New Hampshire Electric Cooperative, Inc.
Minutes of the Meeting of the
Budget, Finance, and Rates Committee

December 13, 2024 8:30 a.m.

Present: Committee members: Jerry Stringham (Chair), Alana Albee, Leo Dwyer, Carolyn Kedersha, Jeff Morrill, John Goodrich, and Bill Darcy
Other Board members: Peter Laufenberg and Tom Mongeon
NHEC employees: Alyssa Clemsen Roberts, Mike Jennings, Jeremy Clark, Kristen Taylor, Chris Axten, Josh Mazzei, Peter Glenshaw, Sonja Gonzalez, Carla Munoz, Rob Howland, Maria Stella, Sydney Marshall, Maddie Conkling, and Edee Murphy (Recording)
Others Present: Todd Fahey and Susan Lowry - NHEC Counsel (Upton & Hatfield)

Meeting Called to Order
Chair Stringham called the meeting to order at 8:30 a.m.

Agenda Review
There were no suggested changes and the agenda was approved unanimously.

Approval of Minutes

Upon motion by Mr. Darcy, seconded by Ms. Albee, it was

VOTED: That the committee approves the minutes of the 10/25/2024 and 11/18/2024 Budget, Finance and Rates Committee meetings as presented.

Vote was unanimous.

Ms. Taylor introduced the new Controller, Chris Axten, and welcomed her to the co-op.

Coop Power and RAC Rate Change

Mr. Clark reviewed his presentation including the following topics:

Co-op Power:

The proposed rates recover forecast Co-op Power costs for the February 1, 2025 to July 31, 2025 rate period. Co-op Power costs are forecast to decrease as compared to the current August 1, 2024 to January 31, 2025 rate period.

Presentation highlights included:
- 2025 Rate Timeline
- Rate Components
- Co-op Power Load Projection
- Co-op Power Cost Projection
- Co-op Power Over/Under Recovery
  - June forecast balance of $1.1M over-recovered by August 2024
  - Current projected balance of $1.1M over-recovered by February 2025
  - $0.6M to be credited in February 2025 – July 2025 rates ($0.00190 credit per kWh)
- Co-op Power Load Forecast
  - Load forecast reduction from October 2024 launch of community power in Campton, Epping, Franklin, Gilford, Lee, Lyme, Northfield, and Wilmot
- Co-op Power Cost Forecast

- Co-op Power Proposed Rates – for most members: 5th consecutive rate decrease; 6% decrease compared to current rate; 20% decrease compared to February 2024 rate
- Co-op Power Charge History

Regional Access Charge (RAC):

The Regional Access Charge is developed by dividing 12 months of forecast costs by 12 months of forecast sales. RNS rates are forecast to increase by nearly 20%, rising from $13.31 per kW-month in 2024 to $15.90 per kW-month in 2025. LNS costs are forecast to increase by 46%, rising by $1.7 million from 2024 to 2025. I&D costs are forecast to be similar in 2025 as compared to 2024.

Presentation highlights included:

- Regional Access Cost Projection
- Regional Access Over/Under Recovery
    - June 2024 forecast balance of $0.2M under-recovered by August 2024
    - Current projected balance of $2.2M under-recovered by February 2025; $0.6M attributable to Primary Ski class
    - $0.00914 per kWh embedded recovery charge in Primary Ski February 2025 – July 2025 rate
    - $0.00209 per kWh embedded recovery charge in all other February 2025 – July 2025 rates
- Regional Access Cost Forecast
- Regional Access Proposed Rates – for most members: 30% (0.9 cent) increase compared to current rate
- Regional Access Charge History
- Residential Bill Impact – when compared to rates in effect on January 1, 2025, the proposed Co-op Power Charge and Regional Access Charge result in a 1.6% total bill increase for a member on a Basic rate with 500 kWh delivered. The increase for a member on a Basic rate with 1,000 kWh delivered is 1.9%.

Discussion:

- ❖ Responding to a question, Mr. Glenshaw commented the new rates will be communicated in the new year and will be focused on the net impact to members. The information will be in the January NHEC Newsletter and there will be a general announcement on the NHEC website.
- ❖ In answer to a question, Mr. Jennings commented that load obligation is a combination of what we have pre-purchased and everything we bought on the market for the whole rate period; committed resources are the known quantities for which we have contracted.
- ❖ In response to a question regarding the definition of net billed sales, Mr. Clark replied it is the end user sales, but noted there is a bills-rendered versus services-rendered factor. When you see the load obligation and committed resources, that is on a services rendered/calendar month basis, whereas net billed kWh sales will be lagging based upon billing schedules.
- ❖ Mr. Darcy suggested the public relations message about the rate increase should include the fact that the 30% increase in largely transmission-related costs not under the control of NHEC staff or the board.
- ❖ Mr. Laufenberg suggested also highlighting in the member communication the things we do have control over, and that we have tried very hard to keep those costs down or lower them.
- ❖ Mr. Jennings mentioned that unfortunately the ISO is projecting the cost of transmission will continue to increase due to capital construction/transmission investment costs. He commended Messrs. Howland and Clark, and also Ms. Marshall and Ms. Conkling, for their work on trying to keep energy rates down where possible.

Upon motion by Ms. Kedersha, seconded by Mr. Goodrich, it was

VOTED: That the committee recommends the Board of Directors authorize staff to set the Co-op Power and Regional Access Charges on a bills-rendered basis effective February 1, 2025 as recommended in the February 1, 2025 Co-op Power and Regional Access Rate Change Proposal as presented.

Vote was unanimous.

Fall Hedging and Rate Purchasing Strategy

Mr. Jennings explained staff would like to discuss with the board where we currently stand with our energy purchases, rates, and contracts; then discuss what the approach will be for hedging and purchasing for the next rate period.

Mr. Howland reviewed the presentation provided in the meeting packet:

Agenda:

- Fall Rate Planning Discussion
  - O Energy Cost Updates
  - O Hedging Discussion
    - NH IOU Approach
    - Proposed Hedge Plan for Fall 2025
    - Financial Results of ACES Analysis
- Budget, Finance & Rates (BFR) Committee Goals

Energy Cost Updates:

- Regarding the Seasonal Rate Cost Comparison slide – Ms. Kedersha requested Community Power rates be added to this comparison.
- Internal Bilateral Transition (IBT) Cost versus Day Ahead Locational Marginal Price (LMP) – IBT are purchases from vendors; contracts we lock in for the rate period.

  Discussion:

  - ❖ Mr. Howland explained NHEC has NDAs with these vendors; staff has explained in more detail who those vendors are in executive session meetings with the NHEC board.
  - ❖ Mr. Jennings added that NHEC has flexibility in purchasing but typically structures its purchases for six-month periods based on the rate period. Investor-owned utilities are locked in for a six-month period of purchases, as they are mandated on how they purchase energy.
  - ❖ Responding to a question, Mr. Howland commented that in most recent rate periods, NHEC has locked in the price of power for the whole six months prior to setting rates and hedged about 80% of our forecasted load. Prior to that, under different management, staff would estimate the future power costs when setting rates and then buy the power on a month-by-month basis during the rate period. But after experiencing market instability, staff thought it was wise to lock in prices before setting rates.
- Variability of DA LMP 2019-2024 – The market experiences significant price differences. Mr. Jennings pointed out the potential maximum price is up to $2,000/MWH which is the maximum price for the ISO.
- Forecasted Costs for Fall 2025 – Total Fall 2025: $28.55M forecasted, of which $22.4M is energy cost.

Fall Hedging Discussion (Start of Fall 2025 Rate Planning, August 2025 – January 2026):

- IOUs Recent Hedging Approach – Significant change in direction (30-50% Day Ahead Market); previously, IOUs utilized "all requirements," "load following" contracts.
- Proposed Hedge Plan for Fall 2025:
  - Balance of rate stability, current approach, lowest cost, and NH utility standard
  - Proposed Hedge Approach:
    - O 1/3 long-term purchases for 5+ years (rate stability)
    - O 1/3 additional hedging purchases beginning 6 months in advance of rate period up to prior month (current approach); mindful of updated load forecasts and market price trends
    - O 1/3 day ahead market (likely lowest cost and NH utility standard)
    - O Purchases equal to approximately 20% of forecasted load have already been closed (includes long-term renewable contracts)
- Creates a well-balanced rate that will be comparable to other NH utilities
- ACES Proposed Hedge Ranges Rolling Multi-Year Approach – Consultant (ACES) recommended a five-year rolling approach; the more we have locked in long term, the less our members will be exposed to market volatility. And if market prices go down, we still have purchasing opportunities to take advantage of that. Purchasing volume would be adjusted/decreased if requirements change depending upon Community Aggregation activity.

- Description of ACES Modeling Approach and Analysis-Fall 2025:
  - ACES model simulates NHEC power resources (load forecasts and committed purchases)
  - Market price assumptions for uncovered energy are provided by ACES
  - Model results include an expected cost with price variability and impacts from prices changes; results calculate the impact of market price fluctuations on total energy costs
- Summary Results of ACES Analysis:
  - Hedging 67% before Fall 2025 Rate Period
    - O 157,000 MWh to be purchased (current load forecast)
    - O Forecast may change due to Community Aggregation
  - Leaving 33% unhedged offers savings potential if spot prices are lower
  - Also exposes NHEC to risk if spot prices rise above forward prices
- Summary Results of ACES Study Energy Costs Fall 2025 – this slide shows expected energy costs ($22.57M) and indicates the cost change if costs swing up or down. Mr. Jennings added that staff wanted to show the board the cost benefit of leaving one-third exposed and what the potential is in the market, to put a value on the results of a board decision.

<u>Discussion</u>:

- ❖ Referencing the IBT purchases chart, Mr. Darcy commented it shows the spot market did better; that by purchasing a few months before the rate period, the IBT vendors are anticipating a rate increase and it is incorporated into their prices a risk premium. Instead of one-third spot market, if we went two-thirds IBT purchases to be completely covered, it would still be a higher price as a result of IBT vendors anticipating the higher price for that rate period.
- ❖ Ms. Albee asked if the committee is situated so they can give decisions on purchasing. Mr. Jennings pointed out that staff has to pick a point in time to present the data; but when we get prices, they are only good for a few minutes because the market is constantly changing. It is a very short-term decision period where we have to lock in or not.
- ❖ Mr. Goodrich commented that if we bought at the spot daily price every day, we would come out ahead on average, but that we are minimizing risk by hedging. Mr. Jennings commented that in a way it is an insurance plan for NHEC. A catastrophic event of the maximum $2,000/MWH would be crippling for NHEC from a financial perspective; utilities have gone bankrupt that way before, and we are trying to minimize that risk. Responding to a comment from Mr. Stringham regarding daily purchases, Mr. Jennings pointed out there would also be costs for lines of credit, additional letters of credit, etc., to be able to have that much exposure to the market.
- ❖ Mr. Dwyer asked if the catastrophic $2000/MWH scenario happens in the spot market, and not in the day ahead market. Mr. Jennings responded that, typically that is correct; however, if you lose a major source of generation it will have a very large impact on the day ahead market for a while to come, especially where some of our largest generators are nuclear facilities, it requires long-term investigation into the cause of the problem before those large units are brought back online.
- ❖ Mr. Howland commented that stability of rates is an important determinant of affordability for NHEC members, and hedging ahead of time offers stability.

- Preliminary Hedge Percentage for Fall 2025 – Approximately 20% is hedged, some of which are long-term renewable contracts with wind and hydroelectric producers; some are 42-month IBT purchases. Staff is suggesting 67% hedged before we get to the next rate period.
- Proposed Hedge Volumes & Percentages for Fall 2025:
  - Total Load Forecast – Non-Ski MWh = 336,904 (subject to change based upon future Community Aggregation activity)
  - Proposed Hedge Coverage Targets: 67% of forecast; already purchased: 20%
  - MWH needed to purchase to meet coverage: 225,726; already purchased: 68,442 (includes long-term renewable contracts)
  - IBT – 47% remaining to be purchased to meet hedge goals
  - IBT – 157,283 MWH remaining to be purchased to meet hedge goals

Proposed Staff Resolution:

That the Budget, Finance and Rates Committee recommends the Board of Directors authorize Staff to purchase Power Resources up to approximately 67% of currently forecasted load to hedge the upcoming Fall 2025 rate period, subject to adjustment in the event of Community Aggregation load migration.

Discussion:

- Mr. Darcy recommended an amendment to the resolution stating that NHEC purchased 20% of the load, which means you have not purchased 33% of long-term purchases yet; any long-term purchases for more than the six-month rate period should be subject to review by the BFR Committee. Ms. Kedersha mentioned these contracts come in the space of a few minutes. Mr. Darcy said he is referring to long-term contracts such as the 42-month contract that cost $2.1M, and those are not last minute.
- Mr. Jennings commented the way NHEC has been purchasing IBT, we typically need to respond immediately; it is possible within the IBT deals to build in a longer timeframe for response; however, that impacts the price they offer because they know prices could vary within that timeframe.
- Mr. Darcy asked if staff is proposing, between now and coming to the board for setting the rates, to enter into more long-term (over six months) contracts that could exceed $1M in cost? Mr. Jennings stated it does not need to be in place for this rate period but, as shown in the ACES hedging strategy, the end goal is one-third day ahead, one-third short term, and one-third the five-year tiered approach.
- Mr. Jennings commented that the availability of renewables contracts have been drying up for NHEC; we will still talk with renewable vendors to check for availability and bring that to the board, but for long-term purchases it is more likely to be IBT-type deals we have used for the short-term upcoming rate period.
- Mr. Darcy commented if NHEC is going to enter into contracts for two or three years, the board should have input on the one-third component that is long-term before those contracts are signed because they could potentially have a very large fiscal impact on the members.
- Mr. Darcy suggested having more discussions and revisiting the issue. He mentioned discussing policies in the first quarter of 2025 to give staff all the authority they need.
- Mr. Jennings pointed out this is something new for NHEC, and staff wanted to be sure they were facilitating the discussion for the board and how we want to approach the process moving forward.
- Mr. Dwyer voiced concern about purchasing long-term because if prices drop, we may not be able to compete with Community Power prices and may lose load; rate stability comes with risk. Mr. Jennings commented there will be positives and negatives to all approaches. Ms. Clemsen Roberts added that if you look at energy projections for the future, no one is projecting extreme downward prices. You want to lock in small portions of power and take advantage if the market dips. She mentioned East Central Maine who locked in at an incredibly low rate for a 10-year period and they have beaten the market over and over.
- Mr. Jennings requested that the committee recommend the board at least authorize staff to make purchases for the 33% of the six-month portion of the short-term IBT deals.

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

VOTED: That the committee recommends the Board of Directors authorize Staff to make 6 months' worth of IBT purchases of up to 33% of expected load for the Fall 2025 rate period.

Vote was unanimous.

Adjournment

Upon motion by Mr. Darcy, seconded by Mr. Goodrich, Chair Stringham adjourned the meeting at 9:46 a.m.