New Hampshire Electric Cooperative, Inc.

Minutes of the Meeting of the

Budget, Finance & Rates Committee

December 12, 2025

Present: Committee Members: Jerry Stringham (Chair), Alana Albee, Bill Darcy, Leo Dwyer, John Goodrich, and Peter Laufenberg

Other Board Members: Tom Mongeon, Jeff Morrill, Harry Viens, Bob MacLeod

NHEC Employees: Michael Jennings, Kristen Taylor, Josh Mazzei, Jeremy Clark, Rob Howland, Christine Alexander, Christine Parent (recording)

Meeting Called to Order

Chair Stringham called the meeting to order at 9:00 am.

Agenda Review and Approval of 11.21.2025 Meeting Minutes

There were no suggested changes to the agenda.

Chair Stringham asked if there were any comments or requested changes to the Draft 11.21.2025 meeting minutes. There were none.

Upon motion from Mr. Goodrich, seconded by Mr. Darcy, it was

VOTED: That the Committee approves the 11.21.2025 Budget, Finance & Rates meeting minutes.

Vote was unanimous.

Co-op Power/RAC Rate Change

Mr. Clark shared the Co-op Power/RAC Change as follows:

- 2026 Rate Timeline
  - January
    - Distribution
    - Schedule Of Fees
    - Energy Efficiency
  - February
    - Co-op Power (Proposed)
    - Regional Access (Proposed)
  - August
    - Co-op Power
    - Regional Access
- Rate Components – The proposed February 2026 Co-op Power and Regional Access rate change affects two of four rate components:
  - Regional Access
    - Transmission, Demand Response, Facilitate Competitive Supplied Energy, RGGI Credits
    - Collected through: kWh Charge on all electricity

    - Adjustment Month: February, August
  - Co-op Power
    - Energy, Capacity, Ancillary Services. Renewable Energy Certificates, etc.
    - Collected through: kWh Charge (Co-op Power Charge does not apply to members with competitive suppliers or community aggregations)
    - Adjustment Month: February, August
- Late Fall 2025
  - After a mild start to the fall 2025 rate period, November and December have been colder than normal.
  - Staff typically lock down spring rate forecasts around Thanksgiving.
  - Based on the forecast at that time, the projected February 1, 2026 Co-op Power under-recovery balance was $1.5 million
  - Early December has been significantly colder than normal, resulting in high loads and historic spot market prices
    - The first 9 days of December ranged from 6 to 22 degrees colder than average
    - This hits rates hard
  - As a result, staff updated fall 2025 rate period projection with current data this week
  - The updated load and pricing data projects a $5.5 million under-recovery balance as of February 1, 2026
- Co-op Power Load Projection
  - Projected co-op Power Load – current August 2025 Rate Period
  - With updates to November and December our updated projection for the current six-month period shows a 2% increase in load.
  - Energy Coverage ratio goes down 2%
  - Capacity goes up 1%
  - Billed Sales are up about 4%
- Co-op Power Cost Projection
  - Due to increased load and LMP, energy costs are up 14%
  - Capacity is about the same
  - Renewable costs are up 9% due to DOE adjusting the RPS Class III requirement
  - Ancillary Services, Day-Ahead Ancillary Services Initiative (DASI) 31% higher
  - Total Cost change is $4.2 million, or 13%
  - Billed Revenue is up 4% due to increased sales
  - Overall, there is a shortfall
- Co-op Power Over/Under Recovery
  - Current Rate Period
    - Forecast $4 million under-recovery on August1, 2025
    - $2.0 million to be collected in rate period
    - 0.6¢ per kWh embedded charge
  - Original February 2026 Ratr Period Projection
    - Forecast $1.5 million under-recovery on August 1, 2025
    - $0.7 million to be collected in rate period
    - 0.2¢ per kWh embedded charge
  - February 2026 Rate Period
    - Forecast $5.5 million under-recovery on February 1, 2026
    - $2.7 million to be collected in rate period
    - 0.9¢ per kWh embedded charge

        - +0.7¢ per kWh change vs. original proposal
- Co-op Power Load Forecast
    - Load Obligation - Spring rate period typically has less load than the fall rate period because there is typically only one cold winter month; -3% vs. August rate period
    - Energy Coverage Ratio – about two-thirds
    - Capacity -1%
    - Net Billed Sales -1%
- Co-op Power Cost Forecast
    - Energy, -10% (lower energy costs)
    - Capacity, 4% (Higher Net Regional Clearing Price)
    - Renewable, 15% (Class III RPS requirement increase)
    - Ancillaries, 28% (Day-Ahead Ancillary Services Initiative)
    - Other, -28% (Lower interest charges)
    - Total Cost, -6%
    - Billed Revenue, -4% (Lower Co-op Power rates)
- Co-op Power Proposed Rates
    - For Basic, most members: Proposed 11.117 cents per kWh, or 3% decrease, compared to current rate
    - Will most likely be lowest of four major utilities in NH
    - Net metering credit goes up a little
- Regional Access Cost Projection
    - RNS slightly higher than forecast
    - RGGI Rebate, due to lower summer 2025 rebate, -16%
- Regional Access Over/Under Recovery
    - Current Rate Period
        - Forecast $0.3 million under-recovery on August 1, 2025
        - 0.1¢ per kWh embedded charge
    - February 2026 Rate Period
        - Forecast $2.0 million under-recovery on February 1, 2026
        - 0.25¢ per kWh embedded charge
- Regional Access Cost Forecast
    - 12 month forecast
    - RNS Load up 1% vs. August rate period
    - Net Billed Sales up 1%
    - RGGI rebates down -27%
    - Total Cost up 9%
    - Billed Revenue up 13%
- Regional Access Proposed Rates
    - For most members: 4.290 cents per kWh, or 10% increase compared to current rate
    - Primary Ski: 4.053 cents per kWh, or 43%
    - Net Metering credits: up due to coincidence with RNS peaks in the past year
- Residential Bill Impact
    - 500 kWh Basic Total Bill $0.25 per month increase
    - 1000 kWh Bill $0.50 per month increase

Mr. Clark shared the Board Resolution.

Discussion:

- Mr. Dwyer asked if the regional access charge is set each month by the peak hour in the month. Mr. Clark asked if Mr. Dwyer meant the transmission costs. Mr. Dwyer replied the transmission costs are the major part of the regional access. Mr. Clark replied that is correct, and we update the rate every six months to reflect that. Mr. Dwyer asked if that is based on our peak as a portion of the coincident peak rate of the whole system. Mr. Clark stated it is based on our readings at the time of the RNS peak. Mr. Jennings added that there is also consideration of how much revenue they've received and what's owed. That also gets adjusted to make sure they get their return on equity for the transmission investments. If the load is higher or lower each year based on that, the rate that applies to the load serving entities would be adjusted accordingly.
- Chair Stringham asked if it is average load or peak load used in terms of our portion coming off the energy grid. Mr. Clark replied for RNS it is the hourly reading of that one peak hour each month. They will look at all of our substation readings in that hour and that will be our portion of that reading relative to the overall readings. It has nothing to do with our overall KWH throughout the month, it's just that one hour. Mr. Mongeon asked if the LNS factors into this too. Mr. Clark replied there are three different transmission products that are included in this rate, including LNS and interconnection and delivery (I&D).
- Mr. Darcy asked if the 5% rate set by DOE for the 2025 RPS Class III REC obligation is subject to review by legislature. Mr. Clark responded the 5% is within the DOE's jurisdiction for 2025. By statute it is up to 8%, but the DOE has recommended to the legislature 5% in the future. Mr. Darcy stated we used to have the PUC adjust that to half of 1% and asked if they have that jurisdiction now or if that is limited. Mr. Clark responded that the jurisdiction was moved to DOE, and they had set it at 1% in 2024, and they set it at 5% for 2025.
- Mr. Dwyer asked what it means that 45% of our purchase is coming from the spot market. Mr. Clark responded that it is from the load forecast, and it is more now due to the incremental load from the weather. Mr. Dwyer asked if that is unusually high. Mr. Jennings responded this was the first time we went with the new purchasing plan, and we proposed to do a third long-term, a third short-term and a third exposed. We didn't approve the third long-term, so we had more than one third exposed to the market this rate period.
- Mr. Goodrich asked how the over and under recovery calculation is done. Mr. Clark replied we take our over or under recovery at the start of the rate period and spread that balance over the next two rate periods so you're not having volatility or hitting seasonal members with something they may not have created. Mr. Goodrich asked if it's a daily calculation or an accumulation. Mr. Clark replied this is based on actuals through October and projections for November, December and January. Mr. Jennings added that our rate is flat through the rate period, but prices per month vary. We project the difference between rate revenue compared to the cost. We have months within each rate period that we expect to be over or under, and this totals them for the remainder of the rate period.
- Ms. Albee asked for additional information on RGGI and why it impacts rates. Mr. Clark responded by sharing the RGGI Rebate Forecast. Growth was built into rates, but the growth did not happen. Ms. Albee stated she doesn't understand what is pushing the dramatic change. Mr. Dwyer asked what the auction is for. Mr. Jennings replied it is carbon credits, and less people are bidding, which causes the decrease. He added it is essentially the CO2 allowances for generators for the states that choose to participate in it. Mr. Dwyer asked if that means there's less carbon in the mix. Mr. Jennings replied he would assume that.

- Mr. Darcy stated there is only a 2/10 of 1% increase, and this is a great result for our members. Mr. Jennings added that Investor-Owned Utilities are about 50% exposed. He also thanked the team for noticing and responding to the recent price changes. Mr. Jennings added he thinks we will have the best rate compared to other utilities in the state and agreed that it's a great result.
- Chair Stringham added that usage has not gone up, but the price is higher, so the energy we are using is more expensive and we are charging at the old rate. Mr. Jennings replied that that is the greatest contributor. There is additional load that's coming in at a higher price as well, but the greatest contributor is driven by the price. Mr. Dwyer added that a significant impact is that we were less hedged than we usually are in terms of pre-buying and pre-committing, so we were more exposed without the increased load.

Upon motion by Mr. Laufenberg, seconded by Mr. Dwyer, it was

VOTED: That the Committee recommend that the Board of Directors authorizes staff to set the Co-op Power and Regional Access Charges on a bills-rendered basis effective February 1, 2026 as recommended in the February 1, 2026 Co-op Power and Regional Access Rate Change Proposal presented to the Budget, Finance and Rates Committee on December 12, 2025.

Vote was unanimous.

Fall Hedging and Rate Purchasing Strategy

Mr. Howland presented the Fall 2026 Power Purchase Plan and Schedule Proposal

- Introduction & Summary
  - Fall 2026 Rate Period: August 1, 2026 – January 31, 2027
  - Total Load Forecast for Fall 2026 Period: 355,500 MWH
  - Recommendation:
    - Hedge 67% of Total Load
    - Continue to monitor market price daily, hedging at the current very high prices is not recommended
  - Purchasing timeframe: March 2026 – May 2026
- Load Forecast, Hedging Approach & Forecasted Pricing
  - Fall 2026 Total Load Forecast: 355,544 MWH
  - Total Cost Projection: $28.6 million, average rate of $80.56 per MWH
  - Total to Hedge 67%: 238,214 MWH
    - Average price $77.57/MWH
  - Already purchased 53,000 MWH with 42-month purchase contracts that were put in place early 2024 when prices were $57.36/MWH
  - Long-Term Renewables: $59.09/MWH
  - Need to Purchase: 163,176 MWH
    - Average current price: $86.64/MWH
    - This is high and why we will be waiting to purchase
  - Total Unhedged: Spot Market Purchases (33% of total load): 117,329 MWH
    - Average current price: $86.64/MWH
- Rate Planning Schedule
  - Six Purchases from March to May are flexible

  - The August 1, 2026 Rates Effective date is not flexible
  - Mid-May to June is not as flexible as when we can make purchases
- Long-Term Purchase Proposal
  - PR&A proposes hedging including one 6 MW flat strip long-term purchase starting August 1, 2026.
  - The proposed 5-year purchase beginning August 2026 would account for 1 of the 6 purchases needed to meet the Fall hedge.
  - Total MWH needed to purchase is 163,000, split into six purchases is around 27,000 MWH
  - A 6 MW purchase for 5 years will acquire about 263,000 MWH, or 7 ½% of total load over five years at a price of about $64/MWH, compared to over $80/MWH for the current six month fall period
  - Good idea to start thinking about long-term hedging
    - It is being discussed at the Board level
    - We hired a consultant, Aces, that gave us a report a year ago that said we should be starting to layer in some long-term purchases
    - Another company, Black & Veatch, looked at out power purchasing a few years ago and said the same thing
    - The commitment over a five-year period is $16.8 million
    - Presenting this to the Board
    - Prices are lower than what we can buy for the six-month fall period
- Long-Tem Natural Gas Spot Prices
  - When they go up, historically, they always come down
  - Current prices are high compared to the last 10 years, so based on history, we should see the natural gas price, and therefore, electricity prices come down
- Forecasted Market Price: Probability of Exceedance
  - January 2027 is extremely high
  - Probability of these prices coming down is very high
- Comparison of Historical LMP to Current Pricing
  - Another indication we are seeing very high prices, especially in December and January
- August & January Historical LMPs
  - There is a lot of variation in prices from January 2021 through 2025
- Five Year Hedge Forecast
  - Load forecast is flat
  - 67% hedge shows big difference in what we've committed to purchase and our load
  - The potential five-year purchase of 27,000 MWH is very small compared to what our forecasted load is
- Default Service Rates 2022 – 2025
  - From fall 2022 to fall 2025, NHEC has been a low-cost provider for most of that time
- Spring 2026
  - Estimated ISO-NE spot rate for remaining 33% not under contract: $0.07615/KWH
  - Rate for 42-mont contracts: $0.05736/KWH
  - Average rate for renewables PPAs:
    - Energy Only - $0.05945/KWH
    - All Products - $0.08653/KWH
- Renewable Portfolio Standards (RPS)

  - 2024 renewable portfolio standard obligation: 112,000 RECs, about $3.0 million
  - 2025 the obligations increased, and we are purchasing more RECs and market price has gone up, totaling $4.5 million

Discussion:

- Mr. Darcy asked if there is flexibility within the March through May timeframe to purchase. Mr. Howland responded, yes, there is flexibility. It makes sense to purchase over a period of weeks or a couple of months.
- Chair Stringham asked why we are waiting until March to purchase. Mr. Jennings replied costs fluctuate with the season and tend to decrease starting in March.
- Mr. Dwyer asked Mr. Howland if we know what is driving the higher prices. Mr. Howland replied the weather is the main driver, and natural gas production and usage plays a large role. In New England, the price of electricity is almost always tied to natural gas.
- Mr. MacLeod asked if Washington energy policies do what they are supposed to do if that would begin to decrease the cost of energy. Mr. Jennings replied that the price increases are not necessarily long-term, and the futures are looking a lot lower than near term.
- Mr. Goodrich asked if the timing is strictly individually determined or collectively determined. Mr. Howland replied that they are individually determined. He added that IOUs are controlled a bit more and have a narrow timeframe in which they need to purchase.
- Ms. Albee asked why the January 2027 Remainder Need to Purchase is so much higher, and why we wouldn't front load it more. She asked if it was unusual to let the remainder grow to that extent. Mr. Jennings responded that January uses a higher load typically and that is just the allocation for that given month. Ms. Albee asked why we don't front end more given that we know those are going to be higher load months. Mr. Jennings replied that is why we are purchasing more, because it is a higher load month.
- Mr. Darcy asked Mr. Jennings to break it down this way to show the Board how our flexibility is different from other utilities. They are required to make six-month purchases, which could be high-priced. NHEC has options to purchase longer term, and the 42-month contracts and long-term renewables are much cheaper.
- Mr. Laufenberg asked what gives us the flexibility that IOU's don't have. Mr. Jennings replied the investor-owned utilities are strictly instructed on how they have to procure. We have all the options in our toolbox on how we want to do it, whether it's timing or different hedging techniques or different purchasing strategies. Mr. Darcy added there have been bills in the legislature in the last three to four years to allow investor-owned utilities to have more flexibility to do long-term contracts, and they have not been enthusiastically embraced.
- Mr. Dwyer asked if we have run into any activity with the data centers. Mr. Howland replied that we have not. ISO New England says there is no activity that they are aware of in New England, other than a few small ones that are already in place.
- Mr. Goodrich asked if the price difference between three years and five years is favorable enough for us to go that route and asked Mr. Howland if he is put off at all by any risks. Mr. Howland replied it is a judgement call, and the lower price is nice and five years is a reasonable timeframe per our consultants. He added that most public power entities in New England look at the five-year timeframe for forward purchases.
- Mr. Jennings added this is the perfect opportunity to look at long-term purchases. This not only affords us the ability to reduce costs for the next rate period, but at the same time it helps us hedge against future volatility. If we were not looking long-term, the next rate period would have a higher increase just based on our current pricing that we see. Mr.

Jennings added it is advantageous to have some additional long-term hedging and that additional price decrease for that rate period.

- Chair Stringham stated that a lot of members have the opportunity to buy power from another source if our rates increase too much and asked what the worst-case scenario is in terms of load percentage. Mr. Jennings replied these long-term purchases are not made all at once and are more of a tiered approach.
- Mr. Darcy stated that he did not support a 42-month contract in June of 2024 because the staff never told them about it. The Board can now make informed decisions about what Mr. Howland and Mr. Jennings are proposing, and it seems to be a good measure of risk management.
- Mr. Goodrich asked who we would purchase power from. Mr. Howland stated we have six vendors with a master agreement for purchase power, and we can choose the best rate from them. The future energy cost figures are based on estimates given by the vendors.
- Mr. Dwyer asked how linked we are to other markets and if we could ever end up exporting electricity, or if we are so high-priced that it will never happen. Mr. Howland replied the connections to the outside word are two Canadian provinces, where we almost always import power from, except in emergency situations, and the state of New York. There are quite a few transmission interconnections to New York. The power flows both ways, but generally, there is no long-term obligation for New England to provide power to New York. Mr. Dwyer asked if we are generally priced higher than New York. Mr. Jennings replied ISO New England provides resource allocation for links with other ISOs and provinces to be monitored and revised to what the contribution could be to the capacity need for the region.
- Mr. Jennings stated we do need a resolution, because this is the first long-term purchase we are asking the Board for. He asked the Committee what they are comfortable with.

Mr. Goodrich made the following motion, seconded by Chair Stringham:

That the Committee recommend to the Board to support the strategy presented by Mr. Howland for long-term, five-year purchase contracts.

<u>Discussion on the Motion</u>:

- Mr. Darcy stated he is supportive of the motion and that it is a logical strategy to do longer-term contracts.
- Mr. MacLeod asked if this will go before the full Board for approval and added he thinks it's a great idea to move forward with Mr. Howland's proposal. Mr. Darcy stated the Board should vote on it, and this is a recommendation to the Board for approval and support.
- Ms. Albee stated It makes sense, and it's 7 ½% of the whole portfolio and it would be good to work towards what the benchmark is for. Mr. Jennings agreed that it is 7 ½% and stated this is a $16.8M purchase, and he would like the full Board's approval.
- Mr. Dwyer asked who else can participate in long-term contracts and specifically asked if IOUs can participate. Mr. Jennings stated it's more municipalities and cooperatives and some energy marketers. Mr. Dwyer stated in a way, what we are doing is lending our credit to the other guy. For example, you can't go out and finance a power plant just on "I want to have a power plant," you need a commitment for a long-term plan. Mr. Jennings replied a lot of companies are making commitments for energy over time and then taking it and reselling it to the load serving entities, so there are a lot of middle people. Mr. Dwyer asked if they are just taking the risk. Mr. Jennings replied, yes.

VOTE: For the motion was unanimous.

Focused Budget Topics for 2026

Chair Stringham shared Deep Dive 2026 Activities as follows:

- Underlying Principles of a "Deeper Dive"
    - A deeper dive is a look at specific budget category or categories that could have significant impact on NHEC to best meet or improve on its strategic objectives.
        - Lower member costs
        - Improve reliability
        - Enhance safety for employees, vendors, members and customers
- Ways to identify deeper dive topics
    - What we spend our members' money on (budget driven)
    - Member recommendations (surveys, requests)
    - Recommendations of the SLT
    - Recommendations of Board Members
        - Consider skill set of the BFR Committee or Board to match opportunity with skill set
- Potential areas for nominations
    - Challenge Property Tax
        - $7.4 million directly by NHEC
            - Additional through rates paid by our energy suppliers
        - Avenues to challenge
        - Legislative ideas
    - Tree trimming/Burying additional lines ($10 million)
        - Business Opportunities
            - Bring tree trimming in-house
                - Through start up or acquisition
        - Accelerate burying highly vulnerable power lines (costly)
        - Pave areas under tree lines
    - Company benefit package
        - Estimated $4 million in medical insurance annually
        - Is it what our employees need to thrive?
        - Trade-off in salary vs. benefit
        - Retirement plans and programs
    - AI – Opportunity and threats
        - Replace the BOD with an AI BOD
            - How AI Could Be Used (the AI-Assisted Board)
            - AI could serve as a tool to enhance the efficiency and decision-making capabilities of a human board of directors. An AI-assisted board framework could involve:
                - Data Analyst
                - Policy advisor
                - Financial Modeler
                - Member Engagement Synthesizer
                - Risk Auditor

<u>Discussion:</u>

- Mr. Jennings stated he's not sure if an AI Board would make life easier or harder, but he supports the need to look into tree trimming, and he has already spoken to Mr. Mazzei about this. He would like to focus on that this year and see if we can save money without jeopardizing reliability. Mr. Goodrich added he is not sure he is in favor of paving because we don't want to be accused of messing up the landscape. He suggested we plant things that have a limited height under our lines after we clear them so they shade out anything else that might compete with them. Mr. Jennings replied that is part of our normal vegetation management practices. We maintain and leave behind any low-growth species to help prevent future growth.
- Ms. Albee agreed we should take a deeper dive on tree trimming and look at some of he practices in Vermont because they have some different strategies on vegetation management. Ms. Albee added she wonders if we should look into pole attachments and pole replacements. Mr. Jennings replied we are regulated regarding pole attachments.
- Mr. Dwyer stated he likes the data analytics, and he suggested sharing what the current and peak load is real-time.
- Mr. Goodrich thanked Mr. Clark and Mr. Howland for their excellent work.

Adjournment

Chair Stringham adjourned the meeting at 10:25 a.m.