, as Mr. Ryan and Mr. Bingel explain further, GMP is proposing a minor modification to its New Plan to ensure that power supply costs, including transmission, and any revenues associated with the GF utility proposal, are handled by adjustors in the New Plan. This will ensure that regardless of whether the GF utility proposal is adopted or the extended term contract controls in FY23, any variation against our modeling will be addressed in the adjustors and the financial outcome for GMP customers will be essentially the same.

Q8. Please introduce your exhibits.

A8. I sponsor the following exhibits, organized by the categories below:

Test Year Power Supply Cost Information

- **Exh. GMP-MF-1** contains an annual summary of all costs and credits.
- **Exh. GMP-MF-3** contains a higher-level monthly summary.
- **Exh. GMP-MF-4** through **Exh. GMP-MF-9** contain monthly detailed information for all power supply-related categories.

Rate Year Power Supply Cost Information

- **Exh. GMP-MF-2** contains the annual summary of all power-supply-related cost information.
- **Exh. GMP-MF-10** contains monthly Rate Year sales and related loads.
- **Exh. GMP-MF-11** contains forward energy market prices.
- **Exh. GMP-MF-12** through **Exh. GMP-MF-19** contain monthly detailed projections of costs and volumes for all power supply-related categories.

Rate Year and Test Year Power Cost Comparisons

- **Exh.GMP-MF-21** compares Rate Year and Test Year energy volumes and costs.
- **Exh. GMP-MF-22** compares Rate Year and Test Year purchased transmission costs.

FY24–FY26 Power Cost Forecast

- **Exh. GMP-MF-23** contains forecasted power costs for FY24–26.

Q9. Please provide an overview of GMP's power supply portfolio.

A9. GMP serves an annual retail load, including distribution system losses, of approximately 4.3 million MWh/year. Providing that power to customers safely, reliably, and cost effectively while supporting energy transformation and renewable development is critical to our work. We procure this energy, and other required products including capacity, RECs, and ancillary services, from a variety of sources. These sources include owned and purchased physical energy from specific generating plants, system energy that is not tied to specific plants, and a variety of purchase agreements from short-term agreements of less than five years to long-term contracts of up to 30 years.

Q10. Please describe GMP's owned resources.

A10. GMP owns, either solely or jointly with others, approximately 390 MW of generating capacity that is expected to provide approximately 870,000 MWh, or almost 20% of GMP's needs to supply power to customers in the Rate Year. This is primarily intermittent renewable energy from several dozen hydro facilities, GMP's two wind projects (Kingdom Community Wind and Searsburg), and several small solar installations. GMP also owns a share of about 20 MW in the Millstone 3 nuclear plant that is expected to produce about 182,000 MWh of baseload generation. GMP anticipates that the dispatchable wood-fired JC McNeil biomass plant in Burlington, operating at roughly a 53% capacity factor, will provide GMP with about 75,000 MWh of energy, capacity, and regional Class 1 RECs. Finally, GMP owns a share of several combustion turbine and diesel units, along with joint ownership shares in the Wyman 4 oil-fired steam unit in Yarmouth, Maine, and the three Stony Brook intermediate combined cycle units in Massachusetts, which burn natural gas or oil. These units account for about 150 MW of peaking capacity, which provides value in the capacity and other markets but are only projected to generate about 8,000 MWh of energy in the Rate Year.

Q11. What are GMP's most significant power supply purchases?

A11. GMP purchases power from a variety of sources and generation types in state and regionally. GMP's HQUS energy contract will provide about 1.05 million MWh of Rate Year energy along with renewable attributes associated with the Hydro-Quebec generation system. The energy from HQUS makes up more than a quarter of GMP's energy need for the Rate Year. At least 95% of this energy will be from hydroelectric sources and will contribute to meeting our RES Tier I requirement.

The other major resources that GMP purchases power from on a long-term basis include NextEra's Seabrook nuclear plant, the Granite Reliable Wind project, the Deerfield wind project, the Ryegate wood-fired plant, and the Sheldon Springs hydro facility. Most of these sources feature zero air emissions or are relatively low-emitting generators. Granite, Deerfield, and Ryegate all provide RECs that in the Rate Year are qualified as Class 1 resources for Renewable Portfolio Standards ("RPS") in one or more neighboring states. During the Rate Year, GMP will also begin receiving power from Great River Hydro, which includes a fleet of 13 hydroelectric facilities along the Connecticut and Deerfield rivers in Vermont, New Hampshire, and Massachusetts, including RECs that qualify for Vermont Tier I. In total, these renewable and nuclear

PPA sources are projected to supply almost 964,000 MWhs of energy in the Rate Year, or about 26% of GMP's needs.

During the Rate Year, GMP will also purchase around 750,000 MWh under short-term, market-based forward energy contracts that GMP has put in place during the past several years. The volumes of these fixed price bilateral purchases are shaped on a monthly basis and by on- and off-peak periods to match GMP's forecasted net short position. This monthly and on- and off-peak shaping allows GMP to limit the potential year-to-year variance in power costs and retail rates, as well as potential intra-year power cost fluctuations, due to changes in energy market prices.

Q12. What are the other components of GMP's power supply portfolio?

A12. Other than our own generation and the major supply contracts noted above, the rest of GMP's retail load need is served through smaller bilateral purchases, spot market purchases, and Vermont programs for net-metering, Standard Offer, and other small renewables.

Many of the Standard Offer sources and new net-metered ("NM 2.0") projects also provide high-value Vermont Tier II RECs that can be used for Tier II compliance to benefit our customers. Total Rate Year energy supply through these programs for GMP is projected to be 432,000 MWh, about 10% of the retail load. As new net-metering and Standard Offer projects continue to come online, these sources will contribute an increasing share of our power supply portfolio in the Rate Year.

GMP makes bilateral purchases for energy and/or RECs from several other small renewable projects, mostly hydro and solar. Batteries have also become a growing and important part of GMP's portfolio to best serve customers, with 25 MW of installed capacity expected by the end of the Rate Year.

GMP purchases and sells energy on an hourly basis through the ISO-NE day-ahead and real-time markets (together, the "spot market") as needed. Generally, GMP plans its energy supplies (including the long-term and short-term sources discussed above) to be approximately in balance with forecasted load requirements during peak and off-peak periods each month. In practice, our customers' power needs and the output of intermittent generating sources can fluctuate significantly within a given month around the averages that are the basis of our forecasts. As a result, we often buy or sell significant amounts of spot market energy in particular hours and days depending on variations in customer consumption and generation output. Generally, energy markets tend to experience the greatest volatility during the winter months, when our energy position depends on intermittent generation and customers' demand, which can result in significant variances. For the Rate Year as a whole, GMP's loads and resources are projected to be closely balanced, with GMP projected to be a net purchaser of about 30,000 MWh (less than 1% of GMP's Rate Year requirements) in the spot market.

Q13. Please summarize how GMP approached the development of power supply costs for the Rate Year.

A13. Most of the volumes and prices that determine GMP's projected net power supply costs in the Rate Year are based on values from the Test Year, adjusted to reflect known and measurable changes. These changes include contractual changes in PPA prices or volumes, the addition and expiration of certain power sources, or changes in the market price environment for electricity, fuel, or RECs. As discussed below and in the direct testimony of Edward Ryan and Rob Bingel, Rate Year load and sales are based on forecasts for that period. Normalizing adjustments were applied to intermittent power sources for which production tends to fluctuate around long-term average weather values. The most prominent categories of adjustments are as follows:

- Market purchases and sales were adjusted to reflect changes in GMP's forecasted load requirements and the forecasted output of power sources that supply GMP, along with changes in the wholesale market price outlook for energy, capacity, fuel, and RECs.
- Purchased power expenses were adjusted to reflect the expiration of existing PPAs and the addition of new sources (e.g., Great River Hydro, new Standard Offer projects, and inclusion of Joint Venture Solar, or "JV Solar," in owned generation during the Rate Year).
- Purchased power expenses were adjusted to reflect contractual price changes in existing PPAs (e.g., for HQUS energy, NextEra Seabrook, Granite Reliable Wind), volume changes for some sources, and weather normalization for intermittent sources.
- Transmission expenses were adjusted to reflect VELCO and ISO-NE projections for regional transmission rates, along with the estimated peak loads upon which these expenses are allocated.

- Capacity-related expenses were adjusted to reflect known changes in ISO-NE Forward Capacity Market ("FCM") pricing, changes to contracted capacity supply volumes, and updates to GMP's projected share of regional capacity obligations.
- Energy output from intermittent renewable sources was adjusted to reflect normalized or long-term average volumes and planned outages for maintenance and upgrades.
- Fuel prices at GMP's owned and jointly owned fossil-fired units were adjusted on a plant-specific basis based on recent futures market prices for oil and natural gas.
- The quantity of REC sales was adjusted to reflect long-term average generation from GMP's owned plants and PPAs. Net REC revenues were adjusted to reflect forward sales that GMP made for deliveries during the Rate Year and also updated REC market price estimates for projected REC volumes that have not been sold forward.
- RES costs were updated to reflect the expected compliance cost of RES Tiers I, II, and III during the Rate Year.
- Operating & Maintenance ("O&M") expenses for GMP's wholly owned generating units were adjusted to reflect the most recent forecasts of those expenses, as discussed in the testimony of Joshua Castonguay; O&M expenses for jointly owned plants reflect five-year averages.

Many of these changes are discussed in more detail in Section III of my testimony.

Q14. What is the role of RECs in GMP's power supply?

A14. RECs are the means by which Vermont and the region ensure that renewable requirements and greenhouse gas reduction goals are monetized, tracked, and accounted for properly. As explained below, GMP is both a buyer and a seller of RECs. This is an outcome of the Vermont renewable policy framework which has been a major factor in shaping GMP's mix of current power sources.

Q15. What volume of retail load is reflected in the GMP Rate Year power costs that you are presenting?

A15. The power costs for the Rate Year reflect a retail load requirement of about 4.3 million MWh. That is the forecasted GMP retail sales volume for the year, as developed by the consulting firm, Itron. It includes energy losses on the distribution system and is essentially unchanged from the Test Year. Mr. Ryan and Mr. Bingel introduce and discuss the Itron forecast in their joint testimony.

Q16. How are GMP's Rate Year power supply costs represented in GMP's cost of service filing?

A16. Overall, projected total power-supply-related costs increase $12.8M from the Test Year to the Rate Year. The changes are reflected in **Exh. GMP-ER-RB-4** as the following Cost of Service ("COS") Adjustments:

COS Adjustment	Amount
COS Adjustment 1: Purchased Power. This adjustment includes all purchased power costs, including net-metering, and all resales of power, including REC revenues.	$7.988M increase
COS Adjustment 2a: Production Fuel costs	$0.939M decrease
COS Adjustment 2b: Joint Ownership costs	$0.740M increase
COS Adjustment 2c: GMP Owned Production (O&M) costs	$0.187M increase
COS Adjustment 3: Transmission by Others ("TbyO")	$4.781M increase
COS Adjustment 4: Other Transmission-related costs	$0.024M increase

These changes are discussed in greater detail in the following sections of my testimony, except for wholly owned and joint owned O&M costs, which are addressed in the testimony of Mr. Castonguay.

III. Rate Year Power Supply Costs

Q17. What is the purpose of this section of your testimony?

A17. The changes described in this section explain nearly all the change in GMP's net power costs from the Test Year to the Rate Year. Some of these changes affect several power cost components, so I will generally explain these linked changes together.

Inflation

Q18. How does inflation impact power supply costs for the Rate Year, and how is this reflected in GMP's Rate Year power costs?

A18. The impact of inflation on power supply costs during the Rate Year is largely driven by the application of inflation index values to some of GMP's largest supply contracts. Two of GMP's long-term PPAs—HQUS and NextEra Seabrook—have prices that are adjusted based on a national inflation index[2] and adjusted annually. Published inflation index values have increased markedly as the economy recovered after COVID-19 shutdowns and many supply chains remained disrupted. The high-inflation environment has resulted in larger year-over-year PPA price increases for each of these contracts than historically experienced. Following the Rate Year, we are projecting rates of inflation to return to more typical recent values for the remainder of the MYRP period.

Forward Energy Prices

Q19. Please describe the drivers of current trends in forward prices for around-the-clock energy in New England.

A19. Supply disruptions and tremendous variation in the demand for oil, natural gas, and electricity during the pandemic resulted in significant price volatility for these products. Rising demand for energy has increased faster than production of these products has rebounded, resulting in significantly higher energy prices. In New England, forward prices for electricity to be delivered in 2022 and 2023 have risen dramatically in a short time because of significant changes in the price and availability of natural gas in these periods, especially during winter months. Increased demand for liquified natural gas in other parts of the world facing energy shortages related to COVID-19 has further affected the price and availability of these supplies for our region, adding considerable uncertainty

[2] The HQUS PPA utilizes the Gross National Product-Implicit Price Deflator index ("GNP-IDP"); the NextEra PPA utilizes the Gross Domestic Product-Implicit Price Deflator index.

to winter prices in the near term. The result has been roughly a 35% increase in forward prices for around-the-clock energy during the Rate Year since last winter, led by price increases for deliveries in the peak winter months of December through March.

Q20. How are forward energy prices reflected in the Rate Year power costs?

A20. As previously explained, GMP makes forward energy sales and purchases to help match supply and demand on a seasonal basis—with GMP typically buying additional supply during winter months and selling excess supply during the spring and summer. GMP also purchases and sells energy on an hourly basis through ISO-NE day-ahead and real-time markets. To estimate the expense and revenue resulting from GMP's open energy positions, we typically apply price quotations that approximate the fixed prices at which buyers and sellers are willing to transact for deliveries during future months. For Rate Year power costs, GMP has used broker quotes from December 6, 2021. Higher forward prices, particularly during peak winter months, typically result in higher costs for spot market purchases, which are somewhat offset by higher revenues from spot market sales.

As noted previously, the HQUS PPA price also has a component tied to market prices, both historical and forward.

HQUS PPA

Q21. How is the HQUS PPA reflected in GMP's Rate Year costs?

A21. The HQUS PPA price is formula-based with components tied to inflation and historical and forward energy prices. Each year, this price is adjusted based on a blend of:

- The Reference Price, which is the first-year price escalated by the general level of prices in the U.S. economy as determined by a lagging measure of the GNP-IPD.
- The Energy Market Price Index ("EMPI") reflecting an averaging of one-year historical actual Highgate node pricing for the contract profile (7x16) and one-year forward on-peak New England Hub traded energy prices adjusted for delivery point and to reflect a 7x16 delivery profile.

The price each year is calculated based on an average of the Reference Price (60%) and the EMPI (40%), subject to a 15% annual upward or downward limit on price changes. The resulting price when applying the current inflation rate and the extraordinary increase in regional forward energy market prices is $60.17/MWh for energy deliveries beginning November 1, 2022. The current contract year, which runs through October 31, 2022, and is in effect for one month of the Rate Year, is $57.01/MWh. The average contract price during the Test Year of $51.74/MWh has increased to $56.48/MWh for the Interim Year. The projected price for the Rate Year is $60.17/MWh, which translates to about a $9M increase in HQUS PPA expense from the Test Year. Looking forward, as inflation and energy prices moderate, the HQUS PPA price will also moderate and year-over-year costs will be relatively flat.

Net-Metering

Q22. What are the costs associated with net-metering?

A22. The power supply costs associated with net-metering for the Rate Year are $52.7M compared to costs in the Test Year of $44.4M and costs in the current Rate Year, FY22, of $49.9 M, for a change of $8.3M from the Test Year to the Rate Year for this 307,000

MWh of energy. This Test Year to Rate Year increase in costs for net-metering is similar in scale to the cost increase for the HQUS PPA, but net-metering meets only 7% of our energy needs for the Rate Year compared to 24% for the HQUS PPA. The increasing costs reflect continued deployment of net-metered projects even though the rates paid are gradually decreasing.

Costs are estimated by applying applicable rates to expected generation in each program.[3] NM 1.0 projects retain the environmental attributes and are compensated at retail rates plus an adjustor, with positive adjustors expiring after 10 years. During the Rate Year, there are more than 7 MWs of projects that will have expiring adjustors, resulting in lower costs, which are offset by rising retail rates. The total cost of NM 1.0 is projected to be $34.3M in the Rate Year. Starting with NM 2.0, the compensation structure changed, and project compensation is based on residential retail rates, REC ownership and project siting, denoted by category. A mix of Categories I, II, III, and IV net-metering projects were assumed, with almost half of the projects assumed to be larger and in Category III. While the residential rates have been increasing, the REC and siting adjustors have been adjusted downward in accordance with Rule 5.100. All future net-metering projects are assumed to assign the RECs to GMP in exchange for higher compensation. NM 2.0+ projects are expected to cost $18.4M.

[3] Net-Metering 1.0 (NM 1.0) includes net-metering projects with an application date before January 1, 2017. Net-Metering 2.0+ (NM 2.0+) includes all net-metering projects in subsequent net-metering programs (e.g. Net-Metering 2.0, Net-Metering 2.1, etc.) with application dates on or after January 1, 2017.

Q23. Does this represent the full impact of net-metering costs on GMP's rates?

A23. No. In addition to the power supply costs described above, net-metered generation that is consumed by customers onsite reduces GMP's retail sales (kWh). The lower retail sales effectively increase GMP's rates for customers by reducing the volume of sales over which GMP's cost of service can be spread.

Q24. Can you expand on how net-metering affects GMP's Rate Year power costs?

A24. Net-metering affects GMP's Rate Year power costs in several ways:

- Net-metered generation that is consumed onsite to offset load reduces GMP's retail sales and revenues. This impact is reflected in the retail sales and revenue forecast performed by Itron as described in more detail in the testimony of Mr. Ryan and Mr. Bingel.
- Net-metered generation beyond customers' load is called Net-Metered Excess and is represented as a power supply resource and booked as a purchased power expense. All generation from off-site group net-metering projects is considered Net-Metered Excess at net-metering rates. Additionally, when the generation of an onsite project exceeds the customer's monthly usage, that excess generation is considered Net-Metered Excess. Net-Metered Excess tends to be greatest in the months of high solar generation and moderate customer loads.
- Net-Metered Excess costs also include adjustors that are applied to all net-metered generation, whether consumed-onsite or excess generation. Adjustors are based on a project's application date, size, siting location, and REC disposition. Positive

adjustors expire after 10 years, while negative adjustors continue for the life of the project.

- Net-metered generation reduces the volume of energy that GMP needs to purchase from the wholesale market or other sources. The avoided purchase requirements are weighted toward the summer and spring seasons, and toward the days and hours when Vermont solar generation is highest.
- RECs from net-metered projects that elect to transfer the RECs to GMP and came online after July 2015 are used for Tier II compliance. NM 1.0 did not differentiate compensation based on whether a customer elected to transfer or retain the RECs. Therefore, GMP does not receive a meaningful amount of RECs from NM 1.0 projects. Customers with NM 2.0+ projects who transfer the RECs to GMP receive greater compensation than customers who retain the RECs. As a result, most NM 2.0+ projects transfer the RECs to GMP, which are then used for GMP's Tier II RES compliance.
- To the extent that net-metered projects are producing at the time of ISO-NE's annual peak load, GMP customers will benefit through a reduced GMP share of annual FCM requirements starting in the following June. An estimate of these savings is included in the Rate Year power costs.
- Monthly transmission peaks on the VELCO system have shifted to evening hours when solar output tends to be small or zero. GMP does not expect that additional net-metered solar power will provide any meaningful reduction in peak-driven RNS costs.

Q25. Is net-metering capacity expected to continue to grow in the Rate Year?

A25. Yes. In calendar year 2021, GMP received net-metering applications for almost 35 MW of projects. As of the end of 2021, there were 46 MWs of projects in the queue, meaning projects that have submitted applications but have not yet been built. Additionally, the pricing and terms available to future net-metering projects appear at this time to remain attractive for developers and customers to install new projects. Future project development will continue to be supported by the Federal Investment Tax Credit ("ITC") that is expected to remain at least through calendar year 2023 along with the prospect for continued declining capital costs.

Q26. How much met-metering capacity is included in Rate Year costs?

A26. The volume of net-metering projects in the Rate Year was developed using actual installed net-metering projects through the Test Year, estimated future projects based on the current queue, and expected future applications informed by historical trends.

Net-metering projects are categorized by program (e.g. NM 1.0, NM 2.0, NM 2.1, etc.) based on their application date and costs estimated based on the program's compensation rates and applicable adjustors. At the end of 2021, there were about 246 MW[4] of solar net-metered projects online in GMP's territory, and an additional 46 MW that have submitted applications but are not yet built. The table below shows a summary of the project applications and installations by program at the end of 2021.

[4] At the end of 2021, there was 253 MW of installed net-metering capacity made up of 246 MW of solar and 7 MW of non-solar projects.

PROGRAM	NM 1.0	NM 2.0	NM 2.1	NM 2.2	NM 2.3	NM 2.4	TOTAL
Active	140	47	24	27	7	1	246
Proposed	0	2	5	17	16	5	46
Total	140	49	29	44	22	6	291

By the end of the Test Year, there was 236 MW of solar net-metering installed with an additional 31 MW expected during the Interim Year, and 28 MW more expected to come online during the Rate Year. New net-metering is made up of a combination of projects in programs NM 2.0 through NM 2.4, with more than two-thirds falling under NM 2.4 and future programs, and about 20% in NM 2.2. By the end of the Rate Year, we have projected almost 295 MW of solar net-metering to be online in our territory.

Other Renewable Power Sources

Q27. Do the changes in GMP's power supply mix in the Rate Year include any increases in supply from renewable sources?

A27. Yes. GMP's power supply strategy has focused on meeting the goal of a low-cost, low-carbon, and reliable portfolio and has seen additions of significant renewable resources in recent years. We set a goal to be carbon-free on an annual basis by 2025 and were able to meet that goal early, in 2020, and expect to maintain a carbon-free portfolio annually going forward. We will be 100% renewable on an annual basis by 2030. Notable changes in the Rate Year power supply include anticipated increases in production from net-metering and Standard Offer programs, and a new hydro PPA from Great River Hydro. Many of the other changes in GMP's power supply mix are associated with shorter-term transactions that GMP uses to manage the size and cost of its open position, while also managing GMP's power costs and thereby the retail rates that our customers pay.

Q28. Are GMP's purchases under Standard Offer reflected in the Rate Year power costs?

A28. Yes. All projects that are currently online as part of Standard Offer are included in Rate Year power costs at the contracted prices. Additionally, GMP has worked with the administrator VEPP Inc. to identify projects that have been awarded Standard Offer contracts and are likely to be online during the Rate Year. These projects are also included in GMP's Rate Year power costs. Standard Offer costs included in the Rate Year are $19.6M, compared to the $18.6M that was included in Rate Year 2022 costs and $15.5M in the Test Year. Contracts are now awarded through a competitive RFP process, resulting in lower contract prices; as a result, the average cost of the generation has decreased from $175/MWh in the Test Year to $158/MWh for the Rate Year.

Q29. Is GMP's PPA transaction with Great River Hydro reflected in the Rate Year power costs?

A29. Yes. Deliveries of energy and environmental attributes from the Great River Hydro PPA will begin in January 2023. The contract includes two distinct energy delivery schedules: peaking and firm baseload. In 2023, peaking deliveries will begin and provide 20% of the hourly output from three units on the Connecticut River, called the Fifteen Mile Falls facilities. Deliveries during the Rate Year are expected to be around 107,000 MWh.

Additionally, Great River Hydro will deliver 800,000 Vermont Tier I qualified RECs annually beginning in 2023.

Q30. How is GMP JV Solar included in Rate Year power costs?

A30. As detailed in Mr. Ryan and Mr. Bingel's testimony, on October 1, 2022, the five GMP JV Solar projects will become wholly owned by GMP. The Test Year included $2.9M in PPA costs as well as $30/MWh REC expense from these projects. With the transition to GMP ownership, there will be no PPA costs or REC expenses associated with the 35,000 MWhs of expected annual generation from these projects beginning in the Rate Year. Additional costs are included elsewhere in the Cost of Service.

REC Revenues and RES Compliance Costs

Q31. Please describe how GMP participates in REC markets.

A31. GMP is both a buyer and seller of regional RECs. GMP acquires and retires RECs to demonstrate compliance with the Tier I (total renewable) and Tier II (distributed renewable) requirements of the Vermont RES. GMP retires RECs from both owned and purchased resources for compliance. Costs associated with these retired RECs are represented as a power supply expense.

GMP also sells RECs, to be used for compliance, in neighboring states. Most REC sales are associated with renewable generators that were developed during the past decade and are eligible as Class 1 RECs in neighboring states but are not eligible for Tier II in Vermont because they are larger than 5 MW or were completed before July 2015. Many of these projects were developed to support the rapid development of renewables under the framework of Vermont's former SPEED program. These resources fill an important role in GMP's energy supply by helping provide stable-priced power that reduces the amount of energy and capacity that must be purchased from the ISO-NE market or other sources, but they do not contribute to GMP's RES compliance. When GMP sells RECs from these sources, the revenue is used to reduce GMP's net power costs and retail rates which directly benefits customers. Importantly, GMP does not count the generation from these resources as renewable energy delivered to our customers.

Q32. Please explain how REC revenues affect GMP's net power supply costs, and how net REC revenues for the Rate Year were developed.

A32. GMP's supply portfolio produces substantial volumes of RECs—particularly from wind, solar, hydroelectric, and biomass sources—that typically qualify as Class I or Class II resources for RPSs in neighboring states. These RECs are tracked in the NEPOOL Generation Information System ("GIS," or "NEPOOL GIS"), the platform used to track all environmental attributes in ISO-NE. In NEPOOL GIS, each MWh of generation actually delivered in the region has an associated environmental attribute that describes the fuel type, emission rate, renewable program eligibility, and other attributes.

GMP seeks to meet the RES requirements in the most cost-effective way for customers by continuing to procure renewable power and achieve Tier III savings at the lowest cost. In 2020, as reported in our Annual RES Compliance Filing, GMP achieved a 100% carbon-free portfolio that was also about 68% renewable. By 2030, we have committed to reaching 100% renewable, and our approach to RES compliance has us meeting those commitments.

During the Test Year, GMP sold most high-value RECs, except for those needed to cover volumes subscribed to under GMP's voluntary retail green power programs and those required for meeting GMP's obligations under Tier II of Vermont's RES program. Additionally, GMP retired significant volumes of Tier I qualified RECs to comply with Tier I of the RES program. Each year, RES requirements increase with calendar year 2023 requirements of 63%, 4.6%, and 6.0% for Tiers I, II, and III, respectively. We anticipate using the same approach to REC sales and retirements in the Rate Year as the Test Year and have estimated GMP's net power supply costs accordingly.

REC sales and retirements are straightforward in concept, but there are several unique features of REC markets and the associated accounting for REC revenues and expenses. First, GMP recognizes REC revenues net of the portion of PPA prices that GMP accrues for the cost of RECs produced by most renewable PPA sources (e.g., Granite Reliable Wind, Deerfield Wind, etc.) and any associated REC sale transaction costs such as broker fees. Second, the creation and delivery of RECs in the NEPOOL GIS, and the revenue that GMP receives from REC sales in that quarter, are conducted on a quarterly basis that lags production of the associated energy by approximately six months. Consistent with this lag, estimated REC revenues for the Rate Year are based on renewable energy production from the applicable sources during the 12-month period from April 2022 through March 2023.

Q33. Can you summarize how and when GMP conducts its REC sales?

A33. GMP has sold most of the projected Rate Year supply of high-value RECs on a forward basis, under contracts that were negotiated from a few months to several years in advance of delivery. This helps control costs for customers. These are mostly fixed-volume, fixed-price contracts that reflect the regional market for Class 1 RPS supply on the dates they are negotiated. This forward-sale approach helps stabilize net power costs and mitigate the risk of potential declines in regional REC market prices. We have assumed that the remainder of the REC supply will ultimately be sold at prices that reflect recent broker quotes. In total, we project that GMP's Rate Year premium REC sales will amount to over 1.1 million RECs, at an average sale price around $32.50/REC, for gross revenue of almost $36M to reduce overall rates.

Q34. What are the estimated net REC revenues for the Rate Year?

A34. **Exh. GMP-MF-18** presents the Rate Year figures by month, in terms of their major components. After incorporating the REC purchase portion of PPA expenses that are noted above, the resulting net REC revenue is about $18.4M for the Rate Year, an increase of $6M over the Test Year and an increase of $3.5M over what is included in our current rates for FY22. The increase is largely due to higher REC market prices, driven by delays in regional mega projects that have eroded the supply surplus that was present during the Test Year. Most RECs that will be delivered during the Rate Year have prices that have been locked in through forward sales, again providing benefits to customers.

Q35. Do the net Rate Year power costs that you are presenting also include costs associated with compliance with Vermont's RES requirements?

A35. Yes. Besides the net revenues associated with REC sales as described above, the power costs include about $17M in estimated costs associated with RES compliance for 2023 and 2024, an increase of about $3M from the current Rate Year. The increase is a result of the program's year-over-year increasing requirements.

Q36. Are there any notable features associated with the estimation of RES compliance expenses that you would like to mention?

A36. Yes. Under the RES program, utilities may "bank" RECs above the current year's RES requirement in the NEPOOL GIS and use those banked RECs for compliance in future years. In the event that GMP banks RECs in excess of compliance requirements in a year, we defer the costs associated with the excess RES compliance and recognize them as expenses only in the year that the RECs are used to meet RES requirements.

Energy Market Purchases

Q37. Have you made any Rate Year adjustments to GMP's net energy market purchases? If so, why?

A37. Yes. Net bilateral energy market purchases of fixed-price purchases for terms of less than five years decline by about 89,000 MWh from the Test Year to the Rate Year, as some existing purchases expired. A primary reason for the trend of declining bilateral market purchases is that increasing amounts of GMP's energy needs are being met with renewable sources. The nominal decrease in costs resulting from changes in these purchases is about $2.6M; the average price of the remaining purchases increases from about $44.55/MWh in the Test Year to about $46.30/MWh in the Rate Year.

Forward Capacity Market Costs

Q38. Please explain how the FCM works and GMP's capacity obligation in that market.

A38. The FCM is the market-based mechanism by which ISO-NE ensures that sufficient capacity resources are in place to meet the future demand for electricity. Annual Forward Capacity Auctions ("FCAs") are conducted for the delivery of capacity three years in advance of the capacity period, which runs for the 12-month period from June through May. Resources participate in the auction to acquire a commitment to supply capacity and are compensated at a market-priced payment rate. Capacity market prices are driven by the supply of and demand for capacity resources, and the prices at which participants are willing to commit to supply capacity.

Load-serving entities, like GMP, are responsible for a share of the capacity that ISO-NE purchases each year; these capacity requirements are allocated to load-serving entities based on their respective contribution to the ISO-NE annual peak load. GMP may meet that obligation using its owned or purchased capacity resources, or through payments to ISO-NE.

Q39. What are the capacity costs for the Rate Year?

A39. Capacity costs in the Rate Year are expected to be $35.8M, a $6.4M decrease from the Test Year. The decrease is driven by known lower clearing prices for FCAs 13 and 14, the expiration of higher-priced bilateral capacity contracts, and battery initiatives that help reduce GMP's coincident peak load. FCA 13, which applies to the Capacity Period from June 2022 through May 2023, had a clearing price of $3.80/kW-mo and applies to eight months of the Rate Year. The other four months of the Rate Year are in Capacity Period 14, with a clearing price of $2.00/kW-mo. During the Test Year, applicable Capacity Periods 11 and 12 had clearing prices of $5.30/kW-mo and $4.63/kW-mo, respectively. The Test Year also included bilateral capacity purchases that were replaced by ISO-NE purchases at a lower cost.

Ancillary Services, Congestion, and Losses

Q40. Have you made any adjustments for ancillary service charges or congestion in the Rate Year?

A40. Yes. Charges for ISO-NE ancillary services, congestion, and losses of $6.2M are included in net power costs for the Rate Year, compared to about $5.4M in the Test Year. This category includes the net marginal loss and congestion components of energy costs for all purchases and sales of energy with ISO-NE, as well as the net cost for ancillary products including reserves, net commitment period compensation, and regulation.

The net ancillary costs reflect charges that are based on GMP's load, less ancillary revenues that GMP resources provide. Marginal losses and congestion are the largest components of this category and are projected to increase from $4.9M in the Test Year to $5.9M in the Rate Year, largely because energy prices in the Rate Year are projected to be higher than in the Test Year. Offsetting some of this effect is the Lowell-to-Morrisville transmission project, which is expected to alleviate some of the high congestion charges experienced by Kingdom Community Wind, HQUS imports, and

Sheldon Springs. The upgrade has been completed, but not yet reflected in ISO-NE modelling; it is expected to be reflected for all of the Rate Year. For the Rate Year, we have assumed congestion costs (as a percentage of energy prices) to be less than half of what was experienced during the Test Year for Kingdom Community Wind, HQUS, and Sheldon Springs, providing benefits to customers.

Other ancillary costs are estimated using Test Year actual charges and credits, adjusted for energy market prices which are higher for the Rate Year than the Test Year.

Q41. Are there any other significant changes in energy costs you wish to highlight?

A41. Yes. Other notable changes affecting GMP's net energy costs are as follows:

- Generation from Kingdom Community Wind is consistent with the annual generation volumes assumed when the Project received its Certificate of Public Good. Average historical generation is not an appropriate expectation for the Rate Year because of the important upgrades coming online to alleviate transmission constraints. Mr. Castonguay's testimony discusses the specific upgrades in more detail.
- In the Rate Year, projected generation from GMP-owned hydro units is projected to be 87,000 MWh higher than the Test Year. In recent years, New England has experienced significant drought conditions, which affected Test Year generation. Rate Year generation is based on a historical 20-year average, adjusted for known changes such as plant upgrades or river flow requirements and planned outages.

IV. Transmission Costs

Q42. Please provide an overview of GMP's purchased transmission and related costs.

A42. GMP's purchased transmission costs consist of Regional Network Service ("RNS") charges that are part of the NEPOOL Open Access Transmission Tariff ("NOATT"), VELCO 1991 Vermont Transmission Agreement ("'91 VTA Common") charges, Hydro-Quebec Phase 1 and 2 support charges, various ISO-NE and NEPOOL tariff charges, and a number of smaller charges from other utilities whose transmission facilities GMP uses. Transmission costs have grown significantly in recent years, primarily for RNS due to the region's high-voltage Pool Transmission Facilities ("PTF") transmission network. RNS costs represent approximately 67% of all purchased transmission costs for the Rate Year, and are out of GMP's control.

VELCO '91 VTA Common charge costs are generally the second-largest component of transmission costs but can vary significantly from year to year. Under the '91 VTA Common, net VELCO monthly costs are assigned to Vermont electric distribution companies based on each utility's share of trailing 12-month coincident and non-coincident loads, reduced by the Purchaser's Internal Generation Adjustment ("IGAP") credits. '91 VTA Common charges are a limited fraction of total VELCO costs due primarily to reimbursements through ISO-NE for VELCO's PTF assets, which typically represent 80% or more of VELCO's revenues. Please see VELCO Chief Financial Officer Michele Nelson's testimony for more information on VELCO's actual

Test Year and projected Rate Year costs and revenues, and the resulting increase to the '91 VTA Common charge.[5]

Q43. What is the projected change in purchased transmission costs between the Test Year and Rate Year, and what are the drivers of the increase?

A43. Purchased transmission costs (which include certain ISO-NE tariff charges) for GMP are projected to increase from $114M in the Test Year to $119M in the Rate Year, an increase of $4.8M. It is important to keep in mind that these net figures are affected by the removal of GF from our cost projections starting in FY23. Outside of this downward adjustment, the primary driver of the difference between Test Year and Rate Year is a projected $6.6M increase in the VELCO '91 VTA Common charge (which is based on Ms. Nelson's testimony regarding VT Transco costs and revenues). All other purchased transmission costs are projected to decrease $1.8M. As described earlier, an important difference between the Test Year and the Rate Year is GMP's share of VELCO's total, which in the Test Year was 78% but is assumed to decrease to 71.7% in the Rate Year when GF is no longer included in GMP's load.[6]

GMP charges for RNS were $81.7M in the Test Year and are projected to decrease to $80M in the Rate Year. This decrease reflects significantly lower monthly peak loads resulting from GMP's many successful peak shaving measures, including

[5] Ms. Nelson's testimony presents statewide figures. GMP's share for the Rate Year is expected to be 71.7 percent of VELCO's total, which does not include GF in GMP's load.
[6] In the event that GF remains a retail customer in FY23, our VELCO share would remain at 78%, and as noted above, and as described further in Mr. Ryan and Mr. Bingel's testimony, GF retail payments would be tracked in our existing power supply adjustor mechanism in a manner that is rate neutral for our customers, regardless of GF's status.

various battery programs, and the removal of about 50 MW of peak demand each month associated with GF, which is not included in GMP's load beginning in October 2022 for RNS billing purposes.[7] Absent this adjustment to peak loads, RNS costs would have seen a significant increase for customers consistent with the rate increase from $133/kw-year in the Test Year to over $148/kw-year for the Rate Year, or an 11% increase. The increase in RNS rates is largely due to ongoing increases in overall PTF costs in the region, reflecting increases in the net bulk transmission plant in service. Because New England is not experiencing growth in peak loads, increasing PTF costs translate to higher RNS rates on a dollar-per-kW basis. Helping to mitigate these increasing rates are GMP's important peak shaving resources.

From the Test Year to the Rate Year, GMP's VELCO VTA Common charge expense is projected to increase from $20.2M to $26.8M, an increase of about $6.6M. Ms. Nelson explains the primary reasons for the increase. In summary, VELCO's revenue requirement is projected to increase by about $12.4M from the Test Year to the Rate Year. Primary drivers of this increase are revenue requirements associated with major construction projects placed in service in 2021 and 2022 and increased maintenance and administrative costs. At the same time, revenues from sources other than the VTA Common charge are expected to only increase by about $3.5M, as the share of VELCO's revenue requirements that will be recovered through RNS charges is projected to drop to about 81% in the Rate Year from about 84% in the Test Year.

[7] As with other transmission costs, in the event that GF remains a retail customer in FY23, any variation in RNS costs would be captured in adjustors under the New Plan in a rate neutral manner.

Reasons for this shift include high coincident regional peaks during the Test Year that delivered an additional $5M in revenues, as well as the return of excess Accumulated Deferred Income Tax ("ADIT")[8] which will lower VELCO's revenue requirement.

Q44. What are some of the other projected changes in Transmission costs?

A44. Purchased transmission costs excluding RNS and VELCO VTA Common are not expected to change significantly from the Test Year.

V. Fiscal Year 2024–26 Power Supply and Revenue Forecasts

Q45. How has GMP developed its power supply and revenue forecasts for the remainder of the New Plan?

A45. Power supply costs and revenue forecast for the remainder of the New Plan, through FY26, used the same methods used for the Rate Year.

Based on Itron's retail sales forecast plus distribution losses, a forecast of the cost to serve that load is developed. This forecast incorporates many of the same adjustments described in the traditional rate filing and above in my testimony. A summary of projected power supply costs by year of the New Plan is set forth in **Exh. GMP-MF-23**. Some notable items for Fiscal Years 2024, 2025, and 2026 include the following:

- Increasing energy deliveries from Great River Hydro, Standard Offer, and net-metering.

[8] On December 22, 2021, FERC issued an order in Docket Nos. ER20-2572-000 and ER21-1130-000 accepting New England Transmission Owner's ("NETO") Settled Formula Rate to go into effect January 1, 2022, as reflected in the VELCO forecast used for the Rate Year.

- Forward energy market prices to reflect broker quotations from December 6, 2021, consistent with the forwards used for the Rate Year. Average around-the-clock energy prices gradually decline from the Rate Year throughout the forecast period, with the annual average for FY26 about 7% lower than the Rate Year.
- Projected PPA costs for indexed contracts such as HQUS and Seabrook reflected forecasted PPA prices. Inflation and forward market prices are expected to subside in the future, which will result in more moderate annual changes than experienced in the Rate Year.
- The current Ryegate contract, which provides about 135,000 MWh of energy annually, will expire at the end of Calendar Year 2024 in accordance with current statutory authority. Given that, we have not assumed a further extension of the contract; the MWhs will be replaced at market prices, which are significantly lower than the contract price and will save our customers money.
- GMP currently has a lease with HydroQuebec ("HQ") for GMP's share of the Phase 2 transmission line to HQ in exchange for a fee along with environmental attributes associated with output from hydroelectric projects in Quebec that are imported into New England. The current agreement expires at the end of 2024. This agreement is not assumed to be extended, nor a similar agreement entered into.
- Annual increasing costs for compliance with RES to reflect increasing requirements for Tiers I, II, and III.

Q46. How and why will these forecasts be adjusted during the New Plan?

A46. These forecasts will be updated each year in the Annual Base Rate Filing. As explained by Mr. Smith in his MYRP testimony, while GMP's power supply portfolio features many relatively stable contracts, over the duration of the New Plan total power supply costs will continue to be subject to changes that may not be foreseeable at the time of this filing. Annually adjusting the retail sales and power costs will ensure that GMP's electric rates reasonably reflect expected net power supply costs and retail electric sales for the current year, and limit reliance on adjustors to collect or return funds to customers. This annual adjustment framework has previously been approved by the Commission in Case No. 18-1633-PET and is supported by the Department in this proceeding.[9] Therefore, while these forecasts are important to include in a consideration of our overall cost of service and rate path through the term of the New Plan, GMP's actual base rates will be set by reference to annual reforecasts, closer in time to incurring power supply costs.

Q47. Do you wish to make a revision to a New Plan exhibit?

A47. Yes, as described by Mr. Ryan and Mr. Bingel, GMP has submitted a revised, redlined version of **Exhibit GMP-ER-RB-1, Attachment 4** in the New Plan proceeding. The revision reflects the addition of FERC account 555.1, Power Purchased for Storage Operations, in Component A, and also makes minor corrections of typographical errors. Costs associated with charging energy for battery operations are reported under FERC account 555.1. Please see the exhibit for details of these revisions.

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[9] *See* Case No. 21-3707-PET, *Direct Prefiled Testimony of Philip Picotte* at 4, 6.

Q48. Does that conclude your testimony at this time?

A48. Yes.