[NAME] Community Power

[INSERT SEAL/LOGO]

Electric Aggregation Plan Overview

[Insert Date]

Presented by: [NAME] [COMMITTEE NAME]

Presented to: [INSERT]

[NAME] Community Power will allow the [GOV TYPE] to provide energy supply and related services on behalf of [NAME]'s residents and businesses.

Community Power programs create an economy of scale that can result in more affordable electricity and expanded options for renewables and innovative energy technologies.

TEMPLATE INSTRUCTIONS

- Click the "Edit" dropdown menu at the top of your screen
- Select "Find" and from the resulting menu, "Replace"
- Type into the "Find what…" search bar, and replace with [NAME] (e.g., Acworth); [GOV TYPE] (e.g., City or Town); [GOV BODY] (e.g., Select Board, Town Council, City Council); [LEGISLATIVE BODY] (e.g., Town Meeting, City Council); [COMMITTEE NAME]; [UTILITY] (e.g., Eversource);
- Insert dates and customize orange text throughout slides
- Delete these instructions and replace with a picture from your community.
- Contact henry@cpcnh.org for assistance

Agenda

1. What is Community Power?
2. Electric Aggregation Plan
3. Community Power Coalition of New Hampshire
4. Timeline for [NAME] Community Power
5. Questions & Discussion

What is Community Power?

- Community Power programs pool, or aggregate, the demand of customers in a community and purchase electric power on behalf of that community with the goal of **lowering costs** and expanding **access to renewable energy** and other innovations.
- Community Power programs are enabled by New Hampshire's updated Community Power law RSA 53-E, Relative to Aggregation of Electric Customers by Municipalities & Counties.
- The Legislature's intent in enacting RSA 53-E was to "***encourage voluntary, cost effective and innovative solutions to local needs with careful consideration of local conditions and opportunities***".

What is Community Power?

New Hampshire cities, towns, and counties can procure **electric power supply** on behalf of their residents and businesses and provide related services.

Pooled Purchasing Power for **Energy Supply**

- Access to competitive markets
- Lower costs & price stability
- Option to source power locally & access more renewables

Utilities continue to **Deliver** Power

- Owns & maintains the power grid
- Delivers generation to load
- Ensures reliable electric service

Community Benefits from **Value Added Services**

- Affordable rates
- Access to green power options
- Time-of-Use rate options
- Solar, storage, electric vehicle support

Benefits of Community Power

Local Control

Democratizing energy procurement to the community level

Lower Costs

MA, NY, CA and other markets have demonstrated lower rates than regulated utilities

Renewables

Build & Buy Clean Energy
Support more local renewables

Resilience & Innovation

New Technologies
Market Competition
Price Signals
Customer Empowerment

"[NAME] Community Power will only launch if… [INSERT GUIDING STATEMENT]"

(Page 2 of proposed Electric Aggregation Plan)

Electric Bill:
Supply & Delivery

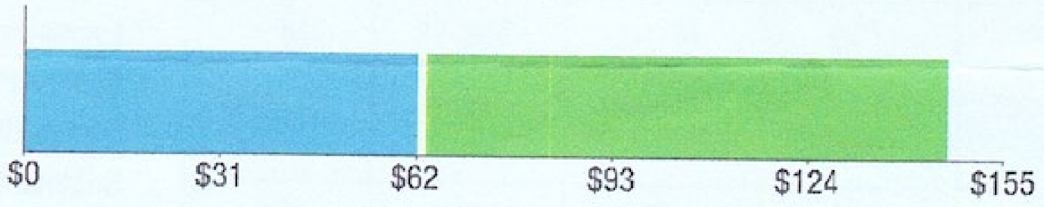
Page 1

Payment will be sent to bank for processing on 09/24/21 **$145.64**

Amount Due On 08/29/21	$26.47
Last Payment Received On 08/25/21	-$26.47
Balance Forward	$0.00
Total Current Charges	$145.64

Current Charges for Electricity

Supply	Delivery
$62.31	$83.33
Cost of electricity from Eversource	Cost to deliver electricity from Eversource



Your electric supplier is

Eversource
PO Box 330
Manchester, NH 03105-0330

Electric Bill: Supply & Delivery

Page 2

Total Charges for Electricity

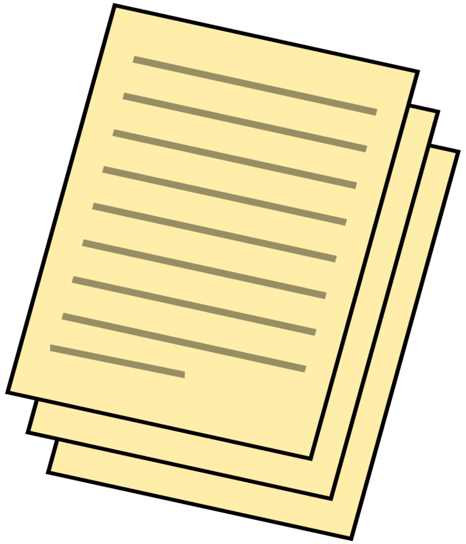
Supplier → **Supplier**

Eversource → [NAME] Community Power

Service Reference: [redacted]		
Energy Chrg - Rate R	706.00kWh X $0.08826	$62.31
Subtotal Supplier Services		$62.31
Delivery		
(RATE R RESIDENTIAL SVC)		
Service Reference: [redacted]		
Customer Chrg		$13.81
kWh Distribution Chrg	706.00kWh X $0.05177	$36.55
Regulatory Reconciliation Adj	706.00kWh X $-0.00016	-$0.11
Transmission Chrg	706.00kWh X $0.03046	$21.50
Strnded Cst Recovery Chrg	706.00kWh X $0.00896	$6.33
System Benefits Chrg	706.00kWh X $0.00743	$5.25
Subtotal Delivery Services		$83.33
Total Cost of Electricity		**$145.64**
Total Current Charges		**$145.64**

Key Points

- **[UTILITY] will continue to deliver electricity** to customers, and to own and operate the local distribution system (poles, wires, transformers, sub-stations, etc.). They will also continue to provide customer service and billing.
- The [GOV BODY], with advisory support from the [NAME] [COMMITTEE NAME], will be **authorized to contract for the necessary professional services and power supplies to launch [NAME] Community Power.**
- **Participation in Community Power is completely voluntary.** After electricity rates are established, all customers not already on competitive supply will be notified and automatically enrolled. Customers can choose to opt-out and stay with [UTILITY] for electricity supply. Customers on competitive supply may choose to opt-in to [NAME] Community Power or stay with their current supplier.



2. The Electric Aggregation Plan

What is the Electric Aggregation Plan?

- The [GOV BODY] designated the [NAME] [COMMITTEE NAME] as the Electric Aggregation Committee pursuant to RSA 53-E.
- The [GOV BODY] tasked the Committee with preparing an Electric Aggregation Plan. This is a detailed plan that explains how our Community Power program will operate. It is available for your review on our webpage or at [INSERT LINK TO PUBILCALLY POSTED EAP DRAFT]
- The [NAME] [COMMITTEE NAME] (also pursuant to RSA 53-E) will hold 2 Public Hearings, on [INSERT DATE] and [INSERT DATE], to educate the community about the plan and get community input.

Purpose of the Electric Aggregation Plan

- Defines program goals and objectives
- Defines governance (E.g., process for approving rates)
- Summarizes the implementation process
- Commits [NAME] to comply with applicable statutes and regulations in terms of:

  (a) *Providing universal access, reliability, and equitable treatment of all classes of customers;*

  (b) *Meeting, at a minimum, the basic environmental and service standards established by the Public Utilities Commission and other applicable agencies and laws and rules.*

The Plan does:

Address issues required to be considered by RSA 53-E including:

(a) How net metering will be provided; and

(b) How customers enrolled in the Electric Assistance Program will receive their discount.

The Plan does not:

- Commit the [GOV TYPE] to any defined course of action; or
- Impose any financial commitment or liability on the [GOV TYPE] of [NAME] or its taxpayers.

Electric Aggregation Plan Overview

Chapters:

1. Introduction to Community Power
2. Overview of [NAME] Community Power
3. Community Power Coalition of New Hampshire
4. [NAME]'s Goals, Objectives & Requirements
5. Statutory Requirements for [NAME]'s Plan

Attachments:

1. Net Energy Metering, Group Net Metering & Low-Moderate Income Solar Project
2. [NAME]'s Public Planning Process
3. [GOV TYPE] Policy Excerpts
4. How Load Serving Entity Services will be Implemented
5. Customer Data Protection Plan
6. Abbreviations

[NAME] Community Power will

1. **Serve as the default electricity supplier** on an “opt-out” basis
2. **Offer innovative service and rate options to customers on an "opt-in" basis** such as more renewable energy and time-varying rates
3. **Operate on a competitive basis –** Customers will be able to switch back to [UTILITY] energy service or other supplier *with no penalty.*
4. **Be self-funded** by rates paid by participating customers – **The [GOV TYPE] will not use taxes to cover program expenses.**

The [GOV BODY], with advisory support from the [COMMITTEE NAME], will contract for the necessary services and power supplies to implement and operate the program, set customer rates prior to program launch, and continue to provide oversight thereafter.

Customer Notification and Enrollment Process

- At least **30 days before program launch all [NAME] electric customers will be mailed notifications** that will include the initial fixed rate for [NAME] Community Power service compared with [UTILITY]
- Customers currently on default energy service provided by [UTILITY] will be **able to decline participation or "opt-out"** of [NAME] Community Power by a return postcard, online, or by calling a customer service number.
- If a **customer is already getting their power from a competitive supplier**, nothing will change unless they choose to switch and **"opt-in"** to [NAME] Community Power.
- New utility customers will get similar opt-out notices.
- All [NAME] Community Power default service customers will always be able to know the fixed rate at least 30 days in advance and be able to switch supplier at next meter read upon request with **no penalty or exit fee**.

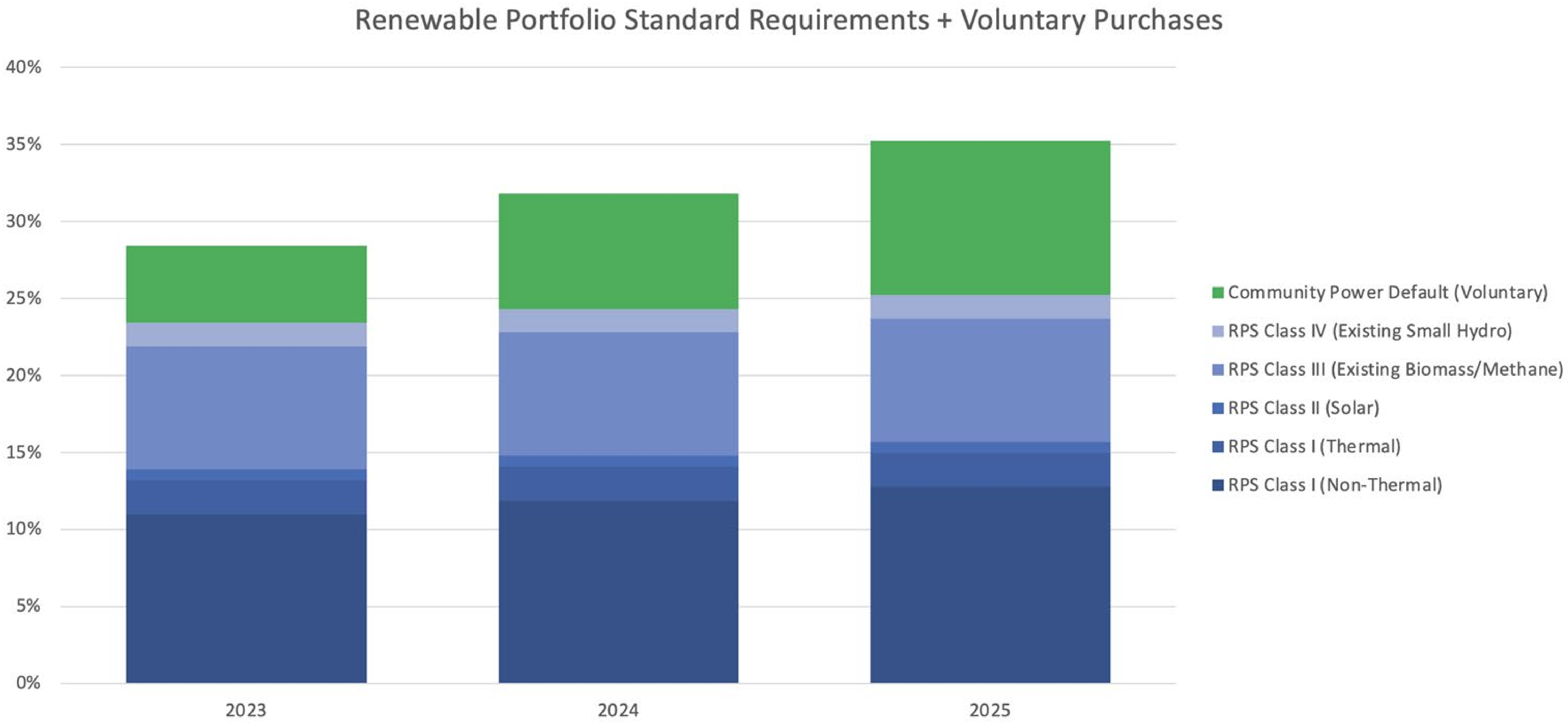
Example of Customer Rates and Optional Products

Example default service product and optional rates that could be offered to customers:

PRODUCT	CONTENT	MEMBER ELECTIONS
Granite Basic	Minimum RPS Content (23.4%)	Default, opt-down/in, or N/A
Granite Plus	33% Renewable or Carbon Free	Default, opt-up/in, or N/A
Clean 50	50% Renewable or Carbon Free	Opt-up/in or N/A
Clean 100	100% Renewable or Carbon Free	Opt-up/in or N/A

(The Renewable Portfolio Standard (RPS) is a New Hampshire state policy setting a minimum requirement for renewable energy to be provided to customers. RPS requirement for 2023 is 23.4%)

Illustrative Renewable Energy Purchases

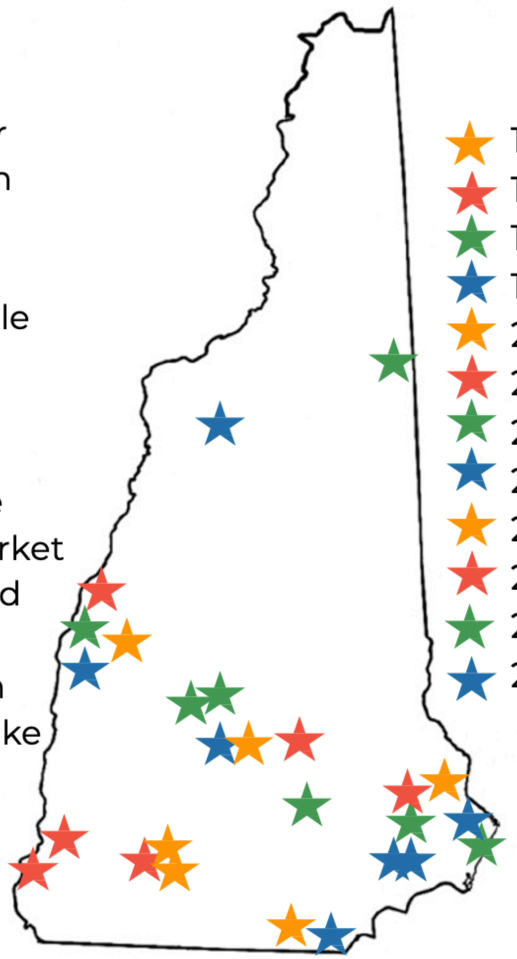


3. Community Power Coalition of New Hampshire (CPCNH or "The Coalition")

Community Power Coalition of New Hampshire

- Community-governed not-for-profit Joint Power Agency formed on 10/1/21
- **27 Members representing:**
  - **21% of NH population**
  - ~119,000 customers
  - ~960,000 MWh / year
  - ~$150 million / year revenues (controlled by communities)
- Target windows for program launch:
  - Spring 2023 for 12 Members
  - Spring 2024 for 15 Members

1. Hanover
2. Lebanon
3. Exeter
4. Nashua
5. Harrisville
6. Rye
7. Warner
8. Dover
9. Walpole
10. Newmarket
11. Plainfield
12. Enfield
13. Durham
14. Pembroke
15. Hudson



16. Webster
17. Cheshire County
18. New London
19. Portsmouth
20. Peterborough
21. Canterbury
22. Wilmot
23. Sugar Hill
24. Hancock
25. Westmoreland
26. Shelburne
27. Brentwood

Governed "for Communities, by Communities"

BOARD OF DIRECTORS

1 Director Clifton Below, City of Lebanon (alternate: Greg Ames)
2 Director Christopher G. Parker, City of Dover (alternate: Jackson Kaspari)
3 Director Kimberley Smith Quirk, Town of Enfield (alternate: Jo-Ellen Courtney)
4 Director Evan Oxenham, Town of Plainfield (alternate: Steve Ladd)
5 Director Terry Clark, Cheshire County (alternate: Chris Coates)
6 Director Kevin Charette, City of Portsmouth (alternate: Peter Rice)
7 Director Rick Labrecque, Town of Brentwood (alternate: Tom Palma)
8 Director Kent Ruesswick, Town of Canterbury (alternate: Howard Moffett)
9 Director Amanda (Mandy) Merrill, Town of Durham (alternate: Nat Balch)
10 Director Nick Devonshire, Town of Exeter (alternate: Julie Gilman)
11 Director Jim Callihan, Town of Hancock (alternate:)
12 Director April Salas, Town of Hanover (alternate: Peter Kulbacki)
13 Director Andrea Hodson, Town of Harrisville (alternate: Andrew Maneval)
14 Director Craig Putnam, Town of Hudson (alternate: Kate Messner)
15 Director Doria Brown, City of Nashua (alternate: Deb Chisholm)
16 Director Jamie Hess, Town of New London (alternate: Tim Paradis)
17 Director Toni Weinstein, Town of Newmarket (alternate: Steve Fournier)
18 Director Steve Walker, Town of Peterborough (alternate: Danica Melone)
19 Director Matthew Miller, Town of Pembroke (alternate: Jacqueline Wengenroth)
20 Director Lisa Sweet, Town of Rye (alternate: Howard Kalet)
21 Director Michael Prange, Town of Shelburne (alternate: Ray Danforth)
22 Director Jordan Applewhite, Town of Sugar Hill (alternate: Margo Connors)
23 Director Paul Looney, Town of Walpole (alternate: Dennis Marcom)
24 Director Clyde Carson, Town of Warner (alternate: George Packard)
25 Director Martin Bender, Town of Webster (alternate: David Hemenway)
26 Director Mark Terry, Town of Westmoreland (alternate: John Snowdon)
27 Director William Chaisson, Town of Wilmot (alternate:)

OFFICERS & COMMITTEE CHAIRS

Clifton Below
Chair

City of Lebanon
Assistant Mayor & City Councilor

Kim Quirk
Treasurer

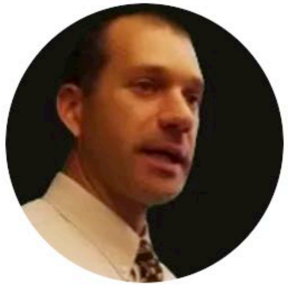
Town of Enfield
Energy Committee

Christopher Parker
Vice Chair

City of Dover
Deputy City Manager

Evan Oxenham
Secretary

Town of Plainfield
Energy Committee



Matt Miller
Chair, Risk Management

Town of Pembroke
Energy Committee

Lisa Sweet
Chair, Member Operations

Town of Rye
Energy Committee

Mandy Merrill
Chair, Regulatory & Legislative Affairs

Town of Durham
Energy Committee

April Salas
Chair of CEO & Staff Search

Town of Hanover
Sustainability Director

COMMITTEES (1) Executive (2) Finance (3) Risk Management (4) Member Operations & Engagement (5) Regulatory & Legislative Affairs (6) CEO & Staff Search

Operations: Wholesale, Retail, Members

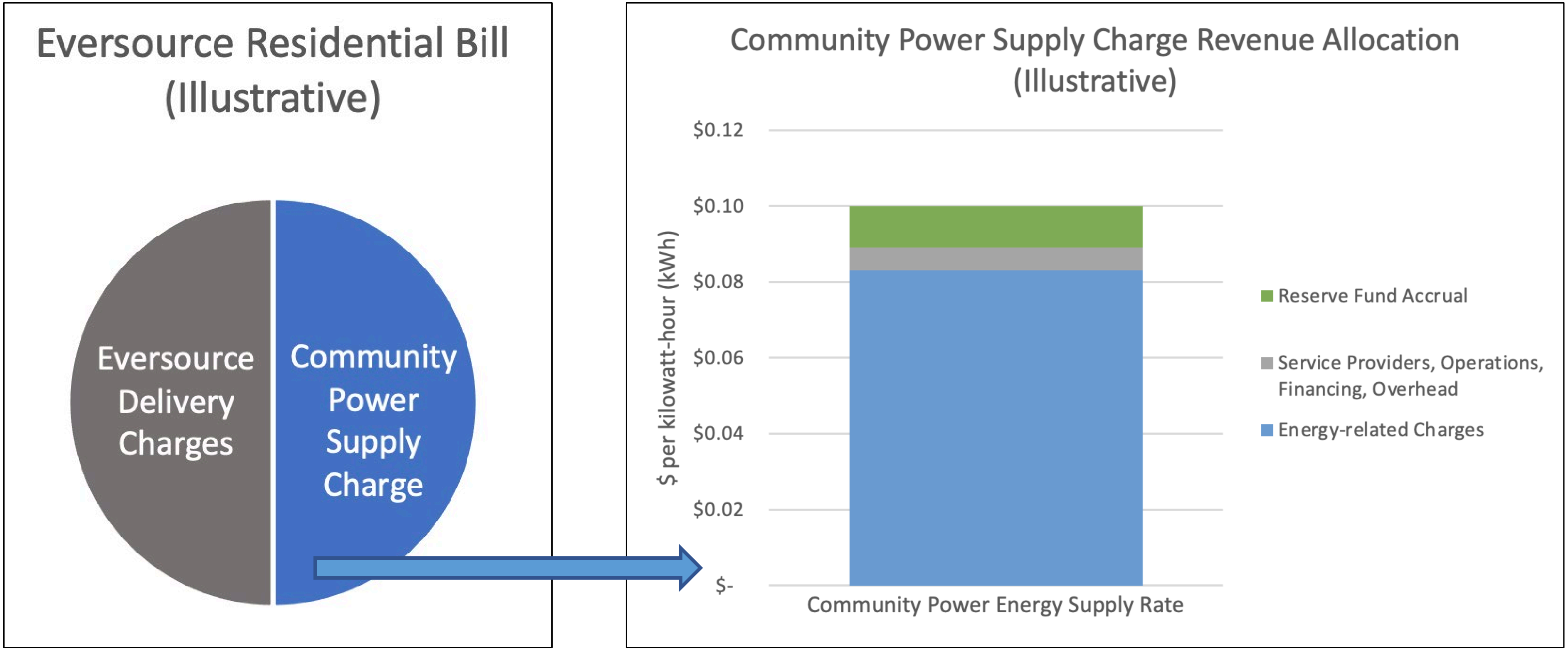
Request for Proposal for Comprehensive Services & Credit Support

Four service categories:

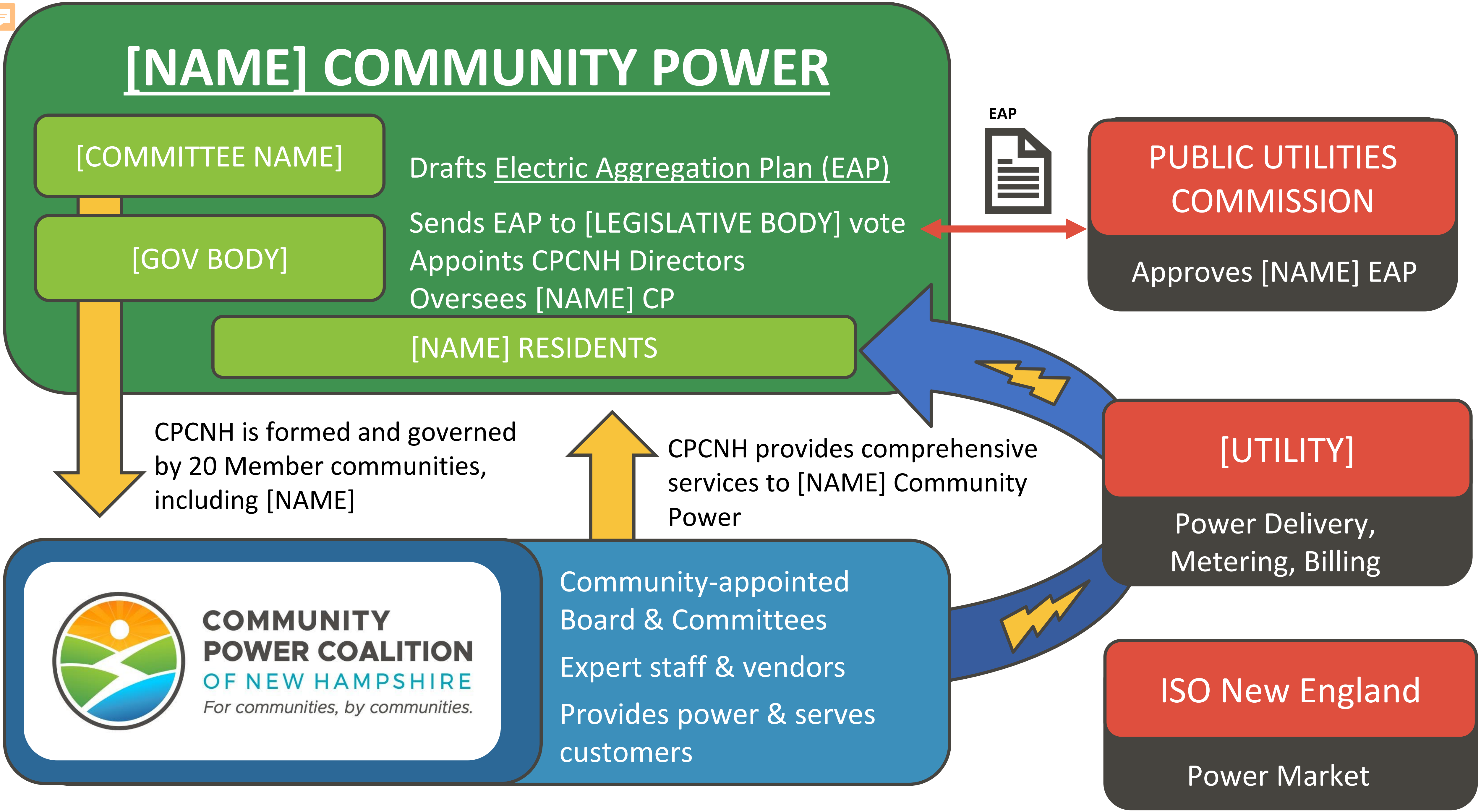
1. Energy Portfolio Risk Management → Ascend Analytics
2. Retail Customer Services → Calpine Energy Solutions
3. Member Services → Clean Energy NH, Your Voice in All Energy Matters
4. Financial + Accounting → River City Bank + (TBD)

CPCNH is in the process of negotiating service & financing agreements with these firms

Illustration of Energy Supply Charge Revenue Allocation



(Average energy supply rates between 2019-2021 were ~ $0.08 per kilowatt-hour (kWh). Supply increased to over $0.15 per kWh in 2022. Energy supply rates fluctuate over time depending on market forces, availability of fuel and generators, weather, climate, and other factors. The $0.10 per kWh supply rate in the graphic is for illustrative purposes.)



[NAME] COMMUNITY POWER
[COMMITTEE NAME]
Drafts Electric Aggregation Plan (EAP)
[GOV BODY]
Sends EAP to [LEGISLATIVE BODY] vote
Appoints CPCNH Directors
Oversees [NAME] CP
[NAME] RESIDENTS
EAP
PUBLIC UTILITIES COMMISSION
Approves [NAME] EAP
CPCNH is formed and governed by 20 Member communities, including [NAME]
CPCNH provides comprehensive services to [NAME] Community Power
[UTILITY]
Power Delivery, Metering, Billing
COMMUNITY POWER COALITION OF NEW HAMPSHIRE
For communities, by communities.
Community-appointed Board & Committees
Expert staff & vendors
Provides power & serves customers
ISO New England
Power Market

4. Timeline for [NAME] Community Power

[NAME] Community Power Timeline

- **Step 1:** Conduct Research and Form Community Power Committee
- **Step 2:** Draft Community Power Plan / Hold Public Hearings
- **Step 3:** Bring Plan to [LEGISLATIVE BODY] for vote of adoption
- **Step 4:** Contract with Service Provider, Notify Customers, Launch!

5. Questions/Comments

THANK FOR YOUR INTEREST!

[NAME]
Community
Power

LEARN MORE AT:

[INSERT WEBSITE]

Questions? Comments

[INSERT EMAIL]

√The [NAME] Electric Aggregation Plan
√Presentation on the Electric Aggregation Plan
√Frequently Asked Questions

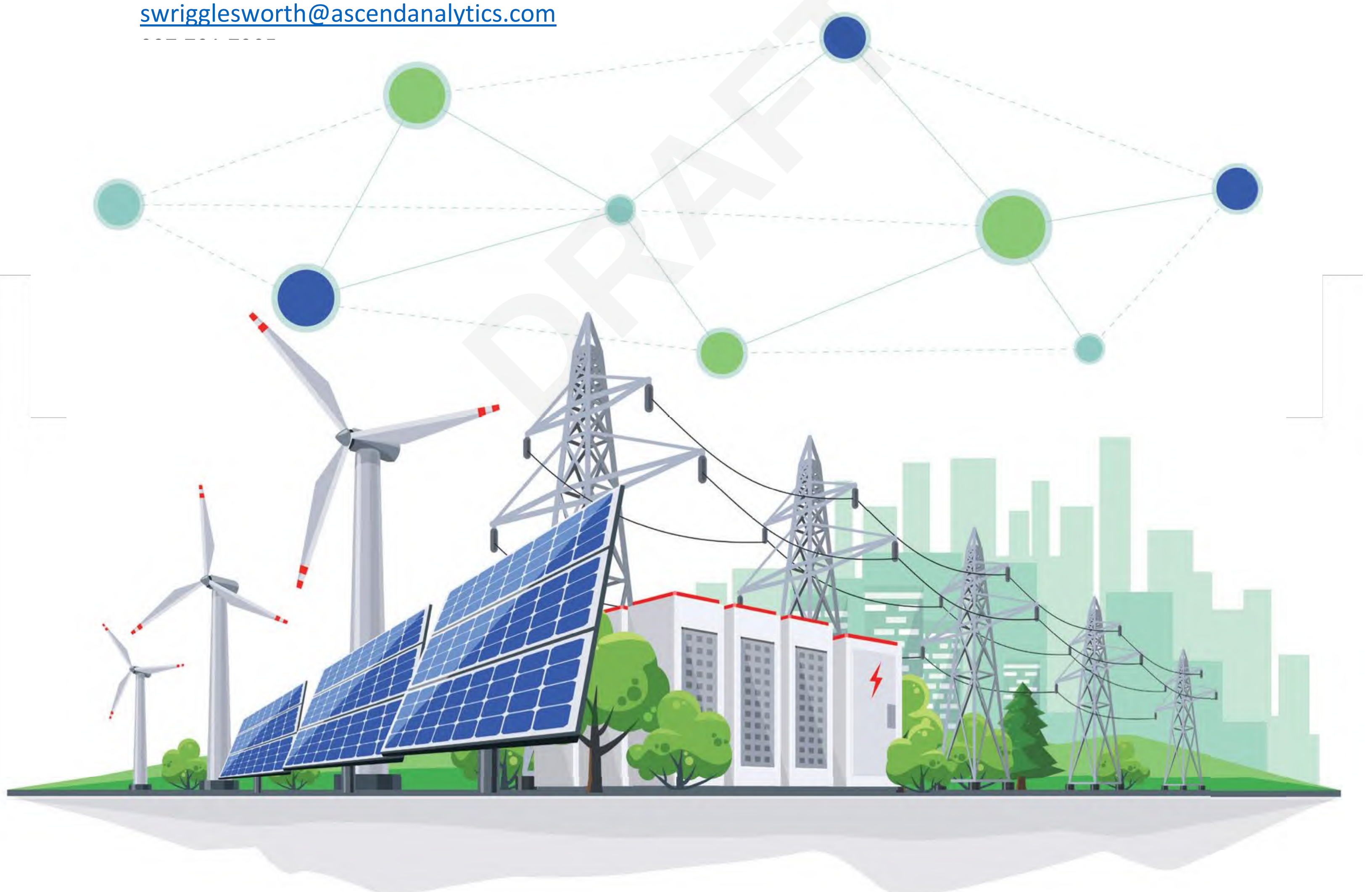
√ **NEXT PUBLIC INFORMATION SESSION on [DATE]**

Ascend
Analytics to Power the Energy Transition

Community Power Coalition of New Hampshire Technical Assessment for Viability of Launch

Prepared by: Ascend Analytics

Contact:
Scott Wrigglesworth
Managing Director of Operations & Strategy
swrigglesworth@ascendanalytics.com



Executive Summary

Ascend Analytics LLC (Ascend) conducted and prepared this comprehensive Technical Assessment to advise on the viability of the Community Power Coalition of New Hampshire (CPCNH) launch. As it pertains to the scope of its Technical Assessment, Ascend is able to recommend to the CPCNH Board, Committees and Member CPAs that the Coalition is ready for launch.

To its knowledge, Ascend does not believe that any community power initiative has ever pursued its technical assessment with the rigor of stochastic analysis, as was performed in preparation of this assessment. Ascend conducted numerous scenarios, stress tests, and stochastic analysis on all anticipated outcomes of reasonable probability, and the results show that CPCNH remains a viable agency offering independent local control of power supply for it is communities while pursuing the clean energy transition across New Hampshire. Further, the aggregate benefit of a CPCNH launch for its CPA members is both quantitatively and qualitatively strong.

The Technical Assessment provides context and findings from Ascend Analytics review of many factors. However, it is important to point out three main elements for consideration of all seeking technical advisement on the viability of launch. Herein, Ascend concludes the following:

1. The financial benefit of launching CPA service in April 2023 are stronger than at any prior point in time analyzed by Ascend (dating back to 2018), due to how far above market utility default supply rates are under current and forecasted market conditions. Consequently, Wave 1 CPA Members should expect to realize strong results over the initial 3-year term of service offered under the Cost Sharing Agreement's Member Service Contract for CPCNH's "Complete Service Bundle".

2. While future-year price simulations are subject to a number of conservative assumptions made by Ascend, CPCNH's business model achieves a better value proposition relative to the cost savings a community is likely to achieve through a brokered power supply deal, based on what the latter model has demonstrated being capable of achieving on average in an adjacent market (i.e., Massachusetts).

3. Ascend's base case scenario assumes Nashua launches in June 2023, rather than in April with the other 'Wave 1' Members. However, CPCNH's viability and performance remains robust across all reasonable scenarios related to community participation levels, including the scenario in which Nashua never launches CPA service through CPCNH.

It should be understood upfront that Ascend's analysis does not speculate, quantitatively, on what may happen in the event of a prolonged and/or severe market disruption. As context:

- Such 'black swan' events are a residual risk, inherent to the industry, which may impact CPCNH's financial performance in securing and delivering power to customers at rates fixed for 6-month periods (mirroring utility default supply periods).

- However, CPCNH's risk management strategy, embodied in the framework created under CPCNH's Energy Portfolio Risk Management Policy, is liable to be compromised to this degree only by a market disruption significant enough to impact not just CPCNH, but all major suppliers, including those under contract to provide utility default supply service.

- If multiple major power suppliers were to go bankrupt or otherwise exit the ISO-NE market, Ascend anticipates the high likelihood of customer rates being impacted to a comparable degree regardless of whether taking service through CPCNH or the utilities.
- In such an event, maintaining CPCNH's general competitive position — in terms of its ability to maintain competitive rates relative to utility default service so as to avoid customer switching to the degree that would erode CPCNH's financial viability — should be achievable.

As described herein, several key performance and financial metrics are identified and measured in a stochastic manner. It is important to understand the tradeoffs involved with different strategic decisions and market scenarios on those metrics. (For example, fulfilling an objective of providing greater customer savings generally presents a trade-off to the objective of building greater financial reserves.)

This assessment captures the financial performance implications and interdependencies inherent in trade-off decisions, models a variety of scenarios assuming different balances of trade-off decisions by CPCNH and its Members, and summarizes the results by generating a significant number of output metrics and charts, including financial reserves, customer savings, and the aggregate effective community benefit (the cumulative total of a Member's financial reserves and customer bill savings).

Based on our results, Ascend strongly recommends CPCNH maintain the April 2023 target launch date for Wave 1 CPA Members.

- Our recommendation is predicated on a variety of factors; chief among them are current market conditions, high utility auction premiums, and the resulting financial benefit that would be maximized by launching in April.
- Consequently, an April 2023 launch would ensure CPCNH achieves robust financial performance for Wave 1 Members — which, in turn, will maintain the recruitment of new communities and expansion of CPA program service for Wave 2 and across all subsequent future-year waves.

Regarding the opportunity to achive CPCNH's broader value proposition, Ascend concludes that the Inflation Reduction Act and the pilot project framework authorized by Senate Bill 321 strongly support the business case for CPCNH to prioritize developing local projects on behalf of participating Members.

As detailed in this report and summarized in our concluding "Evaluation and Recommendations" section, Ascend has confirmed that the pathway most likely to maximize financial benefits for all Members is defined by (1) prioritizing the expansion of CPCNH's membership and (2) prioritizing the development of local projects, both of which generate significant surplus revenues and benefits for participating customers, communities, and the Joint Powers Agency.

In short, the findings of our Technical Assessment confirm CPCNH's economic viability, validate CPCNH's mission and strategic objectives, and encourage action and initiative be taken by all Members in light of these opportunities.

Table of Contents

CPCNH Technical Parameters & Assumptions

Communities and Customer Mix

The aggregation of communities gives CPCNH strength and economies of scale. The following figures detail the communities and customer count estimates by utility for those included in the Technical Assessment. This data represents the best available data for each community and/or estimates of volumes based upon populations. Figure 1 details the overall counts compiled in support of Base Case and scenario analysis. It should be noted at inception that while a relatively small number of New Hampshire Electric Cooperative (NHEC) customers are listed, for reasons explained later, NHEC customers are deemed to be 'opt-in' and will not be enrolled at launch, nor assumed to be added for assessment purposes.

Figure 1 : Overall Customer Counts under Different Scenarios

			TOTAL		Eversource		Liberty		NHEC		Unitil	
		Community	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
Launch April 2023	**Initial Wave 1 Members**	**Cheshire**	0	10	0	10	0	0	0	0	0	0
		Durham	3,171	450	2,854	405	0	0	317	45	0	0
		Enfield	2,418	335	16	2	2,257	315	145	18	0	0
		Exeter	6,500	1,702	5,850	1,531	0	0	0	0	650	171
		Hanover	2,791	434	96	20	2,599	394	96	20	0	0
		Harrisville	658	92	658	92	0	0	0	0	0	0
		Lebanon	6,548	1,326	0	0	6,548	1,326	0	0	0	0
		Nashua	32,558	4,969	32,558	4,969	0	0	0	0	0	0
		Plainfield	792	150	286	48	289	66	217	36	0	0
		Rye	2,802	502	2,802	502	0	0	0	0	0	0
		Walpole	1,667	270	0	0	1,667	270	0	0	0	0
	New Wave 1	**Peterborough**	2,378	632	2,378	632	0	0	0	0	0	0
	Wave 1 Total		**62,282**	**10,871**	**47,498**	**8,211**	**13,359**	**2,370**	**775**	**119**	**650**	**171**

			TOTAL		Eversource		Liberty		NHEC		Unitil	
		Community	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
Launch April 2024	**Initial Wave 2 Members**	**Dover**	13,934	2,015	13,934	2,015	0	0	0	0	0	0
		Hudson	9,128	1,774	9,128	1,774	0	0	0	0	0	0
		New London	2,380	455	2,380	455	0	0	0	0	0	0
		Newmarket	4,020	381	4,020	381	0	0	0	0	0	0
		Pembroke	2,860	401	2,574	361	0	0	0	0	286	40
		Portsmouth	7,320	1,152	7,320	1,152	0	0	0	0	0	0
		Warner	1,546	300	1,546	300	0	0	0	0	0	0
	New Wave 2	**Webster**	900	92	450	46	0	0	0	0	450	46
		Canterbury	931	85	409	40	0	0	5	0	517	45
		Hancock	641	171	641	171	0	0	0	0	0	0
		Sugar Hill	212	49	134	36	0	0	78	13	0	0
		Westmoreland	632	168	632	168	0	0	0	0	0	0
		Wilmot	538	122	339	90	0	0	199	32	0	0
	Wave 2 Total		**45,042**	**7,165**	**43,507**	**6,989**	**0**	**0**	**282**	**45**	**1,253**	**131**

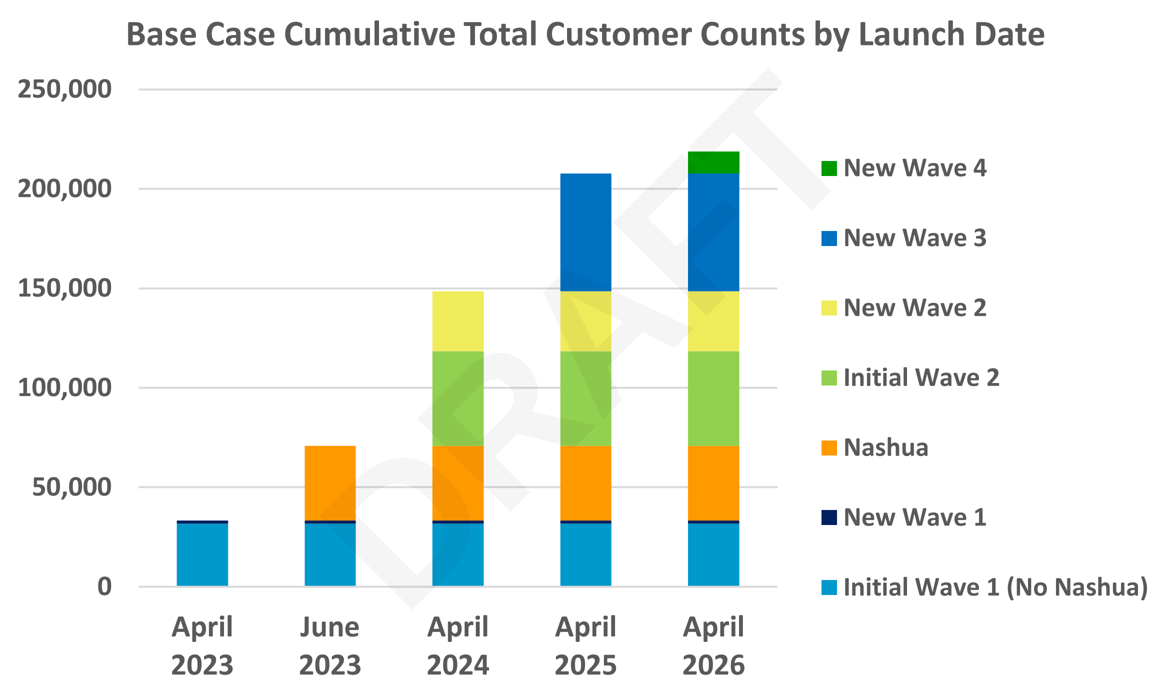
		TOTAL		Eversource		Liberty		NHEC		Unitil	
Launch	**Additional Prospective Communities**	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res	Res	Non-Res
April 2024	**New Wave 2 Growth**	**48,408**	**18,786**	20,606	14,356	2,860	508	9,957	1,546	14,985	2,376
April 2025	**New Wave 3 Growth**	**97,463**	**24,507**	84,627	22,410	3,799	675	3,084	478	5,953	944
April 2026	**New Wave 4 Growth**	**22,910**	**5,115**	13,672	3,621	2,423	430	5,141	798	1,674	266

The following describes the Base Case scenario for this assessment along with a cross section of P050 scenarios for alternate possible outcomes on future CPCNH CPA participation levels. Due to the significant size of Nashua, several scenarios explore outcomes related to Nashua's timing and participation. Part of the value proposition CPCNH brings as a coalition is economies of scale. Thus scenarios explore changes in participation. As a reminder, this section details assumptions while the next section presents the key findings.

Base Case Assumption:

Initial Wave 1 & 2 communities, with a Nashua launch delay[1] of two months, plus 50% of new wave 1-4 communities. Figure 2 illustrates the cumulative customer counts at various launch dates associated with this scenario.

Figure 2 : Base Case Cumulative Total Customer Counts by Launch Date



[1] Nashua, as a wave 1 member, has expressed likely delays due to due diligence efforts. The Base Case scenario assumes Nashua delays 2 months and launches in June. Other scenarios address further delays on Nashua's part, and the impact on the Coalition were Nashua choose to not participate at all.

Figure 3 highlights identified members by size and Figure 4 shows residential and non-residential customer counts by utility.

Figure 3 : Identified or Prospective Members by Total Customer Count

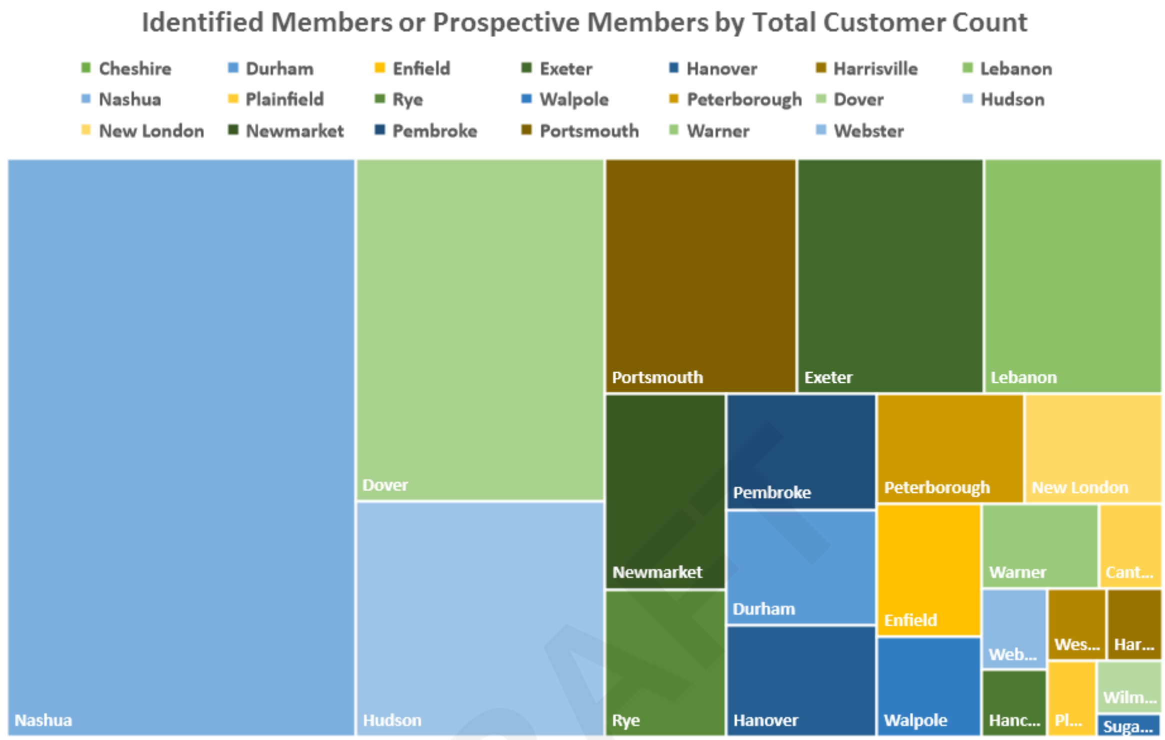
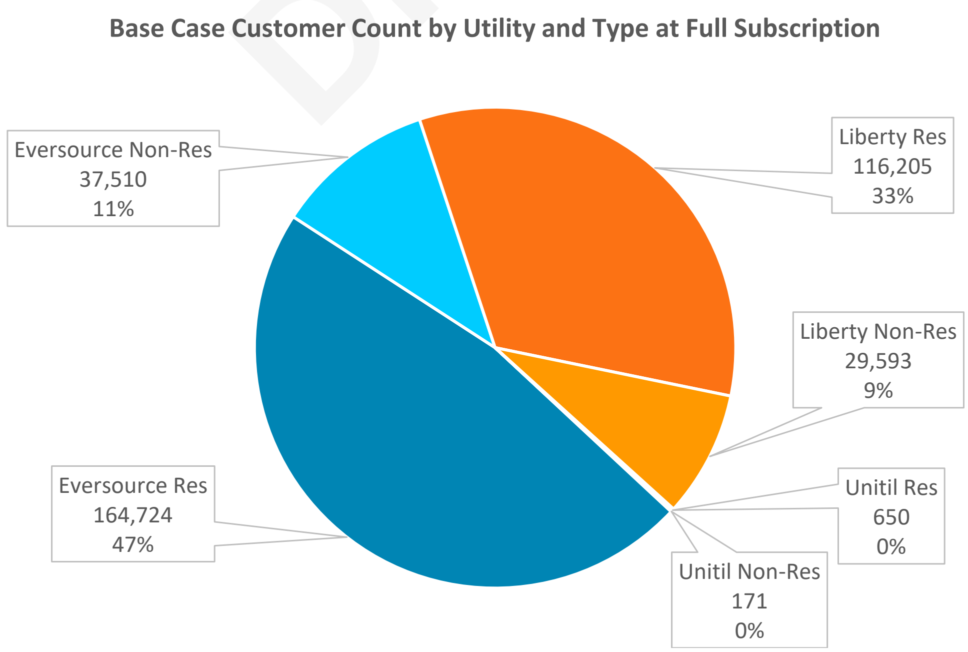


Figure 4 : Base Case Count by Utility and Type at Full Subscription

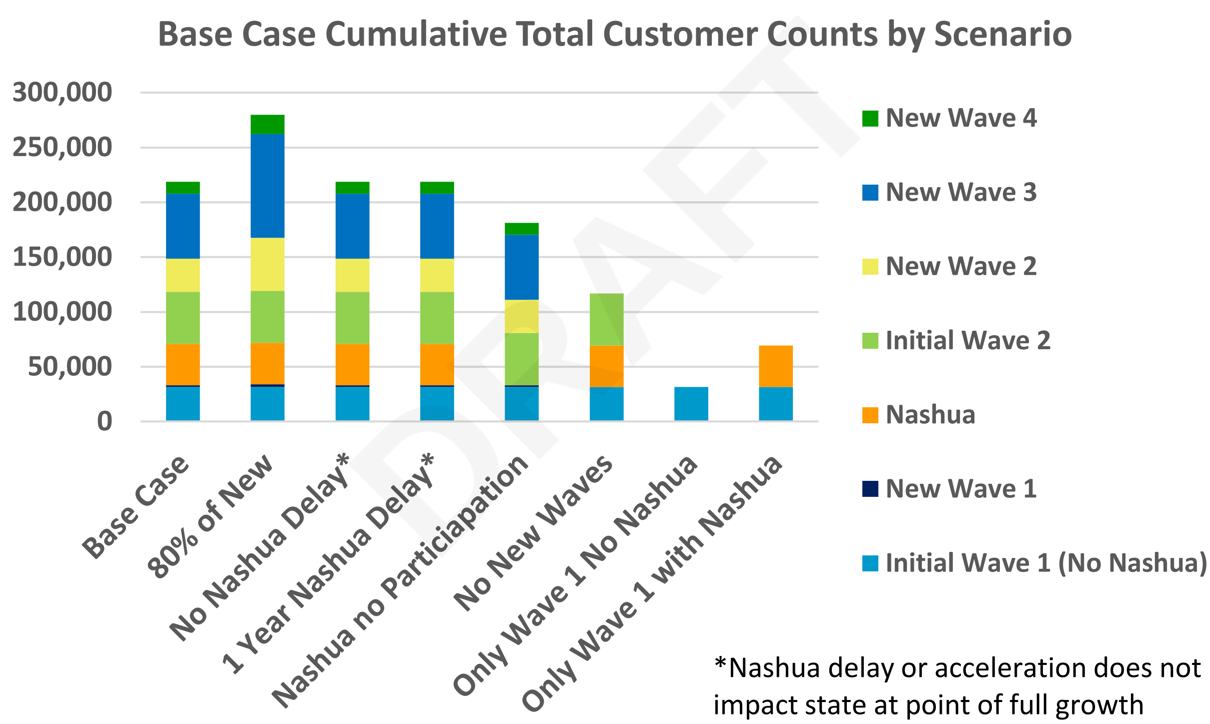


Ascend tested the following scenarios to assess the CPCNH's financial performance across various levels of Membership participation in CPA service:

- Base case, but 80% of new communities
- Base case, but no Nashua delay
- Base case, but Nashua delays 1 year instead of 2 months
- Base case, but Nashua never participates
- Base case, but no New Wave communities
- Base case, but no Nashua and no future waves after wave 1
- Base case, but no future waves after wave 1

Figure 5 demonstrates the overall total customer counts associated with eventual full subscription in future years.

Figure 5 : Base Case Cumulative Total Customer Counts by Participation Scenario



Expected Initial Enrollment and Opt-out

For the Technical analysis, opt-out assumptions are uniform across all scenarios. Ascend deems these opt-out assumptions to be conservative and reasonable for Opt-out aggregation, especially given that default utility loads have possessed retail choice for some time. Customers taking default service in an evolved choice market are generally more 'sticky' than early adopters who have likely already selected a retail energy supplier. The cumulative opt-out assumptions are in shown in Figure 6.

Figure 6 : Cumulative Opt-Out assumption by month for Residential and Non-residential

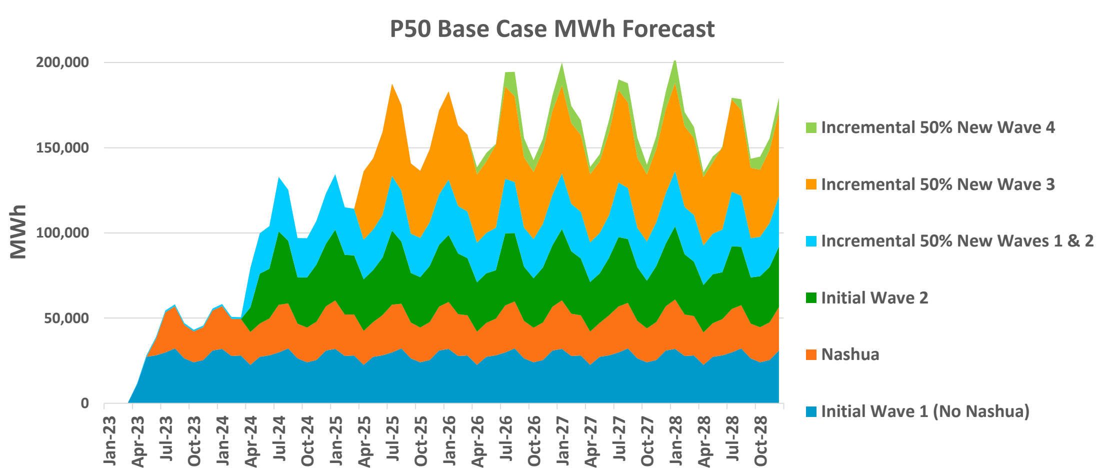
Months Since Enrollment	Cumulative Opt-Out Residential	Non-Residential
1	1%	2%
2	2%	4%
3	4%	6%
4	5%	8%

Projected Electricity Consumption

Ascend used a mosaic approach to compile the best possible picture of the eligible load participants. The data sources used in this process include public data from utility retail electric supplier websites, community specific customer lists obtained by individual CPAs from the utilities, as well as other publicly available information including population data. All data is subject to change as more accurate and/or detailed information is obtained via new CPA requests, new utility reporting requirements, new community participation interest, and the receipt of official pre-enrollment lists. After analyzing the existing data, Ascend believes it is reliable and useful for analysis.

After applying opt-out assumptions, CPCNH Initial Wave 1 members including Nashua equate to 592,000 MWh per year (68 MW Avg / ~135 MW Peak). Wave 2 is roughly 334,000 MWh per year (38 MW Avg / ~76 MW Peak). The Base Case assumes 50% of New Wave communities which equates to 974,000 MWh (111 MW Avg / ~222 MW Peak). Figure 7 shows projected total MWh across the forecast horizon for the assessment Base Case. When specific community data is unavailable, the analysis is based on average customer size to approximate the amount of load based upon customer count.

Figure 7: P50 Base Case MWh Forecast



Renewable Energy Portfolio Requirements

New Hampshire has a state Renewable Portfolio Standard (RPS) target that increases over time. *Figure 8* illustrates the base and scenario compliance/over-compliance targets and projected RPS costs on a per MWh served basis. The wholesale cost section of this report details the calculation of RPS cost to serve customers.

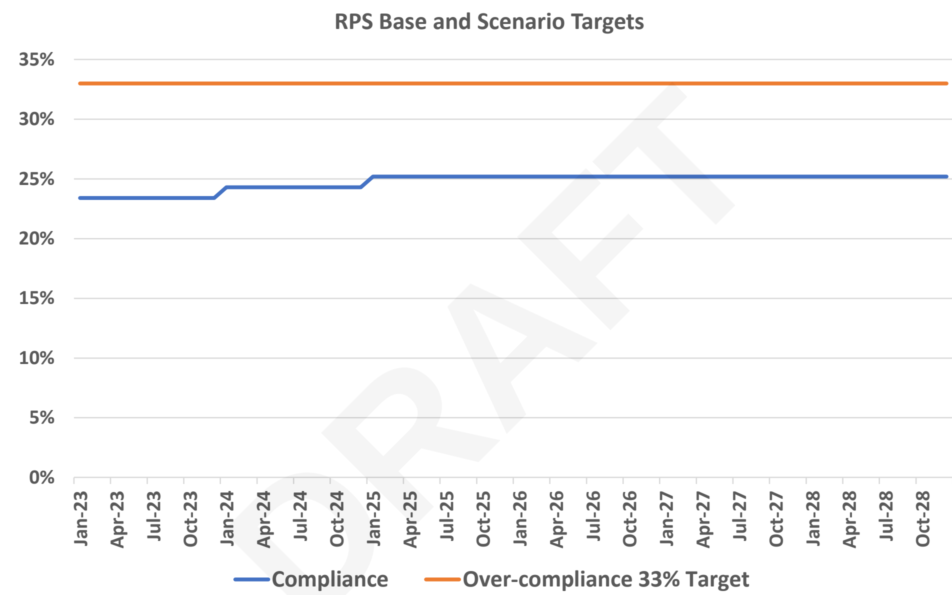
Base Case Assumption:

CPCNH launches with an RPS target based upon compliance.

Alternate Scenario:

CPCNH establishes its own default 33% RPS target as part of its default product content.

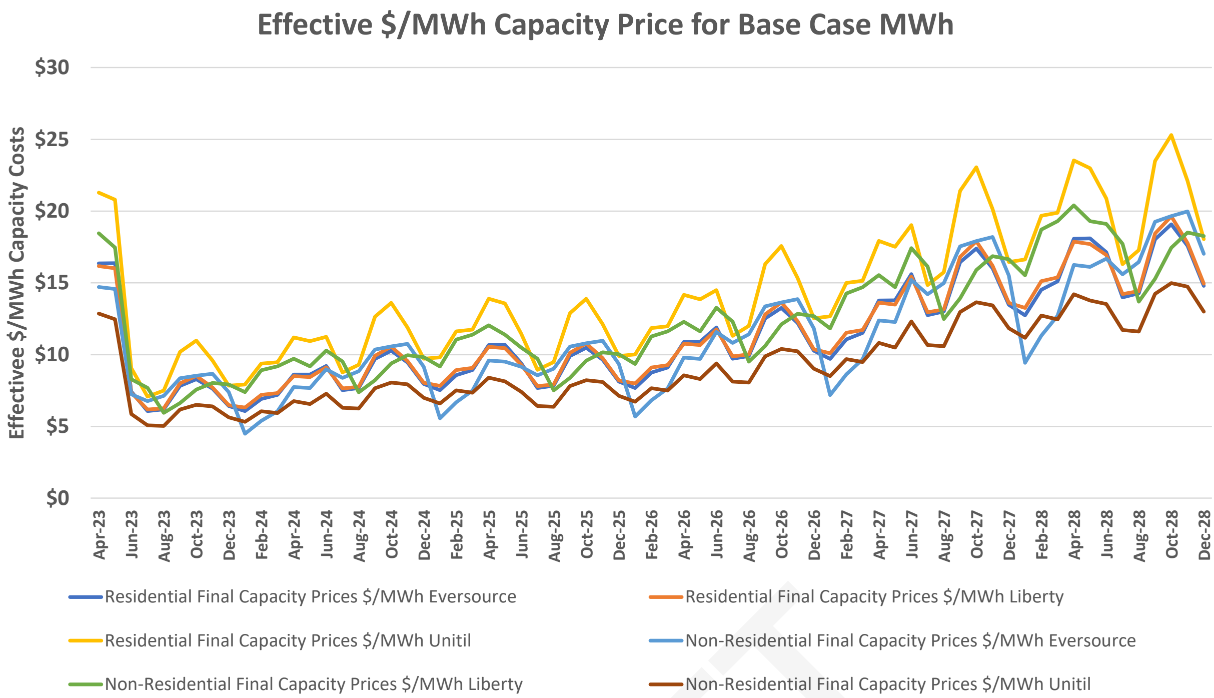
Figure 8: RPS Base and Scenario Targets



Capacity Requirements

Due to the limited availability of capacity requirement data, Ascend estimated capacity ICAP requirements based upon utility load asset ID profiles. For this Technical Assessment, Ascend performed pricing of capacity (described in the Cost-of-Service Elements section) on a $/MWh profile basis. ISO-NE ICAP Obligations for load are estimated on a $/MWh forecast as part of the cost of supply based upon utility load asset IDs. Figure 9 shows this forecast in terms of $/MWh. The Base Case and all scenarios use the same assumption on capacity cost as sensitivity to capacity pricing is limited given all market participants (utilities, retail suppliers, brokers, CPAs) generally pass capacity costs through in the build-up of market pricing.

Figure 9: Effective $/MWh Capacity Price for Base Case MWh



Revenue Assumptions and Elements

Rate Setting

For this Technical Assessment, CPCNH advised Ascend to pursue a rate setting methodology based upon a discount to utility tariff approach. This approach is prudent as it ensures customers receive a discount to utility tariff in an equitable and assured fashion. The following describes the utility tariff forecasting process used in this Technical Assessment.

Base Case Assumption:

- 5% discount to utility tariff unless the discount needs to be reduced to maintain debt service coverage ratios (DSCR).

Alternate Scenarios:

- 7.5% discount to utility tariff unless the discount needs to be reduced to maintain DSCR.

Tariff Forecast

Utility Auction Risk Premiums

With the exception of NHEC, utility auctions for the energy supply for default customers clear in the month or two leading up to a utility default service period. For a variety of reasons, including uncertainty of load volumes and load shape, market price uncertainty, market liquidity (depth of market participation in the auctions), and requirements to hold winning bids open until PUC approval is obtained, the auctions clear at a premium to the observed market forwards on the day of the auction. Ascend analysts performed research of past auctions to monitor the trends and recent behavior of utility auctions. Eversource and Liberty's residential / small commercial auctions cleared prior to the completion of this Technical Assessment and model results were updated to reflect the recent results.

Figure 10 shows the historical auction results for small customer Asset IDs (residential and small commercial customers), and

Figure 11 shows the historical auction premiums for large customer Asset IDs (larger commercial and industrial customers.

Figure 10: Small Historical Headroom Analysis

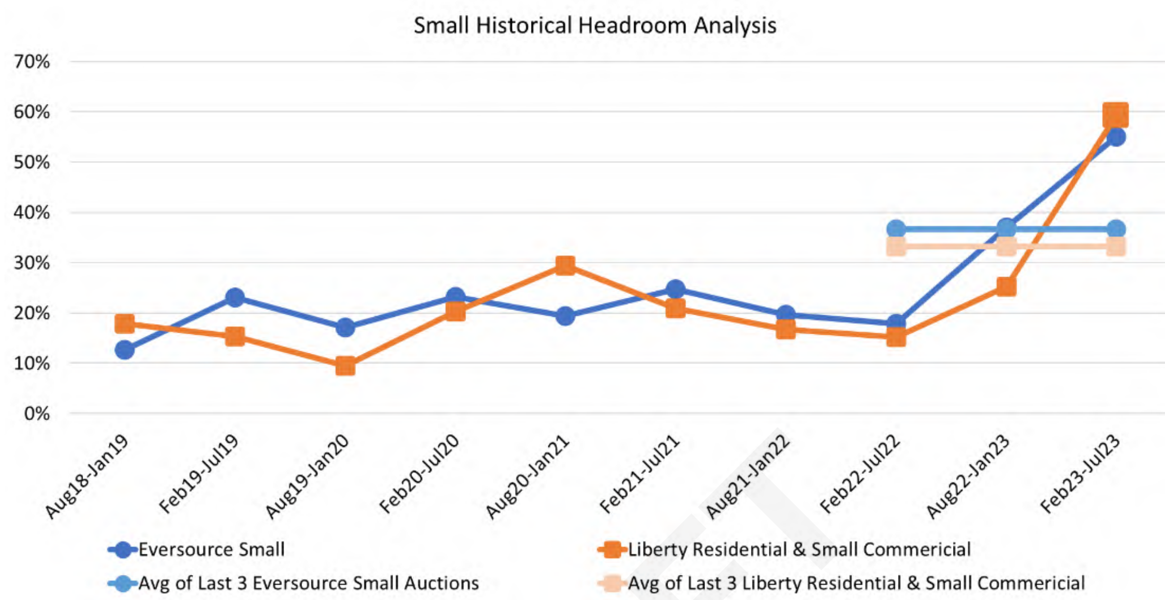
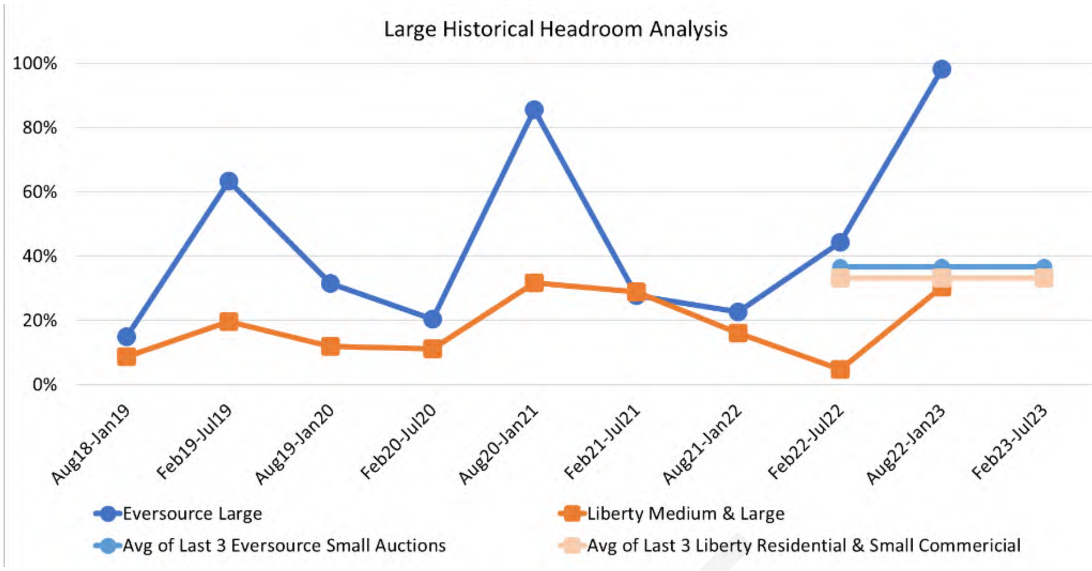


Figure 11: Large Historical Headroom Analysis



Ascend concluded that, due to market dynamics in ISO-NE and market volatility and uncertainty conditions, the average of the last three auctions is the appropriate forecast assumption moving forward. Consequently:

- For the February through July default service period, Ascend's model employs headroom assumptions based on the latest utility auctions and current posted utility rates.
- The forecasted auction premiums, based on applying the 3-year prior average premiums shown above, apply after July 2023; this may be conservative, as the 3-year prior average premiums are lower than the premiums from the current period.

Lastly, Ascend further opted to employ a conservative assumption in applying the small customer premium to the large customer Asset IDs, as the latter have been more volatile from auction to auction. (While higher future premiums could be justified, CPCNH's large customer load is relatively less compared to residential and small commercial load.)

Appendix D provides detail behind the determination of the premiums.

Current Competitive Supply Offers

Figure 12 provides posted supplier retail choice offers as of 12/19/2022. Since default utility load and eventual CPCNH opt-out load is not contractually bound, nor has a cancellation fee to leave CPCNH. Generally, most proactive energy choice customers have already left utility default service. The value proposition of competitive open access suppliers is limited, and pricing offered to customers may require long-term commitments to obtain favorable rates. The longer-term rates offer immediate savings, but based on forward markets, are likely to be above future utility rates. The competitive offers of suppliers is something CPCNH must monitor but may not warrant undue concern given the one-by-one nature of customer acquisition and the absence of a compelling missing for renewable and local community power.

Figure 12: Select Posted Supplier Retail Choice Offers (12/19/2022)

Class	Utility	Supplier	Months	$/KWH	Cancel fee	RE%
SML COM	Eversource	Direct	12	$ 0.19	$0	0
SML COM	Eversource	Direct	24	$ 0.17	$0	0
SML COM	Eversource	ENH Power	12	$ 0.19	$100	0
SML COM	Eversource	Xoom	12	$ 0.19	$500	0
SML COM	Eversource	Xoom	24	$ 0.18	$1,000	0
RES	Eversource	Direct	12	$ 0.20	$0	0
RES	Eversource	Direct	24	$ 0.18	$0	1
RES	Eversource	Direct	30	$ 0.17	$0	0
RES	Eversource	N. American	10	$ 0.19	$10	0.25
RES	Eversource	N. American	18	$ 0.19	$10	0.25
SML COM	Liberty	ENH Power	12	$ 0.20	$100	0
RES	Liberty	N. American	12	$ 0.19	$10	0.25
RES	Liberty	N. American	12	$ 0.20	$10	1
RES	Liberty	ENH Power	12	$ 0.20	$100	0
RES	Eversource	Ambit	12	$ 0.20	$0	0
RES	Eversource	Ambit	12	$ 0.19	$0	0
RES	Eversource	Smart	12	$ 0.23	$0	1
RES	Eversource	Townsquare	12	$ 0.20	$0	0
RES	Eversource	Xoom	12	$ 0.20	$110	0
RES	Eversource	Xoom	24	$ 0.19	$200	0
RES	Liberty	Ambit	12	$ 0.20	$0	0
RES	NHEC	Ambit	12	$ 0.19	$0	0
RES	NHEC	ENH Power	12	$ 0.21	$100	0
SML COM	NHEC	ENH Power	12	$ 0.21	$100	0
RES	Unitil	Ambit	12	$ 0.20	$0	0
RES	Unitil	ENH Power	12	$ 0.20	$100	0
RES	Unitil	N. American	10	$ 0.19	$10	0.25
RES	Unitil	N. American	18	$ 0.19	$10	0.25
RES	Unitil	Smart	12	$ 0.23	$0	1
RES	Unitil	Townsquare	12	$ 0.20	$0	0
SML COM	Unitil	ENH Power	12	$ 0.20	$100	0

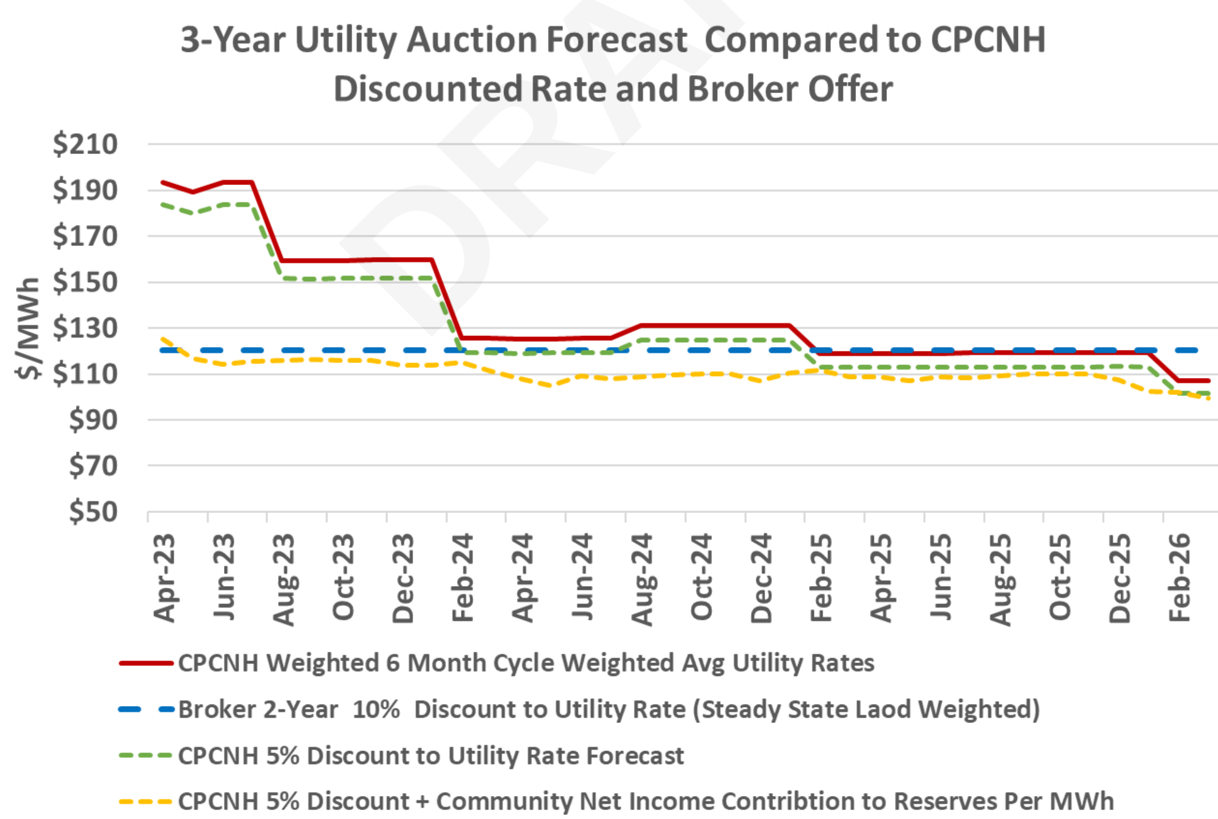
CPCNH Value Proposition vs the Broker Model

Ascend forecasted the default utility rate over future periods by applying the auction premiums to market forward prices, and incorporating non-energy wholesale costs. This assessment is important for clarity, as CPAs *could potentially* take a brokered deal for power supply independent of CPCNH. Such an election would result in the CPA losing many of the non-price related value proposition of CPCNH (portfolio management, local power, a mission for the energy transition, etc.). However, as is with most commodities, alternatives aside, economics are the most pressing factor in decision making:

- Proponents of the 'broker model' have pointed to assessments of the Massachusetts market, representing that customer savings of ~10% 'on average' are achievable and expected.
- CPCNH offers rate decreases and also accrues financial reserves on behalf of Members. In this context, CPCNH's Cost Sharing Agreement permits Wave 1 Members the option of terminating their continued participation in CPCNH at the end of their initial 3-year term, and to "cash out" at this juncture, using any accrued financial reserves to provide a rebate to customers (for example).
- Therefore, the question communities may ask is whether the "total potential savings" with CPCNH (computed by adding cumulative forecasted rate decreases and financial reserves) will outweigh the discount to the current rate committed to under a brokered power supply contract.

Figure 13 illustrates the following initial steps in Ascend's analysis of this question: given the utility rate forecast (red), achieving an average 10% discount over a 3-year term would imply a fixed price of approximately $120/MWh (blue); savings are large over the first 10 months, slightly better the next 12 months, before rising slightly above utility rates for the subsequent 14 months. In comparison, CPCNH's base case assumption is to offer a 5% discount to utility rates in each period (green). Consequently, the broker price would appear favorable, purely on the basis of immediate-term rate savings. However, adding the financial reserves to the customer bill discounts on a dollar per MWh basis reveals that CPCNH Members would pay less for supply service over the 36-month period (yellow).

Figure 13: 2-year Utility Auction Forecast Compared to CPCNH Discounted Rate and Broker Offer

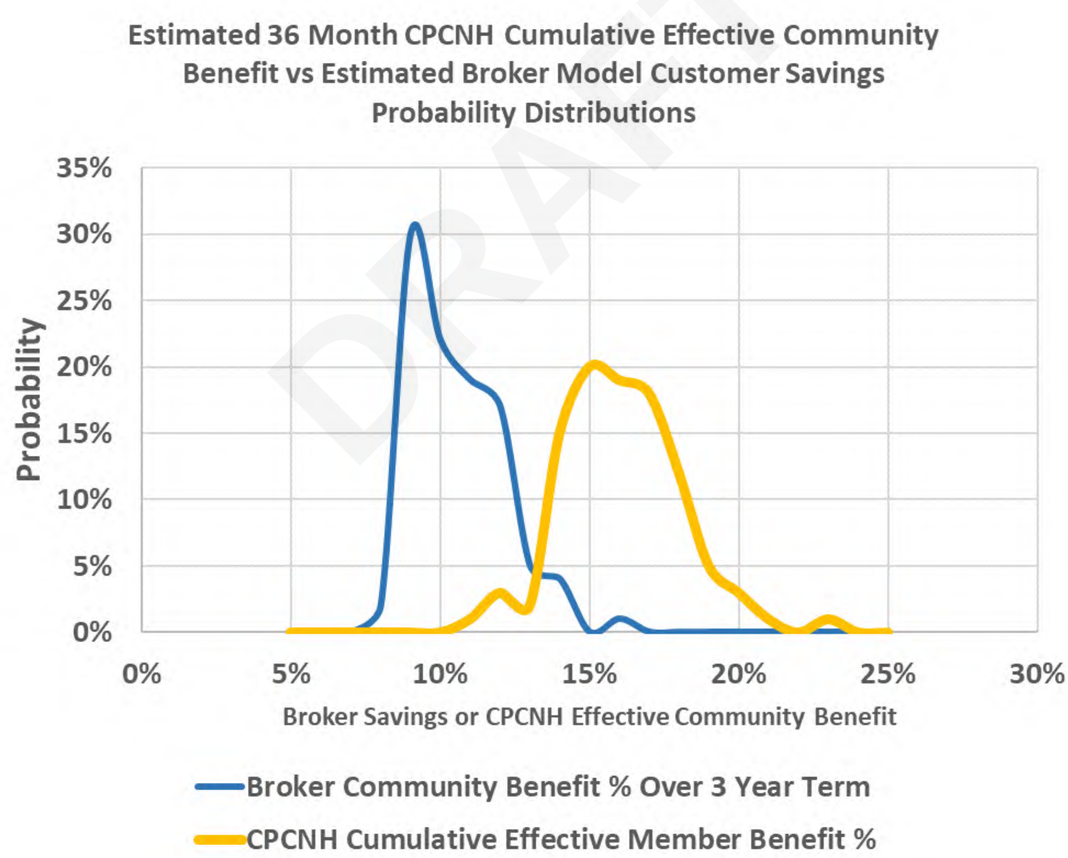


However, a single forecast based on an assumed "known" utility rate is not sufficient to ensure informed decision-making for Members evaluating whether to participate in CPCNH, because the financial benefit offered under both models is dependent upon future utility rates.

Ascend therefore stochastically simulated and analyzed the results from over 100 different scenarios of market price movements and corresponding utility default service rates. Comparing the initial fixed-price assumed under the brokered power supply deal to what utility rates would be in each scenario revealed that actual customer savings could fluctuate between 6% and 14% over the 36-month initial period. In comparison, the "total potential savings" that a Member would achieve taking service from CPCNH, given the same scenarios, fell between 11% and 22.6%.

These probability distributions are presented in Figure 14 below. However, it is important to note that, while the distributions appear to overlap, the financial benefits for a Member participating in CPCNH were larger than what the Member would have gained by contracting for the fixed-price brokered supply deal in every single scenario.

Figure 14 : Probability distribution of estimated 36 month CPCNH cumulative effective community benefit vs. estimated broker model customer savings



Headroom

Headroom is the difference between the utility tariff and the CPCNH market build-up cost of supply. Figure 15 and Figure 16 below illustrate the headroom during the first portion of the initial four months of operation (April - July 2023) during the utilities' February – July 2023 default service period. The significant headroom in the current market environment is a major advantage as CPCNH establishes its market position and builds initial reserves. It is important to note the absence of headroom within NHEC. It is for this reason Ascend recommends CPCNH designate NHEC customers as opt-in, so as to not offer a discount and take a loss on customers, nor charge customers over their existing tariff. Headroom is before accounting for operating costs. An illustration in the findings sections shows headroom net of operating costs over a six year period for the Technical Assessment Base Case.

Figure 15: Estimated Small Headroom Comparison

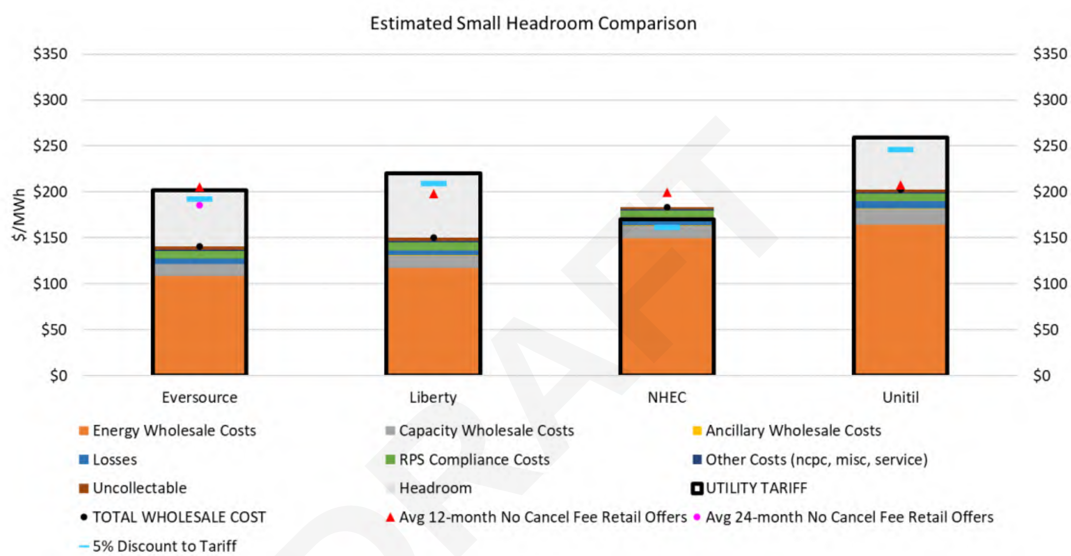
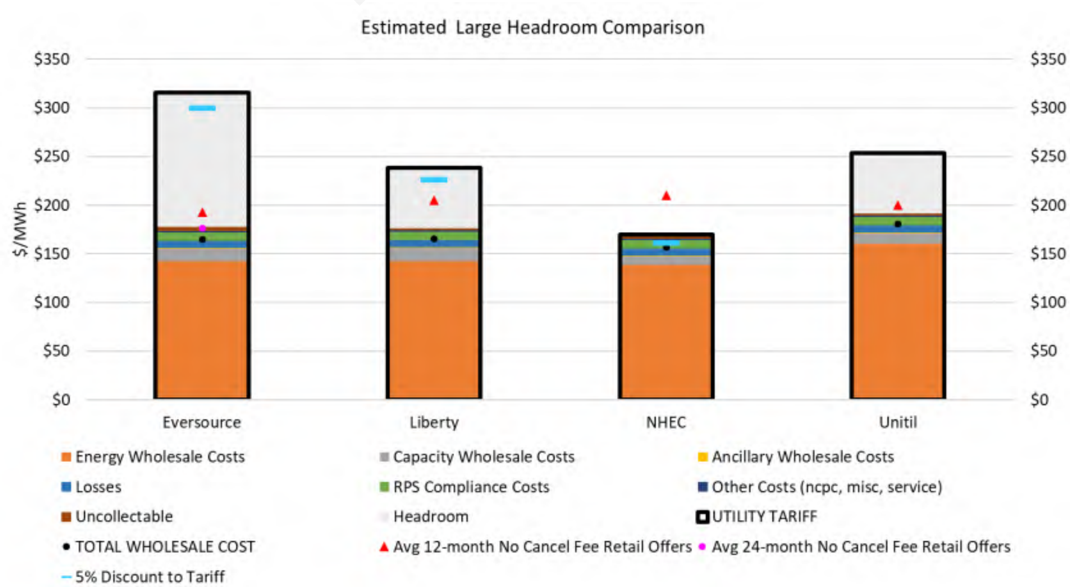


Figure 16: Estimated Large Headroom Comparison



Cost of Service Elements

Energy

To simulate the loads that will be served by CPCNH, Ascend harvested publicly available historical hourly load data from Eversource, Until, Liberty, and NHEC for each available asset ID. Table A below summarizes the asset IDs that were available. These historical loads are correlated with historical weather to simulate potential future loads. These potential load futures are coupled with simulated prices to arrive at the cost of supplying energy. The asset IDs considered can be observed in Figure 17. Although NHEC Asset IDs were evaluated, NHEC was excluded from final results for reasons explained in this Technical Assessment.

Figure 17: Asset ID, Utility and Asset Type

Utility	Asset ID	Asset Type	Rate Classes
Eversource	43493	Small Customer Load	R, R-OTOD, G, G-OTOD, OL, EOL
Eversource	752	Large Customer Load	CV, LG, B, OL
NHEC	RESIDENT	Residential	Residential - Single Phase, Residential - Mulit Phase
NHEC	PRIMARYG	General/Primary Service	General - Single Phase, General - Multi - Phase, Primary Service
NHEC	COMLARGE	Primary Service - Ski	Primary Service -Ski
NHEC	COMMERCL	Group Net Metering Host	Group Net Metering Host
NHEC	STREETLT	Street Lights	Outdoor Lighting - Metered, Outdoor Lighting Service
Liberty	11436	Small Customer Load	D, D-10, C-3, M, T, V
Liberty	11437	Large Customer Load	G-1, G-2
Unitil	11451	Small Customer Load	D
Unitil	11452	Medium Customer Load	G2, OL
Unitil	10019	Large Customer Load	C1

Energy Cost of Supply

Asset ID Profiles

Historical hourly profiles for the asset IDs covering the New Hampshire load served by each of the utilities considered were harvested from each utilities' respective websites. Eversource and Liberty had data available between 2015-2021, Unitil had data between 2017-7/2022, and NHEC data available for 2021. With these historic load profiles, a weather-load correlation was established that is used in PowerSIMM to simulate stochastic load scenarios based on simulated weather scenarios.

Weather is the driver of the meaningful uncertainty connecting both the price simulation and the load simulations. For example, extreme weather scenarios result in higher loads to support the increased demand for heating and cooling, and this spike in loads drives up the price of power and gas commodities. These historically observed relationships are evident in the weather, load, and price simulations that this technical assessment relies on. On average the load simulations will scale to the expected load forecast, and on average the hourly spot price simulations will scale to the expected forwards as harvested from ICE futures price quotes. However, each stochastic scenario represents a unique weather simulation, and therefore the model can capture potential high load high price futures and low load low price futures in order to assess forward looking risks that are anchored in historically observed trends.

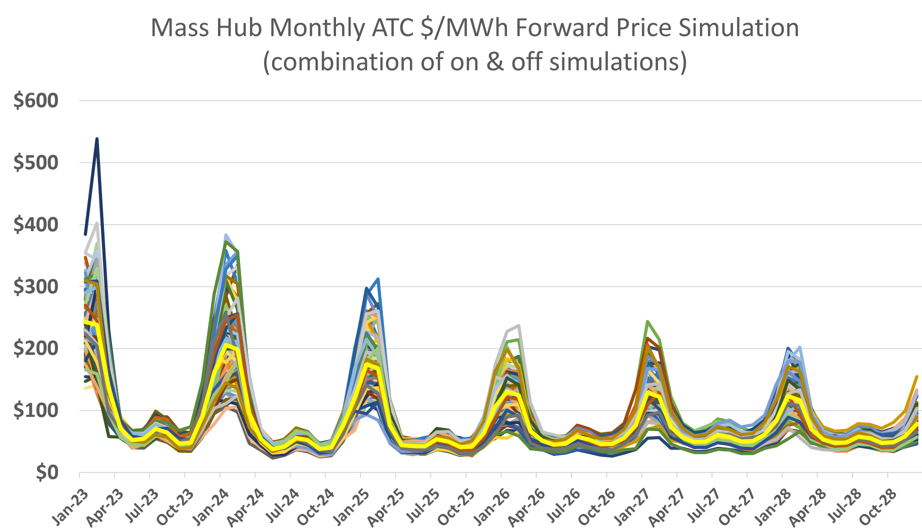
Figure 18: Historical Load Data used in PowerSIMM

For more information on load simulations and their relationship to weather and price simulations please refer to Appendices E and F (available upon request).

Market Prices

Forward contract prices are modeled with an Autoregressive, or AR, model with volatilities and correlations estimated from historical data or with inputs provided in the Forward Price Constraints. Forward price simulations follow a random process with a reversion term that pull back to the monthly mean values based on the mean reversion rate. As seen in Figure 19: Mass Hub Monthly ATC $/MWh Forward Price SimulationsFigure 19 below, Ascend forward price simulations are unique across iterations. To ensure consistency with the forward curve, the average of the forward price simulations converges to the forward market prices used as of the time of the simulation. However, there is a range of prices simulated which is consistent with the volatility assumptions. Figure 19 shows Mass Hub Monthly ATC $/MWh Forward Price Simulation (Combination of On and Off-Peak Simulations)

Figure 19: Mass Hub Monthly ATC $/MWh Forward Price Simulations



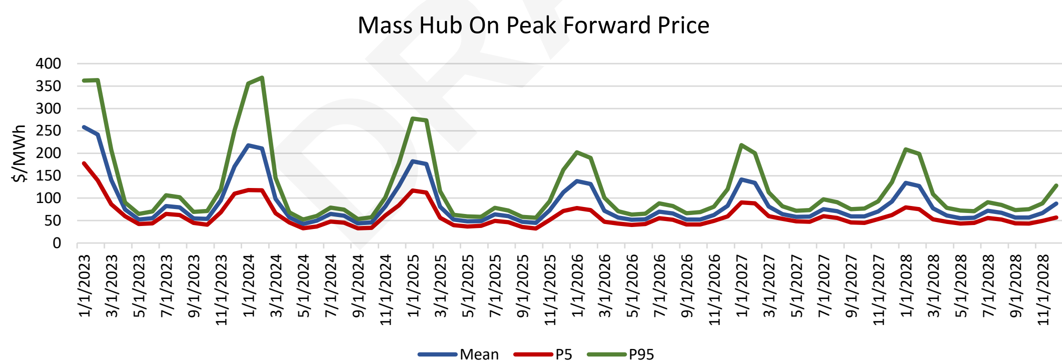
Power and Natural Gas Prices

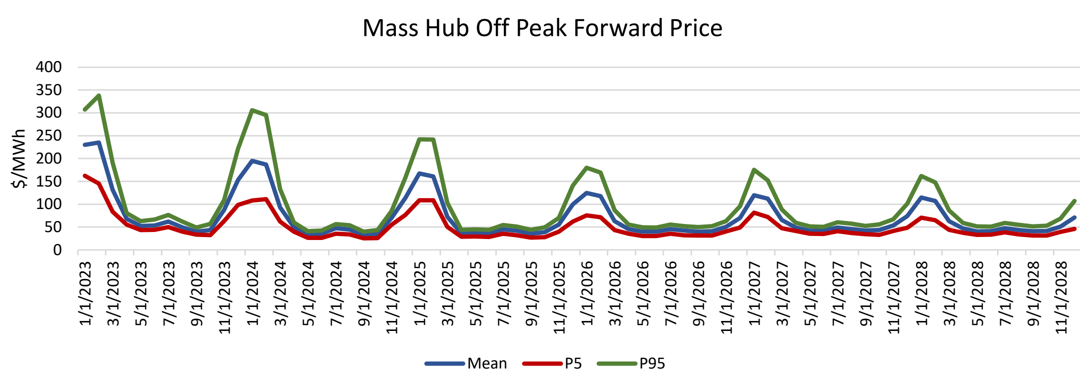
This technical assessment is based on forward price quotes as of December 6, 2022 harvested from ICE. The mean price in the forward price simulation converges to these market quotes, but the price in any given iteration/weather simulated scenario will vary based on forward curve constraints imposed on the model, namely the volatility and correlation constraints. Ascend implements a term structure volatility which is updated monthly to best capture market dynamics that tend to have greater volatility in the short term than in the long term, for this reason the range of uncertainly around the mean price captured by the P5 and P95 price differential is highest at the front end of the sims and declines through time.

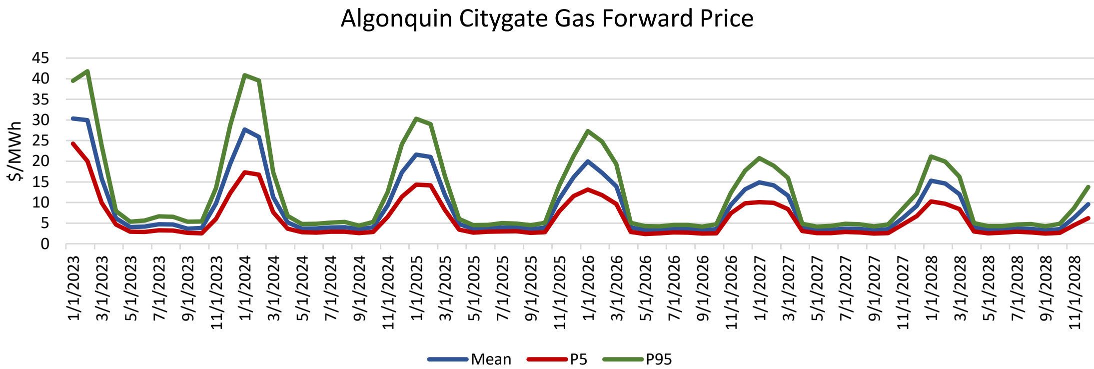
Forward prices are simulated using an autoregressive (AR) model with a lag of one while limiting the coefficient to a value of less than 1. An AR coefficient less than 1 is equivalent to a Geometric Brownian Motion (GBM) model with mean reversion. Thus, simulated forward prices follow a random walk with a constant pull back to the monthly mean values. The extent to which these simulated forward prices can deviate from mean values is determined by the forward volatility limits discussed previously.

When specifying correlation constraints Ascend ensures that the correlation matrix is positive semi-definite where each commodity (on-peak power, off-peak power, gas, etc.) is correlated with itself and each other commodity both within each month and across all months. This process ensures that expected commodity relationships are maintained such as those between gas prices, off peak and on peak power prices. *Figures 20*shows the P5, mean and P95 values from simulated forward curves for Mass Hub on-peak and off-peak forward prices as well the Algonquin Citygate forward gas prices.

Figures 20 : Simulated P5, Mean and P95 for Mass Hub On Peak, Off Peak and Algonquin Citygate



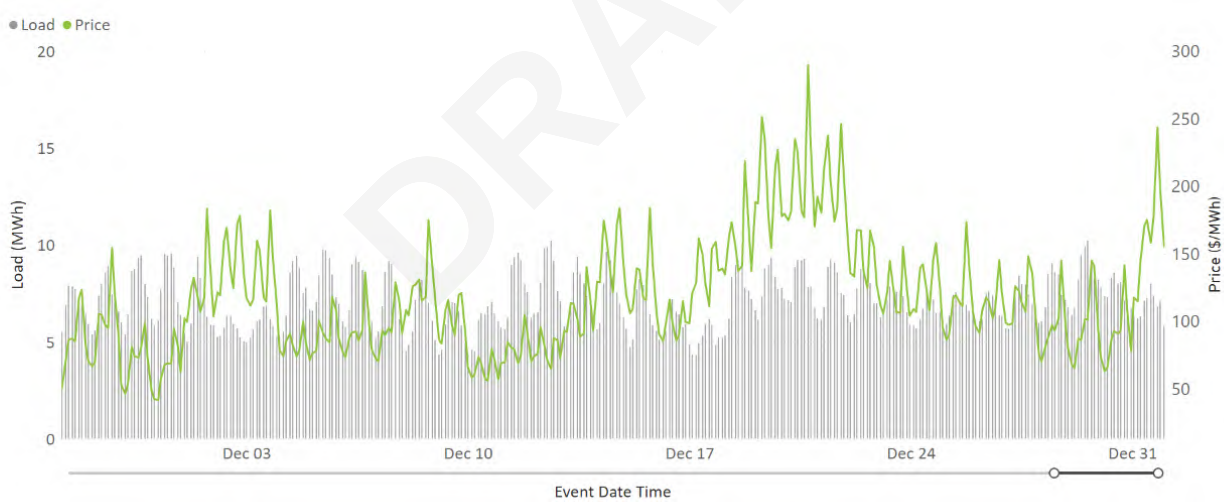




For more information on the mechanics behind Forward Price simulations refer to Appendix F (available upon request).

PowerSIMM also simulates hourly load and power prices. Figure 21 shows a sample of one iteration of PowerSIMM's stochastic hourly simulation of load and price. While summaries and figures are reported in aggregate figures, it is important to note the rigor of price simulations. Appendix E provides more content on the validations of simulation data.

Figure 21 : Sample Iteration of Simulated Hourly Loads and Prices



Non-Energy Wholesale Costs

In addition to modeling energy costs, Ascend also developed forecasts for a number of different non-energy cost expectations. The methodology and input assumptions for the relevant non-energy cost forecasts is discussed below:

Capacity Costs

For capacity cost of service information, a $/MWh capacity cost was estimated for each month utilizing ISONE website data on cleared auction information as well as long term Ascend Market Intelligence capacity price forecasts. Cleared auction results for capacity markets are available through May 2026 as of now. Once the next auction clears for 2026/2027, the Ascend team will update its forecast to align with the new cleared capacity auction information. Long-term Ascend Market Intelligence capacity price forecasts are updated on a regular basis after evaluating fundamental factors in ISONE that may contribute to potential changes in price expectations.

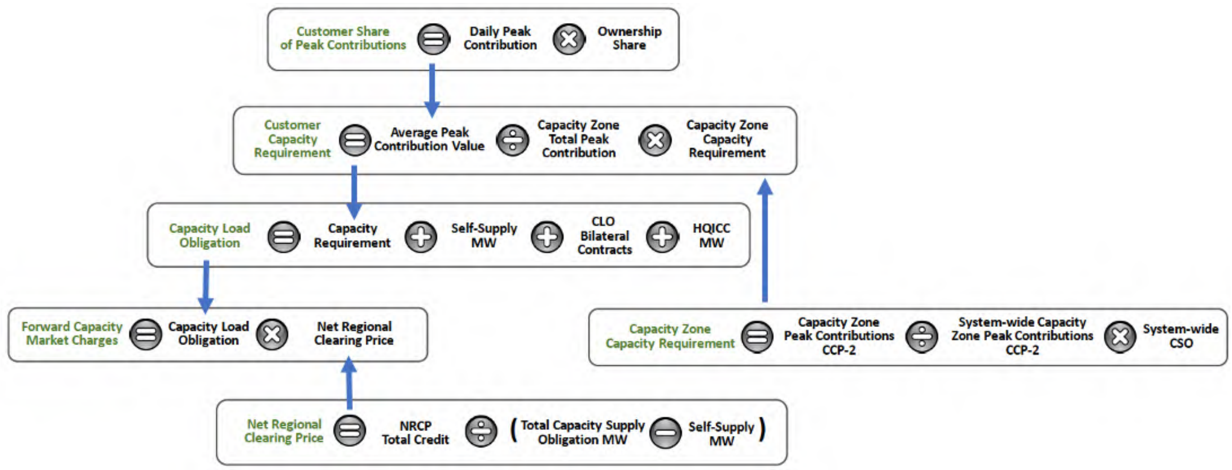
To derive a capacity cost in dollars for each Asset ID, the monthly $/MWh capacity cost value is used as an input into PowerSIMM and applied to the same MWh load forecast for each month in each iteration of the model results. These costs represent not only the expected cost of service for capacity but also the distribution of possible outcomes for capacity cost of service for the electric load owned by CPCNH.

The Forward Capacity Market (FMC) ensures that ISONE will have sufficient resources to meet future demand for electricity (Source: ISONE.com). Each year, an auction is conducted by the ISO to determine the $/kW-mo price for capacity delivered three years into the future. Thus, at any point in time, there is a known cleared capacity price for at least the next three years. For example, as of 2022, there are cleared capacity prices through May 2026. Ascend's $/kW-mo capacity price forecast starts with these cleared capacity prices and then uses Ascend's Market Intelligence team forecast for future months where prices have not cleared yet. The Market Intelligence price forecast methodology includes forecasted supply & demand of electricity in ISONE as well as future costs of new entry for various types of generation.

Once the forecast for the $/kW-mo cleared capacity price has been estimated, the next step consists on converting it into a final $/MWh rate that can be applied to all load MWh to calculate total capacity costs going forward.

As a first step, Ascend uses the ISONE website to identify zonal capacity obligations for the northern new England zone that New Hampshire is in. All the information required to determine zonal capacity obligations is available for the cleared auction periods. In the next step, settlement data and ICAP tag information for each utility is obtained from the utility websites to identify how much unaccounted for energy is in the ICAP tags. The utility MWs are then used to forecast the zonal capacity obligation for each utility by class (Small/Large). These obligations are applied to the $/kW-mo capacity price to estimate capacity costs in dollars. These are then divided into the wholesale MWh for each utility to arrive at a $/MWh capacity price. The various elements considered in the modeling of capacity $/MWh price assumptions are shown in Figure 22 below. An additional assumption is that the factors contributing to converting $/kW-mo capacity prices into $/MWh beyond the cleared capacity market are consistent with the last cleared auction information.

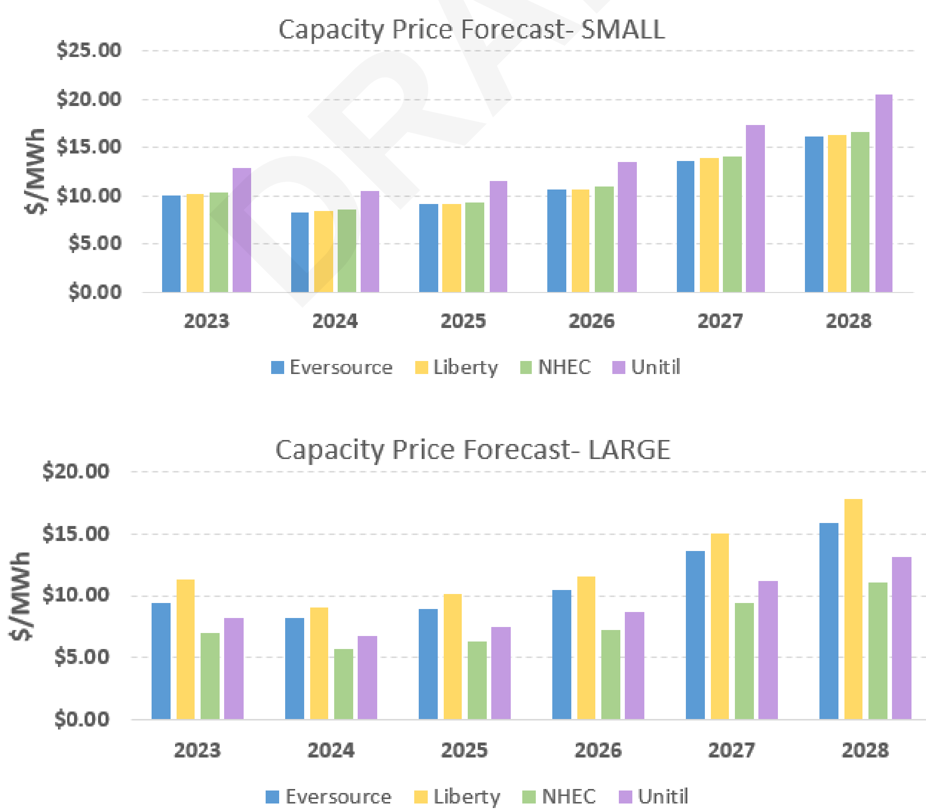
Figure 22: Elements considered to model capacity $/MWh price assumptions



source: ISO-NE tariff

Capacity price forecast ($/MWh) for Small and Large Segments by Utility are shown in Figure 23

Figure 23: Capacity Price Forecast for Small and Large Segments



Ancillary Markets

Ancillary Market modeling includes the following cost components that are charged to electricity providers: Regulation, Reserves (Forward & Real-Time), and Financial Transmission Auction Rights.

The Regulation market pays generators that can increase or decrease supply every four seconds. This includes assets that can be controlled by the ISO automatically. Reserve markets are for assets that the ISO needs to be ready to generate if needed but that might not actually turn on and thus need to be compensated outside of the energy markets for the costs associated with being ready to turn on at short notice. Financial transmission rights are related to congestion between two different price locations.

All of these markets have payments that are paid to generators by the ISO and then charged to load owners based on how much electric load they serve. While these costs are significantly smaller than energy and capacity market costs, it is still important to include them as costs in the analysis.

For this Technical Assessment, a $/MWh price that represents ancillary costs is input into the model. The starting point is the average of the last 12 months of ancillary costs in the wholesale market report for New Hampshire on ISONE website (Source: https://www.iso-ne.com/static-assets/documents/2022/09/2022_08_wlc.pdf). Figure 24 shows NH Load Zone Cost Components for All hours, On Peak and Off Peak. The initial price is adjusted year over year at the same rate of change used in Ascend's Market Intelligence ancillary price forecast for generators in ISONE. The Market Intelligence forecast is developed by looking at a variety of fundamental factors that impact ancillary markets in ISONE.

Figure 24: NH Load Zone Wholesale Load Cost Component

3.3.2 New Hampshire Load Zone Wholesale Load Cost Components, Last 13 Months

Component (All Hours)	AUG2021	SEP2021	OCT2021	NOV2021	DEC2021	JAN2022	FEB2022	MAR2022	APR2022	MAY2022	JUN2022	JUL2022	AUG2022
Total Wholesale Rate ($/MWh)	$58.02	$54.84	$64.52	$67.47	$68.15	$156.48	$117.73	$74.22	$66.40	$86.09	$87.24	$106.54	$109.73
Energy	$49.59	$46.86	$56.35	$59.39	$59.96	$148.63	$109.31	$66.14	$58.36	$74.08	$72.31	$91.72	$96.78
Capacity	$6.26	$6.46	$6.28	$6.40	$6.41	$6.20	$6.86	$6.30	$6.41	$6.20	$12.18	$10.18	$10.01
NCPC	$0.84	$0.42	$0.79	$0.73	$0.95	$1.27	$1.11	$0.86	$0.64	$1.45	$0.82	$2.50	$1.38
Ancillary Markets	$0.62	$0.43	$0.42	$0.45	$0.41	$0.60	$0.59	$0.58	$0.43	$0.57	$1.35	$1.63	$1.27
Misc Credit/Charge	($0.24)	($0.31)	($0.28)	($0.46)	($0.54)	($1.20)	($1.14)	($0.63)	($0.42)	($0.38)	($0.40)	($0.47)	($0.68)
Wholesale Mkt Service Charge	$0.96	$0.97	$0.96	$0.97	$0.96	$0.97	$1.00	$0.97	$0.98	$0.97	$0.98	$0.97	$0.97
RTLO (MWh)	(1,139,651)	(899,494)	(864,897)	(892,934)	(1,009,920)	(1,094,003)	(928,288)	(938,240)	(815,101)	(876,000)	(909,130)	(1,122,788)	(1,136,920)
Total Cost	$66,123,467	$49,327,165	$55,802,653	$60,250,655	$68,830,765	$171,186,534	$109,283,328	$69,636,492	$54,122,619	$75,412,536	$79,309,668	$119,621,435	$124,754,102

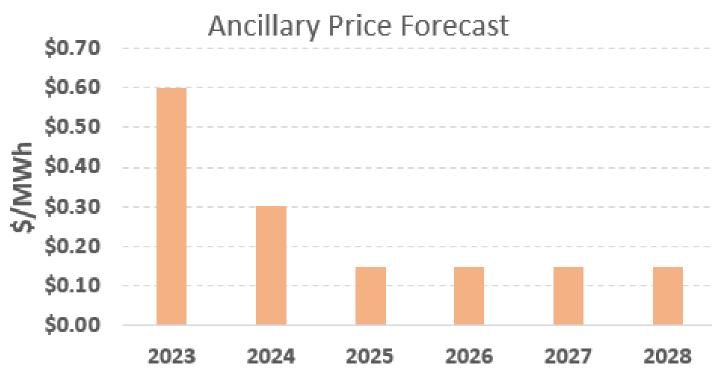
Component (On Peak)	AUG2021	SEP2021	OCT2021	NOV2021	DEC2021	JAN2022	FEB2022	MAR2022	APR2022	MAY2022	JUN2022	JUL2022	AUG2022
Total Wholesale Rate ($/MWh)	$70.63	$60.14	$71.95	$70.84	$73.91	$169.99	$123.19	$74.12	$69.90	$94.09	$92.26	$125.34	$122.04
Energy	$61.60	$51.98	$63.53	$62.50	$65.61	$161.75	$114.78	$65.75	$61.82	$79.46	$76.33	$109.32	$108.26
Capacity	$6.26	$6.46	$6.28	$6.40	$6.41	$6.20	$6.86	$6.30	$6.41	$6.20	$12.18	$10.18	$10.01
NCPC	$1.02	$0.39	$0.83	$0.85	$1.00	$1.53	$0.93	$0.95	$0.52	$1.77	$0.70	$2.52	$1.42
Ancillary Markets	$1.07	$0.68	$0.65	$0.62	$0.53	$0.82	$0.81	$0.81	$0.62	$0.79	$2.55	$2.92	$2.22
Misc Credit/Charge	($0.29)	($0.35)	($0.31)	($0.49)	($0.60)	($1.28)	($1.19)	($0.67)	($0.46)	($0.42)	($0.47)	($0.57)	($0.84)
Wholesale Mkt Service Charge	$0.96	$0.97	$0.96	$0.97	$0.96	$0.97	$1.00	$0.97	$0.98	$0.97	$0.98	$0.97	$0.97
RTLO (MWh)	(620,406)	(473,952)	(439,504)	(458,803)	(547,897)	(537,744)	(476,623)	(505,516)	(416,909)	(429,765)	(500,310)	(554,588)	(636,013)
Total Cost	$43,816,412	$28,502,192	$31,620,135	$32,502,500	$40,493,725	$91,409,858	$58,713,918	$37,466,739	$29,140,384	$40,435,510	$46,157,539	$69,511,394	$77,621,077

Component (Off Peak)	AUG2021	SEP2021	OCT2021	NOV2021	DEC2021	JAN2022	FEB2022	MAR2022	APR2022	MAY2022	JUN2022	JUL2022	AUG2022
Total Wholesale Rate ($/MWh)	$46.70	$50.20	$58.40	$64.54	$62.52	$145.35	$112.76	$74.32	$63.34	$79.50	$82.43	$92.35	$97.68
Energy	$38.81	$42.38	$50.44	$56.68	$54.44	$137.83	$104.34	$66.52	$55.34	$69.65	$68.47	$78.45	$85.54
Capacity	$6.26	$6.46	$6.28	$6.40	$6.41	$6.20	$6.86	$6.30	$6.41	$6.20	$12.18	$10.18	$10.01
NCPC	$0.67	$0.45	$0.76	$0.62	$0.91	$1.05	$1.27	$0.78	$0.74	$1.18	$0.93	$2.48	$1.33
Ancillary Markets	$0.21	$0.21	$0.23	$0.30	$0.29	$0.43	$0.39	$0.35	$0.27	$0.38	$0.21	$0.66	$0.33
Misc Credit/Charge	($0.20)	($0.27)	($0.27)	($0.43)	($0.48)	($1.13)	($1.10)	($0.59)	($0.39)	($0.35)	($0.33)	($0.39)	($0.51)
Wholesale Mkt Service Charge	$0.96	$0.97	$0.96	$0.97	$0.96	$0.97	$1.00	$0.97	$0.98	$0.97	$0.98	$0.97	$0.97
RTLO (MWh)	(519,245)	(425,542)	(425,393)	(434,132)	(462,023)	(556,258)	(451,665)	(432,723)	(398,191)	(446,235)	(408,820)	(568,200)	(500,907)
Total Cost	$24,249,988	$21,363,317	$24,844,737	$28,017,267	$28,887,615	$80,852,764	$50,929,980	$32,161,293	$25,221,702	$35,475,252	$33,700,742	$52,474,183	$48,927,862

Source: ISONE.com

Ancillary price forecasts ($/MWh) for 2023 to 2028 are shown in Figure 25

Figure 25: Ancillary Price Forecast ($/MWh)



RPS Compliance Costs

In 2007, the New Hampshire Department of Energy enacted a Renewable Portfolio Standard requirement which requires each electricity provider to purchase a certain amount of renewable supply to serve its customers' loads. The percentage requirement information, as well as information on historical prices for compliance payments for those entities that do not purchase RECs (renewable energy credits) or own enough renewable generation to meet their requirements can be found online ([Renewable Portfolio Standard | NH Department of Energy]). Figure 26 shows Renewable Portfolio Standard Obligations by Year by Class.

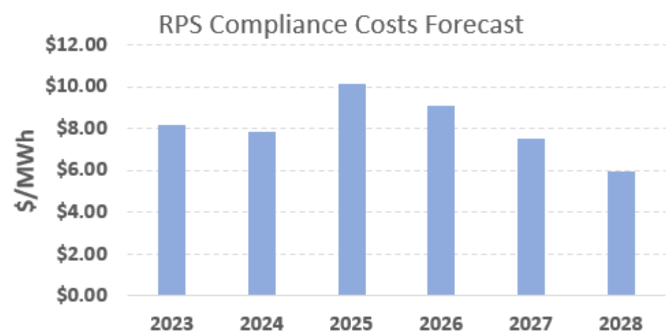
Figure 26: Renewable Portfolio Standard Obligations by Year

Renewable Portfolio Standard Obligations							
Calendar Year	**Total RPS Requirement**	**Class I Non-Thermal***	**Class I Thermal**	**Total Class I**	**Class II**	**Class III**	**Class IV**
2008	**4.00%**	0.00%	0.00%	**0.00%**	**0.00%**	**3.50%**	**0.50%**
2009	**6.00%**	0.50%	0.00%	**0.50%**	**0.00%**	**4.50%**	**1.00%**
2010	**7.54%**	1.00%	0.00%	**1.00%**	**0.04%**	**5.50%**	**1.00%**
2011	**9.58%**	2.00%	0.00%	**2.00%**	**0.08%**	**6.50%**	**1.00%**
2012	**5.55%**	3.00%	0.00%	**3.00%**	**0.15%**	**1.40%**	**1.00%**
2013	**5.80%**	3.80%	0.00%	**3.80%**	**0.20%**	**0.50%**	**1.30%**
2014	**7.20%**	4.60%	0.40%	**5.00%**	**0.30%**	**0.50%**	**1.40%**
2015	**8.30%**	5.40%	0.60%	**6.00%**	**0.30%**	**0.50%**	**1.50%**
2016	**8.50%**	5.60%	0.60%	**6.20%**	**0.30%**	**0.50%**	**1.50%**
2017	**17.60%**	6.80%	1.00%	**7.80%**	**0.30%**	**8.00%**	**1.50%**
2018	**18.70%**	7.50%	1.20%	**8.70%**	**0.50%**	**8.00%**	**1.50%**
2019	**19.70%**	8.20%	1.40%	**9.60%**	**0.60%**	**8.00%**	**1.50%**
2020	**14.70%**	8.90%	1.60%	**10.50%**	**0.70%**	**2.00%**	**1.50%**
2021	**14.60%**	9.60%	1.80%	**11.40%**	**0.70%**	**1.00%**	**1.50%**
2022	**22.50%**	10.30%	2.00%	**12.30%**	**0.70%**	**8.00%**	**1.50%**
2023	**23.40%**	11.00%	2.20%	**13.20%**	**0.70%**	**8.00%**	**1.50%**
2024	**24.30%**	11.90%	2.20%	**14.10%**	**0.70%**	**8.00%**	**1.50%**
2025 and thereafter	**25.20%**	12.80%	2.20%	**15.00%**	**0.70%**	**8.00%**	**1.50%**

Source: energy.nh.gov

In this Technical Assessment, an RPS requirement percentage was applied to Ascend's Market Intelligence forecast for REC prices in ISONE to create a $/MWh price that can be applied to all load MWh owned. Ascend's REC price forecasts are developed by modeling expected supply and demand for renewables over time. RPS compliance cost forecasts from 2023 to 2028 are shown in Figure 27

Figure 27: RPS Compliance Costs Forecast ($/MWh)



Other Costs

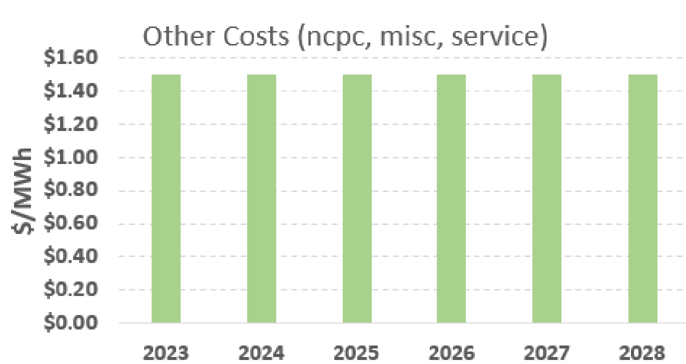
Net Commitment Period Compensation (NCPC), Miscellaneous Charges, and Wholesale Market Service Charges are also forecasted as costs in this Technical Assessment.

According to ISONE, "**NCPC** is the payment to a market participant for its generator or external transaction that did not recover its effective offer costs from the energy market during an operating day. The **NCPC** payment is intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule." (Source: [Net Commitment-Period Compensation (iso-ne.com)]). These payments are made by the ISO to generators and then charged by the ISO to load owners.

Miscellaneous Charges and Wholesale Service Charges represent other costs that load owners pay to the ISO. The assumptions for these costs were developed taking the average of the last 12 months in the New Hampshire Wholesale Load cost report found on ISONE's website. Given that these costs are small and do not vary much month to month, these costs are assumed to remain constant in all future months of the forecast. These costs are applied as a $/MWh value to all load MWh owned.

Others cost forecasts ($/MWh), including NCPC, miscellaneous and other service are shown in Figure 28

Figure 28: Other Costs (NCPC, Miscellaneous, Wholesale Market Service Charges)



Non-Wholesale Operating Costs

Ascend worked with CPCNH regarding its staffing, vendor and general overhead budgeting to comprehensively include all costs in the Technical Assessment. The following is a brief overview of those assumptions which were held static across scenarios.

Operating Budget Assumptions

Staffing

CPCNH has identified initial roles for 11 staff members it projects to hire over the 30 months of operations. CPCNH is actively recruiting a CEO targeting March 2023 onboarding. Six other positions are slated to start in 2023, with the remaining four in 2025. This hiring is realistic and prudent as CPCNH builds in-house capabilities. While not tested in scenarios, CPCNH financials should be able to withstand a more aggressive hiring pace should the various considerations learned in the initial months and year of operations inform changes to the expected hiring shown in Figure 29.

Figure 29: Start Date Assumptions for

Staff Starts	
Mar-23	CEO
May-23	CFO
Jul-23	General Counsel
Jul-23	Director, Policy & Regulatory Affairs
Jul-25	Director, Technology & Analytics
Jul-23	Director, Marketing & Customer Services
Sep-23	Strategic Accounts Manager
Jun-25	Power Resources Manager
Sep-23	Analyst 1
Sep-25	Analyst 2
Sep-25	Analyst 3

Operating Costs

Figure 30 shows CPCNH's operational costs based on total dollars or unit costs. When those costs are variable, these elements are incorporated in the financial model to fluctuate with the customer counts and changes by scenario.

Figure 30: CPCNH Operational Cost Assumptions

	2022	2023	2024	2025	2026	2027	2028	
Non-Contracted Cost Increase Assumption		6.4%	6.2%	5.0%	4.2%	4.0%	4.0%	

	2022	2023	2024	2025	2026	2027	2028	
Portfolio Risk Management & Operations						Assume 1/3 cost after 36th month of Ascend service		
Ascend Analytics		$82,062	$87,114	$91,428	$95,244			***$/Month***
LSE		$45,000	$60,000	$60,000	$15,000	$0	$0	***Annualized Cost***
$6 MM ISO Credit Support		$1.00	$0.50	$0.45	$0.40	$1.00	$1.00	***$/MWh***
Vendor Operating Credit $2.5MM (First 18 Months)		12.5%	12.5%	22.5%	22.5%	22.5%	22.5%	***Rate on Loan (4.5%+Prime)***
Vendor Support Line of Credit $1MM (First 18 Months)		12.5%	12.5%	22.5%	22.5%	22.5%	22.5%	***Rate on Loan (4.5%+Prime)***
Other Operations								
Calpine (Platform, Utility Data, Billing)		$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	***Cost Per Meter***
	OR	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	***Cost Per Meter***
	plus	$25,000	$25,000	$25,000	$25,000	$25,000	$25,000	***Cost Per Customer Per Month***
Support Services								
Accounting and Audits		$140,000	$148,618	$155,979	$162,488	$168,971	$175,713	***Annualized Cost***
Marketing and Branding		$150,000	$159,234	$167,120	$174,094	$181,040	$188,264	***Annualized Cost***
Legal Advice and Regulatory Engagement (DWGP)		$300,066	$318,538	$334,314	$0	$0	$0	***Annualized Cost***
Community Choice Partners		$0	$0	$0	$0	$0	$0	
Herdon Enterprises		$121,478	$128,956	$135,343	$140,991	$146,616	$152,466	
Clean Energy New Hampshire		$76,600	$81,315	$85,343	$88,904	$92,451	$96,140	
Utility Fees		$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	***Cost Per Customer Per Month***
NEPOOL Expenses		$0	$19,200	$19,200	$19,200	$19,200	$19,200	***Cost Per Year***

Deferred Compensation Repayment

CPCNH relies on five vendors that have committed to support pre-launch activities in exchange for payment after launch of CPA service, on the at-risk, deferred compensation basis assumed below:

Figure 31: Aggregate Deferred Compensation Repayment

Aggregate Deferred Compensation Repayment			
2023	**2024**	**2025**	**2026**
$485,903	$796,286	$572,831	$183,095

Total Deferred Compensation Dollars	$2,038,116
Base Case MWh from Five Year Allocation Period	10,620,659
Projected $/MWh Cost of Deferred Start Up Cost	$0.19
Projected ¢/kWh Cost of Deferred Start Up Cost	0.019¢

Cash Flow Assumptions

Across all scenarios and stochastics, static Line of Credit (LOC) assumptions are utilized in the modeling. Modeled draws may differ across scenarios and stochastics but the assumptions on the cost of various facilities are as follows:

- LSE LOC for ISO-NE initial float and collateral for the ISO credit support listed in the prior operating cost section, assumed in place from launch to be utilized through March 2024.
- Vendor Operating line of credit at Prime + 4.5% for initial coverage of operating costs from launch through March 2024.
- From April 2024 onward, an expected transition to CPCNH's own Line of Credit assumed at 3-Month SOFR + 2.26%

It is worth noting that given an on-schedule launch, CPCNH establishes ample reserves such that a draw on lines of credit is not needed beyond the first year of operation in financial modeling. It is also worth noting that CPCNH may elect to use lines of credit to fund future activities. However, in the Technical Assessment Ascend did not attempt to weigh the qualitative factors that may lead to such a decision. Instead Ascend built the Technical Assessment model to conservatively assume CPCNH weathers poor market conditions by drawing on reserves and/or temporarily reducing customer discounts. In reality, Ascend acknowledges other strategies may be employed, but this method of assessment in the financial modeling takes a conservative approach to such conditions.

Also impacting cash flows are the fact that CPCNH customers will consume power and remit payment to utilities on the utility billing cycles. Those revenues will be lagged as the revenues are collected and funds are transfer to CPCNH's secured revenue account. Ascend estimated the retail billing lag factors shown in Figure 32 for its adjustment of revenue cash flows:

Figure 32: Retail Billing Lag Factors

	Month 1	Month 2	Month 3
Retail Billing Lag Factors	2%	60%	38%

Local Projects

A major value proposition for CPCNH is its ability to bring local projects to the forefront through the market-based pilot mechanism authorized under Senate Bill 321. SB321 permits CPCNH to launch up to 2 MW of capacity in each utility service territory. These projects benefit from not only renewable production for energy and RPS credits, but also avoided capacity and transmission costs.

Base Case:

- 2 MW of Local Projects

Alternate Scenarios:

- A full 8 MW up to the SB321 Cap
- 10 MW additional for a total of 18 MW assuming the SB321 cap may be lifted

The Tables in Figure 33, Figure 34 and

Figure 35 are excerpts from the base scenarios for the purpose of highlighting the value of Local projects to CPCNH and to affirm the competitive advantage that local projects provide to the Coalition.

Figure 33: Base Case Local Projects

Month	2023	2024	2025	2026	2027	2028
Local Projects Revenue (Cost Reduction) ($/MWh)	**$0.22**	**$0.31**	**$0.27**	**$0.23**	**$0.26**	**$0.25**
Market Energy Value	$0.69	$0.61	$0.34	$0.28	$0.30	$0.29
Renewable Energy Credit Value	$0.27	$0.22	$0.19	$0.15	$0.12	$0.10
Capacity Credit Value	$0.00	$0.02	$0.03	$0.04	$0.05	$0.06
Transmission Credit Value	$0.19	$0.25	$0.23	$0.23	$0.24	$0.27
PPA Cost	$0.94	$0.79	$0.52	$0.47	$0.45	$0.47
Local Projects Revenue (Cost Reduction)	**$84,623**	**$352,946**	**$474,806**	**$455,621**	**$515,615**	**$483,448**
Market Energy Value	$264,618	$687,343	$598,160	$553,691	$595,280	$559,549
Renewable Energy Credit Value	$104,483	$247,127	$331,566	$295,205	$244,247	$194,443
Capacity Credit Value	$0	$19,825	$54,610	$80,054	$103,694	$121,669
Transmission Credit Value	$73,750	$286,740	$412,906	$445,938	$481,613	$520,142
PPA Cost	$358,229	$888,090	$922,435	$919,266	$909,219	$912,355

Figure 34: 8 MW Scenario Local Projects

Month	2023	2024	2025	2026	2027	2028
Local Projects Revenue (Cost Reduction) ($/MWh)	**$0.22**	**$0.94**	**$1.26**	**$1.21**	**$1.34**	**$1.42**
Market Energy Value	$0.69	$0.80	$0.63	$0.53	$0.56	$0.55
Renewable Energy Credit Value	$0.27	$0.30	$0.34	$0.26	$0.21	$0.18
Capacity Credit Value	$0.00	$0.02	$0.10	$0.16	$0.21	$0.25
Transmission Credit Value	$0.19	$0.76	$0.94	$0.91	$0.96	$1.07
PPA Cost	$0.94	$0.94	$0.74	$0.66	$0.61	$0.63
Local Projects Revenue (Cost Reduction)	**$84,623**	**$1,056,271**	**$2,224,554**	**$2,379,095**	**$2,680,109**	**$2,758,333**
Market Energy Value	$264,618	$895,273	$1,116,544	$1,047,641	$1,129,771	$1,074,955
Renewable Energy Credit Value	$104,483	$338,562	$594,512	$519,389	$430,684	$343,598
Capacity Credit Value	$0	$19,825	$175,959	$320,217	$414,774	$486,675
Transmission Credit Value	$73,750	$860,220	$1,651,622	$1,783,752	$1,926,452	$2,080,569
PPA Cost	$358,229	$1,057,609	$1,314,084	$1,291,904	$1,221,574	$1,227,462

Figure 35: 18 MW Scenario Local Projects

Month	2023	2024	2025	2026	2027	2028
Local Projects Revenue (Cost Reduction) ($/MWh)	**$0.22**	**$0.94**	**$1.26**	**$1.21**	**$1.34**	**$1.42**
Market Energy Value	$0.69	$0.80	$0.63	$0.53	$0.56	$0.55
Renewable Energy Credit Value	$0.27	$0.30	$0.34	$0.26	$0.21	$0.18
Capacity Credit Value	$0.00	$0.02	$0.10	$0.16	$0.21	$0.25
Transmission Credit Value	$0.19	$0.76	$0.94	$0.91	$0.96	$1.07
PPA Cost	$0.94	$0.94	$0.74	$0.66	$0.61	$0.63
Local Projects Revenue (Cost Reduction)	**$84,623**	**$1,056,271**	**$2,224,554**	**$2,379,095**	**$2,680,109**	**$2,758,333**
Market Energy Value	$264,618	$895,273	$1,116,544	$1,047,641	$1,129,771	$1,074,955
Renewable Energy Credit Value	$104,483	$338,562	$594,512	$519,389	$430,684	$343,598
Capacity Credit Value	$0	$19,825	$175,959	$320,217	$414,774	$486,675
Transmission Credit Value	$73,750	$860,220	$1,651,622	$1,783,752	$1,926,452	$2,080,569
PPA Cost	$358,229	$1,057,609	$1,314,084	$1,291,904	$1,221,574	$1,227,462

Active Portfolio Management for Load Scheduling & Hedging

Ascend Analytics believes active portfolio management increases value to CPCNH. Ascend assessed technical analysis of Mass Hub forward prices and believes roughly 1.5% improvement in hedge pricing can be achieved through ongoing market monitoring to add incremental hedges when market conditions are favorable.

Further, Ascend believes that in concert with CPCNH's risk management committee, another 1% reduction in hedge cost is practical given good judgment to hedge timing can be employed beyond a 'set-it-and-forget-it' programmatically timed hedge strategy. Therefore, Ascend believes that 2.5% hedging cost reduction through active portfolio management of forward hedges is reasonable for the Technical Assessment. Ascend conducted a perfect foresight analysis on stochastic market simulation data and found, that if hedging decisions were always made at the exact best time, 20% savings is achievable. Given this upper bound, 2.5% is a conservative 'on-average' expectation.

Further, Ascend is committed to integrate its SmartBidder solutions to realize additional value from CPCNH's native short position through balancing the risk and return of day-ahead (DA) versus real-time (RT) commitments to serve CPCNH load (forming the day-ahead to real-time price spread referred to as the DART spread). Based on application of a mosaic of models that combine to probabilistic assess the DART spread, SmartBidder provides suggested quantity commitment allocation between DA and RT realization of load to market prices. The bidding strategies of SmartBidder are supplied to the LSE for submission to the ISO. Based upon historical absolute DART spreads, Ascend expects 1.5% savings over uniformly scheduling all load into the day-ahead market. The 1.5% assumed improvement in costs also follow a risk/return assessment measured through the Sharp ratio of the same or improved over the traditional all load committed in the day-ahead market.

CPCNH Technical Assessment Findings

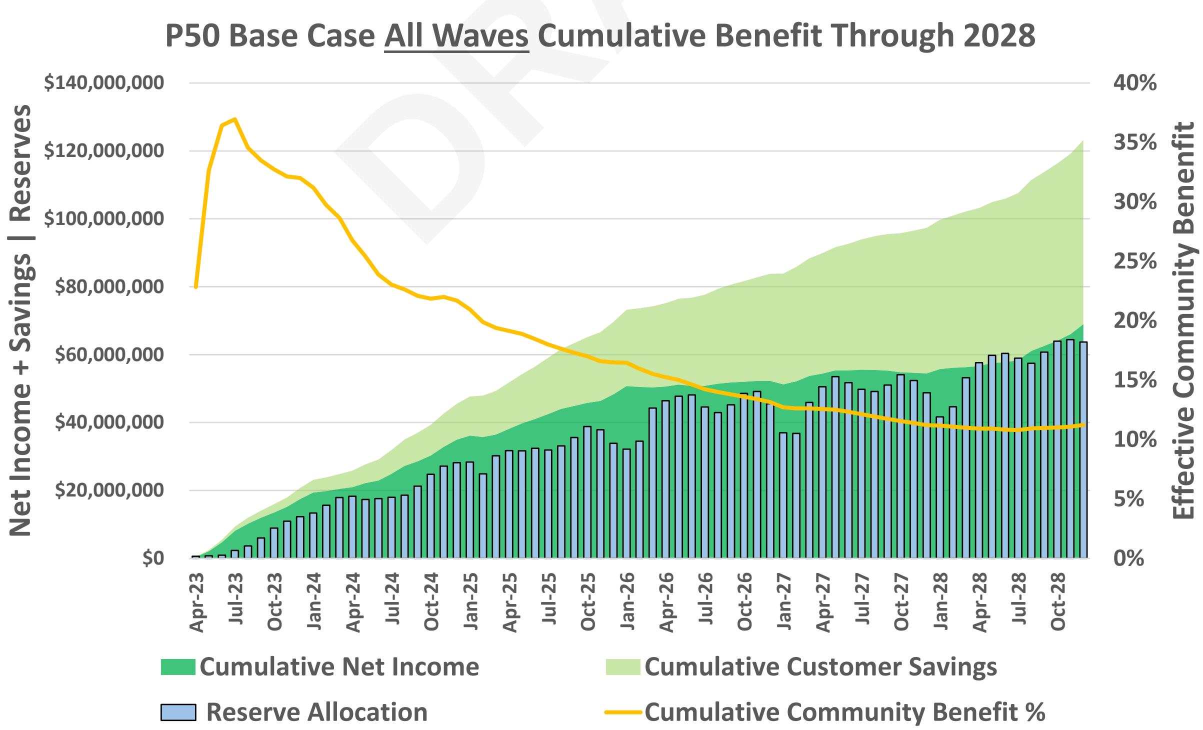
The following details the results of Ascend's analysis surrounding the various Base Case, stochastic and alternative scenario analysis. Several key metrics are assessed to convey not only potential outcomes, but potential trade-offs between events or decisions that may impact the CPCNH portfolio. While not exhaustive of possible scenarios, or combinations thereof, Ascend believes that this Technical Assessment provides sufficient review of 'what-ifs' to inform its members for a decision on whether to launch. To its knowledge, no CPA implementation assessment has ever performed comparably rigorous stochastic analysis of potential outcomes to support the launch of service.

Base Case P50

The Base Case assumptions are P50 is the 50th percentile, statistically the median across the 100 Base Case simulations performed in PowerSIMM as defined by the simulation producing the median cumulative member benefit percentage at the end of 2028. Appendix B contains detailed annual income statement information for the P50 Base Case. The following section illustrates the key takeaways from the Base Case given the assumptions and methodology highlighted in previous sections.

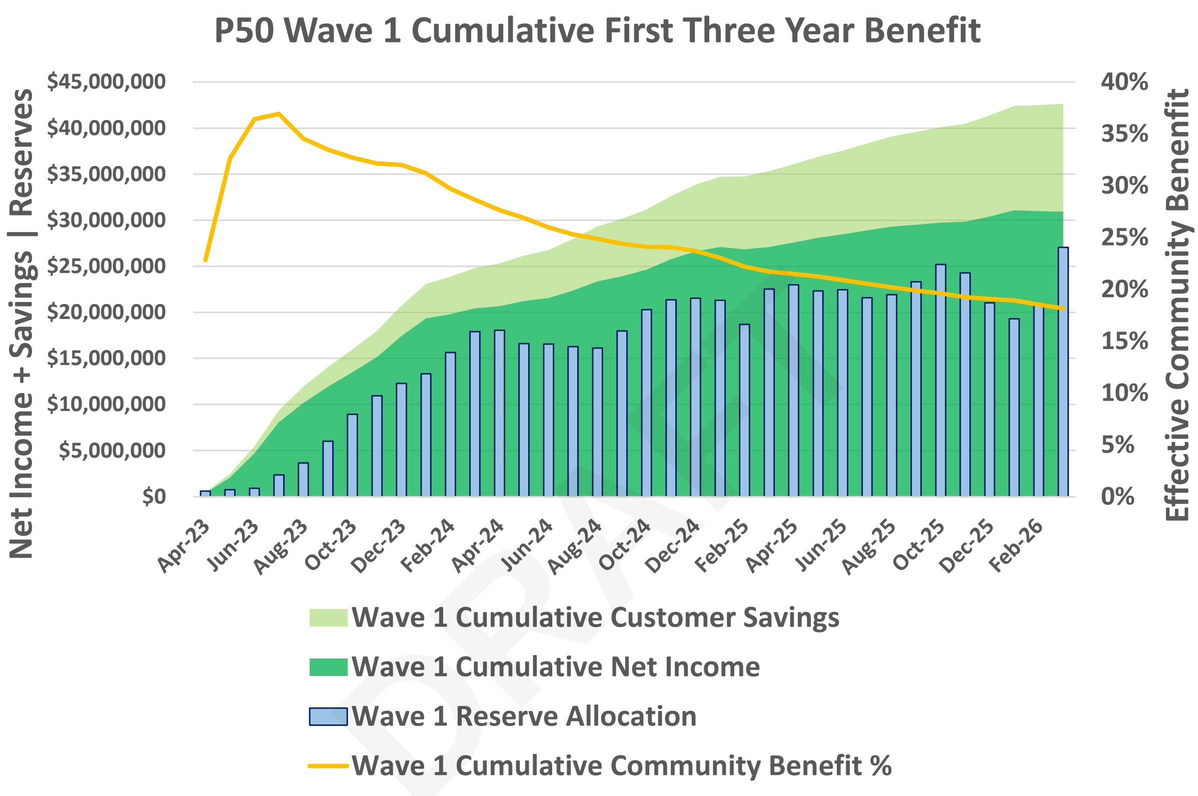
Figure 36 shows the P50 Base Case through 2028 cumulative net income, cumulative customer savings, cumulative community benefit % metrics, and reserve allocation for initial and projected CPCNH members. Base Case finding demonstrates that by year end 2028 over $60MM in reserves will be amassed and 6-year cumulative effective community benefit will exceed 10% inclusive of nearly $60MM in customer utility bill savings.

Figure 36: P50 Base Case Cumulative Benefit through 2028 for All Waves



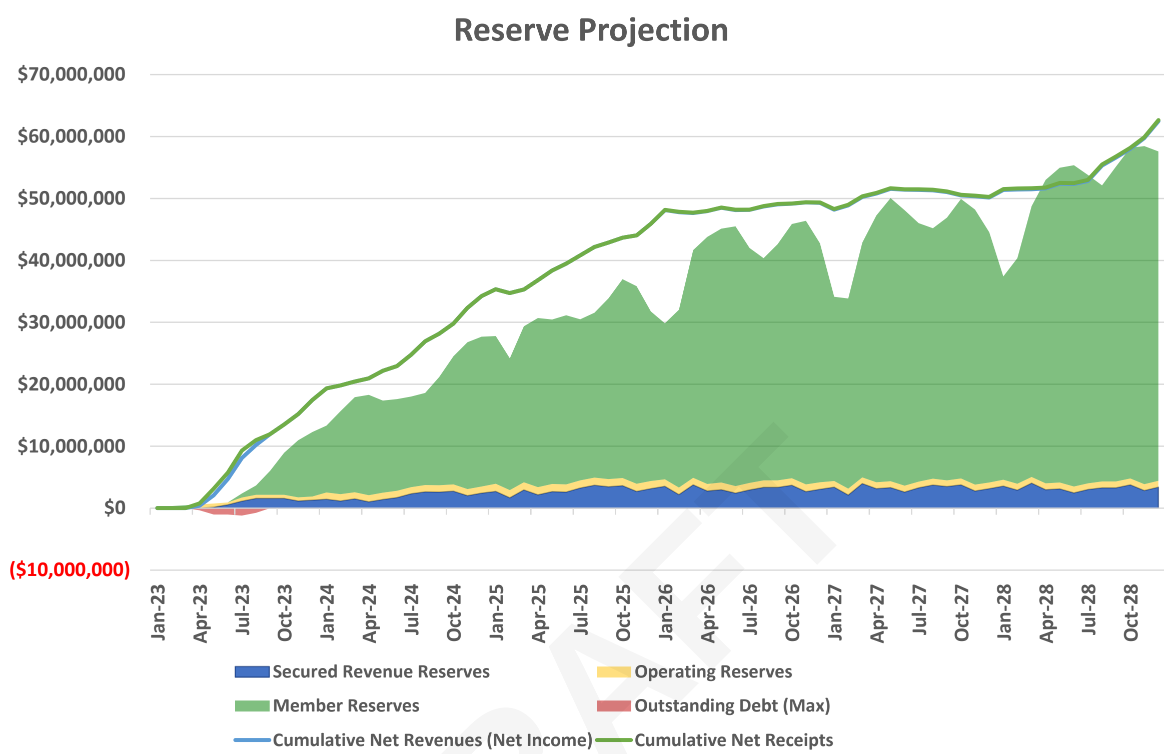
Given a decision to launch is at the discretion of initial Wave 1 members, Ascend investigated the same metrics for the Wave 1 members for just the initial 36-month commitment term. The P50 three-year cumulative net income, cumulative customer savings, cumulative community benefit % metrics for Wave 1 as well as all other reserve allocation can be seen in Figure 37. It demonstrates that after 36 months Wave 1 member allocations should be between $25-30MM with $10MM in savings for customer utility bills equating to a 19% benefit for Wave 1 members.

Figure 37: P50 Wave 1 Cumulative First Three Year Benefit



The projection of the level of reserves can be seen in Figure 38. CPCNH member reserves are expected to grow gradually over time and reach levels to meet policy targets and provide financial stability.

Figure 38: Reserve Projection 2023-2028

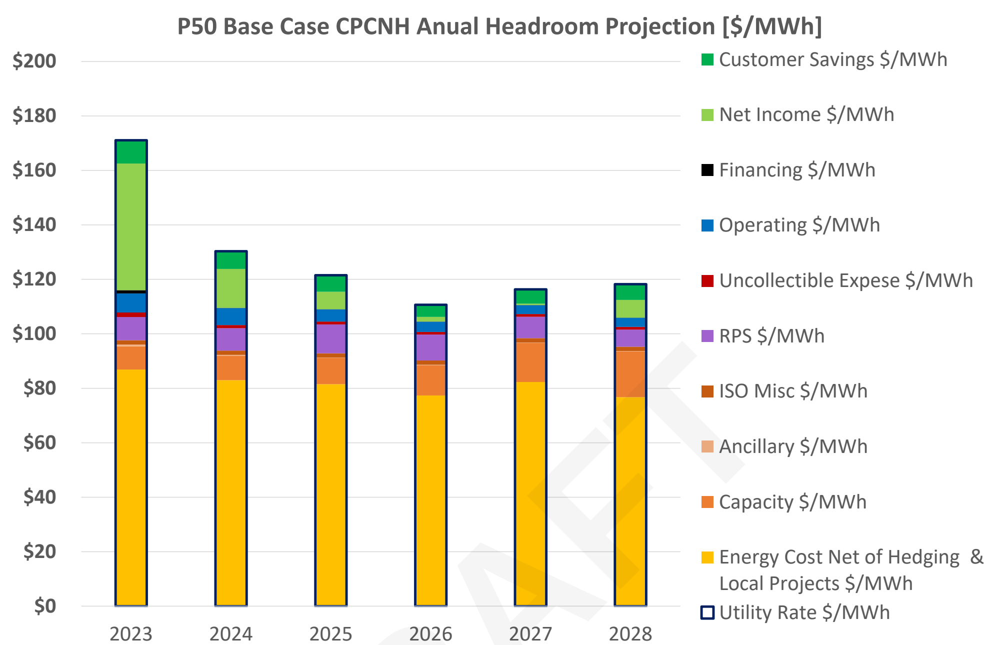


The P50 Base Case for the Annual Headroom projection measured in $/MWh is shown in

Figure 39. The analysis also provides details on the different components that determine headroom levels on a yearly basis from 2023 to 2028.

- Headroom in 2023 is high due to high market prices coupled with high utility auction premiums.
- In 2024 and 2025, headroom tightens as the forward curve show lower future prices and additional waves of participation are effectively weight averaged into the subsequent years (not exclusively giving the spring launch benefit on all CPCNH load like the first year).
- Years 2026 and 2027 are the tightest for three reasons: 1) the forward curve is at its lowest point in those years, 2) new wave volume has an even lesser impact on a weighted average basis, 3) the P50 base case is shown, which is one discrete simulation outcome (i.e., some simulations may be better, while others have negative headroom requiring rate adjustment).

Figure 39: P50 Base Case CPCNH Annual Headroom Projection ($/MWh)

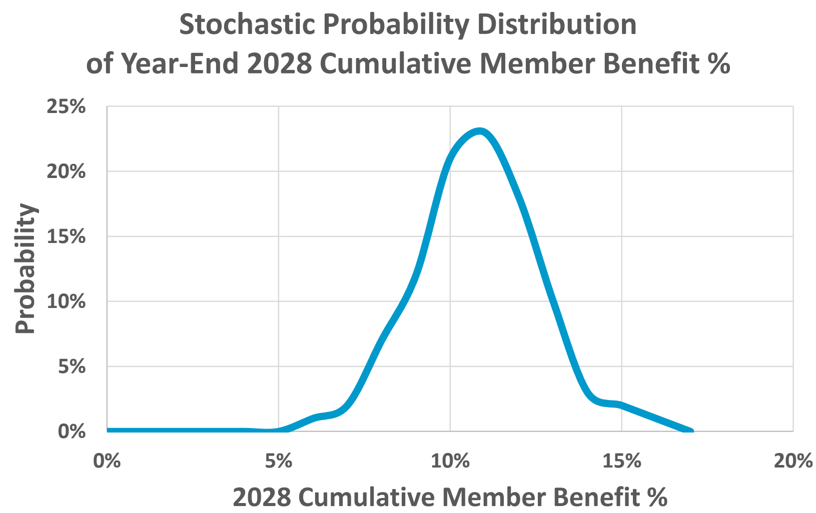


Stochastic Analysis

This section presents results from stochastic analysis to understand the expected range of outcomes for key metric over time with meaningful uncertainty.

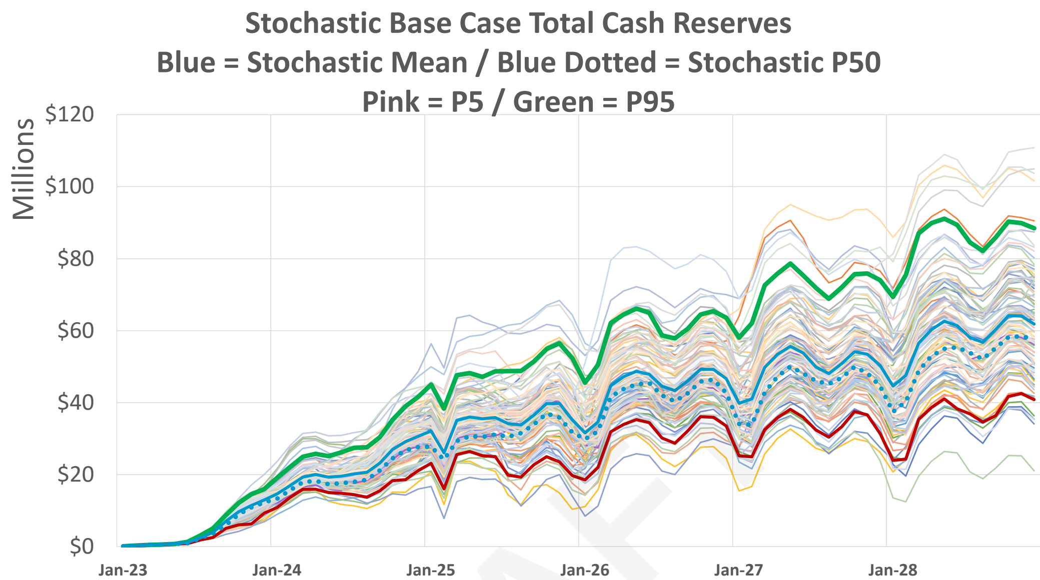
The stochastic probability distribution of year-end 2028 cumulative member benefit percentage is shown in Figure 40. The cumulative benefits range from 5% to slightly above 15%, and a number larger than 10% in a significant number of stochastic scenarios. This outcome assumes the 2023-2028 horizon and the base case member participation described in the assumptions section of this Assessment.

Figure 40: Stochastic Probability Distribution of Year-End 2028 Cumulative Member Benefit %


Stochastic Probability Distribution
of Year-End 2028 Cumulative Member Benefit %
Probability
25%
20%
15%
10%
5%
0%
0%
5%
10%
15%
20%
2028 Cumulative Member Benefit %

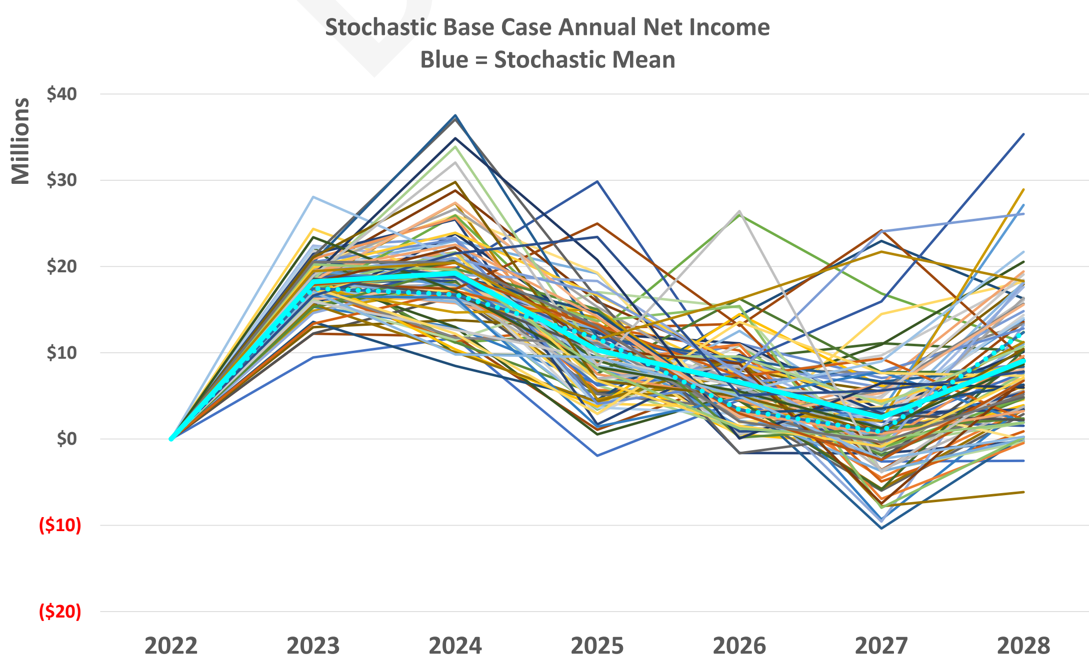
The Base Case total cash reserves by month under different stochastic scenarios over time is shown in Figure 41. Using the last simulated period results to determine the percentiles, the chart below show the stochastic mean, the stochastic P50, the P05 and P95 total cash reserves over time. It also shows each of the 100 simulations, illustrating the range of potential outcome and the rigor of the Assessment.

Figure 41: Stochastic Base Case Total Cash Reserves



The Base Case annual net income under different stochastic scenarios over time is shown in Figure 42. The stochastic mean is shown in blue. Annual Net Income is expected to be positive under most scenarios with an annual average value between $10-$15 million per year for the simulated period.

Figure 42: Stochastic Base Case Annual Net Income



The financial reserves policy sets three target levels of Joint Reserves, which shall be in addition to any financial covenants entered into by CPCNH, relative to the forecasted expense of operations as reflected in CPCNH's budget. Those target levels are:

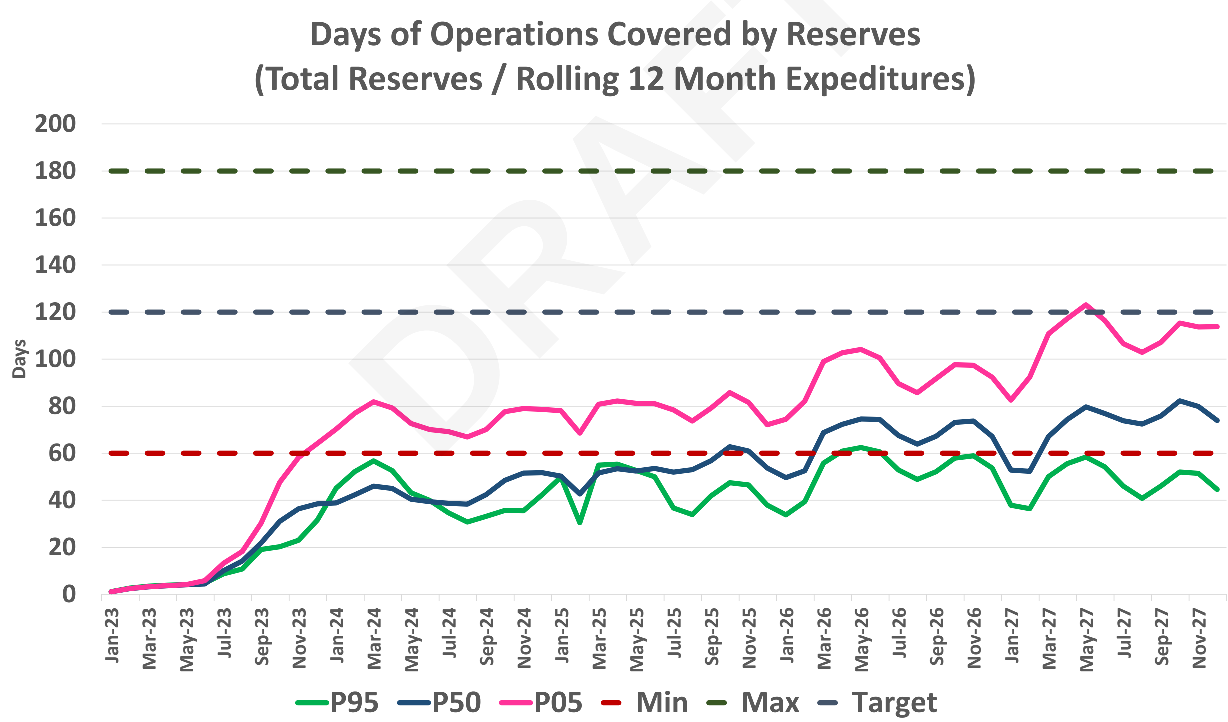
- Minimum Operating Reserve: 60 days of operations.
- Target Operating Reserve: 120 days of operations.
- Maximum Operating Reserve: 180 days of operations.

Figure 43 shows the P5, P50, P95 levels of Days of Operations Covered by Reserves as well as the Minimum, Maximum and Target levels. Based on the expected accumulation of reserves, the target levels would be met in the following timelines:

- The Minimum Operating Reserve level would be reached within 3 years.
- To Target Operating Reserve level would be reached within 5 years.

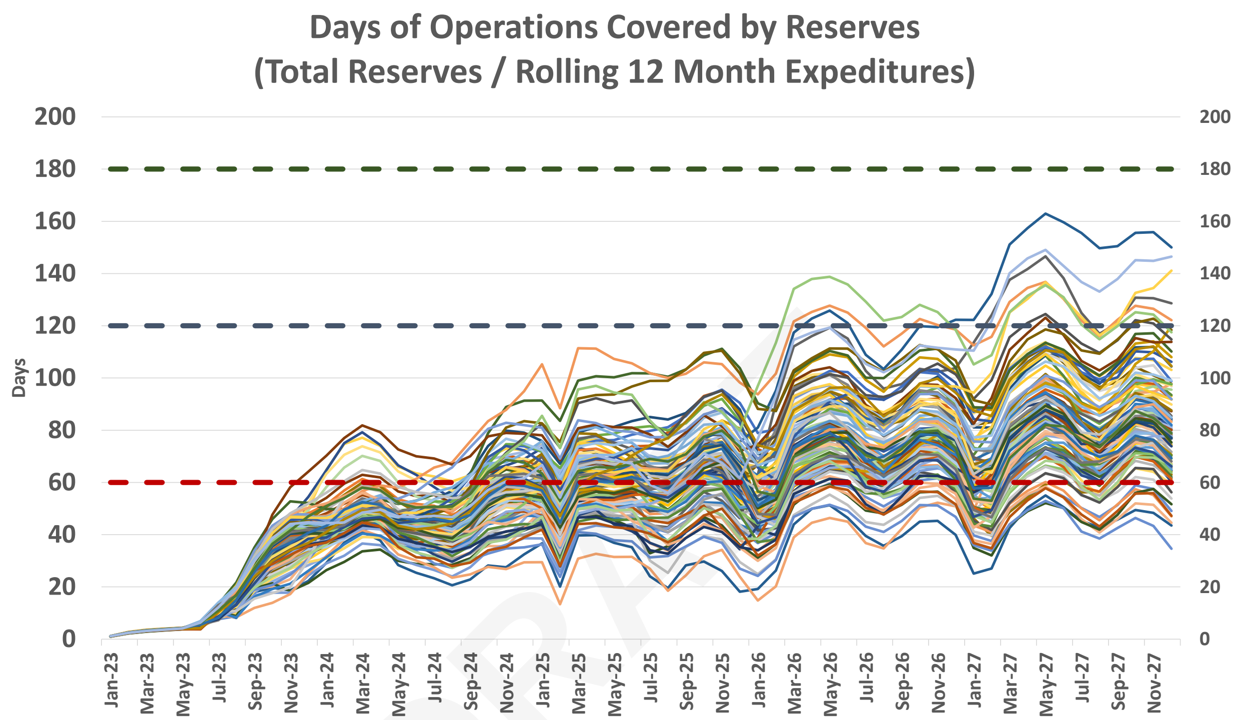
The Maximum Reserve level would provide strong protections against any significant adverse events and represents a longer-term goal.

Figure 43 : Days of Operations Covered by Reserves (P5, P50, P95, Min, Max, Target)



The stochastic scenarios of days of operations covered by reserves are presented in Figure 44. The analysis shows the level of reserves under 100 different stochastic scenarios relative to the Minimum, Target and maximum levels set in the Financial Reserves Policy. These results are based upon Base Case assumptions and do not include potential upsides like expansion of Local Projects for added contribution to reserves.

Figure 44: Stochastic Scenarios of Days of Operations Covered by Reserves



P50 Scenario Analysis

This section presents scenario analysis results around different plausible variations from the P50 case. Appendix A contains summary scorecards for the annual results of key metrics by year. In this section summary results are presented for three key cumulative metrics after 36 months and through the end of 2028. These metrics are: 1) Customer Savings, 2) Accumulated Total Reserves, 3) Effective Community Benefit Percentage.

Community Participation Scenarios

For purposes of illustrating various outcomes related to community participation, Ascend compiled the following tests against the P50 simulation. The 'what-ifs' for Wave 1 Members are important to lead in the decision to launch. Figure 45 conveys results for the initial three-year commitment period and what also for each scenario through the end of 2028. Ascend believes it important to point out the impact of delaying launch until June 2023 instead of April 2023.

Figure 45 : Cumulative Savings, Cumulative Reserves and Cumulative Effective Community Benefit under different scenarios

	3-Year Period Ending March 2026			6-Year Period Ending December 2028		
	Cumulative Savings [$MM]	Cumulative Reserves [$MM]	Cumulative Effective Community Benefit	Cumulative Savings	Cumulative Reserves	Cumulative Effective Community Benefit
P50 Base Case	$23.6	$41.7	14.9%	$51.9	$57.6	10.4%
80% of New Waves	$28.1	$51.1	15.8%	$66.5	$72.8	10.9%
No Nashua Delay	$24.5	$46.7	15.5%	$53.0	$63.1	10.8%
1 Year Nashua Delay	$22.2	$40.8	15.5%	$50.8	$56.9	10.5%
Nashua never Participates	$18.5	$33.4	15.0%	$41.7	$46.2	10.1%
Wave 1 only with Nashua	$6.1	$17.3	10.2%	$12.2	$17.9	6.9%
Wave 1 only without Nashua	$2.1	$7.1	7.1%	$2.1	$5.3	2.9%

The P50 cumulative cash reserves by each scenario considered are shown in Figure 46. The results also point out the financial impact of delaying launch until June 2023 instead of April 2023.

Figure 46: P50 Cumulative Cash Reserves by Scenario

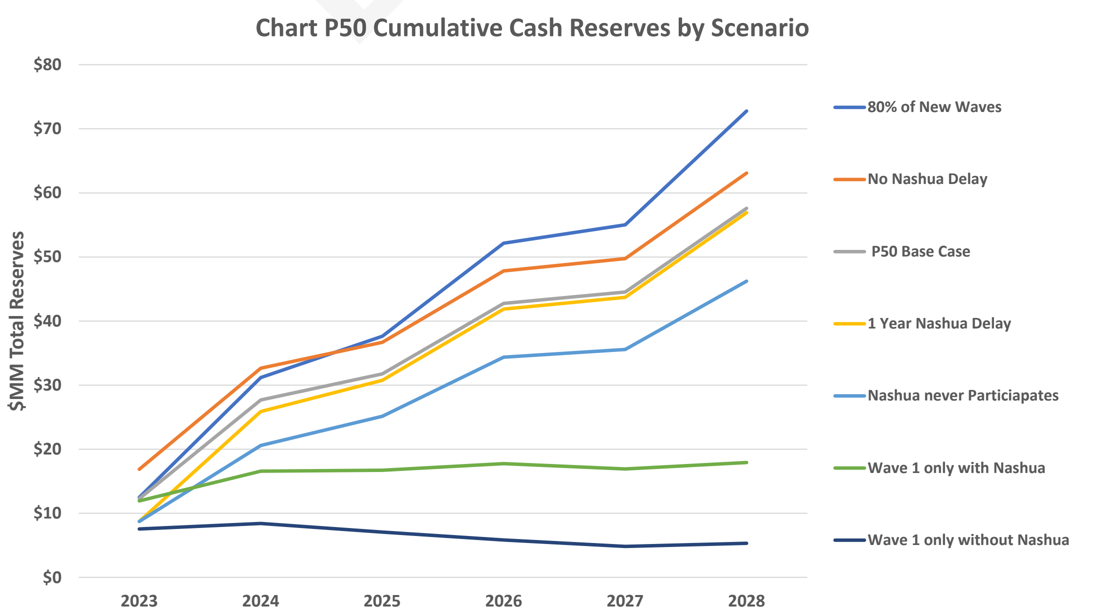
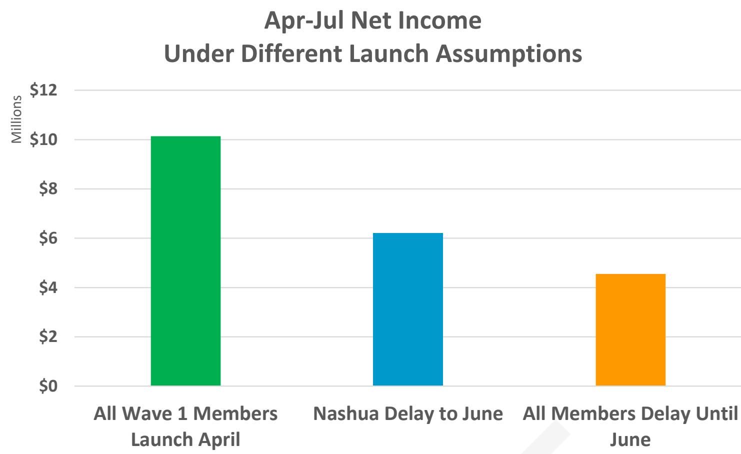


Figure 47 shows the Net Income over the first four months (April-Jul) under difference launch timing for Wave 1 and Nahua. The financial impact is also significant under the different scenarios.

Figure 47: Expected Net Income under different assumptions for April to June 2023



Ascend provides more insight below into the 3-Year period for Wave 1 members in the Base Case, a scenario where only ever Wave 1 members launch with Nashua on a 2-month delay, and only ever Wave members launch without Nashua. While these two scenarios' departures from Base Case seem unlikely, they may shed some insights into how participation levels in CPCNH may evolve over time. These two scenarios result in limited economies of scale, but it is important to note they do not produce extreme negative outcomes across the initial 3-year commitment period.

Figure 48: P50 Wave 1 Cumulative Benefit for first three years under Base Case of community participation (same as figure 34 presented earlier; here for reference)

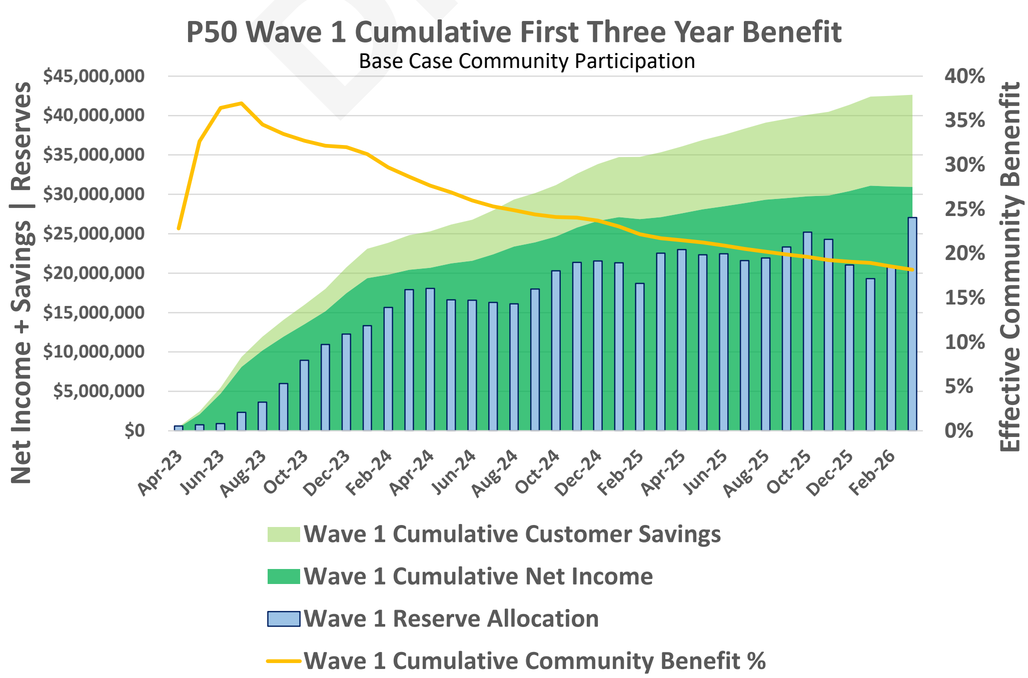


Figure 49: P50 Wave 1 Cumulative Benefit for first three years with Nashua

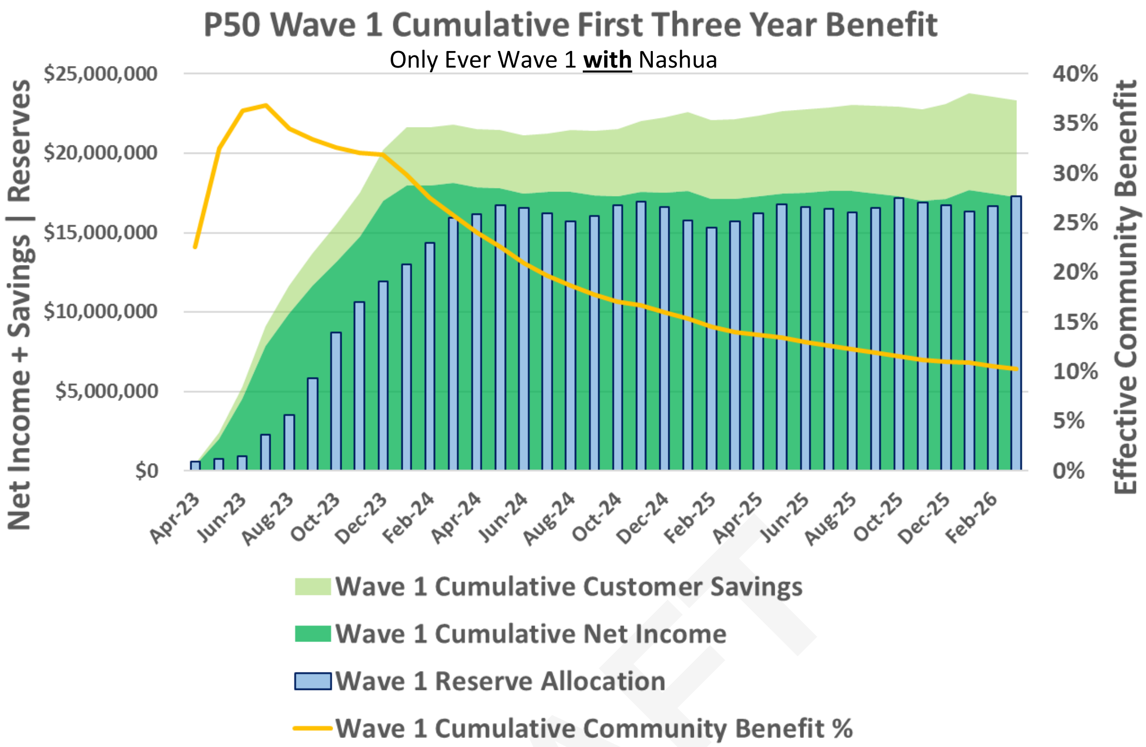
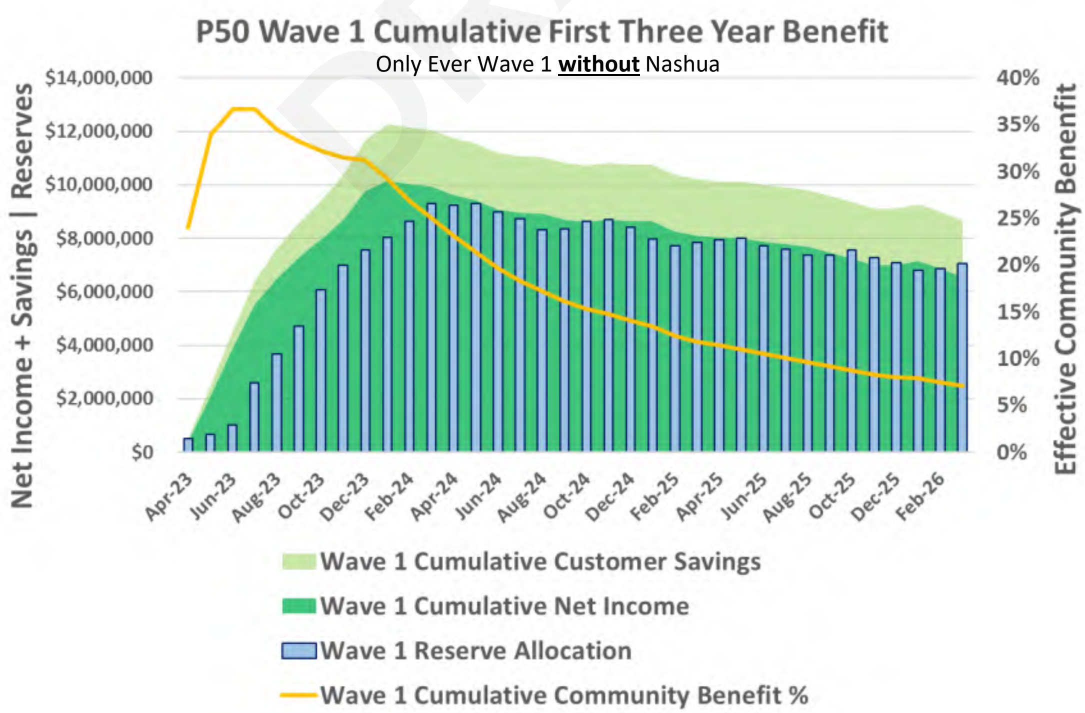


Figure 50 : P50 Wave 1 Cumulative Benefit for first three years without Nashua



Other Stress Test Scenarios

Ascend further analyzed the following scenarios relative to the P50 Base Case:

- **P50 Base Case**
  The 'P50', or median, is the middle simulation of a stochastic (100 simulation Monte Carlo analysis) in which market prices and customer load volumes vary. The P50 case represents the expected outcome given modeling and serves an anchor for other scenarios and probabilistic outcomes. The assumptions of this case are exhaustive and should be reviewed and understood in the assumptions section of this Technical Assessment.

- **18 MW of Local Projects**

  The Base Case calls for a conservative 2 MW of local projects to be built. It is the goal of CPCNH to advocate for SB 321 2 MW per utility caps to be lifted. In this scenario, 10 MW extra in local projects is pursued, growing to a noteworthy amount of CPCNH's supply portfolio and lowering costs for customers.

- **8 MW of Local Projects**

  Given the base case calls for a conservative 2 MW of local projects, this scenario assumes CPCNH is able to fully leverage local projects under current SB 321 limits to not miss out on any value allowed under current regulations.

- **33% RPS Target**

  New Hampshire's Renewable Portfolio Standard (RPS) calls for a renewable goal of approximately 25% over time. This scenario supposes that CPCNH over-complies with the standard and procures 33% RPS at a modest incremental expense as the default service offering with no incremental rate increase from the base 5% discount assumption.

- **7.5% Discount to Utility (instead of 5%)**

  The Base Case assumption is that CPCNH offers a 5% discount to customer utility bill generation supply. This scenario modifies this base case assumption to suppose a 7.5% discount is made the default offering.

- **Lower Auction Premium**

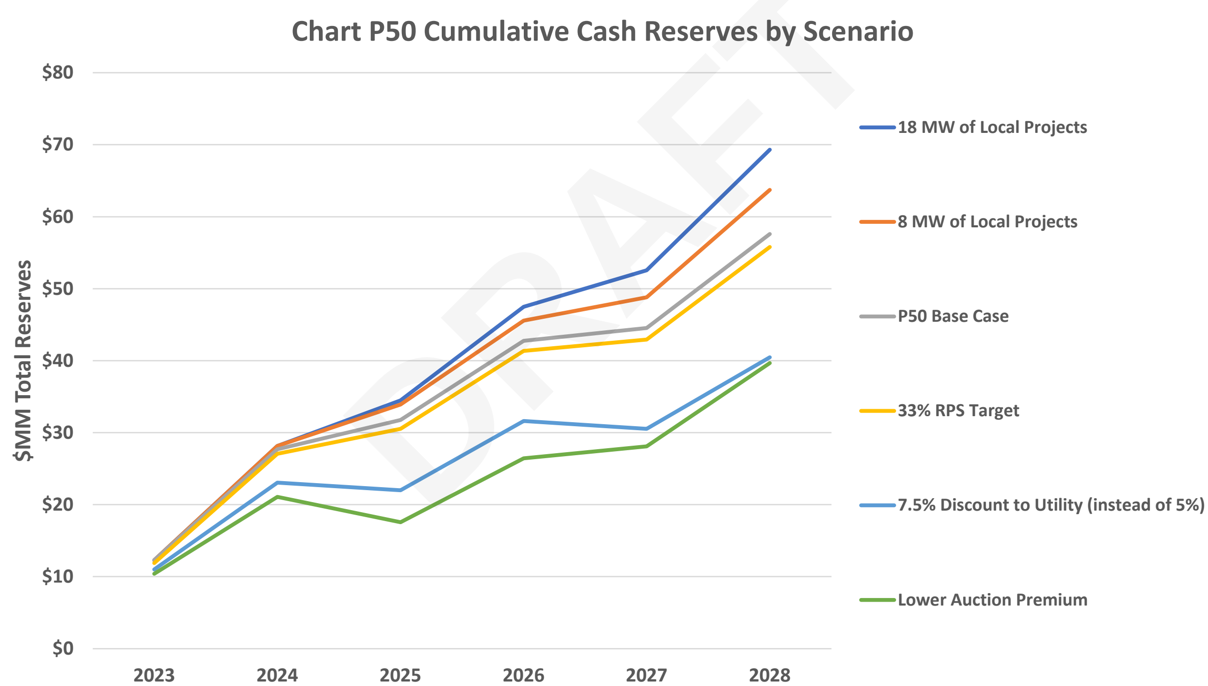
  The Base Case assumes that future utility auctions clear with the average auction premiums observed in the last three small asset ID (residential/small commercial) auctions of each utility. Market option quote data suggest that the premiums will be 25% lower if regulatory change is implemented to shorten the PUC approval process (which currently poses added risk for winning suppliers). This scenario lowers future auction premiums 25% from the Base Case.

Figure 51: Cumulative Savings, Cumulative Reserves and Cumulative Effective Community Benefit under other stress scenarios

	3-Year Period Ending March 2026			6-Year Period Ending December 2028		
	Cumulative Savings [$MM]	Cumulative Reserves [$MM]	Cumulative Effective Community Benefit	Cumulative Savings	Cumulative Reserves	Cumulative Effective Community Benefit
P50 Base Case	$23.6	$41.7	14.9%	$51.9	$57.6	10.4%
18 MW of Local Projects	$24.2	$45.3	15.8%	$55.4	$69.3	11.9%
8 MW of Local Projects	$23.9	$44.3	15.5%	$54.3	$63.7	11.2%
33% RPS Target	$24.1	$40.3	14.4%	$52.3	$55.8	10.1%
7.5% Discount to Utility (instead of 5%)	$34.8	$30.6	14.9%	$70.1	$40.5	10.4%
Lower Auction Premium	$21.7	$27.3	11.8%	$36.4	$39.7	7.6%

Figure 52 shows the P50 Cumulative Cash Reserves under each of the scenarios considered. The best results from a cumulative cash reserve perspective correspond to the two scenarios with 18MW and 8MW of Local Projects. Lower auction premiums and higher discount rates relative to utility rates show the lowest level of reserve accumulation under the P50 assumptions.

Figure 52: P50 Cumulative Cash Reserves by Scenario



Qualitative Explanation of Risks and Mitigations

This Technical Assessment, to varying degrees, incorporates and/or gives consideration to the following key risks that CPCNH may face in future operation and management of its portfolio. These risk certainly do not cover *all* risk but address key risks associated with managing a power portfolio.

The following subsections describe the nature of each risk, and the degree to which it is considered in the results of this Technical Assessment. Ascend has prepared an executive-level Business and Operations Plan for CPCNH, which will further present and analyze key risks, and provide mitigating strategies, drawing upon the findings from this Technical Assessment.

CPCNH's participation in the wholesale energy markets exposes member CPAs to certain risks with material financial implications:

Market Risk

Market risk is the uncertainty of CPCNH's financial performance due to variable commodity market prices (market price risk) and uncertain price relationships (basis risk). Variability in market prices creates uncertainty in CPCNH's procurement costs, which has a direct impact on customer rates and the ability to accumulate reserves to meet the Financial Reserve Policy minimum and target levels. Stochastic model results in this Technical Assessment are based on simulation of forward, spot market prices and other material portfolio risk drivers under different scenarios. The stochastic results of the Base Case fully contemplate market price risk as described in the Energy Cost of Supply section. The implications of 'black swan' events are not contemplated in the '1 in 100' range of outcomes performed in the full hourly stochastic simulation. In practice, sound portfolio risk management will cover most exposures to extreme events. Further, as CPCNH build reserves it will have resources to weather unforeseen events. Overall, members should be aware that while probabilities are small, no energy portfolio is completely insulated from extreme events.

Volumetric Risk

Volumetric risk reflects the potential adverse financial outcomes due to the uncertainty in the quantity of different power supply products required to meet the needs of CPCNH and its members. Customer load is subject to fluctuation due to customer opt-outs or departures, temperature deviation from normal, unforeseen changes in the growth of behind the meter generation by CPCNH customers, unanticipated energy efficiency gains, new or improved technologies, as well as local, state, and national economic conditions. The interaction between market and volumetric risk is particularly critical for CPCNH financial performance. Stochastic model results in this Technical Assessment are based on simulation of material portfolio risk drivers, including volumetric risk, under different scenarios (PowerSIMM technical documentation is available upon request).

Imbalance Risk (Deviations between Actual Energy Use and Contracted Purchases)

Power portfolio hedging will often use expected block power transactions as a financial offset to load obligation. The basic concept is that if the cost of load at the ISO goes up, the value of the hedge goes up for CPCNH largely offsetting the increase in costs. There is a risk that due to unexpectedly high or low load upon power flow may create inadequate hedge coverage or over coverage. Retail power has always struggled with this dynamic in every market.

Further, when over-hedged market prices are often low, resulting in the excess hedge yielding less value and when underhedged market prices are often high yielding higher cost related to filling the open position with spot purchases. Sound portfolio management understands these risks and chooses hedge levels that financially (not volumetrically) minimize risk. Further, if prudent, the market does offer other hedging instruments like options to assist in mitigating risk in high price scenarios.

The Technical Assessment Base Case stochastic results largely consider all these risks and the implication of these risks are represented in model outcomes across the stochastic Base Case representations. For the Technical Assessment it is assumed that CPCNH enters each delivery period with a 100% hedge ratio at the expected (mean) load level.

CPCNH will likely hedge its ISO load obligations using Internal Bilateral Transactions (IBTs). IBTs carry with them three beneficial factors that Ascend contemplated in the Technical Assessment modeling:

1. IBTs can be purchased with a flat annual (or period) price. In doing so there is some measure of cash flow smoothing that reduces cash reserve volatility. This is due to the flat price hedge paying off in the money seasonally (all else equal) and thus offsetting higher ISO settlement cost periods. Conversely it settles out of the money when ISO load costs are low.
2. IBTs are scheduled in as physical generation for the variable revenue side of the hedge's payoff. This results in the hedge netting with load obligations and reducing ISO load collateral posting obligations.
3. IBTs are invoiced by the counterparty for the fixed side cost of the hedge in the subsequent calendar month permitting a greater amount of meter read billing cycle customer revenues to be received for use in paying the fixed power cost invoice.

Legislative and Regulatory Risk

CPCNH is subject to an evolving and uncertain legal and regulatory landscape at the state and federal level. Regulatory risk encompasses risks associated with shifting state and federal regulatory policies, rules, and regulations that could negatively impact CPCNH. Legislative risk is associated with actions by federal and state legislative bodies, such as any adverse changes or requirements that may infringe on CPCNH's autonomy, increase its costs, impact its customer base, or otherwise negatively impact CPCNH's ability to fulfill its mission. The Technical Assessment is based on existing policies, rules and regulations that impact CPCNH such as NH Senate Bill 321 passed on June 2022.

In this Technical Assessment one Regulatory risk was contemplated. This risk is related to utility requests to shorten the utility auction approval windows to attempt to reduce risk premiums. Auction suppliers are often required to hold their pricing open for one to three weeks while the PUC undertakes its approval process. Ascend obtained a market option quote for the time near a utility auction and determined that the cost of holding the position open two weeks was roughly 25% of the auction premium. Thus, the scenario representing lower auction premiums represents a regulatory risk. Other regulatory risks are numerous and even unknown. They are often difficult to quantify. Many of these risks face end power consumers with or without the existence of CPCNH as suppliers and utilities seek to pass costs associated with regulatory changes on to customers as soon as practical.

Counterparty / Collateral Call Risk

During the normal course of business CPCNH is exposed to both counterparty credit risk from non-performance from a counterparty in bilateral power transactions as well as liquidity risk to fund operations, meet ISO-NE collateral requirements and potential collateral obligations from bilateral power transactions. Results from this Technical Assessment do not model explicitly potential credit losses from counterparty risk exposures or potential collateral calls from hedges. Such exposures are subject to the pending negotiation of enabling agreements or arrangements for forward power purchase through credit sleeves. CPCNH intend to use such arrangements, in concert with lock box guarantees, to minimize this exposure. This is possible due to the dynamics addressed in the following section.

Evaluation and Recommendations

Ascend Analytics advises that it is opportunistic to achieve a spring 2023 launch of its member CPAs as organized and operated by CPCNH. Launch in the spring ensures a firm start to the accrual of reserves while serving the four lesser priced months of the six-month utility auction. Further, an April 2023 launch also allows CPCNH to maximize member benefit. The Coalition is viable irrespective of Nashua's launch timing, although Nashua's participation brings a boost to achieving economies of scale.

Wave 1 members, the pioneers of CPCNH, are projected to see significant benefit for their communities. Wave 1 cumulative effective savings (the "community benefit" of customer rate decreases combined with accrual of financial reserves) across the initial 3-year commitment period is 17%. Considering that CPCNH structured the Cost Sharing Agreement to permit a Wave 1 member the option of terminating their continued participation in CPCNH at the end of their initial 3-year term, and "cash out" at this juncture, this figure can be thought of as the proper "risk-adjusted return" or "potential total savings" for communities that initially commit to taking service through CPCNH.

Our comparative analysis of the range of potential future market price movements demonstrates that the Coalition's business model presents a stronger value proposition here relative to the cost savings a community is likely to achieve through a brokered power supply deal, based on what the latter model has demonstrated being capable of achieving on average over a number of years in an adjacent market (i.e., Massachusetts).

- The Coalition's stronger value proposition here, purely in terms of cumulative effective savings, holds firm across the hundreds of scenarios and stochastic forecasts of market price movements analyzed.
- While our analysis necessarily focused on evaluating the relative benefits for Wave 1 members (based on current and forecasted market conditions), Ascend expects the relative results of this analysis to hold firm, going forward — such that refreshing the same analysis for future wave communities (with then-current market conditions) will continue to demonstrate the superiority of CPCNH's value proposition for future wave Members.
- Ascend therefore believes it is unlikely that many communities, properly informed, will elect to take a brokered power supply deal over participating in CPCNH.

Consequently, Ascend expects CPCNH's membership to continue to grow, achieving the financial benefits of economy of scale for all Members, and positioning CPCNH to succeed in achieving the membership's broader vision regarding the provision of innovative services and programs to customers, the continued achievement of political success regarding the passage of new laws and regulations, and the development of local energy projects and infrastructure investments (within the service territories of participating communities).

The experience of other markets where CPAs have achieved success on these same outcomes (e.g., California) strongly suggests that communities are not likely to opt-out of participating in CPCNH so long as they continue to derive such substantial benefits from participating.

On this basis, Ascend concludes that the Coalition may launch with a high degree of confidence in achieving the membership's objectives for the enterprise — namely, short-term financial benefits, long-term fiscal stability, and the multitude of capabilities, and benefits, that inherently accrue by virtue of operating a democratically-governed power agency.

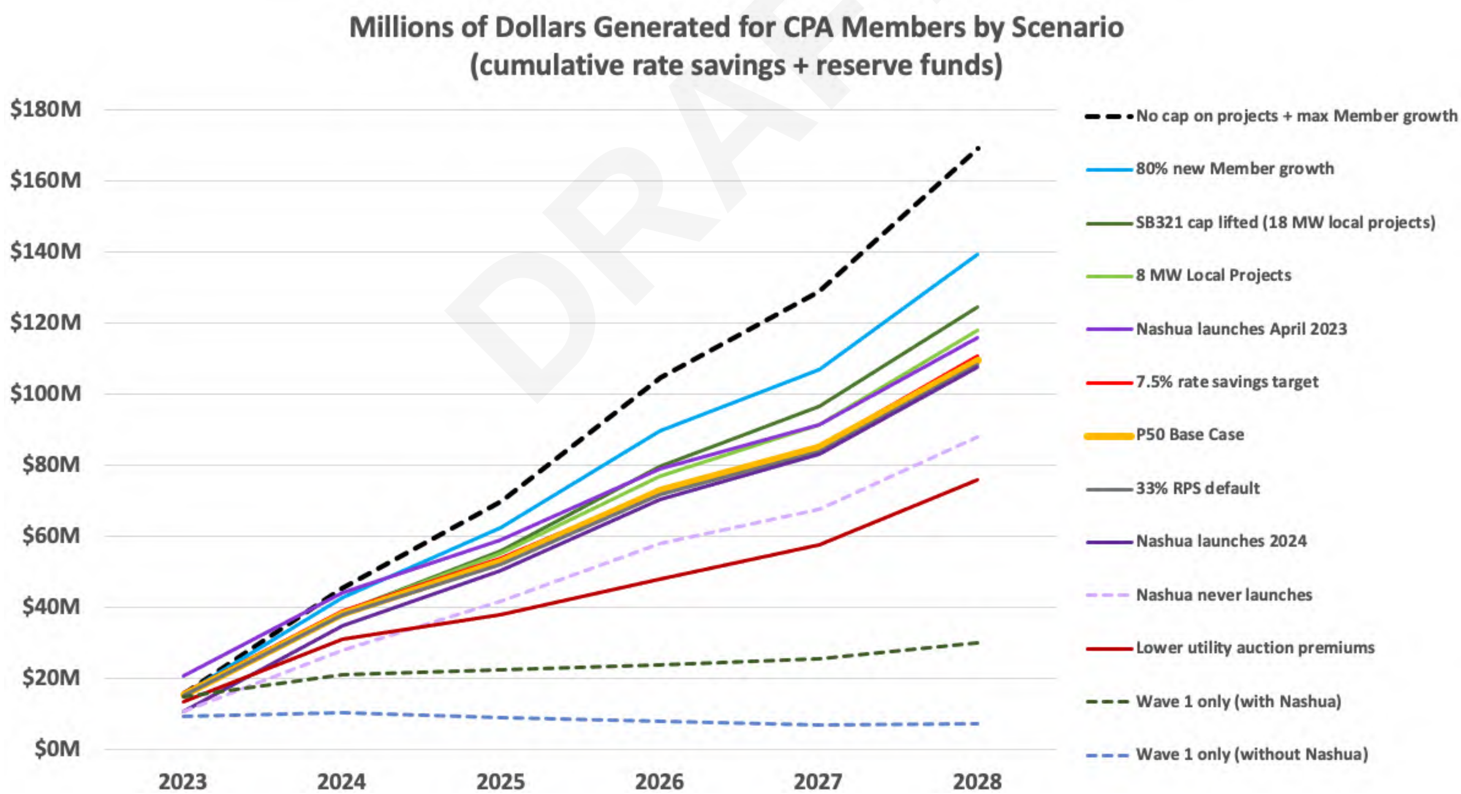
When Ascend set out on the journey of compiling the contents of this Technical Assessment it did not know what the analysis would yield. Ascend believes it is the best at performing 'Analytics that Power the Energy Transition' and trusts this Technical Assessment affords members good context for decision making. To this end, Ascend has intentionally attempted to present conservative scenarios without compounding positive outcomes for communities that participate in CPCNH.

However, in a world where the communities of New Hampshire see the success of Wave 1 Members and decide to participate and benefit from the realization of CPCNH's vision, Ascend has prepared a concluding scenario to approximate the potential benefits of full success. This scenario assumes:

- Out of the ~50 communities that have expressed interest in joining CPCNH become Members, almost all (e.g., 95%) decide to join and launch CPA service.
- The Membership prioritizes near-term engagement at the Legislature to remove the current caps (under SB 321) limiting the development of local projects to 8 Megawatts; CPCNH is subsequently able to develop a total of 18 Megawatts of distributed generation and storage across the Membership service territory by 2025.

As shown by the dotted black line in the chart below, this scenario achieves the maximum creation of net financial benefit for CPA Members compared to all other scenarios in this report (net financial benefit is defined as the sum of cumulative customer rate savings and reserves accrued over time):Figure 53

Figure 53: Net Financial Benefits by Scenario



In this scenario, CPCNH will become the effective leader driving and accelerating New Hampshire's energy transition, for the benefit of communities and customers. This scenario results, by the end of 2028, in the creation of $66,500,000 in additional financial benefit for participating Member CPAs.

- Most of the new value is created by and accrues to new Members, accessing the benefits of CPCNH's market-based pricing; forecasted supply bill savings for these new customers would total $20,200,000, and financial reserves for these new Members would total $30,500,000.
- The remaining $15,800,000 in new benefits would be net revenues generated by the local clean energy projects CPCNH would develop, which would accrue to all Members participating in the Project Contracts. This positive business case reflects Ascend's confirmation that developing local, small-scale and clean projects in New Hampshire is cost-effective — significantly so, in that such projects increase net revenues relative to continuing to purchase wholesale power from the ISO-NE market — under the market-based framework established by Senate Bill 321.

To conclude, Ascend's technical assessment demonstrates that the pathway to maximize risk-adjusted financial returns for all Members is to (1) prioritize the recruitment and onboarding of new Member communities, and (2) achieve the political reforms necessary to allow CPCNH to freely contract for the development of local projects on behalf of participating Members.

Appendices

Appendix A: Scenario Scorecards

P50 Base Case Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	57,202	128,839	194,799	209,773	209,690	209,690
Annual MWh	382,742	1,124,895	1,763,988	1,964,599	2,005,152	1,947,826
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$3.3	$7.3	$10.7	$8.8	$10.5	$11.3
Net Income ($MM)	$17.5	$16.8	$11.7	$3.4	$0.8	$12.4
Member Benefit* (%)	32.0%	16.6%	10.5%	5.7%	4.9%	10.4%
End of Year Reserves ($MM)	$12.3	$27.7	$31.8	$42.8	$44.5	$57.6
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	Ba	Ba	Ba	Baa
Days Liquidity	43.3	68.5	61.9	77.4	79.3	100.2

Annual Savings & Net Income / (Revenues+Savings)

Base Case P50 with 80% New Wave Participation Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	29	40	62	62	62
Annual Average Customers	58,047	144,439	244,539	268,497	268,364	268,364
Annual MWh	387,884	1,268,048	2,202,607	2,529,762	2,590,611	2,515,836
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$3.3	$8.3	$13.4	$12.7	$14.2	$14.7
Net Income ($MM)	$17.7	$21.5	$19.5	$4.6	$1.6	$17.0
Member Benefit* (%)	32.1%	18.2%	12.4%	6.2%	5.3%	10.7%
End of Year Reserves ($MM)	$12.5	$31.2	$37.6	$52.1	$55.0	$72.8
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	B	Ba	Ba	Baa
Days Liquidity	43.2	67.5	59.0	74.4	76.0	97.7

Annual Savings & Net Income / (Revenues+Savings)

Base Case P50 with No Nashua Delay Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	67,750	130,108	195,860	210,769	210,687	210,687
Annual MWh	448,368	1,145,485	1,784,943	1,985,304	2,026,002	1,968,106
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$3.9	$7.5	$10.8	$8.9	$10.5	$11.3
Net Income ($MM)	$22.3	$16.9	$11.8	$3.4	$1.0	$12.6
Member Benefit* (%)	34.0%	16.5%	10.5%	5.7%	4.9%	10.4%
End of Year Reserves ($MM)	$16.9	$32.7	$36.7	$47.8	$49.7	$63.1
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	Ba	Ba	Ba	Baa
Days Liquidity	53.1	83.3	70.8	85.9	87.3	109.2

Annual Savings & Net Income / (Revenues+Savings)

Base Case P50 with a 1-Year Nashua Delay Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	11	28	35	49	49	49
Annual Average Customers	23,257	122,688	195,909	210,819	210,737	210,737
Annual MWh	247,361	1,069,050	1,781,365	1,981,815	2,022,478	1,964,683
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$2.1	$6.9	$10.8	$8.9	$10.7	$11.4
Net Income ($MM)	$11.4	$22.6	$11.7	$3.4	$0.9	$12.5
Member Benefit* (%)	32.0%	21.5%	10.5%	5.7%	4.9%	10.4%
End of Year Reserves ($MM)	$8.7	$25.9	$30.8	$41.9	$43.7	$56.9
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	B	Ba	Ba	Baa
Days Liquidity	51.8	65.8	59.4	75.2	77.2	98.0

Annual Savings & Net Income / (Revenues+Savings)

Base Case P50 without Nashua Ever Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	11	27	34	48	48	48
Annual Average Customers	23,257	100,005	172,586	188,593	188,503	188,503
Annual MWh	247,361	852,727	1,479,615	1,682,808	1,721,588	1,671,963
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$2.1	$5.5	$9.0	$6.9	$8.6	$9.6
Net Income ($MM)	$11.4	$14.8	$10.6	$2.9	$0.4	$10.0
Member Benefit* (%)	32.0%	18.6%	11.0%	5.3%	4.6%	10.0%
End of Year Reserves ($MM)	$8.7	$20.6	$25.1	$34.4	$35.6	$46.2
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	B	Ba	Ba	Baa
Days Liquidity	51.8	67.9	57.2	71.4	73.4	92.8

Annual Savings & Net Income / (Revenues+Savings)

Only Ever Wave 1 without Nashua Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	11	11	11	11	11	11
Annual Average Customers	21,218	22,037	22,037	22,037	22,037	22,037
Annual MWh	218,630	304,392	309,330	305,654	307,845	299,168
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$1.9	$0.2	$0.0	$0.0	$0.0	$0.0
Net Income ($MM)	$9.8	($1.1)	($1.7)	($1.9)	($1.3)	$0.4
Member Benefit* (%)	31.3%	-2.3%	-4.5%	-5.7%	-3.8%	1.3%
End of Year Reserves ($MM)	$7.6	$8.4	$7.1	$5.8	$4.8	$5.3
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	Ba	Ba	B	B
Days Liquidity	52.0	81.8	72.4	67.4	54.9	54.1

Annual Savings & Net Income / (Revenues+Savings)

Only Ever Wave 1 with Nashua Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	12	12	12	12	12
Annual Average Customers	55,792	66,293	66,293	66,293	66,293	66,293
Annual MWh	374,173	584,381	593,703	587,445	591,409	575,031
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$3.2	$1.5	$1.2	$0.2	$2.7	$3.4
Net Income ($MM)	$17.0	$0.5	($0.4)	$0.1	($2.0)	$0.8
Member Benefit* (%)	31.9%	2.7%	1.2%	0.4%	1.0%	6.3%
End of Year Reserves ($MM)	$11.9	$16.6	$16.7	$17.8	$16.9	$17.9
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	Ba	Baa	Baa	Baa
Days Liquidity	43.3	82.7	87.2	101.6	99.7	103.2

**Annual Savings & Net Income / (Revenues+Savings)*

SB 321 Cap Lifted and 18 MW of Local Projects Installed Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	57,202	128,839	194,799	209,773	209,690	209,690
Annual MWh	382,742	1,124,895	1,763,988	1,964,599	2,005,152	1,947,826
Local Project Year End MW	1	8	18	18	18	18
Customer Savings ($MM)	$3.3	$7.3	$10.7	$10.9	$11.7	$11.5
Net Income ($MM)	$17.5	$17.5	$14.3	$5.2	$4.0	$16.4
Member Benefit* (%)	32.0%	17.1%	11.8%	7.5%	6.8%	12.3%
End of Year Reserves ($MM)	$12.3	$28.2	$34.5	$47.5	$52.6	$69.3
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	Ba	Ba	Baa	A
Days Liquidity	43.3	69.2	66.0	86.7	92.9	121.5

**Annual Savings & Net Income / (Revenues+Savings)*

SB 321 Cap Maximized to 8 MW of Local Projects Installed Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	57,202	128,839	194,799	209,773	209,690	209,690
Annual MWh	382,742	1,124,895	1,763,988	1,964,599	2,005,152	1,947,826
Local Project Year End MW	1	8	8	8	8	8
Customer Savings ($MM)	$3.3	$7.3	$10.7	$10.2	$11.3	$11.4
Net Income ($MM)	$17.5	$17.5	$13.4	$3.9	$2.2	$14.5
Member Benefit* (%)	32.0%	17.1%	11.4%	6.6%	5.9%	11.4%
End of Year Reserves ($MM)	$12.3	$28.2	$33.9	$45.6	$48.8	$63.7
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	Ba	Ba	Ba	Baa
Days Liquidity	43.3	69.2	65.4	83.1	86.6	111.2

**Annual Savings & Net Income / (Revenues+Savings)*

33% RPS Target Instead of Compliance Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	57,202	128,839	194,799	209,773	209,690	209,690
Annual MWh	382,742	1,124,895	1,763,988	1,964,599	2,005,152	1,947,826
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$3.3	$7.5	$11.0	$8.6	$10.6	$11.4
Net Income ($MM)	$17.0	$16.5	$11.0	$3.3	$0.6	$12.1
Member Benefit* (%)	31.0%	16.2%	10.1%	5.4%	4.7%	10.2%
End of Year Reserves ($MM)	$11.9	$27.1	$30.5	$41.4	$42.9	$55.8
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	B	Ba	Ba	Baa
Days Liquidity	41.2	65.1	58.2	72.9	75.0	95.2

Annual Savings & Net Income / (Revenues+Savings)

7.5% Discount to Utility Tariff Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	57,202	128,839	194,799	209,773	209,690	209,690
Annual MWh	382,742	1,124,895	1,763,988	1,964,599	2,005,152	1,947,826
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$4.9	$11.0	$16.1	$9.3	$13.5	$15.3
Net Income ($MM)	$15.8	$13.1	$6.4	$2.8	($2.1)	$8.4
Member Benefit* (%)	32.0%	16.6%	10.6%	5.7%	4.9%	10.4%
End of Year Reserves ($MM)	$11.0	$23.1	$22.0	$31.6	$30.5	$40.5
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	B	B	B	B	Ba
Days Liquidity	40.1	58.7	46.8	57.1	57.1	71.7

Annual Savings & Net Income / (Revenues+Savings)

Lower Utility Auction Premium Scenario Scorecard						
	2023	2024	2025	2026	2027	2028
Year End CPA Count	12	28	35	49	49	49
Annual Average Customers	57,202	128,839	194,799	209,773	209,690	209,690
Annual MWh	382,742	1,124,895	1,763,988	1,964,599	2,005,152	1,947,826
Local Project Year End MW	1	2	2	2	2	2
Customer Savings ($MM)	$3.1	$7.0	$10.4	$1.1	$8.0	$6.8
Net Income ($MM)	$14.8	$11.4	$5.4	$1.2	$0.8	$10.9
Member Benefit* (%)	29.0%	13.2%	7.7%	1.1%	3.8%	8.0%
End of Year Reserves ($MM)	$10.4	$21.1	$17.6	$26.4	$28.1	$39.7
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	B	B	B	B	Ba
Days Liquidity	39.1	54.4	38.1	49.0	51.1	67.8

Annual Savings & Net Income / (Revenues+Savings)

SB 321 Cap Lifted and 18 MW of Local Projects with 95% New Wave Participation Scenario Scorecard						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Year End CPA Count	12	33	45	70	70	70
Annual Average Customers	58,470	152,238	269,409	297,859	297,702	297,702
Annual MWh	390,454	1,339,625	2,421,916	2,812,344	2,883,341	2,799,840
Local Project Year End MW	1	8	18	18	18	18
Customer Savings ($MM)	$3.3	$8.7	$14.7	$15.6	$16.8	$16.5
Net Income ($MM)	$17.9	$24.5	$26.0	$8.1	$5.5	$23.4
Member Benefit* (%)	32.1%	19.2%	14.0%	7.7%	6.7%	12.2%
End of Year Reserves ($MM)	$12.6	$33.4	$43.3	$62.5	$69.7	$93.6
Max CPCNH LOC Draw	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Credit Rating	B	Ba	Ba	Ba	Ba	Baa
Days Liquidity	43.2	67.7	60.9	80.1	85.9	113.7

Annual Savings & Net Income / (Revenues+Savings)

Appendix B: Annual Net Income Statement

Month	2022	2023	2024	2025	2026	2027	2028
Customer Counts		**57,202**	**128,839**	**194,799**	**209,773**	**209,690**	**209,690**
Residential		**47,851**	**100,301**	**150,329**	**167,611**	**169,662**	**169,662**
Eversource Residential		35,189	80,032	124,306	138,990	140,568	140,568
Liberty Residential		12,075	13,712	15,416	16,725	17,005	17,005
NHEC Residential		0	0	0	0	0	0
Unitil Residential		588	6,557	10,607	11,896	12,089	12,089
Non-Residential		**9,351**	**22,329**	**34,996**	**39,512**	**40,028**	**40,028**
Eversource Non-Residential		6,810	18,627	30,312	34,369	34,802	34,802
Liberty Non-Residential		2,370	2,563	2,881	3,125	3,177	3,177
NHEC Non-Residential		0	0	0	0	0	0
Unitil Non-Residential		171	1,139	1,804	2,018	2,050	2,050
Retail Load at the Meters (MWh)		**382,742**	**1,124,895**	**1,763,988**	**1,964,599**	**2,005,152**	**1,947,826**
Wholesale Load ISO Energy Settlement (MWh)		**(400,243)**	**(1,177,026)**	**(1,847,180)**	**(2,058,791)**	**(2,101,696)**	**(2,041,645)**
Residential							
Eversource Residential		(196,064)	(595,981)	(946,467)	(1,054,951)	(1,074,502)	(1,045,088)
Liberty Residential		(75,294)	(114,871)	(131,687)	(141,111)	(144,826)	(140,265)
NHEC Residential		0	0	0	0	0	0
Unitil Residential		(4,506)	(48,277)	(82,272)	(90,499)	(93,611)	(88,048)
Non-Residential							
Eversource Non-Residential		(67,004)	(315,159)	(558,111)	(633,338)	(646,749)	(629,651)
Liberty Non-Residential		(54,303)	(79,799)	(91,352)	(97,692)	(99,827)	(97,586)
NHEC Non-Residential		0	0	0	0	0	0
Unitil Non-Residential		(3,071)	(22,938)	(37,290)	(41,201)	(42,181)	(41,007)
Hedging IBT (MWh)		**401,772**	**1,185,305**	**1,826,296**	**2,057,222**	**2,085,694**	**2,085,694**
Executed IBT Hedges		**0**	**0**	**0**	**0**	**0**	**0**
'What-If' IBT Hedges (Hypotheticals)		**401,772**	**1,185,305**	**1,826,296**	**2,057,222**	**2,085,694**	**2,085,694**
Retail Revenue ($)		**$61,529,780**	**$137,879,882**	**$201,615,926**	**$206,612,427**	**$220,528,091**	**$216,831,609**
Residential Uncollectible Expense		($626,489)	($1,284,446)	($1,825,174)	($1,865,005)	($1,986,447)	($1,947,651)
Non-Residential Uncollectible Expense		($45,206)	($122,081)	($187,739)	($193,331)	($207,078)	($204,563)
Residential							
Eversource Residential		$30,929,875	$71,299,412	$104,970,180	$107,982,011	$114,502,909	$112,565,251
Liberty Residential		$12,533,229	$13,473,279	$14,416,891	$14,147,377	$15,229,961	$14,915,620
NHEC Residential		$0	$0	$0	$0	$0	$0
Unitil Residential		$655,820	$5,681,249	$9,146,341	$9,208,964	$10,157,738	$9,677,667
Non-Residential							
Eversource Non-Residential		$9,767,342	$37,051,411	$61,331,793	$63,709,901	$68,281,255	$67,414,705
Liberty Non-Residential		$7,886,472	$9,243,386	$9,851,598	$9,700,028	$10,328,429	$10,282,825
NHEC Non-Residential		$0	$0	$0	$0	$0	$0
Unitil Non-Residential		$428,736	$2,537,672	$3,912,035	$3,922,481	$4,221,323	$4,127,754
Wholesale Load ISO Energy Settlement Cost ($) & Active M		**$33,480,173**	**$87,299,297**	**$125,639,762**	**$134,351,511**	**$147,563,591**	**$135,383,121**
Active Management: Load Bidding Optimization DA-RT		($509,850)	($1,329,431)	($1,913,296)	($2,045,962)	($2,247,161)	($2,061,672)
Residential							
Eversource Residential		$16,934,570	$45,336,489	$65,421,452	$70,006,907	$76,562,669	$70,413,079
Liberty Residential		$6,319,332	$10,039,856	$9,319,338	$9,256,890	$10,266,904	$9,390,655
NHEC Residential		$0	$0	$0	$0	$0	$0
Unitil Residential		$381,192	$3,092,324	$5,760,714	$5,988,491	$6,677,201	$6,005,156
Non-Residential							
Eversource Non-Residential		$5,739,154	$22,085,742	$38,331,572	$42,282,567	$46,457,383	$42,644,683
Liberty Non-Residential		$4,359,855	$6,610,261	$6,169,491	$6,191,864	$6,893,583	$6,283,085
NHEC Non-Residential		$0	$0	$0	$0	$0	$0
Unitil Non-Residential		$255,921	$1,464,055	$2,550,490	$2,670,754	$2,953,013	$2,708,135
Wholesale Total On-Peak		*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Wholesale Total Off-Peak		*$0*	*$0*	*$0*	*$0*	*$0*	*$0*
Hedging IBT MtM & Active Management		**$910,093**	**($4,169,568)**	**($15,265,083)**	**($14,614,434)**	**($14,202,178)**	**($11,010,610)**
Active Management: Forward Hedging Strategy		($769,522)	($2,201,250)	($3,343,350)	($3,509,083)	($3,776,934)	($3,603,785)
Executed IBT Hedges		n/a	n/a	n/a	n/a	n/a	n/a
'What-If' IBT Hedges (Hyptheticals)		$910,093	($4,169,568)	($15,265,083)	($14,614,434)	($14,202,178)	($11,010,610)
Excuted IBTs Variable Revenue		*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
Executed IBTS Fixed Cost		*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
'What-If' IBT Varialbe Revenue		*$31,690,959*	*$83,880,437*	*$118,468,934*	*$125,748,900*	*$136,875,166*	*$133,140,809*
'What-If' IBT Fixed Cost		*$30,780,866*	*$88,050,004*	*$133,734,017*	*$140,363,334*	*$151,077,343*	*$144,151,420*
Local Projects Revenue (Cost Reduction)		**$84,623**	**$352,946**	**$474,806**	**$455,621**	**$515,615**	**$483,448**
Market Energy Value		$264,618	$687,343	$598,160	$553,691	$595,280	$559,549
Renewable Energy Credit Value		$104,483	$247,127	$331,566	$295,205	$244,247	$194,443
Capacity Credit Value		$0	$19,825	$54,610	$80,054	$103,694	$121,669
Transmission Credit Value		$73,750	$286,740	$412,906	$445,938	$481,613	$520,142
PPA Cost		$358,229	$888,090	$922,435	$919,266	$909,219	$912,355
NON-ENERGY Costs ($)		**$7,384,661**	**$21,503,372**	**$38,727,777**	**$43,948,311**	**$48,038,583**	**$48,231,545**
Capacity Post Adjustments							
Residential							
Eversource Residential		**$1,479,955**	**$5,005,196**	**$8,559,829**	**$11,052,766**	**$14,546,729**	**$16,596,727**
Liberty Residential		**$643,023**	**$953,588**	**$1,201,545**	**$1,500,154**	**$1,987,670**	**$2,259,462**
NHEC Residential		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unitil Residential		**$47,950**	**$521,134**	**$941,601**	**$1,205,420**	**$1,611,550**	**$1,776,748**
Non-Residential							
Eversource Non-Residential		**$545,240**	**$2,765,237**	**$5,030,494**	**$6,580,137**	**$8,655,958**	**$9,789,178**
Liberty Non-Residential		**$529,255**	**$723,509**	**$920,196**	**$1,130,277**	**$1,493,008**	**$1,730,153**
NHEC Non-Residential		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unitil Non-Residential		**$20,743**	**$159,796**	**$274,983**	**$354,905**	**$469,765**	**$533,865**
Ancillary Prices		**$240,146**	**$353,108**	**$277,077**	**$308,819**	**$315,254**	**$306,247**
RPS Compliance Costs		**$3,277,986**	**$9,256,265**	**$18,751,282**	**$18,727,647**	**$15,806,104**	**$12,176,699**
Other Costs (ncpc, misc, service)		**$600,364**	**$1,765,539**	**$2,770,769**	**$3,088,187**	**$3,152,544**	**$3,062,467**
Gross Margin ($)		**$21,659,661**	**$25,260,591**	**$22,458,110**	**$14,153,792**	**$11,239,354**	**$22,689,780**

Gross Margin ($)		**$21,659,661**	**$25,260,591**	**$22,458,110**	**$14,153,792**	**$11,239,354**	**$22,689,780**
Other Start-Up Revenue	**$300,980**	**$600,000**					
Donations	$70,980	$0					
Grant - NHCF	$80,000	$0					
Calpine Start-Up Funding	$150,000	$600,000					
Pre-Launch Start-Up Costs	**$257,668**	**$764,303**	**$0**	**$0**	**$0**	**$0**	**$0**
Staffing & Overhead	$7,667	$214,204					
Personnel		*$150,000*					
CEO		*$108,333*					
CFO		*$41,667*					
General Counsel		*$0*					
Director, Policy & Regulatory Affairs		*$0*					
Director, Technology & Analytics		*$0*					
Director, Marketing & Customer Services		*$0*					
Strategic Accounts Manager		*$0*					
Power Resources Manager		*$0*					
Analyst 1		*$0*					
Analyst 2		*$0*					
Analyst 3		*$0*					
Benefits Loading		$37,500					
Office & Equipment	$0	$6,000					
Miscellaneous Overhead	$7,667	$20,704					
Outreach & Communications Materials	**$8,236**	**$163,800**					
Events and Marketing	$8,236	$163,800					
Support Services	**$241,764**	**$386,299**					
Contractors	$241,764	$386,299					
Expenses from Operating Activities		**$2,690,239**	**$7,006,666**	**$8,012,886**	**$7,381,204**	**$6,574,450**	**$6,577,554**
Non-Power Supply Expenses		**$2,204,335**	**$6,210,379**	**$7,209,655**	**$6,967,709**	**$6,344,050**	**$6,347,154**
Staffing & Overhead		**$892,708**	**$1,977,688**	**$2,374,232**	**$2,831,019**	**$2,916,473**	**$3,004,426**
Personnel		*$714,167*	*$1,550,150*	*$1,865,416*	*$2,229,163*	*$2,296,038*	*$2,364,919*
CEO		*$162,500*	*$334,750*	*$344,793*	*$355,136*	*$365,790*	*$376,764*
CFO		*$125,000*	*$257,500*	*$265,225*	*$273,182*	*$281,377*	*$289,819*
General Counsel		*$150,000*	*$309,000*	*$318,270*	*$327,818*	*$337,653*	*$347,782*
Director, Policy & Regulatory Affairs		*$100,000*	*$206,000*	*$212,180*	*$218,545*	*$225,102*	*$231,855*
Director, Technology & Analytics		*$0*	*$0*	*$119,351*	*$245,864*	*$253,239*	*$260,837*
Director, Marketing & Customer Services		*$100,000*	*$206,000*	*$212,180*	*$218,545*	*$225,102*	*$231,855*
Strategic Accounts Manager		*$50,000*	*$154,500*	*$159,135*	*$163,909*	*$168,826*	*$173,891*
Power Resources Manager		*$0*	*$0*	*$92,829*	*$163,909*	*$168,826*	*$173,891*
Analyst 1		*$26,667*	*$82,400*	*$84,872*	*$87,418*	*$90,041*	*$92,742*
Analyst 2		*$0*	*$0*	*$28,291*	*$87,418*	*$90,041*	*$92,742*
Analyst 3		*$0*	*$0*	*$28,291*	*$87,418*	*$90,041*	*$92,742*
Benefits Loading		$178,542	$387,538	$466,354	$557,291	$574,009	$591,230
Office & Equipment		$0	$30,000	$31,847	$33,424	$34,819	$36,208
Miscellaneous Overhead		$0	$10,000	$10,616	$11,141	$11,606	$12,069
Local Programs		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Outreach & Communications Materials		**$58,253**	**$91,391**	**$93,779**	**$38,052**	**$30,098**	**$30,098**
Enrollment Mailers (enrollments & churn)		$58,253	$71,391	$63,779	$23,052	$15,098	$15,098
Events and Marketing		$0	$20,000	$30,000	$15,000	$15,000	$15,000
Operational Services		**$1,253,374**	**$2,556,870**	**$3,332,152**	**$3,037,443**	**$2,831,002**	**$2,816,002**
Portfolio Risk Management & Operations		$738,558	$1,085,312	$1,152,824	$624,789	$392,165	$377,165
Ascend Analytics		*$738,558*	*$1,040,312*	*$1,092,824*	*$564,789*	*$377,165*	*$377,165*
LSE		*$0*	*$45,000*	*$60,000*	*$60,000*	*$15,000*	*$0*
Calpine (Platform, Utility Data, Billing)		$514,816	$1,471,559	$2,179,328	$2,412,654	$2,438,837	$2,438,837
Support Services		**$0**	**$788,144**	**$836,661**	**$878,099**	**$566,478**	**$496,628**
Accounting and Audits		$0	$140,000	$148,618	$155,979	$162,488	$168,971
Marketing and Branding		$0	$150,000	$159,234	$167,120	$174,094	$181,040
Legal Advice and Regulatory Engagement (DWGP)		$0	$300,066	$318,538	$334,314	$0	$0
Community Choice Partners		$0	$0	$0	$0	$0	$0
Herdon Enterprises		$0	$121,478	$128,956	$135,343	$140,991	$146,616
Clean Energy New Hampshire		$0	$76,600	$81,315	$85,343	$88,904	t
Utility Fees		**$0**	**$103,009**	**$155,673**	**$173,983**	**$176,140**	**$176,140**
At-Risk Contracting Repayment		**$485,903**	**$796,286**	**$572,831**	**$183,095**	**$0**	**$0**
Deferred Comp Schedule		$485,903	$796,286	$572,831	$183,095	$0	$0
NEPOOL Expenses		**$0**	**$0**	**$230,400**	**$230,400**	**$230,400**	**$230,400**
Operating Margin ($)	**$43,312**	**$19,569,423**	**$18,253,925**	**$14,445,224**	**$6,772,588**	**$4,664,904**	**$16,112,226**
Non-Capital Financing Activities		**($446,524)**	**($84,317)**	**$0**	**$0**	**$0**	**$0**
CREDIT FACILITIES		$1,196,737	$0	$0	$0	$0	$0
Energy LOC Funding		$0	$0	$0	$0	$0	$0
Non-Energy LOC Funding		$1,196,737	$0	$0	$0	$0	$0
DEBT SERVICE		($1,643,261)	($84,317)	$0	$0	$0	$0
Principal		($1,196,737)	$0	$0	$0	$0	$0
Energy LOC Repayment		$0	$0	$0	$0	$0	$0
Non-Energy LOC Repayment		($1,196,737)	$0	$0	$0	$0	$0
Interest/Fees		($446,524)	($84,317)	$0	$0	$0	$0
Energy LOC Fee/Interest		($400,243)	($84,317)	$0	$0	$0	$0
Non-Energy LOC Interest		($46,281)	$0	$0	$0	$0	$0
Commitment Fees for CPCNH LOC		$0	$0	($3,473)	($46,037)	($55,051)	($53,429)
Line of Credit (LOC) Fee		$0	$0	$0	$0	$0	$0
Letter of Credit (LC) Fee		$0	$0	($3,473)	($46,037)	($55,051)	($53,429)
Net Income ($)	**$0**	**$17,464,074**	**$16,764,644**	**$11,671,232**	**$3,400,563**	**$832,920**	**$12,362,561**

Appendix C: Effective $/MWh Income Statement

Month End of Month	2022	2023	2024	2025	2026	2027
Customer Counts		57,202	128,839	194,799	209,773	209,690
Retail Load at the Meters (MWh)		382,742	1,124,895	1,763,988	1,964,599	2,005,152
Wholesale Load ISO Energy Settlement (MWh)		(400,243)	(1,177,026)	(1,847,180)	(2,058,791)	(2,101,696)
Hedging IBT (MWh)		401,772	1,185,305	1,826,296	2,057,222	2,085,694
Utility Retail Rate Projections ($/MWh)		$171.07	$130.34	$121.51	$110.68	$116.33
Block+Auction Premium+Capacity+Ancillary+Basis+ISOFees+Loses+Uncollectible Premium						
Auction Premium Check		41%	30%	30%	29%	27%
Residential						
Eversource Residential		$174.04	$131.94	$122.38	$111.90	$117.10
Liberty Residential		$183.25	$129.48	$120.85	$109.58	$115.55
NHEC Residential		$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential		$160.26	$129.56	$122.67	$111.20	$119.22
Non-Residential						
Eversource Non-Residential		$160.47	$129.28	$120.99	$109.75	$115.79
Liberty Non-Residential		$158.55	$126.86	$118.10	$107.64	$112.83
NHEC Non-Residential		$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Non-Residential		$153.32	$121.54	$115.49	$103.80	$109.68
CPCNH Revenue Rates, (Applying Discount to Utility of Cos		$162.52	$123.82	$115.44	$106.22	$111.07
Residential Uncollectable Adjustment		1.42%	1.42%	1.42%	1.42%	1.42%
Non-Residential Uncollectible Adjustment		1.42%	1.42%	1.42%	1.42%	1.42%
Residential						
Eversource Residential		$165.34	$125.34	$116.26	$107.38	$111.82
Liberty Residential		$174.09	$123.01	$114.80	$105.16	$110.32
NHEC Residential		$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential		$152.25	$123.09	$116.54	$106.72	$113.84
Non-Residential						
Eversource Non-Residential		$152.45	$122.82	$114.94	$105.31	$110.55
Liberty Non-Residential		$150.62	$120.52	$112.20	$103.34	$107.70
NHEC Non-Residential		$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Non-Residential		$145.66	$115.46	$109.71	$99.61	$104.74
ENERGY Forward Prices ($/MWh)		$87.47	$77.61	$71.22	$68.39	$73.59
Mass Hub ATC		$105.74	$84.27	$74.82	$66.34	$70.15
Mass Hub On-Peak		$112.27	$91.75	$82.25	$73.76	$80.07
Mass Hub Off-Peak		$100.09	$77.73	$68.35	$59.83	$61.43
New Hampshire Zone ATC		$105.69	$84.48	$75.11	$66.51	$70.23
New Hampshire Zone On-Peak		$111.36	$90.45	$81.84	$74.01	$79.35
New Hampshire Zone Off-Peak		$100.78	$79.27	$69.24	$59.92	$62.23
Effective Load Weighted (ISO Obligation/Meter Load)		$83.65	$74.17	$68.02	$65.26	$70.21
Active Management: Demand Bidding DART		($1.33)	($1.18)	($1.08)	($1.04)	($1.12)
Residential						
Eversource Residential		$90.53	$79.70	$72.46	$69.62	$74.77
Liberty Residential		$87.78	$91.66	$74.21	$68.81	$74.37
NHEC Residential		$0.00	$0.00	$0.00	$0.00	$0.00
Unitil Residential		$88.49	$67.00	$73.40	$69.40	$74.83

Appendix D: Utility Tariff Auction Premium Backcasts & Utility Migration Data

Eversource Small Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23	Feb23-Jul23
Fixed Retail Rate	$ 94.1	$ 99.9	$ 88.3	$ 83.1	$ 70.7	$ 66.3	$ 88.3	$ 106.7	$ 225.7	$ 202.2
Total Eversource RPS + ES Adj.	$ 4.6	$ 3.7	$ 7.0	$ 9.0	$ 5.8	$ 5.7	$ 4.4	$ 4.7	$ 5.8	$ 5.9
Base ES Rate (Average)	$ 89.6	$ 96.1	$ 81.2	$ 74.0	$ 64.9	$ 60.6	$ 83.8	$ 102.0	$ 219.9	$ 196.3
Wholesale Cost + Losses	$ 83.0	$ 83.9	$ 73.4	$ 64.9	$ 58.0	$ 52.6	$ 73.0	$ 89.4	$ 164.7	$ 128.7
Energy Only Cost + Losses	$ 51.6	$ 52.9	$ 45.9	$ 39.5	$ 35.7	$ 32.3	$ 55.1	$ 70.9	$ 149.2	$ 113.7
$/MWh Auction Premium Over Block	$ 6.6	$ 12.2	$ 7.9	$ 9.2	$ 6.9	$ 8.0	$ 10.8	$ 12.6	$ 55.2	$ 67.7
% Auction Premium to Block	13%	23%	17%	23%	19%	25%	20%	18%	37%	55%

Liberty Small Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23	Feb23-Jul23
Retail Rate	$83.0	$83.0	$77.1	$71.9	$68.3	$64.3	$84.0	$111.2	$222.3	$220.1
ES Reconciliation	-$9.7	-$9.7	-$8.2	-$8.2	-$3.8	-$3.8	$1.5	$1.5	$1.0	$1.0
ES Cost Reclassificiation Adj	-$1.2	-$1.2	$1.3	$1.3	$0.4	$0.4	$0.5	$0.5	$0.6	$0.6
RPS Adder	$2.9	$2.9	$5.4	$7.1	$7.4	$7.4	$6.8	$6.8	$7.8	$7.8
Base ES Rate (Average)	$91.0	$91.0	$78.7	$71.8	$64.2	$60.2	$75.2	$102.4	$212.9	$210.7
Wholesale Cost + Losses	$82.3	$83.5	$74.4	$63.9	$53.8	$53.0	$66.7	$91.1	$173.2	$138.0
Energy Only Cost + Losses	$48.6	$49.5	$44.8	$38.5	$35.5	$34.8	$50.5	$74.5	$157.5	$122.7
$/MWh Auction Premium Over Block	$8.7	$7.6	$4.2	$7.8	$10.5	$7.3	$8.5	$11.3	$39.7	$72.7
% Auction Premium to Block	18%	15%	9%	20%	29%	21%	17%	15%	25%	59%

Eversource Large Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23
Average Retail Rate	$98.0	$125.0	$93.8	$83.1	$90.8	$67.7	$90.8	$119.0	$315.4
Total Eversource RPS + ES Adj.	$4.6	$3.7	$8.7	$10.7	$6.3	$9.3	$6.3	$4.7	$3.5
Base ES Rate (Average)	$93.5	$121.3	$85.1	$72.4	$84.4	$58.4	$84.4	$114.4	$311.9
Wholesale Cost + Losses	$86.1	$88.0	$70.9	$64.5	$53.5	$49.8	$72.2	$84.5	$165.1
Energy Only Cost + Losses	$49.3	$52.4	$45.3	$39.2	$36.1	$31.1	$54.1	$67.5	$149.5
$/MWh Auction Premium Over Block	$7.4	$33.2	$14.2	$8.0	$30.9	$8.6	$12.3	$29.9	$146.8
% Auction Premium to Block	15%	63%	31%	20%	86%	28%	23%	44%	98%

Liberty Large Auction Premium Backcast

	Aug18-Jan19	Feb19-Jul19	Aug19-Jan20	Feb20-Jul20	Aug20-Jan21	Feb21-Jul21	Aug21-Jan22	Feb22-Jul22	Aug22-Jan23
Retail Rate	$78.3	$79.0	$73.2	$67.4	$69.8	$66.6	$83.3	$108.4	$222.3
ES Reconciliation	-$9.7	-$9.7	-$8.2	-$8.2	-$3.8	-$3.8	$1.5	$1.5	$1.0
ES Cost Reclassificiation Adj	-$2.3	-$2.3	$2.6	$2.6	$0.8	$0.8	-$1.2	-$1.2	$2.5
RPS Adder	$4.6	$2.9	$5.4	$7.1	$7.4	$7.4	$6.8	$6.8	$7.8
Base ES Rate (Average)	$85.7	$88.1	$73.5	$65.9	$65.3	$62.1	$76.1	$101.3	$211.0
Wholesale Cost + Losses	$81.2	$78.3	$68.0	$61.6	$53.9	$52.0	$67.8	$97.6	$165.6
Energy Only Cost + Losses	$52.0	$50.4	$45.8	$39.0	$36.1	$34.9	$51.9	$78.8	$149.8
$/MWh Auction Premium Over Block	$4.5	$9.8	$5.4	$4.3	$11.4	$10.1	$8.3	$3.7	$45.4
% Auction Premium to Block	9%	20%	12%	11%	32%	29%	16%	5%	30%

Unitil Auction Premium Backcast

	Jun22-Nov22	Dec22-Jul23
Retail Rate	101.17	259.25
Reconciliation	$1.64	-$1.23
RPS	$4.38	$5.28
Base ES Rate (Average)	$96.79	$253.97
Wholesale Cost + Losses	$ 84.97	$ 180.75
Energy Only Cost + Losses	$ 65.76	$ 167.43
$/MWh Auction Premium Over Block	$11.82	$73.22
% Auction Premium to Block	18%	44%

		Small			
Class:					
Utility:		Eversource	Liberty	NHEC	Unitil
Date of Most Recent Available Auction		12/6/2022	12/13/2022	6/28/2022	9/20/2022
Energy Wholesale Costs	$/MWh	$108.43	$117.03	$149.72	$164.10
Capacity Wholesale Costs	$/MWh	$12.77	$13.03	$13.34	$16.91
Ancillary Wholesale Costs	$/MWh	$0.70	$0.70	$0.70	$0.70
Losses	$/MWh	$5.26	$5.70	$7.27	$7.96
Other Costs (ncpc, misc, service)	$/MWh	$1.50	$1.50	$1.50	$1.50
TOTAL WHOLESALE COST	$/MWh	$128.66	$137.96	$172.53	$191.17

		Large			
Class:					
Utility:		Eversource	Liberty	NHEC	Unitil
Date of Most Recent Available Auction		6/14/2022	6/7/2022	6/28/2022	9/20/2022
Energy Wholesale Costs	$/MWh	$142.32	$142.57	$138.45	$160.10
Capacity Wholesale Costs	$/MWh	$13.40	$13.62	$9.18	$11.12
Ancillary Wholesale Costs	$/MWh	$0.70	$0.70	$0.70	$0.70
Losses	$/MWh	$7.17	$7.19	$6.98	$7.33
Other Costs (ncpc, misc, service)	$/MWh	$1.50	$1.50	$1.50	$1.50
TOTAL WHOLESALE COST	$/MWh	$165.09	$165.57	$156.81	$180.75

Most Recently Reported 12 Month Utility Customer Migration

Utility	Segment	Total Utility MWh	Segment Share of Utility Load	Migrated Load	Remaining Default Load	Segment Share of Default Load
Eversource	Residential	3,433,211	44%	537,891	2,895,320	74%
	Small Commercial	1,644,923	21%	846,179	798,744	20%
	Large Commercial	2,765,000	35%	2,549,251	215,749	6%
Liberty	Residential	294,617	33%	18,781	275,837	60%
	Small Commercial	108,621	12%	23,160	85,461	19%
	Large Commercial	499,710	55%	400,629	99,080	22%
Unitil	Residential	521,496	45%	44,976	476,520	67%
	Small Commercial	316,143	27%	139,606	176,537	25%
	Large Commercial	327,374	28%	271,979	55,395	8%

Note: Eversource & Unitil data available for period ending Q3 2022, Liberty ending Q1 2022.

Appendix E: PowerSIMM Model CPCNH Simulation Validation

As a part of the model stand up process ascend conducts validations of PowerSIMM's Simulation Engines (namely Load, Weather, and Forward Sims) to ensure that the model can accurately capture historically observed trends in forecasts. This is generally done by comparing simulated, historical, and back cast data. To read more in depth information about the simulation engines refer to Appendix F.

The first simulation engine is weather: weather is the driver of uncertainty. To simulate weather, Ascend harvests 30 years of historical daily Min and Max drybulb temperatures for weather stations across New Hampshire from the National Climatic Data Center (NCDC). Weather stations simulated included Berlin, Concord, Jaffrey, Lebanon, Manchester, Rochester, and Whitefield. Historic weather is fed to the model to inform the simulations, and ensure that the simulated mean, P5, and P95 temperatures are in line with the historically observed temperature conditions. This is confirmed at both a monthly level as seen in Figure 54, and at a daily level as seen in

Figure 55. In the daily validation plot shown in

Figure 55, the historical observations in red produce a line that shows more variability because our simulations are the averaging of over 100 weather futures, whereas the historical timeseries represent the single history that has occurred.

Figure 54: Sample Monthly Min Dry Bulb Temperature Validation Plot for Jaffrey, NH.

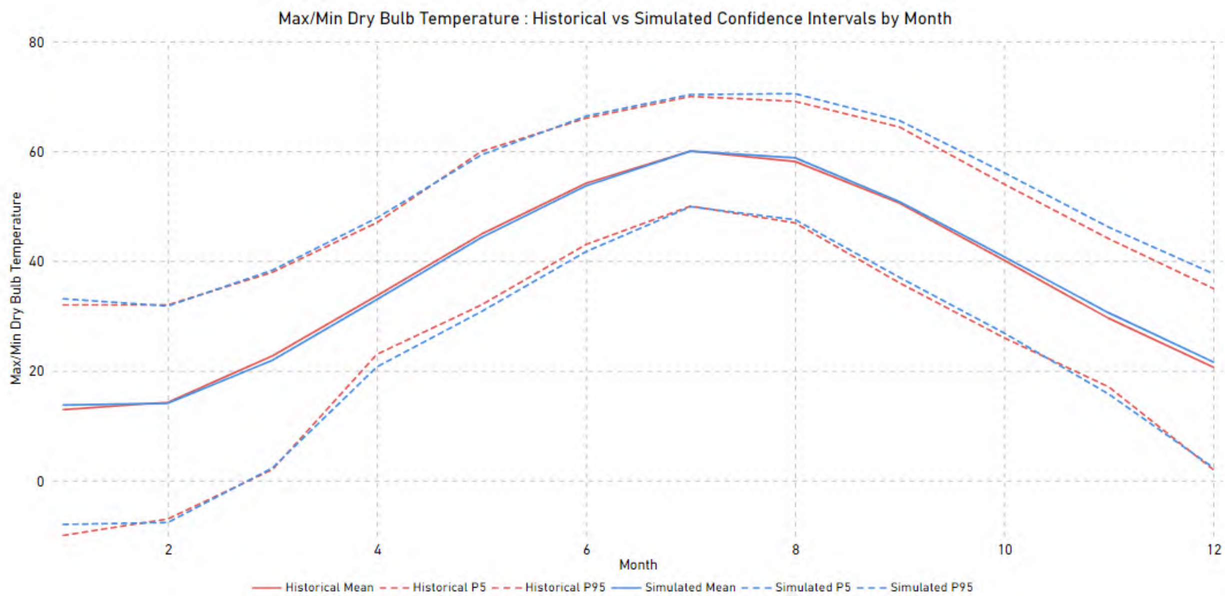
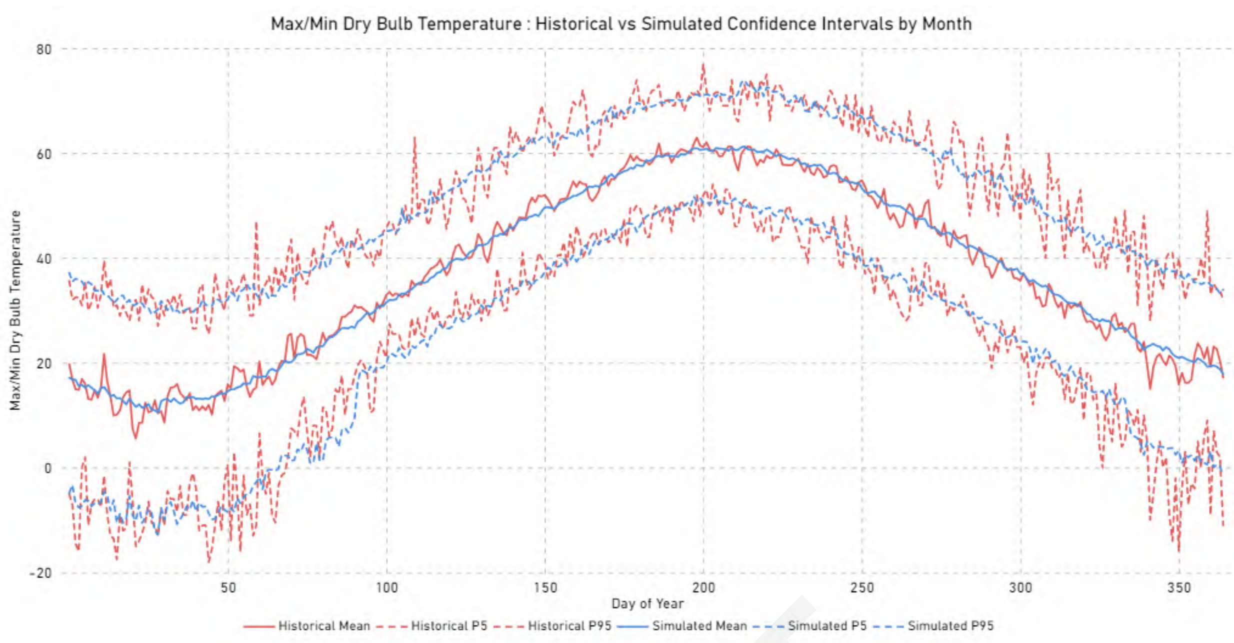


Figure 55: Sample Daily Min Dry Bulb Temperature Validation Plot for Jaffrey, NH.



PowerSIMM uses the historical weather-load correlation to simulate load once weather has been simulated. below shows the historic and backcast load vs temperature relationship – load is highest at the more extreme cold and hot temperatures.

While weather is simulated on a daily basis, load gets simulated on an hourly basis, so in addition to ensuring that the simulations match the monthly and daily historically observed patters discussed above with weather validations we also ensure that historically observed hourly load patterns are maintained. This validation is shown in below where the mean, P5, and P95 hourly loads for simulated and backcast load are compared. The simulated backcast data match the historical mean exactly with simulated P5 and P95s well in line with historical data.

Figure 56: Historical vs Backcast Load vs Temperature Relationship for Eversource Load

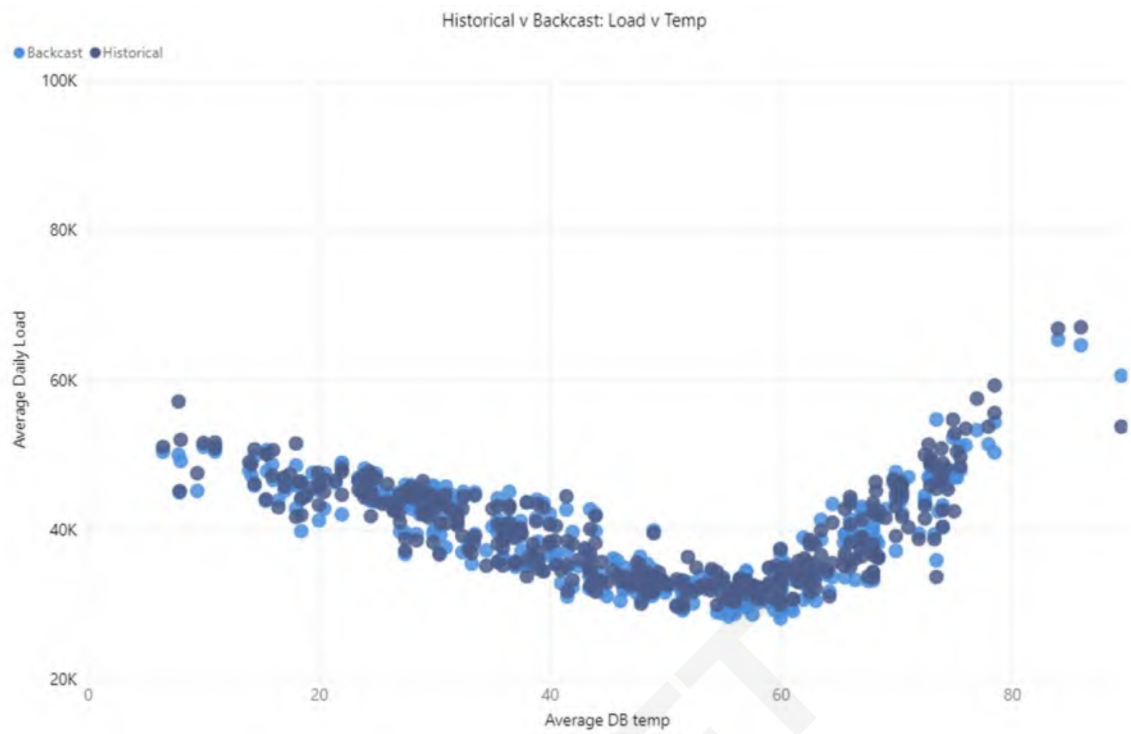
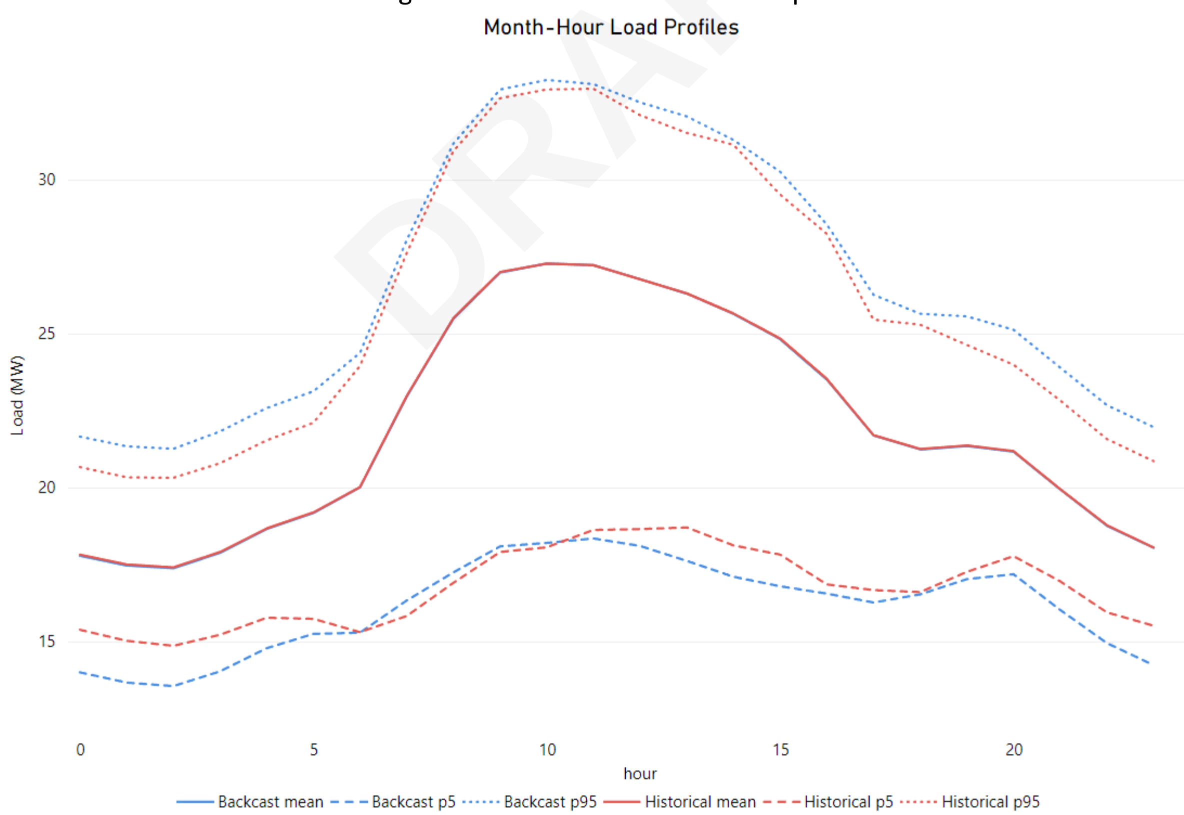


Figure 57: Month – Hour Load Shape



Appendix F: PowerSIMM Level 1 Documentation

Available upon request to Member CPAs subject to Non-Disclosure Agreement and agreement to not redistribute

Appendix G: Ascend ISO-NE Market Report

Available upon request to Member CPAs subject to Non-Disclosure Agreement and agreement to not redistribute

Customer Accounts and Electricity Usage Estimates
The tables below show the total number and annual electricity usage of customers within Portsmouth's territory who would initially receive either "opt-out" or "opt-in" notifications:

	Utility Default Supply Customers (Eligible for Opt-Out Notifications & Automatic Enrollment)		Competitive Supply Customers (Eligible for Opt-In Notifications & Voluntary Enrollment)	
	Customer Accounts	Annual Usage (MWh)	Customer Accounts	Annual Usage (MWh)
Municipal? (G)	2,245	51,986	1,143	51,047
Residential (R)	10,554	58,788	1,381	8,921
Small Commercial & Industrial (<1000 kW) (GV)	17	51,986	71	96,048
Large Commercial & Industrial (>1000 kW) (LG)	0	0	7	104,467
Street Lighting (OL)	152	628	0	0
Total	12,968	163,388	2,602	260,483

Aggregated data shown was provided by Eversource for the 12 months ending November 30, 2022.

PORTSMOUTH COMMUNITY POWER
City of Portsmouth NH

PORTSMOUTH COMMUNITY POWER
City of Portsmouth NH

PORTSMOUTH COMMUNITY POWER
City of Portsmouth NH

PORTSMOUTH COMMUNITY POWER
City of Portsmouth NH

Portsmouth Community Power Postcard Mailing

Objective: Mail two-sided color postcard. The postcard will engage respondents through a weblink and QR code.

Quantity: approximately 11,000 pieces
Date: by 2nd week of January
Services: Printing 6x9" postcard, color/b&w, addressing, pre-sort, and mailing
Budget: up to $5,500

Name	Quantity	Printing & Addressing	Postage	TOTAL
Spectrum Marketing	14,045 residences	$2,664.34	$2,570.24	$5,234.58
Southport Printing	13,812 residents & businesses in 03801 zipcode	$2,955	Every Door Direct Mailer - $2,486	$5,441
Eastern Marketing	No reply	--	--	--

Spectrum Marketing

6" x 9" Postcards
- 4/4 (full color; double sided), 6 x 9 Card, 9pt C2S
Digital Proofs
Offset Printing
Trimming
- Mail-A (mail preparation)
Saturation Data, Resident only (we are dropping business addresses)
Black Inkjet-Letter
Postage-MM Saturation-Letter <3.5 ozs SCF (2023-01-22)
14,045 - $5234.58 total - $0.3727 each

Southport Printing

13,812 EDDM ("every door direct mailer") that would go to all residential and businesses in the 03801 zip code.
Printing/Addressing $2,955.00
Postage: $2,486-2,762.

Total: $5,4421-5,717 ($0.39 each)

Eastern Marketing Services

No reply.

To: Portsmouth Energy Advisory Committee

From: John Tabor, Chair

Re: Update on December activity 12/9/22

Colleagues,

Here is an update and look-ahead for our committee's work. Please don't reply all to save discussion for public session at our January meeting currently planned for **January 5, 2023.**

CPCNH update: According to Kevin Charette, focus is on finalizing for Board vote on December 15 the energy portfolio risk management, rate setting, financial reserves and cost sharing policy documents which will guide the coalition's activities. The CEO search is in the preliminary stages with the executive search firm TrueSearch. The goal is to have a CEO in place late March. The contract with Calpine to provide billing, customer service and utility interface is signed and they are at work. The contract with Ascend Analytics for portfolio management is nearly done and Ascend is contracting for bulk purchasing through an agent. Ascend is also updating all the revenue models in the business plan. Also, a contract for community engagement work is nearing completion with Clean Energy New Hampshire. The Coalition has $750,000 startup capital from Calpine.

Discussions are underway for Concord to join the Coalition.

Survey: The city's purchasing department is getting three vendor quotes to send out the postcard. The design, which drives users to the online survey through a URL and QR code, is in the last meeting packet. In discussion amongst our working group, we propose to you that the survey go out mid-January with a note to those completing it to learn more at public hearings February 9 and March 2. A newspaper op-ed will preview the survey to the community.

Logo: We have two designs for a logo – one from CPCNH based on the city seal with a ship and railroad, and one from our own Allison Tanner with the North Church steeple against a shining sun. We'll pick one at our January meeting.

Branding: Current thinking on our web presence is to create a Portsmouth Community Power page on the city website that is a short description and benefit statement, but also keep an in-depth page for the Energy Advisory Committee's documents, meetings/minutes, and FAQs, and cross link the pages. PEAC remains the implementing governmental body until the program is launched.

Energy Aggregation Plan: The draft plan is ready to move to CPCNH review and city legal review unless members have changes to improve it, however we still await load data.

Community Engagement: I spoke to the PHS Eco Club who would like a speaker from PEAC. Last night's working group also recommended the Chamber email blast should be in advance of the survey, and suggested a speaker at Portsmouth Rotary.

Meeting Schedule 2023 – January to June. Second Thursday of each month: February's meeting will be the public hearing Feb 9, followed by March 9, April 13, May 11 and June 8.

Best of the holidays to everyone. If all goes well, you can light up your house next year with Portsmouth Community Power electricity!

Cost Sharing Agreement

[Member]

COMMUNITY POWER COALITION OF NEW HAMPSHIRE

COST SHARING AGREEMENT

This Cost Sharing Agreement ("Agreement") is made and entered into this __ day of _________, ____, by and between the ____________________________________, a subdivision of the State of New Hampshire, ("the Member") and the Community Power Coalition of New Hampshire ("CPCNH" or "Corporation"), pursuant to the provisions of the CPCNH Joint Powers Agreement ("JPA") (collectively, the "Parties").

RECITALS

WHEREAS, ___________________________ may choose to implement Community Power Aggregation ("CPA") service to provide all-requirements electricity for its residents and businesses pursuant to New Hampshire Revised Statutes Annotated ("RSA") 53-E, the Community Power Act, which found "*it to be in the public interest to allow municipalities and counties to aggregate retail electric customers, as necessary, to provide such customers access to competitive markets for supplies of electricity and related energy services*;"

WHEREAS, the Constitution of New Hampshire declares that "*Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it;*"

WHEREAS, CPCNH is a nonprofit all-requirements Joint Powers Agency and governmental instrumentality operating pursuant to the Joint Powers Agreement entered into by the ____________________________ on the ___ day of _________, ____, for the purpose of jointly exercising the powers granted to municipal corporations pursuant to NH RSA 33-B, NH RSA 53-E, NH RSA 53-F, and NH RSA 374-D (including, by reference, NH RSA 33) in accordance with RSA 53-A, Agreements Between Governments;

WHEREAS, CPCNH is jointly controlled and governed by its Members, united as a single entity to operate for the mutual benefit of the Members collectively, to promote the common good, general welfare, economic vitality, and prosperity of local communities in New Hampshire, to use the powers and authority granted by the Members to gain economies of scale and scope to launch, operate, and evolve Community Power Aggregation ("CPA") programs, and to advance other energy and climate policies and actions on behalf of the Members; and

WHEREAS, CPCNH's Joint Powers Agreement requires this Cost Sharing Agreement be entered into by all Members to ensure that the costs, expenses, debts, and liabilities directly or indirectly incurred by CPCNH on each Member's behalf are recovered through said Member CPA's revenues, or from grants or other third-party sources;

NOW, THEREFORE, in consideration of mutual benefits, covenants, and considerations hereinafter set forth, CPCNH and the Member hereby agree as follows:

REFERENCE TABLE

ARTICLE I
PURPOSE

The purpose of this Cost Sharing Agreement is to ensure that (i) the expenses, debts, and liabilities (“costs”) directly or indirectly incurred by CPCNH on behalf of the Member are allocated to them based upon cost causation principles, to the extent practical, and (ii) that such costs are recovered from their CPA program revenues, or revenues from grants or other third-party sources.

This Cost Sharing Agreement (i) affirms that the resolutions and articles of the Joint Powers Agreement, as applicable herein, represent a mutual and collectively beneficial approach to cost allocation, whether Members are active or withdrawn from CPCNH, (ii) obligates CPCNH to carry out cost tracking and allocation for recovery from Member CPA revenues in accordance with the methodologies and procedures herein, which are intended to ensure fairness across all Members.

Execution of this Cost Sharing Agreement is a requirement for all Members. Upon execution of this Agreement, Members may subsequently elect to take certain CPA Member Services, which are provided in Exhibit C; each Member Service requires separate execution by the Member to authorize and obligate CPCNH to provide services on behalf of the Member’s CPA.

Electing the Complete Service Bundle of CPA Member Services thereunder authorizes and delegates authority to CPCNH to, pursuant to CPCNH’s Energy Portfolio Risk Management, Rates, and Reserves policies: (i) take all actions necessary and proper to finance, launch, and operate the Member’s CPA; (ii) set rates and provide all-requirements electricity to eligible retail customers taking service within the Member’s service territory; and (iii) collect customer revenues to accrue financial reserves on behalf of the Member and recover the costs allocated to the Member’s CPA pursuant to this Agreement.

ARTICLE II
AMENDMENT

CPCNH's Joint Powers Agreement requires that the Cost Sharing Agreements between the Corporation and each individual Member be uniform in all material respects, except with regard to the scope of Member services and Project Contracts that each Member selects to participate in and pay for.

This Agreement duly provides flexibility to update and evolve the scope of services offered to all Members, for individual Member election, by permitting CPCNH to update Exhibit C for all Members, and to incorporate any Project Contracts entered into by an individual Member in Exhibit F. Similarly, Exhibit B: Cost Allocation Reference Table, Exhibit D: Template Cost Allocation Report, Exhibit E: Template Report Glossary, and the list of current CPCNH Members presented under Article III, below, may all be updated by CPCNH. Excerpts from CPCNH's Joint Powers Agreement herein are also updated upon amendment to the Joint Powers Agreement. The Corporation shall promptly distribute any such updates to all Members in a uniform manner, except that Exhibit F of each Member's Cost Sharing Agreement shall only reflect the Project Contracts, if any, entered into by each Member. The Member agrees that all such updates provided by CPCNH to the Exhibits and Joint Powers Agreement language herein shall be incorporated into and do not constitute an amendment to this Agreement.

To ensure that all other aspects of this Agreement, including the cost allocation methodologies prescribed hereunder, are similarly capable of evolving over time, and in recognition that the changeable nature of energy markets, technologies, and cost-drivers may well warrant refinements to the cost allocation methodologies herein at some point in the future**, this Agreement may be amended by a written amendment unanimously approved by the votes cast at a meeting of the Membership at which a quorum is present, provided that CPCNH's Chief Executive Officer or Chair of the Board shall send written notice of any proposed amendments to the Member Representatives and principal executive officers of each Member at least thirty (30) days prior to such meeting at which it is to be acted upon.**

The Member recognizes that, absent this mechanism, it may become impractical to otherwise amend this Agreement as the number of Members grows over time, given the requirement that the Agreement be maintained as uniform in all material respects across the Membership, and that such an eventuality would be contrary to the interest of every Member.

ARTICLE III
MEMBERSHIP

CPCNH's current Membership, pursuant to CPCNH's Joint Powers Agreement, may individually execute this Agreement and thereby jointly rely on CPCNH to finance, launch, and operate their CPA programs. The Parties acknowledge that the actual sequencing of CPA implementation may vary from this table:

Members currently intending to implement CPA program service in 2023:

City of Lebanon	Town of Rye	Town of Exeter
Town of Hanover	Town of Walpole	Town of Peterborough
City of Nashua	Town of Plainfield	Town of Durham
Cheshire County	Town of Enfield	Town of Harrisville

Members in the process of authorizing CPA programs:

City of Dover	Town of Newmarket	City of Portsmouth
Town of Warner	Town of Canterbury	Town of Westmoreland
Town of Pembroke	Town of Wilmot	Town of Hudson
Town of Webster	Town of Shelburne	Town of Sugar Hill
Town of New London	Town of Hancock	Town of Brentwood

ARTICLE IV
ELECTION OF CPA MEMBER SERVICES & PROJECT CONTRACTS

The CPA Member Service Agreements currently authorized by the Board are provided in Exhibit C, inclusive of any additional terms of service thereof, for elective execution by the Member. Enrollment periods during which any Members may execute a given contract for CPA Member Services offered in Exhibit C may be for pre-defined periods or open-ended, and the Board may also close enrollment in any CPA Member Service contract that was previously open-ended. During the active enrollment period applicable to any given Member Service Agreement, all executed Agreements between CPCNH and each Member that has elected the same service must be uniform in all material respects.

All of the services required to undertake and provide CPA service are initially offered as a Complete Service Bundle. The Board may authorize additional CPA Member Services, including the disaggregated services comprising the Complete Service Bundle, for Members to elect and pay for on an a la carte, elective basis thereunder. The Member agrees that, from time to time, CPCNH may update Exhibit C to modify enrollment periods for specific CPA Member Services contracts, remove CPA Member Services contracts that are no longer offered and in use by any Member, and incorporate new CPA Member Services contracts offered to all Members.

Project Contracts that an individual Member has entered into, upon execution, shall be placed into Exhibit F of the Member's Cost Sharing Agreement and incorporated by reference hereunder.

Exhibit B provides a reference table summarizing how costs shall be allocated, for all Members' ease of reference, which shall be updated by CPCNH commensurate with the removal and/or addition of any CPA Member Services to Exhibit C, or as otherwise warranted at CPCNH's discretion.

ARTICLE V
COST RECOVERY COMMITMENT; LIMITATION

Article V, Section 3 of the JPA requires that the Cost Sharing Agreement entered into by each Member "*ensure that the costs, expenses, debts, and liabilities ("Costs") … directly or indirectly incurred by the Corporation on such Member's behalf are recovered through said Member's CPA revenues, or from revenues from grants or other third-party sources*."

The Member acknowledges and agrees that the costs directly or indirectly incurred by CPCNH on the Member's behalf shall be recovered through the Member's CPA revenues, or from revenues from grants or other third-party sources.

The debts, liabilities, and obligations of CPCNH shall not be debts, liabilities, and obligations of the Member unless and only to the extent agreed to under a Member Service contract entered into by the Member, pursuant to Exhibit C, or Project Contract separately entered into by the Member.

ARTICLE VI
COST REPORTING & RECORDS

This Cost Sharing Agreement puts in place a mandate for transparency regarding how costs are tracked, and allocations are computed. CPCNH will provide for the data collection, analysis, accounting, reconciliation of receipts and aging, and cost allocation between Member CPAs under the methodologies and processes set forth in this Cost Sharing Agreement. As provided for under Article IX hereunder, actual metered customer electricity consumption will be employed where consumption is the determinant of allocation, to the extent possible.

However, the Member acknowledges that CPCNH's reasonable estimations of usage may need to be employed, initially and/or even permanently, depending upon the availability of actual data by Member CPA, but estimations should be subject to periodic reconciliation with actual loads when reasonably practical.

CPCNH will deliver monthly reports to each Member CPA, after it closes its books, encompassing and presenting all costs and allocations by Member. Reports will be prepared at an appropriate level of line-item granularity and will be uniform in all material respects, except with regard to the scope of CPA Member Services and Project Contracts that each Member selects to participate in and pay for. Exhibit D shall present the current report template in use by CPCNH, accompanied by the glossary in Appendix E, which shall be kept current by CPCNH for the Member's reference. Reports will be delivered and distributed to all Members by CPCNH.

Pursuant to CPCNH JPA Article XIII, "*The books and records of the Corporation shall be open to inspection at all reasonable times to each Member and its representatives.*" The Member may, at any time, request detail, clarification and/or revisions of monthly reports, which shall be distributed to all Members.

ARTICLE VII
CPCNH IMPLEMENTATION COSTS

The funding to implement CPCNH is derived from four sources. These sources will cover the initial cost of CPCNH during the Implementation Phase, which refers to the period from the incorporation of CPCNH, on October 1, 2021, through the Start-Up Date, which shall be deemed to be the first of the calendar month in which CPCNH begins receiving customer revenues for delivery of all-requirements electricity to serve the demand of the customers of Member CPAs:

1) Funds provided by Members, gifts, or grants received and recorded by CPCNH as cash contributions.

2) Credit extended by contract to, and received by, CPCNH from vendors or banks, whether extended with interest or deferred interest cost or charged on an alternate basis.

3) Interest-free cash advances, grants, or loans extended by contract to, and received by, CPCNH.

4) Deferred compensation by vendors and contractors under contract for future payment by CPCNH, contingent upon the delivery of all-requirements electricity to serve the demand of the customers of Member CPAs.

The Member acknowledges and affirms that the cost of implementing CPCNH should not be borne solely by the customers taking service from initial Member CPAs, as such costs are foundational to the benefit of all Members of CPCNH at any point. As such, the Agreement provides that:

1) Implementation Costs are defined as costs incurred or accrued by CPCNH during the Implementation Phase which are not directly allocatable to any one Member CPA, in that such costs would have been incurred or accrued by CPCNH irrespective of the participation of any one Member CPA, inclusive of interest or financing charges that continue to accrue on such costs subsequent to the Implementation Period, less funds received by CPCNH pursuant to (1) above.

2) Implementation Costs shall be equitably allocated, on an equal volumetric retail electricity usage basis, to the CPA of each Member that (i) executes this Cost Sharing Agreement and, (ii) supplies all-requirements electricity to retail customers through said Member's CPA program within the five (5) year period commencing on the Start-Up Date ("Implementation Cost Recovery Period").

3) CPCNH intends to pay off Implementation Costs during the initial three (3) years following the Start-Up Date. Consequently, over the course of the five (5) year Implementation Cost Recovery Period, each Member CPA will receive an allocation obligation, providing for the direct payment of Implementation Costs and/or

reimbursements to the Member CPAs that have already paid for the Implementation Costs, such that, at the conclusion of the five (5) year period, the sum of electricity used by retail customers taking service from each CPA over the course of the period divided into the Implementation Costs allocated to each CPA shall be equivalent on a dollar per megawatt-hour ($/MWh) basis.

4) CPCNH shall maintain an internal accounting of the amount of Implementation Costs, and the allocation obligations, payments, and reimbursements of such costs, which record shall be available for inspection by Members at any reasonable time.

ARTICLE VIII
CLASSIFICATION OF COSTS

The three primary categories of costs into which CPCNH must classify all costs, pursuant to Section 3 of Article V of the JPA, are described in further detail below. Refer to Exhibit A for excerpts from the JPA regarding cost sharing principles, which are incorporated herein.

1) <u>**CPA Member Services Costs**</u> are costs related to undertaking and providing CPA service on behalf of Members. Such costs will represent the bulk of the cost that CPCNH will incur, including for the provision of:

   a) CPA Power Supply Costs: costs incurred by CPCNH to secure and sell all-requirements electricity supply to serve the demand of the customers of each Member CPA, the definition and requirements of which are subject to changes in law and rules, and to engage in portfolio risk management, which includes:

      i) The cost of electrical energy, capacity, reserves, ancillary services, transmission services (to the extent allocated to Member CPA service), transmission and distribution losses, congestion management, and other such services or products necessary to provide firm power supply and meet the requirements of New Hampshire's Renewable Portfolio Standard, and financial products.

      ii) The cost of financial products related to portfolio risk management, such as power or natural gas options, swaps, or futures contracts, Financial Transmission Rights (FTR) obligations and options, and products to hedge non-energy cost components of the power supply portfolio.

      iii) Additional attributable costs authorized by individual Member CPAs for any other power supply related products and services, such as for securing or purchasing Renewable Energy Credits in excess of the requirements of New Hampshire's Renewable Portfolio Standard, or for resources that reduce the ISO-NE wholesale load obligations and/or reduce transmission cost allocations, if any, attributable to the Member CPAs, which may also generate credit for avoided transmission costs or avoided capacity costs attributable to customers and/or Member CPAs.

   b) CPA Operational Costs: costs related to undertaking and providing CPA service on behalf of Members that are not CPA Power Supply Costs, which include but are not limited to the following:

      i) Staff, overhead, legal, banking, technical, regulatory, and financial services costs attributable to the provision of CPA service.

      ii) Financing and credit charges incurred for the provision of all-requirements electricity supply, and for operating costs hereunder, excluding those associated with any Project.

      iii) Compliance costs attributable to the provision of CPA service.

      iv) Direct costs and/or costs incurred from third-party providers under contract with CPCNH to provide services, including:

(1) Marketing, advertising, community engagement, and customer noticing pertaining to CPA service.

(2) ISO-NE Load Serving Entity (LSE) services.

(3) Portfolio and risk management services.

(4) Utility data interchange, data management, and customer billing services.

(5) Call center and customer engagement services.

(6) Local program design, administration, and/or financing.

v) Attributable Implementation Costs of the Corporation.

2) **General and Administrative Costs:** costs incurred for the common objectives of all CPCNH Members that are not incurred specifically in connection with a particular Project, Project Contract, or Member Service. Typical costs in this category, which may be fully or partially defined as General and Administrative Costs, include:

a) Administrative offices.

b) CPCNH-wide financial management.

c) Business services.

d) Budget and planning.

e) Personnel management.

f) Central management information systems and operations.

g) General management of CPCNH, such as for strategic direction and Member affairs, Board functions, accounting, procurement, and legal services; operation and maintenance expense; depreciation and use allowances; and interest costs.

h) Attributable Implementation Costs of the Corporation.

3) **Direct Project Costs** are costs incurred for a particular Project pursuant to a Project Contract for a specific Member and/or CPA, or subset thereof, that are not allocated to General and Administrative Costs, to the extent appropriately assigned to specific projects pursuant to Section 4 of Article V of the JPA. These projects can take on many forms but carry a distinct attribute that they are defined by a specific Project Contract entered into by Members participating in particular projects. As such, Direct Project Costs are identified by contract for recovery from the Members that are signatories to the Project Contract.

ARTICLE IX
ALLOCATION OF COSTS

Costs directly or indirectly incurred by CPCNH relating to (1) the CPA Member Services elected by the Member pursuant to Exhibit C, (2) General and Administrative Costs of the Corporation, and (3) the Project Contracts entered into by the Member, if any, will be allocated to the Member in accordance with this Article IX. Refer to Exhibit B for a reference table summarizing these costs and allocation methodologies.

1) **CPA Member Services Costs.** Services required to undertake and provide CPA Member Services are allocated to Member CPAs pursuant to cost causation principles, to the extent reasonably practical, as described herein.

a) **CPA Power Supply Costs.** Each Member will be allocated all costs incurred by CPCNH attributed to the provision of all-requirements electricity supply to the retail customers of said Member's CPA, inclusive of the cost of financial products related to portfolio risk management, as follows:

i) For the net costs attributable to the provision of all-requirements electricity supply to retail customers for each Member CPA:

(1) Where retail customer usage on a temporal and/or geographically specific basis is the determinant of costs:

(a) Actual metered customer electricity usage will be employed to the extent reasonably practical for each Member and to the extent such usage is used for load settlement purposes with ISO-NE ("actual usage").

(b) Estimated or profiled electricity usage will be employed only to the extent that actual metered customer electricity usage is not reasonably available or is not used for load settlement purposes with ISO-NE for said Member.

(2) Where retail customer usage on a temporal and/or geographically specific basis is not the determinant of costs, Members will be allocated net costs on a pro rata volumetric usage basis.

ii) For costs incurred pertaining to financial products related to portfolio risk management, net costs may be allocated <u>either to all Members</u> on a pro rata volumetric usage basis <u>or to each Member</u> based upon either their actual electricity usage, if reasonably available, or alternatively, estimated, or profiled electricity usage.

iii) For costs incurred pertaining to any other power supply related products and services authorized by each Member CPA, net costs will be allocated to said Member CPAs based on a reasonable determination of the cost of providing that service.

b) **CPA Operational Costs.** Each Member will be allocated all costs incurred by CPCNH related to undertaking and providing CPA service on behalf of said Member that are not CPA Power Supply Costs, as follows:

i) For costs attributable to staff, overhead, legal, banking, technical, regulatory, and financial services, costs will be allocated to all Members on a pro rata volumetric usage basis.

ii) For costs incurred pertaining to compliance requirements:

(1) Costs reasonably attributable to each Member will be allocated to said Member.

(2) Costs that are not reasonably attributable to any one Member will be allocated to all Members on a pro rata volumetric usage basis.

iii) For financing and credit charges incurred for the provision of all-requirements electricity supply, and operating costs hereunder, costs may be allocated <u>either to all Members</u> on a pro rata volumetric usage basis <u>or to each Member</u> based upon their actual usage, if reasonably available, or alternatively, estimated, or profiled electricity usage.

iv) For costs incurred from third-party providers of services under contract with CPCNH:

(1) Services charged based on a metric or fee structure that can be reasonably applied to an individual Member basis will be allocated to each Member on that basis.

(2) Services charged based on a metric or fee structure that cannot be reasonably applied on an individual Member basis will be allocated to all Members on a pro rata volumetric usage basis.

<u>2) General and Administrative Costs.</u>

a) Each Member will be allocated General and Administrative Costs on a pro rata basis in accordance with the following formula: Member CPA's Annual Retail Electricity Load divided by all Member CPAs' Annual Retail Electricity Load.

i) "Annual Retail Electricity Load" means the annual amount of metered electricity delivered to retail consumers and supplied through the Member CPA during the most recent 12 whole months.

ii) If less than 12 whole months of load have been supplied through the Member CPA, the calculation of a Member's Annual Retail Electricity Load shall be as follows:

(1) Within a CPCNH Fiscal Year, the Member CPA's allocation of General and Administrative Costs shall initially be based on a reasonable forecast provided by CPCNH of the Member CPA's load for the duration of the Fiscal Year divided by all Member CPAs' forecast Annual Retail Electricity Load for that Fiscal Year.

(2) After the close of the CPCNH Fiscal Year, to the extent reasonably practical, such forecasts shall be reconciled to the Member CPA's actual load over the Fiscal Year divided by the total of actual loads for all Member CPAs for that Fiscal Year.

3) **Direct Project Costs.** Costs incurred for a particular Project pursuant to a Project Contract will be recovered pursuant to the Project Contract that governs Member cost responsibility for the Project. Nothing contained in a Project Contract shall obligate non-participating Members in any respect with the Project. If CPCNH incurs additional costs for a particular Project, then:

a) CPCNH shall provide notice to the Project Committee in question regarding the date upon which the Project Committee must vote upon the matter of how to fully allocate such additional costs amongst participating Members, which shall be considered a Project Matter for this purpose, and CPCNH shall allocate costs pursuant to an affirmative vote by the Project Committee thereof.

b) In the absence of an affirmative vote by the Project Committee thereof, CPCNH shall allocate such additional costs to each Member in proportion to their participation share allocation for the Project.

ARTICLE X
GENERAL TERMS & CONDITIONS

The Joint Powers Agreement carries with it several elements with which this Cost Sharing Agreement shall hold generally consistent but apply specifically to this Cost Sharing Agreement.

Limitations of Liability

As provided for in Article XII of the JPA, *"No debt, liability, or obligation of the Corporation shall be a debt, liability, or obligation of any Member unless otherwise specified and agreed to by individual Members under a Cost Sharing Agreement or Project Contract under this Agreement."*

Indemnification

This Cost Sharing Agreement is a continuation of the authority in the Joint Powers Agreement, and as such, its indemnification language applies (By-Laws, Article 13.1):

> *"Each Member (including its governing body), Member representative, Director, Officer, committee member, employee, assignee, or agent of CPCNH, (and the irrespective heirs, executors and administrators), shall be indemnified and held harmless by CPCNH against any and all claims, demands, losses, costs, penalties, expenses (including attorneys' fees), judgments, damages and liabilities reasonably incurred by, or imposed upon them in connection with any action, suit or proceeding to which*

they may be made a party or with which they shall be threatened, by reason of their being, or having been, a Member, Member representative, Director, Officer, committee member, employee, assignee, or agent of CPCNH (whether or not they continue to be a Member, Member representative, Director, Officer, committee member, employee, assignee, or agent of CPCNH at the time such action, suit or proceeding is brought or threatened), arising in whole or in part, directly or indirectly from conduct in which such Member, Member representative, Director, Officer, committee member, employee, assignee, or agent has engaged in good faith. However, no such indemnification shall apply in relation to any matter involving (i) a breach of their duty of loyalty to CPCNH; (ii) acts or omission which are not in good faith or which involved intentional misconduct or a knowing violation of law; or (iii) a transaction from which the Director, Officer, Member representative, committee member, employee, assignee, or agent derived an improper personal benefit. In the event of settlement of any such action, suitor proceeding brought or threatened, such indemnification shall be limited to matters covered by the settlement as to which CPCNH is advised by counsel that such Member, Member representative, Director, Officer, committee member, employee, assignee, or agent is not liable for misconduct as such. The foregoing right of indemnification shall be in addition to any rights to which any Member (including its governing body), Member representative, Director, Officer, committee member, employee, assignee, or agent may otherwise be entitled."

Further, CPCNH shall, "*Defend, hold harmless, and indemnify, to the fullest extent permitted by law, each Member from any liability, claims, suits, or other actions.*" Articles of Agreement of the Corporation, Article 7.21.

Dispute Resolution

This Cost Sharing Agreement affirms the dispute resolution approach defined in Article XVIII, Section 2 of the JPA, and the Member hereby agrees to extend this provision in support of the Cost Sharing Agreement:

"The Members and the Corporation shall make reasonable efforts to settle all disputes arising out of, or in connection with, this Agreement. Before exercising any remedy provided by law, a Member or Members and the Corporation shall engage in nonbinding dispute resolution or in a manner agreed upon by the Member or Members and the Corporation. The Members agree that each Member may specifically enforce this provision, Article XVI, Section 2, Dispute Resolution. In the event that dispute resolution is not initiated or does not result in a resolution within 60 days after a written request for dispute resolution, any disputing Member or the Corporation may pursue any remedies provided by law."

Continuing Obligations: Participant Withdrawal and Obligations or Buyout Provisions

Continuing obligations shall be pursuant to the same terms for continuing obligations as provided for under Article IV, Section 6 of the JPA:

"Any withdrawn or terminated Member shall continue to be liable for its obligations under any Project Contract and Cost Sharing Agreement(s) for the remaining term of any such Project Contract or Cost Sharing Agreement. The Member's equity or deficit position while a participant in any Project Contract will continue to be reflected in the records and reports of the Corporation. The Corporation may withhold funds otherwise owing to the Member or may require the Member to deposit sufficient funds with the Corporation, as reasonably determined by the Board, to cover the Member's liability for the costs described herein. Any amount of the Member's funds held on deposit with the Corporation above that required to pay any liability or obligation shall be returned to the Member."

ARTICLE XI
TERM

This Agreement shall be deemed to have been in effect commencing upon the date the Member became a Member of CPCNH following execution of the CPCNH Joint Powers Agreement. This Agreement shall continue in full force and effect until terminated by the earlier of (1) dissolution and liquidation of the Corporation, and distribution of any net proceeds, as provided for in Article XI of the By-Laws or (2) the later of (a) withdrawal or involuntary termination of the Member from the Corporation, as provided for in Article 4 and 5 of the JPA, subject to any continuing obligations, as provided for in Article 6 of the JPA, or (b) as otherwise specified in this Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and attested by their respective officers thereunto duly authorized:

MEMBER: ________________________________

By: ________________________________

Title: ________________________________

Name: ________________________________

Date: ________________________________

ATTESTATION: ____________________________
Clerk

COMMUNITY POWER COALITION OF NEW HAMPSHIRE

By: ________________________________
Chair of the Board of Directors

Name: ________________________________

Date: ________________________________

ATTESTATION: ____________________________
Secretary of the Board

APPROVED AS TO FORM: ____________________
General Counsel to the Board

EXHIBIT A: COST SHARING PRINCIPLES

1) **CPCNH's Joint Powers Agreement, Article V,** defines certain cost sharing principles, which are provided below for the Member's reference, and Sections 3-7 thereunder are expressly incorporated herein**:**

ARTICLE V
COST SHARING PRINCIPLES

SECTION 1. Fiscal Year. *The fiscal year shall be the calendar year, subject to the Board's discretion to amend the Fiscal Year. Before changing the Fiscal Year, the Board shall confer with the Treasurer and may confer with the auditor.*

SECTION 2. Budget. *The budget will be established pursuant to the terms reflected in the By-Laws.*

SECTION 3. Cost Sharing Agreements. *An agreement shall be entered into between the Corporation and each respective Member, uniform in all material respects, except with regard to the scope of Member services and Project Contracts that each Member selects to participate in and pay for, to ensure that the costs, expenses, debts, and liabilities ("Costs") directly or indirectly incurred by the Corporation on such Member's behalf are recovered through said Member's CPA revenues, or from revenues from grants or other third-party sources. Such Costs shall be classified as:*

> ***(a) CPA Member Services Costs****: Costs incurred to provide the Complete Service Bundle, or such services that CPCNH offers, shall be recovered directly from Member(s) for the period they contract to receive such service(s). The Complete Service Bundle will include those services CPAs will require to undertake and provide Electric Aggregation Plans and Programs, such as: power supply procurement and management, data and billing, and customer service;*
>
> ***(b) General and Administrative Costs****: Costs described in Article V, Section 4 are incurred for the common objectives of all Members of the Corporation, and are not incurred specifically in connection with a particular Project, Project Contract, or Member Service and shall be allocated to, and recovered from, each Member on a pro rata basis in accordance with the following formula: Member CPA's Annual Retail Electricity Load divided by all Member CPAs' Annual Retail Electricity Load; and*
>
> ***(c) Direct Project Costs****: Costs incurred for a particular Project pursuant to a Project Contract shall be recovered directly from the Member(s) that participate in a particular Project or pursuant to the Project Contract that governs Member cost responsibility for the Project.*

SECTION 4. General and Administrative Costs. *General and Administrative Costs include those that have been incurred for the general operation and administration of the Corporation, and other expenses of a general character, including but not limited to Costs relating to: administrative offices that serve the Corporation; Corporation-wide financial management, business services, budget and planning, and personnel management; operations of the Corporation's central management information systems; general management of the Corporation, such as strategic direction and member affairs, Board functions, accounting, procurement, and legal services; operation and maintenance expense; depreciation and use allowances; and interest costs.*

General and Administrative Costs do not include Costs that relate solely to, or are incurred by, the Corporation for CPA Member Services or as a result of any specific Project or Project Contract. The intent of the Members is to ensure that all Costs incurred by the Corporation that are directly related to CPA Member Services will only be paid by the Members receiving such services or for any specific

Project will be paid only by the Project Participants of that specific Project. As such, when an activity or cost generally included within the General and Administrative Cost category benefits CPA Member Services, a specific Project or Project Contract, or is performed or budgeted for a specific Project or Project Contract, an appropriate adjustment shall be made to assure that the proper portion of the Cost of such activity is categorized and allocated as CPA Member Services costs to a Member receiving such service, or as a Direct Project Cost to the Project Participants, subject to Cost allocation under the applicable Project Contract. The Members intend that all Costs of the Corporation that are not directly assigned for recovery to CPA Member Services, a specific Project or Project Contract will be recovered as General and Administrative Costs.

SECTION 5. Member Advances, Contributions and Repayment. *Upon the request or approval of the Board, any Member may make payments, advances, or contributions to the Corporation for any and all purposes set forth herein, and may contribute personnel, equipment or property, in lieu of other contributions or advances, to assist in the accomplishment of one or more of such purposes. All such payments, advances or contributions, whether in cash or in kind, shall be made to, and may be disbursed or used by, the Corporation. Except as otherwise specified in contracts with Members by the Board, the approved advances will be treated as indebtedness of the Corporation and shall be payable and repaid as such.*

SECTION 6. Refunds. *No Member that withdraws or is terminated shall be entitled to a refund of any payments made in connection with General and Administrative Costs.*

SECTION 7. Funding of Initial Costs*. Any Members that have funded activities necessary to implement the Corporation may request that the Board consider reimbursing said Members for said costs over a reasonable time period and shall provide such documentation of costs paid as the Board may request.*

2) **CPCNH's Articles of Agreement,** under the Joint Powers Agreement, provide for the powers of the Corporation that are expressly incorporated herein, including, as follows:

7.13 *Incur debts, liabilities, and obligations, provided that all debts, liabilities and obligations shall be non-recourse to any and all of the Members unless expressly agreed to by such Members through a Member's Cost Sharing Agreement or Project Contract as those terms are defined in the JPA;*

7.14 *Issue revenue bonds and incur other forms of indebtedness including but not limited to loans from private lending sources, pursuant to NH RSA 33-B, RSA 53-E, RSA 53-F, and RSA 374-D, provided that any such bond or debt issuance is approved by participating Members' governing and legislative bodies as required by statute.*

EXHIBIT B: COSTS ALLOCATION REFERENCE TABLE

Classification	Cost Factor	Allocation Method
General & Administrative	All Costs	$/MWh forecasts and annual true-up to pro rata share of actual "Annual Retail Electricity Load" (JPA defined term)
Direct Project	Costs identified in Project Contracts	As specified in Project Contracts
	Unanticipated Costs	As directed by Project Committee vote; alternatively, Member Project Contract participation share %
CPA Member Services *Power Supply*	All Requirements Electricity	Member CPA actual cost
	Net Hedging	$/MWh (across all CPAs) or actual cost (for each CPA)
	Optional / Opt-Up Products	Member CPA actual cost
CPA Member Services *Operations*	Allocated Staff, Overhead & Misc. Svc	$/MWh
	Member CPA Compliance Costs	Member CPA actual cost
	General Compliance Costs	$/MWh
	Financing and Credit Support	$/MWh (across all CPAs) or actual cost (for each CPA)
	Portfolio & Risk Management Services	$/MWh
	ISO-NE Load Serving Entity (LSE) Services	$/MWh
	Marketing & Community Services	$/MWh
	Customer Notifications	$/Notice
	Data Management & Billing Services	$/Meter
	Call Center & Customer Services	$/Meter
	Local Program Design, Admin & Finance	$/MWh (across all CPAs) or actual cost (for each CPA)
CPA Member Services *Elective Services*	Additional services as authorized by the Board	

I: COMPLETE SERVICE BUNDLE

AS AUTHORIZED BY THE BOARD OF DIRECTORS ON DECEMBER 27, 2022

MEMBER ENROLLMENT PERIOD: OPEN

COMMUNITY POWER COALITION OF NEW HAMPSHIRE

CPA MEMBER SERVICES CONTRACT: COMPLETE SERVICE BUNDLE

This CPA Member Services Contract ("Contract") is made and entered into this __ day of _________, ____, ("Effective Date") by and between the ___________________________________, a subdivision of the State of New Hampshire, ("the Member") and the Community Power Coalition of New Hampshire ("CPCNH" or "Corporation"), pursuant to the provisions of the CPCNH Joint Powers Agreement ("JPA") (collectively, "Parties").

RECITALS

WHEREAS, __________________________ desires to implement Community Power Aggregation ("CPA") service to provide all-requirements electricity for its residents and businesses pursuant to New Hampshire Revised Statutes Annotated ("RSA") 53-E, the Community Power Act, which found "*it to be in the public interest to allow municipalities and counties to aggregate retail electric customers, as necessary, to provide such customers access to competitive markets for supplies of electricity and related energy services*";

WHEREAS, CPCNH is a nonprofit all-requirements Joint Powers Agency and governmental instrumentality operating pursuant to the Joint Powers Agreement entered into by the ___________________________ on the ___ day of _________, ____, for the purpose of jointly exercising the powers granted to municipal corporations pursuant to NH RSA 33-B, NH RSA 53-E, NH RSA 53-F, and NH RSA 374-D (including, by reference, NH RSA 33) in accordance with RSA 53-A, Agreements Between Governments;

WHEREAS, CPCNH is jointly controlled and governed by its Members, united as a single entity to operate for the mutual benefit of the Members collectively, to promote the common good, general welfare, economic vitality, and prosperity of local communities in New Hampshire, to use the powers and authority granted by the Members to gain economies of scale and scope to launch, operate, and evolve CPA programs, and to advance other energy and climate policies and actions on behalf of the Members;

WHEREAS, the Cost Sharing Agreement between __________________________ and CPCNH permits __________________________ to enter into agreements for CPCNH to provide certain CPA Member Services, and ensures that the costs, expenses, debts, and liabilities directly or indirectly incurred by CPCNH on __________________________'s behalf are recovered through __________________________'s CPA program revenues, or from grants or other third-party sources;

WHEREAS, __________________________ adopted an Electric Aggregation Plan on the __ day of _________, ____, and desires CPCNH to finance, launch, and operate a CPA on its behalf;

WHEREAS, this Contract for the Complete Service Bundle shall be inclusive of all services, expertise, and financial support that __________________________ requires to "*undertake and provide Electric Aggregation Plans and Programs, such as: power supply procurement and management, data and billing, and customer service*" in accordance with to Section 3(a) of Article V of the JPA; and

WHEREAS, __________________________ hereby endorses and adopts CPCNH's Data Security and Privacy Policy, Energy Portfolio Risk Management Policy, Retail Rates Policy, and Financial Reserves Policy, as may be amended from time to time by CPCNH's Board of Directors, to provide for the security of individual customer information, procurement of all-requirements electricity supply, price risk management, prudent budgeting and rate setting, and the collection of financial reserves by CPCNH on __________________________'s behalf for the term of this Contract.

NOW, THEREFORE, in consideration of mutual benefits, covenants, and considerations hereinafter set forth, CPCNH and the Member hereby agree as follows:

ARTICLE I
Purpose

1. Definition. The Complete Service Bundle, pursuant to Section 3(a) of Article V of the Joint Powers Agreement ("JPA"), is inclusive of all services, expertise, and financial support that Member CPAs require to "*undertake and provide Electric Aggregation Plans and Programs, such as: power supply procurement and management, data and billing, and customer service*" (hereafter, the "Services").

2. Purpose. The Board of Director's ("Board") overarching purpose, in offering the Complete Service Bundle, shall be to achieve a greater financial benefit for every Member collectively than any one Member would be able to achieve individually, by creating and sustaining: (i) public oversight, transparency, and unbiased expert advice to decision-makers regarding operations and planning; (ii) administrative cost efficiencies and business model innovations; (iii) a sustainable balance, and equitable consideration, between short-term cost-savings and long-term fiscal stability; (iv) powerful representation at the New Hampshire legislature and Public Utilities Commission, including on matters regarding market-enabling reforms and infrastructure investments that impact the Membership's energy future; and (v) the acceleration and development of cost-effective local programs, advanced rate structures, new customer services, and local energy project developments that create new financial value and resiliency for participating Members, at the community-level, and for customers, in terms of their total energy costs, including by lowering transmission and generation capacity charges in addition to wholesale energy purchases.

3. Endorsement. By executing this Contract, the Member endorses this collective purpose for the Services.

ARTICLE II
Decision-Making Framework

1. Acknowledgement. The Member acknowledges that (i) efficient administration imposes limitations to individual Member choice, (ii) procurement and rate setting will present inherent trade-off decisions, (iii) collective decision-making must therefore be relied upon to satisfy and balance the divergence of the Members' prioritization of competing objectives over the short- to long-term, and (iv) achieving the above-stated purpose therefore requires a decision-making framework to define which decisions must be made collectively versus left up to each Member.

2. Establishment of Decision-Making Framework. The Member hereby endorses and adopts CPCNH's Data Security and Privacy Policy, Energy Portfolio Risk Management Policy, Retail Rates Policy, and Financial Reserves Policy ("Policies"), which, in conjunction with and pursuant to the Joint Powers Agreement, establishes an appropriate framework that balances the Member's individual versus collective decision-making considerations regarding CPCNH's provision of services under this Contract.

Appendix A summarizes how the framework is intended to function during initial implementation of the Member's CPA, specifically identifying which decisions will be made collectively, and where the Member may make or delegate certain key decisions, including regarding: (i) choice of whether to procure power initially on the Member's behalf, (ii) choice of rate products offered to the Member's customers, (iii) choice of collecting additional financial reserves for the Member's sole use, and (iv) choice of termination of this Contract, before and after enrollment of the Member's customers.

3. Amendment of Decision-Making Framework. The Member agrees that the Policies are integral to CPCNH's provisions of Services under this Contract, to provide for the security of individual customer information, procurement of all-requirements electricity supply, price risk management, prudent budgeting and rate setting, and the collection of financial reserves on behalf of participating Members. The Member acknowledges that the Board or the Membership of CPCNH may amend the Policies from time to time, and that the Member, pursuant to the Joint Powers Agreement, may observe, inform, and/or participate directly on the Board and in committee decision-making processes relevant to the provision of the Services. The Member agrees that CPCNH shall update this Contract to reflect any amendments to CPCNH policies, which shall be incorporated herein and not constitute an amendment to this Contract.

Appendix B summarizes the Policies and amendment procedures and is provided for the Member's reference. Current Policies are available to the Member upon request and publicly available on CPCNH's website.

ARTICLE III
Limitation of Member Liability

The Member is not liable for the debts, liabilities, or obligations incurred by CPCNH to provide the Services under this Contract.

ARTICLE IV
Delegation of Authority & Commitment to Act

1. Delegation of Authority. The Member hereby expressly authorizes and delegates authority to CPCNH, with immediate effect, to act as an agent of the Member in all circumstances and capacities required to provide the Services as contemplated under this Contract.

2. **CPCNH Commitment to Act.** CPCNH shall take all actions required to provide for the timely delivery of the Services, including by: ensuring effective community engagement and customer noticing, completion of registration requirements with utilities, and compliance with statutory and rule requirements to the provision of CPA service; negotiating and executing contracts for credit support and all-requirements electricity to satisfy the Member's load obligations and manage price risk; setting rates to satisfy the Member's revenue requirements and obligations under this Contract; arranging for revenues received from utilities and CPA customers to be deposited into CPCNH's secured revenue account and pledged to CPCNH's financiers and supplier counterparties; providing for general administration and oversight of the Services; and accruing and tracking financial reserves on behalf of the Member.

2. Member Commitment to Act. The Member agrees to take and perform all acts required to effectuate the delegation of authority to CPCNH as contemplated herein, including by promptly making all necessary filings with any Governmental Authority or Electric Distribution Utility upon CPCNH's request. If requested by CPCNH, the Member shall assist CPCNH in obtaining information regarding the Member's customers from the Electric Distribution Utility. The Member agrees to provide to CPCNH all data, including reports, records, and other information, in the Member's possession, or cause to be provided data not in the Member's possession, which may reasonably facilitate the timely performance of the Services described hereunder.

ARTICLE V
Professional Ability & Service Contracts

CPCNH relies upon qualified service providers, consultants, and personnel to provide the Services jointly, at a beneficial economy of scale, across all Member CPAs. Services will be performed by qualified staff, contractors, consultants, Member Representatives and/or volunteers, as determined by the CPCNH Board of Directors or its designee, and carried out in a competent, professional, and satisfactory manner, in accordance with the standards prevalent in the industry and any applicable policies adopted by the Board.

The Member acknowledges and accepts that the extent of CPCNH's services under this Contract, as a start-up power agency, are predicated on (i) contracts CPCNH has executed with service providers hired through competitive solicitations, (ii) CPCNH's internal capacity, including staff capacity commencing with an anticipated hire of a CEO in March 2023, and (iii) the timeline by which distribution utilities implement Puc 2200 rules, which have not been fully implemented as of December 2022.

CPCNH's current contacts with service providers and consultants are available through CPCNH's website and listed in Appendix C.

ARTICLE VI
Electric Aggregation Plan

1. Acknowledgement. The Member acknowledges that the terms and requirements of the Member's Electric Aggregation Plan may prevent CPCNH from being able to commence provision of some or all the Services.

2. Mutual Commitments. CPCNH commits to promptly review the Member's Electric Aggregation Plan to assess any impact on CPCNH's provision of Services, and to identify and recommend any amendments prudent or necessary thereof. Member commits to promptly consider adoption of any such amendments. During the term of this Contract, the Parties will coordinate on, and the Member may seek CPCNH's advice regarding, any amendments to their Electric Aggregation Plan and shall strive to align any amendments thereto with the common interest and intent of this Contract, the underlying Services, and consistent with applicable statutes or regulations or with CPCNH's provision of the Services.

ARTICLE VII
Term; Procurement and Termination Elections; Financial Reserves

1. Term. The term of this Contract shall commence on the Effective Date and expire upon the termination of the Services as set forth herein.

2. Termination Prior to Commencement of Procurement. The Member may elect to terminate this Contract with immediate effect by submitting written notice to CPCNH, provided that CPCNH has not authorized entering into transactions for power on behalf of the Member's CPA.

3. Election to Delay Initial Procurement.

The Member's Authorized Officer, if authorized hereunder, may elect to delay commencing procurement on behalf of the Member's CPA during the Risk Management Committee meeting convened to authorize the first transactions entered into by CPCNH on the Member's behalf, provided that such election is made prior to the vote authorizing such procurement.

The Committee shall call for any such elections by the Member to be made verbally, after review and discussion of current market conditions and corresponding rate forecasts, and prior to the Committee's vote on whether to authorize procurement. Verbal elections made at the meeting by the Authorized Officer shall be immediately considered effective by CPCNH and promptly followed by written confirmation from the Authorized Officer to CPCNH and the Member's Principal Representatives.

4. Notice of Termination before and after First-Year Operations.

CPCNH's Energy Portfolio Risk Management Policy provides that "*hedging shall not extend beyond 36 months from the date that CPCNH first begins providing electricity service to CPA customers, until one year from that date*." After the first year of operations, CPCNH may authorize entering into forward hedging transactions extending up to 36 months out, on a rolling basis, to serve the collective load of all Member CPAs taking Service.

At any time during the 12-month period after the initial launch of CPCNH's power supply service, commencing on the date when CPCNH first supplies electricity to the retail customers of any Member CPA, the Member may submit written notice to terminate the Services on the first day of the month thirty-six (36) months following the date when CPCNH first supplied electricity to the retail customers of any Member CPA.

At any time after the 12-month period after the initial launch of CPCNH's power supply service, the Member may terminate this Contract by submitting written notice at least thirty-six (36) months in advance of the termination date.

5. Early Termination after Commencement of Service.

The Member may also, submit notice that it wishes to terminate this Contract at an earlier date than as provided for above. Upon receipt of such notice, CPCNH shall promptly assess and inform the Member of the minimum waiting period under which the Member would have no costs for withdrawal. Costs of withdrawal at an earlier date include, but are not limited to, losses from the resale of power contracted for by CPCNH to serve the Member CPA's load. The waiting period will be set to the minimum duration such that there would be no costs transferred to the remaining Members that have elected the Services.

Alternatively, the Member may elect to terminate this Contract during the waiting period, provided that the Member first deposits sufficient funds with CPCNH, as reasonably determined by CPCNH and approved by a vote of the Board of Directors, to cover the Member's liability for the costs described above. The Member may elect to use its allocated share of Joint Reserves or its Discretionary Reserves, collected on Member's behalf and held by CPCNH, for this purpose.

6. Return of Allocated Joint Reserves. After the effective date of the Member's termination of this Contract, any amount of the Member's allocated share of Joint Reserves above that which is required to pay any costs incurred by CPCNH through the date of termination on behalf of the Member shall be allocated back to the Member for use as Discretionary Reserves, pursuant to CPCNH's Financial Reserves Policy.

ARTICLE VIII
Authorized Officer for Member Service Decisions

1. Authorized Officer. The Member may designate an Authorized Officer to take specific actions, as defined in Section 2: Authorizations below, on behalf of the Member pursuant to this Agreement and the Policies. The Member's Authorized Officer, as specified in the Member's Electric Aggregation Plan, or otherwise delegated authority by the governing body hereunder, is:

Title	Name	Phone	Email

The Member's Principal Executive Officer may specify a new Authorized Officer by submitting written notice by electronic mail to CPCNH's Principal Representative, which shall be promptly acknowledged and effective thereof, and such updates to this Contract shall not be considered an amendment.

2. Authorizations. The Authorized Officer may act on behalf of the Member to instruct and authorize CPCNH only on the matters and to the extent explicitly authorized by the Member hereunder. The Member hereby delegates the following authorities to the Authorized Officer to act on the Member's behalf (specify "yes" or "no"):

a) Pursuant to Article VI, Section 3, the Authorized Officer may elect to delay commencing procurement: ___;

b) Pursuant the Retail Rates Policy, the Authorized Officer may specify default and optional products: ___; and

c) Pursuant the Retail Rates Policy, the Authorized Officer may set Discretionary Reserve adders: ___.

3. Disclaimer. CPCNH shall have no liability to the Member for actions taken in reliance on authorizations or instructions received by the Authorized Officer as contemplated hereunder or in compliance with the Policies. Until such time as the Member instructs CPCNH in writing that the individual above, if any, is no longer an "Authorized Officer" hereunder, CPCNH shall have no duty to inquire as to the authority of such Authorized Officer to provide the authorizations or instructions in connection with the Services.

4. Alternatives. If an Authorized Officer is not identified hereunder, or if CPCNH is at any time unsure as to the identity of the Authorized Officer hereunder, or regarding a decision on any matter for which the Member has not delegated authority to the Authorized Officer under Section 2: Authorization, CPCNH may request written instructions from the Member's Principal Executive Officer, or the Member's governing body, pursuant to any applicable Policy, as to the course of action to be adopted by CPCNH. CPCNH shall be entitled to conclusively rely upon such written instructions thereof.

ARTICLE IX
Principal Representatives

The Member's Principal Representatives, for purposes of communicating with CPCNH on any matter associated with the performance of the Services set forth hereunder, in addition to the Authorized Officer, shall be:

Title	Name	Phone	Email
Member Representative			
Alternate Representative			
Principal Executive Officer			
______________________ _			

CPCNH's Principal Representative, for purposes of communicating with the Member on any matter associated with the performance of the Services set forth hereunder, shall be CPCNH's Chief Executive Officer, or in the absence thereof, the Chair of the Board of Directors.

Title	Name	Phone	Email
Chief Executive Officer			
Board Chair			

The Parties shall update the Principal Representatives identified in this section by submitting written notice by electronic mail to the other Party, which shall be promptly acknowledged, and such updates shall not be considered an amendment to this Agreement.

ARTICLE X
Amendments

Article IV of the Cost Sharing Contract requires that "*all executed [Member Services] Agreements between CPCNH and each Member that has elected the same service must be uniform in all material respects*"; any material amendments to this Contract are subject to approval and incorporation by all Members that have executed Member Services Contracts for this Complete Service Bundle. CPCNH may update Appendices, and this Contract to incorporate any amendments to the Policies hereafter, neither of which constitute an amendment to this Contract.

ARTICLE XI
Attestation of Signing Authority; Execution

The Member has taken and performed all acts necessary and has received all necessary authorizations and approvals required to enter into this Contract and to bind the Member to the terms herein. The Member has attached a resolution of its governing body authorizing the execution of this Contract by the authorized signatory below, and any other authorization documents thereof. The authorized signatory represents that (i) this is a true, complete, and accurate list of all such necessary authorizations, approvals, actions and filings, (ii) the Member has provided true, complete, and accurate copies of the authorization documents to CPCNH as of the Effective Date, and (iii) other than the authorization documents, there are no other authorizations, approvals, filings or other actions required for Member to enter into this Contract, perform its obligations hereunder, and delegate authority to CPCNH to perform the Services.

IN WITNESS WHEREOF, the Parties hereto have caused this Contract to be executed and attested by their respective officers thereunto duly authorized:

MEMBER: ____

By: ________________________________

Title:

Name:

Date:

ATTESTATION: ______________________________
Clerk

COMMUNITY POWER COALITION OF NEW HAMPSHIRE

By: ________________________________
Chair of the Board

Name:

Date:

ATTESTATION: ______________________________
Secretary of the Board

APPROVED AS TO FORM: _____________________
General Counsel to the Board

Authorization Documents:

1. Resolution of the Member's governing body authorizing the signatory's execution of this Member Service Contract, inclusive of all individuals named and duly empowered hereunder.

2. The Member's Approved Electric Aggregation Plan.

Appendix A
Decision-Making Framework: Member CPA Implementation

This Appendix summarizes how the decision-making framework for the Complete Service Bundle is intended to function during initial implementation of the Member's CPA. It identifies which decisions will be made collectively, and where the Member may make or delegate certain key decisions, including regarding: (i) choice of whether to procure power initially on the Member's behalf, (ii) choice of rate products offered to the Member's customers, (iii) choice of collecting additional financial reserves for the Member's sole use, and (iv) choice of termination of this Contract, before and after enrollment of the Member's customers.

Activities and decision-making are presented with reference to applicable Policy, in approximate sequential order:

Pursuant to this Contract:

1. CPCNH will assist or provide for the Member's public engagement efforts to market the program in advance of customer enrollment, and work with the Member to finalize marketing materials. The Member will receive a program logo, a content-populated website hosted on a Dot Gov address as follows: [Member].CommunityPowerNH.gov, and template marketing materials including FAQs, flyers, two-pagers, and public presentation decks.

2. The Member's committees, staff, and other individuals involved in the Member's public engagement will be provided with a Public Engagement Campaign handbook, offered training in media and public engagement, and provided direct support to carry out an effective campaign in advance of launch, including for the purpose of carrying out the public meeting required after customer notifications are sent.

3. CPCNH will complete all required utility testing and registration requirements, meet other statutory and rule requirement obligations, implement customer service functions, such as Interactive Voice Recording and live-agent call center services, and design, print, mail, and process customer opt-in and opt-out notices sent on behalf of the Member.

Pursuant to the Energy Portfolio Risk Management Policy, or, as noted, pursuant to this Contract:

4. The decision of whether or not to procure power, by commencing the execution of hedges in advance of the target launch date for any new Member CPAs, is a collective decision made by the Risk Management Committee. The decision is informed by then-current market conditions and the forward-looking analysis and advice of CPCNH's service provider for procurement, price risk forecasting and analysis, and portfolio management.

5. Under this Contract, the Member (1) may terminate this Contract, at any time, before CPCNH has first authorized procurement on behalf of the Member, and (2) may choose to designate an Authorized Officer to elect to delay commencing procurement on behalf of the Member's CPA. The Authorized Officer's election must be made during the Risk Management Committee meeting convened to consider authorizing the first transactions entered into by CPCNH on behalf of the Member, after review and discussion of current market conditions, transaction offers, and corresponding rate forecasts, and prior to the Committee vote.

6. Depending upon market conditions and transaction offers, CPCNH may procure sufficient power on the same day, or the Risk Management Committee may decide to authorize transactions for multiple transaction types, terms, and volumes, on a rolling basis for a period of time, in order to seek price advantages. Regardless, CPCNH will procure and cover its open positions to comply with the Hedge Ratios defined in the Energy Portfolio Risk Management Policy. (Hedge ratios are covered positions expressed as a percentage of load, calculated as fixed price purchases and supply resources divided by forecasted load; maintaining CPCNH's minimum and maximum hedge ratios provides a framework to manage market risk, by limiting CPCNH's net open exposure while allowing flexibility in procurement to maintain competitive rates over time.)

7. After procurement has concluded, rates will be calculated and set at a level that ensures the revenues from Member CPA customers are projected to meet or exceed CPCNH's ongoing operating and capital costs, inclusive of financial reserve targets pursuant to the Financial Reserves Policy.

<u>Pursuant to the Retail Rates Policy, or, as noted, pursuant to this Contract:</u>

8. The Risk Management Committee and Finance Committee shall each convene at least one public meeting to provide for deliberation and public input regarding changes to default rates, prior to rate setting. The CEO (or in the absence of the CEO, the Risk Management Committee, in consultation with the Finance Committee), will then recommend rates to the Board for approval. Advance written notice of Board meetings at which default rates are proposed shall be sent by the CEO or Board Chair to the Member's Principal Executive Officer.

9. The Member may then, in advance of or during the meeting at which rates are approved by the Board, elect to offer different rate products to its customers on a default and opt-in basis, per the framework summarized below:

a) CPCNH shall offer the following rate products and contents to all Members:

PRODUCT	CONTENT *	MEMBER ELECTIONS
Granite Basic	Minimum RPS Content (23.4%)	Default, opt-down/in, or N/A**
Granite Plus	33% Renewable or Carbon Free	Default, opt-up/in, or N/A**
Clean 50	50% Renewable or Carbon Free	Opt-up/in or N/A
Clean 100	100% Renewable or Carbon Free	Opt-up/in or N/A

* Specified percentages are minimums (floors).
** One of these two products must be offered as Default Service.

b) The Member's governing body, or if designated hereunder, the Member's Representative or an alternative Authorized Officer acting on the Member's behalf, may elect:

i) Whether to offer "Granite Basic" or "Granite Plus" as a default product, by customer class or as otherwise determined by the Board and will be advised on the cost implications of such elections by CPCNH's CEO (or Board Chair). Absent any election, "Granite Basic" shall be set the Member's default product. If the Member elects "Granite Plus" as their default product, they may also elect to offer "Granite Basic" as an opt-down choice for customers seeking the most affordable rate product. Absent any election, "Granite Basic" shall be offered as an opt-down/in product.

ii) Whether to offer "Clean 50" and/or "Clean 100" as opt-up/in products. Absent any election, "Clean 50" and "Clean 100" shall be offered as opt-up/in products.

iii) Whether to increase their CPA's rates to include an adder for the accrual and use of Discretionary Reserves, which are financial reserves accrued and allocated for the Member's sole use pursuant to the Financial Reserves Policy.

c) The Member acknowledges that (i) CPCNH may be unable to offer the ability to collect Discretionary Reserves during the initial months of operations following the launch of CPCNH's first Member CPAs, due to system implementation timeline constraints, (ii) the Member's elections are subject to approval by CPCNH's CEO, or in the absence of the CEO, the Board Chair, in advance of or during the meeting at which changes to default rates are approved by the Board.

10. Thereafter, CPCNH's Board and Committees will undertake a variety of activities pursuant to Energy Portfolio Risk Management Policy, Retail Rates Policy, and Financial Reserves Policy designed to ensure continuously monitoring and effective management of CPCNH's power portfolio and rate setting process. The Member may observe, inform, and/or participate directly in these decision-making processes on Board and committees pursuant to the Joint Powers Agreement. The Member will also regularly be afforded the option to decide upon rates in the manner provided for above, in all subsequent rate setting periods, pursuant to the Retail Rates Policy.

11. The Member may elect to terminate this Contract subject to advance notice and satisfaction of obligations thereof, as provided for under this Contract.

Appendix B
CPA Launch Process: Member Elections & Collective Decision-Making

CPCNH's Data Security and Privacy Policy, Energy Portfolio Risk Management Policy, Retail Rates Policy, and Financial Reserves Policy are summarized below, along with amendment procedures, for reference.

Current Policies are available to the Member upon request and publicly available on CPCNH's website.

1. Data Security and Privacy Policy.

CPCNH's Data Security and Privacy Policy defines the specific goals, requirements, and controls necessary to safeguard the confidentiality, integrity, and availability of confidential individual customer information, in compliance with RSA 53-E:4 (Regulation) and RSA 53-E:7 (Aggregation Program); RSA 363:38 (Duties and Responsibilities of Service Providers) and RSA 363.37 (Definitions); and RSA 359-C:20 (Privacy Policies for Individual Customer Data) and RSA 359-C:19 (Definitions); inclusive of procedures that require counsel review of any enacted changes to RSA 359-C (the New Hampshire Right to Privacy Act), RSA 91-A (Access to Governmental Records and Meetings), RSA 363:37-38 (Privacy Policies for Individual Customer Data), RSA 53-A:3 (Agreements Between Government Units, and RSA 53-E (Aggregation of Electric Customers by Municipalities and Counties) or other related statutes that may necessitate, in future, modifying or altering, or otherwise risk negating, the policy.

Note that Members must necessarily comply with applicable statutory and rule requirements prior to accessing individual customer information held in confidence by CPCNH on their behalf.

The Board of Directors may amend the policy by resolution at any time.

2. Energy Portfolio Risk Management Policy.

CPCNH's Energy Portfolio Risk Management Policy outlines the philosophies and objectives of the CPCNH Board of Directors in governing and making decisions necessary to provide the credit support, portfolio analytics, hedging, and daily operating activities required to implement and operate Member CPA power supply services. The Board must approve amendments to the EPRM Policy.

Advance written notice of Board meetings at which changes to the policy are proposed shall be sent to the principal executive officers of each Member by the CEO or Board Chair. Subsequently, any such amendment shall be sent to the principal executive officers of each Member by the CEO or Board Chair.

Pursuant to the policy, CPCNH's Risk Management Committee is responsible for ensuring the development and maintenance of CPCNH's Energy Portfolio Risk Management Regulations (EPRM Regulations) to expand on the roles, strategies, controls, and authorities authorized in the policy to form a comprehensive energy risk management program. After the EPRM Regulations are initially approved by the Board, the regulations may be amended with approval of the CEO, in consultation with the RMC, provided that the CEO sends prompt written notice to the Board of any such amendments.

The Member may directly participate on CPCNH's Board of Directors and Risk Management Committee pursuant to the Joint Powers Agreement.

3. Financial Reserves Policy.

CPCNH's Financial Reserves Policy establishes minimum, target, and maximum levels of cash reserves that will be jointly accrued, used, maintained, and monitored by CPCNH, on behalf of all Members ("Joint Reserves"), and provides for the collection of Joint Reserves in excess of the maximum target joint reserve level to be applied at the discretion of individual Members ("Excess Reserves"). Separately, the policy allows for the collection and use of additional reserves at the sole discretion of each individual Member ("Discretionary Reserves").

The Board of Directors may, by resolution, modify or suspend any provision of the policy for any duration at any time, except that the provisions under the section governing amendments and the section "Rights of Members to Reserve Contributions" may only be modified or suspended by a written amendment unanimously approved by the votes cast at a meeting of the Membership at which a quorum is present. In the event such an amendment is proposed, CPCNH's CEO or Board Chair shall send written notice to the Member Representatives and principal executive officers of each Member at least fourteen (14) days prior to such meeting at which it is to be acted upon. Subsequently, prompt written notice of the effective date of such amendment or suspension shall be sent to the Member Representatives and principal executive officers of each Member by the CEO or Board Chair.

4. Retail Rates Policy.

CPCNH's Retail Rates Policy outlines the requirements, objectives, rate setting authorities, rate setting processes, Member rate product and Discretionary Reserve adder election procedures, and different types of rate structures, products, and product content offered to the Member hereunder.

The CEO, in consultation with the Risk Management Committee and the Finance Committee, or in the absence of the CEO, the Risk Management Committee, in consultation with the Finance Committee, shall recommend default rates to the Board for approval with sufficient notice to be implemented commensurate with regulated default utility rate changes, or otherwise as deemed necessary to support the requirements and objectives of the policy. The Risk Management Committee and Finance Committee shall each convene at least one public meeting to provide for deliberation and public input regarding changes to default rates. The Member acknowledges that CPCNH's Board is required to approve, when necessary to maintain the financial integrity of CPCNH, emergency rate adjustments. Prompt written notice of emergency rate adjustments shall be sent to the principal executive officers of each Member by the CEO, or in the absence of the CEO, the Board Chair.

The Member may directly participate on CPCNH's Board of Directors, Finance Committee, and Risk Management Committee pursuant to the Joint Powers Agreement.

The Board of Directors must approve amendments to the Retail Rates Policy. Advance written notice of Board meetings at which changes to the policy are proposed shall be sent to the principal executive officers of each Member by the CEO. Subsequently, prompt written notice of the effective date of such amendment shall be sent to the principal executive officers of each Member by the CEO

Appendix C

CPCNH Service Contracts

CPCNH's current contracts with all service providers and consultants are accessible online, under "Key Documents" at:

https://www.cpcnh.org/about

EXHIBIT D: TEMPLATE COST ALLOCATION REPORT

[Insert upon commencement of CPA service]

EXHIBIT E: TEMPLATE REPORT GLOSSARY

[Insert upon commencement of CPA service]

EXHIBIT F: PROJECT CONTRACTS EXECUTED BY MEMBER

Energy Portfolio Risk Management, Rates, and Financial Reserves Policies

For Communities, By Communities

COMMUNITY
POWER COALITION
OF NEW HAMPSHIRE

ADOPTED DATE: December 19, 2022

CONTENTS

ENERGY PORTFOLIO RISK MANAGEMENT POLICY

Philosophy, Objectives & Scope

This Energy Portfolio Risk Management Policy (EPRM Policy) outlines the philosophies and objectives of the Community Power Coalition (CPCNH) Board of Directors (Board) in governing and making decisions necessary to provide the credit support, portfolio analytics, hedging, and daily operating activities required to implement and operate Community Power Aggregation (CPA) power supply services.

The Risk Management Committee (RMC) is responsible for ensuring the development and maintenance of CPCNH's Energy Portfolio Risk Management Regulations (EPRM Regulations) to expand on the roles, strategies, controls, and authorities authorized in this policy to form a comprehensive energy risk management program.

Risk Philosophy

As a Joint Powers Agency, CPCNH is in the business of procuring and generating energy for the benefit of its participating Member CPAs. The goal of this policy is to:

- Serve Member CPA needs subject to Board approved risk tolerance limits.
- Provide as much energy supply cost certainty for CPA customers as reasonably possible while maintaining a least cost portfolio.
- Develop and enhance the value of CPCNH and Member CPA assets to meet the financial and local policy goals of the participating Members.

CPCNH recognizes that novel technologies, market dynamics, and regulatory shifts are combining to create new levels and dimensions of risk, and opportunities, that must be integrated into CPCNH's portfolio risk management program.

CPCNH's objective is to develop the least cost, greatest value portfolio to meet load requirements of CPA customers, while maximizing revenues from sales of surplus energy from wholesale and local project resources, and creating new sources of revenue through the intelligent design and integration of price-responsive customer rates, market-enabling products, and local programs (e.g., portfolio optimization).

Unlike a private-sector supplier, CPCNH's primary business purpose is to serve its Members. CPCNH's goal is to be a cost hedger for its Member CPAs load and is therefore precluded by this policy from engaging in purely speculative activities typical to many organizations oriented toward profit maximization.

CPCNH also recognizes that there are additional risks beyond those related to normal power supply operations and hedging activities. CPCNH's goal is to limit, to the extent practicable, exposure to those risks This document serves as a vehicle to describe and define the limits for activities considered as appropriate for CPCNH in a normal course of business of serving loads and procuring power.

Business Activities

CPCNH's primary business is to procure or produce electricity supply to meet CPA customer load requirements. The resource supply portfolio may consist of fixed and variable priced supply contracts of varying lengths, physical assets (such as power plants and distributed energy resources), and agreements for other related supplies and services needed to ensure reliable delivery of electricity to CPA customers.

The objective of the EPRM Policy is to provide a framework for conducting procurement activities that maximize the probability of CPCNH meeting its goals. The policy documents the framework by which CPCNH will:

- Identify risks associated with the procurement of power supply.
- Identify those responsible for administering the various elements of the risk management policy from procurement operations to oversight activities.
- Set parameters and methodologies for managing risk associated with procuring and hedging the power supply portfolio including the specification of authorized products, terms, and transaction limits.
- Provide for the accrual of reserve funds for the purpose of satisfying all financial obligations and objectives associated with management of the portfolio.

The EPRM Policy applies to all power procurement and related business activities that may impact the risk profile of CPCNH and its Member CPAs.

Transacting Objectives

CPCNH's objectives when transacting on behalf of Member CPAs for the procurement of energy and energy related supplies and services are as follows:

1. Meet customer all-requirements electricity requirements, inclusive of all of the electrical energy, capacity, reserves, ancillary services, transmission and distribution losses, congestion management, and other such services or products necessary to provide firm power supply to participants and meet the requirements of New Hampshire's Renewable Portfolio Standard.
2. Provide competitive rates for the participating Member CPAs, and stability and choice for participating customers.
3. Obtain the best available price for power supply while complying with the requirements of this policy and other objectives established by the Board.
4. Develop local renewable, battery storage, and distributed energy projects and customer programs.
5. Manage CPCNH's assets to optimize value.
6. Act to limit exposure to extreme market system changes.
7. Follow effective wholesale counterparty credit management procedures.
8. Develop and maintain financial reserves.

9. Develop and maintain CPCNH's investment grade credit rating.

CPCNH's overall transacting objective is to meet the load requirements of Member CPA customers with an optimized portfolio.

Scope of Policy

This EPRM Policy prescribes the management organization, authority, and processes to monitor, measure and control the risks to which CPCNH is exposed in the normal course of business arising primarily from CPCNH's participation in the wholesale energy markets. CPCNH is exposed to three quantifiable risks:

1. Volumetric risk: load and resource variability.
2. Price risk: market-related cost variability.
3. Counterparty Credit and Collateral Call risk: potential default by a counterparty or requirement to post collateral

This policy applies to all energy and energy related transactions made by CPCNH, and the term "risk management" is herein understood to refer solely to risks related to participation in wholesale energy markets as herein defined.

Specific methodologies used to measure, monitor, and control these risks shall be established by the Risk Management Committee, in accordance with sound utility practices and included in the EPRM Regulations.

From the perspective of risk mitigation, CPCNH's primary objective is to cover load and optimize the value of assets. Taking risks unrelated to CPCNH's normal power supply business activities, is not permitted.

CPCNH is also exposed to regulatory, operational and reputation risks. These risk categories and exposures are managed pursuant to CPCNH's Enterprise Risk Management Policy (ERM Policy).

Policy Administration, Review and Amendments

Energy Portfolio Risk Management will be a regular reporting standing agenda item at meetings of the Risk Management Committee and Board.

The Board, in consultation with the Risk Management Committee, is responsible for adopting this policy and reviewing it as needed at least every two calendar years.

The Board must approve amendments to the EPRM Policy. Advance written notice of Board meetings at which changes to this Policy are proposed shall be sent to the principal executive officers of each Member by the CEO or Board Chair. Subsequently, any such amendment shall be sent to the principal executive officers of each Member by the CEO or Board Chair.

Approval and Amendment of Regulations

After the EPRM Regulations are initially approved by the Board, the regulations may be amended with approval of the CEO, in consultation with the RMC, provided that the CEO sends prompt written notice to the Board of any such amendments.

Applicability

This EPRM Policy is effective immediately upon its adoption by the Board. It applies to CPCNH's wholesale supply operations, long-term contracting for energy/capacity and services, acquisition of generation resources, credit risk management and other related ancillary activities undertaken by CPCNH.

CPCNH Officers, Directors, staff, and contractors engaged in portfolio risk management will adhere to and be governed by this EPRM Policy.

Risk Exposures

CPCNH must procure electric power supplies and operate in the wholesale energy market which exposes CPCNH, and ultimately the customers of participating Members, to various risks. The risks listed related to CPCNH participation in wholesale and retail markets as a Load Serving Entity (LSE). These categories are defined and explained as follows.

Market Risk

Market risk is the uncertainty of CPCNH's financial performance due to variable commodity market prices (market price risk) and uncertain price relationships (basis risk). Variability in market prices creates uncertainty in CPCNH's procurement costs, which has a direct impact on customer rates.

Volumetric Risk

Volumetric risk reflects the potential adverse financial outcomes due to the uncertainty in the quantity of different power supply products required to meet the needs of CPCNH and its members. Customer load is subject to fluctuation due to customer opt-outs or departures, temperature deviation from normal, unforeseen changes in the growth of behind the meter generation by CPCNH customers, unanticipated energy efficiency gains, new or improved technologies, as well as local, state, and national economic conditions.

Opt-Out Risk (Customer Attrition Risk)

Opt-out or attrition risk occurs when customers opt-out of the program by choosing a different supplier. Opt-out risk may be realized by any condition or event that creates uncertainty within, or a diminution of, CPCNH's customer base. Opt-out risk is manifested in two separate ways:

1. First, the ability of customers to return to bundled service from NH utilities creates uncertainty in CPCNH's revenue stream, which is critical for funding EPRM goals

2. Second, customer opt-out risk can potentially challenge the ability of CPCNH to prudently plan for, and cost effectively implement, long-term resource commitments made on behalf of its member communities and the customers it serves

Counterparty Credit Risk

Performance and credit risk refers to the inability or unwillingness of a counterparty to perform according to its contractual obligations or to extend credit. Failure to perform may arise if an energy supplier fails to deliver energy as agreed. There are different general performance and credit risk scenarios:

- Counterparties and wholesale suppliers may fail to deliver energy or environmental attributes, requiring CPCNH to purchase replacement products elsewhere, possibly at a higher cost.
- Counterparties may fail to take delivery of energy or environmental attributes sold to them, necessitating a quick resale of the product elsewhere, possibly at a lower price.
- Counterparties and suppliers may refuse to extend credit to CPCNH, possibly resulting in higher collateral posting costs impacting CPCNH's cash and bank lines of credit.

During the normal course of business CPCNH is exposed to counterparty risk from energy suppliers. In this context, an important subcategory of credit risk is concentration risk. When a portfolio of positions and resources is concentrated in one or a very few counterparties, sources, or locations, it becomes more likely that major losses will be sustained in the event of non-performance by a counterparty or supplier or as a result of price fluctuations at one location.

Liquidity and Collateral Risk

During the normal course of business CPCNH is exposed to liquidity risk to fund operations, meet ISO-NE collateral requirements and potential collateral obligations from bilateral power purchases.

Liquidity Risk is the risk that CPCNH will be unable to meet its financial obligations. This can be caused by unexpected financial events and/or inaccurate pro forma calculations, rate analysis, and debt analysis. Some unexpected financial events impacting liquidity could include:

- Breach of CPCNH credit covenants or thresholds. Any breaches of existing and future credit covenants on CPCNH agreements could result in the withdrawal of CPCNH's line of credit or trigger the requirement to post collateral.
- Calls for collateral from the ISO-NE or CPCNH's counterparties based on terms of transacting agreements.

- CPCNH may be the subject of legal or other claims arising from the normal course of business. Payment of a claim by CPCNH could reduce CPCNH's liquidity if the cause of loss is not covered by CPCNH's insurance policies.

CPCNH will use industry best practices to manage potentially collateral posting and liquidity risk to the energy suppliers (i.e., requirement to post collateral per contractual terms).

Regulatory and Legislative Risk

CPCNH is subject to an evolving legal and regulatory landscape. Regulatory risk encompasses risks associated with shifting state and federal regulatory policies, rules, and regulations that could negatively impact CPCNH. Legislative risk is associated with actions by federal and state legislative bodies, such as any adverse changes or requirements that may infringe on CPCNH's autonomy, increase its costs, impact its customer base, or otherwise negatively impact CPCNH's ability to fulfill its mission.

Operational Risk

Operational risk is the uncertainty of CPCNH's financial performance due to weaknesses in the quality, scope, content, or execution of human resources, technical resources, and/or operating procedures within CPCNH. Operational risk includes the potential for:

- Organizational structure that is ineffective in addressing risk (i.e., the lack of sufficient authority to make and execute decisions, inadequate supervision, ineffective internal checks and balances, incomplete, inaccurate, and untimely forecasts or reporting, etc.).
- Absence, shortage or loss of key personnel or lack of cross functional training.
- Lack or failure of facilities, equipment, systems, and tools such as computers, software, communications links and data services.
- Exposure to litigation or sanctions resulting from violating laws and regulations, not meeting contractual obligations, failure to address legal issues and/or receive competent legal advice, not drafting and analyzing contracts effectively, etc.
- Errors or omissions in the conduct of business, including failure to execute transactions, violation of guidelines and directives, etc.
- Model risk that results in an inaccurate or incomplete representation of CPCNH's actual or forecast financial performance due to deficiencies in models and/or information systems used to capture all transactions.

Reputation Risk

Reputation risk is the potential that CPCNH's reputation is harmed, causing members or customers to opt-out of CPCNH service and migrate back to NH utilities. It includes the potential for energy market participants to view CPCNH as an untrustworthy business partner, thus reducing the pool of potential counterparties and/or having counterparties apply a CPCNH-specific risk premium to pricing.

Risk Strategy & Parameters

An important aspect of implementing an overall energy risk management policy is the development of related strategies to mitigate all of the related risks associated with energy transacting activities. The key strategies of CPCNH are outlined below.

Portfolio Strategy & Cost Allocation

The portfolio management process involves (1) continuous monitoring and modeling of market developments, customer load commitments, rates, attrition, and any offsetting hedge positions, (2) entering into and out of transactions with counterparties to minimize the cost and risk of providing all-requirements electricity, and (3) scheduling load and resources into the ISO-NE wholesale market, and subsequently settling financial obligations with the market operator and counterparties after the conclusion of each trading day.

To minimize the administrative and transaction costs associated with portfolio management, CPCNH will manage one whole portfolio to meet the combined electricity requirements of its Member CPAs. Probabilistic "at-risk" metrics will be used to inform portfolio hedging decisions to manage risk in the context of NH and ISO-NE markets, within the limits set in this policy and the EPRM Regulations. Structures will be put in place to address the accounting of cost to serve by CPA, timing of launch, and customer class.

Portfolio Diversification

CPCNH will strive to develop and maintain a diversified portfolio of physical and financial energy contracts to manage wholesale market risk exposures in an optimal fashion by incorporating a variety of fuel types, contract and pricing terms, counterparties, geographic locations, and types of products and preferred sources (e.g., renewables and battery storage assets, local generators, customer-generators, demand response programs, etc.).

Counterparty Diversification & Credit Exposure

To the extent practical, CPCNH will strive to create a diversified portfolio with multiple counterparties to diversify counterparty exposure.

Pursuant to master enabling agreements approved by the Board, the RMC may authorize entering into transactions with counterparties that possess at least a BBB- (or equivalent investment grade rating) by a nationally recognized statistical rating organization (NRSRO), and with counterparties rated below BBB- pending collateral, parental guarantees, or mutual concessions in credit requirement negotiations.

Effective counterparty management and credit analysis is essential to mitigate counterparty risks from wholesale market transactions. The market value, credit exposure and potential collateral requirements will be monitored using Mark-to-

Market (MtM), Potential Future Exposure and Collateral Call risk metrics. Methodologies for these metrics and objectives are set forth in the EPRM Regulations.

Default Rate Benchmarking

CPCNH's active portfolio management strategy involves taking certain risks relative to benchmark procurement practices from NH utilities. As of December 2022:

- Eversource, Unitil, and Liberty Utilities set default supply rates every six months after entering into all-requirements contracts with suppliers, with fixed prices that include a premium to cover the volumetric risk that suppliers are assuming by agreeing to serve customers.
- The New Hampshire Electric Cooperative actively manages its portfolio, and therefore retains and manages the associated risk of supplying customers itself.

CPCNH will monitor competitor procurement practices and modify its procurement strategy as warranted. Certain key risks for CPCNH in this context are that:

- Any net open positions that CPCNH has relative to the benchmark procurement practice of the utility in question represents an active risk position for CPCNH.
- CPCNH will also be exposed to volumetric risk from higher/lower loads than expected volumes and covariance with market prices.

Reporting Requirements

A vital element of this Policy is the regular identification, measurement, and communication of risk. To effectively communicate risk, all risk management activities must be monitored on a frequent basis using risk measurement methodologies that quantify the risks associated with CPCNH's procurement-related business activities and performance relative to goals.

CPCNH measures and updates its risks using a variety of tools that model programmatic financial projections, market exposure and risk metrics, as well as through short term budget updates.

CPCNH seeks to manage financial exposure to higher-volatility spot market wholesale electricity using hedges. Hedge execution and/or adjustments decisions are supported through timely and automated reporting that presents essential factors behind CPCNH success such as headroom and attrition potential.

The following items are measured, monitored, and reported on at least a weekly basis, or as warranted given daily monitoring of market conditions, with monthly delivery of a reporting packet to RMC:

1. **Open Position (MWh):** net open positions for all energy, capacity, and environmental products.
2. **Open Position ($):** the notional dollar and/or probabilistic-based risk exposure of open portfolio positions at current market prices.

3. **Expected Gross Margins:** expected GM based on current market prices
4. **Expected Cost of Supply:** marking to market is the process of determining the current value of contracted supply
5. **Expected Reserve Levels:** to ensure reserves meet the targeted thresholds as outlined in CPCNH's Financial Reserve Policy.

Risk measurement methodologies shall be re-evaluated on a periodic basis to ensure CPCNH adjusts its methods to reflect the evolving competitive landscape.

Risk Metrics

Portfolio management decisions are supported by risk metrics derived from simulations of future market conditions, loads, and other material risk drivers for the portfolio. The following probabilistic risk metrics are regularly calculated and reported:

1. **Gross Margin at Risk:** Potential adverse changes in net revenues for a given time period and confidence level.
2. **Rates at Risk:** Potential adverse changes to CPCNH's rate competitiveness, relative to the four default utility supply rates, for a given time period and confidence level.
3. **Reserve Levels at Risk:** Potential adverse change in reserves for a given time period and confidence level.
4. **Potential Future Exposure for counterparty credit risk**: Maximum Mark-to-market counterparty exposures for a given time period and confidence level.
5. **Potential Collateral Exposure:** Maximum of collateral that CPCNH may have to post for a given time period and time horizon with a given counterparty.

Stress tests will also be used to understand the potential variability in CPCNH's projected procurement costs, and resulting retail rate impacts and competitive positioning, associated with adverse scenarios of material risk drivers.

Position Limits (Hedge Ratios)

While relying on risk metrics to guide procurement decisions over time, CPCNH will purchase energy on a forward basis to hedge against the risk of open load positions within the minimum and maximum hedge ratios defined herein.

- Hedge ratios are fixed price purchases and supply resources divided by forecasted load (i.e., covered positions expressed as a percentage of load), as measured over time.
- Maintaining minimum and maximum hedge ratios is intended as a framework to manage market risk, by limiting CPCNH's net open exposure while allowing flexibility in procurement sufficient to maintain competitive rates.

- The objective in allowing such flexibility is to develop a procurement strategy focused on hedging against the risk of open load positions, so as to mitigate exposure to market price volatility and other pricing risk.

CPCNH's hedge ratios shall be a function of the rate setting method, as follows:

1. If rate setting is based upon a discount to utility tariff model, the following table of hedge ratios shall apply:

Months to Delivery		Discount to Utility (Auction Based Rates) Minimum	Discount to Utility (Auction Based Rates) Maximum
0+	3	60%	125%
3+	6	50%	110%
6+	9	0%	70%
9+	12	0%	70%
12+	24	0%	50%
24+ *	36	0%	50%

*Hedging shall not extend beyond 36 months from the date that CPCNH first begins providing electricity service to CPA customers, until one year from that date.

2. If rate setting is based upon a cost of service or fixed price model, the following table of hedge ratios shall apply:

Months to Delivery *		Cost of Service ("Fixed Price" Rates) Minimum	Cost of Service ("Fixed Price" Rates) Maximum
0+	3	80%	125%
3+	6	50%	110%
6+	9	40%	90%
9+	12	40%	90%
12+	18	30%	90%
18+	24	20%	90%
24+ *	36	20%	90%

* Hedging shall not extend beyond 36 months from the date that CPCNH first begins providing electricity service to CPA customers, until one year from that date.

Risk Control Principles

Control Principles

CPCNH will strive to conduct its energy risk management activities following best practices of the wholesale electric industry. A balance between costs and benefits will determine most effective controls, which are generally expected to meet the requirements of generally accepted auditing standards (GAAS), financial institutions and credit rating agencies. The processes to identify, monitor, control and track risk exposure will follow these principles:

1. Delegation of authority that is commensurate with responsibility and capability, and relevant training to ensure adequate knowledge to operate in and comply with rules associated with the markets in which they transact (e.g., ISO-NE).
2. Contract origination, commercial approval, legal review, invoice validation, and transaction auditing shall be performed by separate staff or contractor for any single transaction. No single staff member shall perform all these functions on any transaction.
3. Defining authorized products and transactions.
4. Defining proper trade capture process for executing power supply contracts.
5. Complete and precise capture of transaction data.
6. Meaningful summarization and accurate reporting of transactions and other activity at regular intervals.
7. Consultation with legal counsel on all legal issues related to this Policy.
8. Timely and accurate risk and performance measurement at regular intervals.
9. Compliance reviews to ensure that this Policy and the EPRM Regulations are adhered to, with specific guidelines for resolving instances of noncompliance.
10. Active participation by senior management in risk management processes.
11. CPCNH and service providers relied upon to provide for operations will be appropriately subject to regular audits.

The RMC is responsible for ensuring that the EPRM Regulations provide for the controls required to implement this Policy. The required controls shall include all customary and usual business practices designed to (1) prevent errors and improprieties, (2) ensure accurate and timely reporting of results of operations and other information pertinent to management, and (3) facilitate attainment of business objectives.

Transaction Structures and Authorization

CPCNH will transact in certain types of physical and financial products to mitigate various risks outlined in this policy. CPCNH shall have authorization to transact the following products under the limits set by this Policy and the EPRM Regulations:

- Physical power (e.g., Internal Bilateral Transactions (IBTs), physical tolls, etc.).
- Financial power or gas swap or futures (e.g., fixed-for-floating swaps, basis swaps, exchange-traded futures contract).
- Financial power or gas options.
- Financial Transmission Rights (FTR) obligations.
- Financial Transmission Rights (FTR) options.
- Environmental products to meet the Renewable Portfolio Standard (RPS).
- Products to hedge ISO-NE non-energy costs (Capacity, Ancillaries, etc.).

The RMC is responsible for ensuring that the EPRM Regulations authorize transaction types in accordance with this policy.

Segregation of Duties

CPCNH will ensure that integrated but separate responsibilities are in place to control risks with clearly defined roles and responsibilities for the Front Office, Middle Office, and Back Office. Those responsibilities will be delegated to third parties until CPCNH assumes some or all of those functions. CPCNH will maintain oversight functions of these defined roles and ensure they are performed in compliance with this policy.

Conflicts of Interest

CPCNH Directors, Officers, Alternates, Employees, Volunteers, consultants, and any other person acting for or on behalf of CPCNH — except for employees of Members who are not Directors or Alternates, acting in a ministerial (i.e., non-decisional) capacity as part of their public employment — are bound by the terms of CPCNH's Conflict of Interest Policy, unless otherwise noted in contractual agreements between CPCNH and said parties.

CPCNH employees engaged in energy supply resource transactions, counterparty credit evaluation or oversight of the foregoing, are barred from directly investing in or otherwise having a direct financial interest in any company with whom CPCNH has consummated energy or related purchases or sales within the last two years.

Roles, Responsibilities & Organization

This section defines the overall roles and responsibilities for implementation of this EPRM Policy. The coordinated efforts of personnel across several divisions are required to successfully implement CPCNH's risk management program. The basic roles and responsibilities of each organizational function are outlined below.

CPCNH Board of Directors

The Board has the ultimate oversight over CPCNH operations and is responsible for establishing an organizational-wide framework for risk management and ensuring that risk management results are achieved as planned. The Board shall approve and establish organizational policies for risk management and delegate to the CEO the responsibility for implementing the EPRM Policy. With responsibility for the ultimate oversight over CPCNH operations, the Board shall be responsible to ensure that risk management results are achieved in accordance with this policy.

Chief Executive Officer or Board Chair

The CEO (or alternatively hereafter, in the absence of the CEO, the Board Chair) has specific and overall responsibilities for implementing the EPRM Policy and for communicating risk management issues to the Board. The CEO shall be responsible for delegating specific duties for carrying out the policy and ensuring compliance with it by all affected CPCNH employees or contractors. The Board acknowledges that the CEO may delegated certain functions to the RMC, where delegation is ratified by this policy.

Risk Management Committee (RMC)

The RMC is responsible for maintaining and overseeing compliance to this policy. The primary responsibility of the RMC is to ensure that the procurement activities carried out on behalf of CPCNH are executed within the guidelines of this Policy and are consistent with the Member's goals. RMC is responsible for:

- Evaluating and voting on all proposed hedging recommendations.
- Determining if changes in the hedging strategy, or changes to this policy, are warranted.
- Understanding the financial and risk models relied upon to support hedging decisions.
- Understanding and reviewing the risk reports used to monitor for compliance with this policy.
- Reviewing the effectiveness of all hedging and procurement activities.
- Reviewing any reported violations to this policy.

Front Office

CPCNH's Front Office role has the responsibility for managing CPCNH's market price risk associated with Member CPA load serving requirements. The Front Office is responsible for:

1. Analyzing fundamental factors affecting load and supply, and net position.
2. Analyzing CPCNH's net position's exposure to market price risk.
3. Communicating results to the RMC and proposing transactions within the limits of this policy to balance those positions.
4. Recommending additional transaction types for approval by RMC, pursuant to the EPRM Regulations.

5. Negotiating the price and structure of hedging transactions with counterparties.
6. Transacting with counterparties only after approval from the RMC or within delegated limits approved by the RMC, and subject to those transactions:
    - Being for an approved product and executed with a counterparty with an approved credit limit.
    - Being duly authorized, within risk limits, and not causing either aggregate or individual counterparty credit limits to be exceeded.
    - Utilizing contract terms intended to minimize the risk of loss if a counterparty fails to deliver, take delivery, or pay for transactions provided.
    - Being executed and documented following standardized procedures.
    - Complying with applicable laws, regulations, and court orders.

CPCNH's Front Office will maintain a list of authorized personnel approved to transact by the RMC. Any requested changes to the list of authorized personnel will be subject to RMC approval.

Middle Office

CPCNH Middle Office will provide independent oversight of the Front Office functions and adherence to this policy. The Middle Office is responsible for:

- Providing independent oversight of load, supply, hedge positions, and net position.
- Maintaining the list of approved products.
- Ensuring accurate market curves used in valuation and risk management.
- Overseeing and validating the risk management models including prices, price volatilities and price correlations used in price simulations.
- Ensuring accurate load forecasts and load simulations.
- Calculating Counterparty Credit Exposure.
- Preparing position and risk reports for and providing feedback to the RMC.

Back Office

CPCNH Back Office Functions will provide the administrative activities to support the execution of Front Office transactions. The Back Office will provide a wide range of supporting activities to necessary to settle transactions with counterparties and support Middle Office risk control responsibilities consistent with this policy.

The Back Office has the responsibility for ensuring that transactions with counterparties meet all the terms intended by the Front Office. Primary responsibilities are:

- Confirmation of all transactions and reconciliation of differences with the counterparty.

- For exchange traded products through a clearing broker, the Back Office should balance daily with the broker statement.
- Reviewing transactions adherence to approved limits.
- Ensuring all trades have been entered into the system of record.
- Monitoring Counterparty Credit Exposure and report mark to market exposures relative to contractual contract requirements.

Authorities, Delegations, Limits, and Prohibitions

All executed transactions shall conform to the policies set forth herein. It shall be the responsibility of the RMC, with approval of the CEO, to establish appropriate individual transacting authority limits for the various personnel and contractors involved in the Front Office function in the EPRM Regulations.

All staff and contractors with designated responsibility for Middle Office or Back Office functions are strictly prohibited from executing any wholesale transactions. The Middle Office shall be responsible for informing counterparties of such approved authorizations, including transacting authority and restrictions, along with product types and/or term and dollar limits.

Policy Compliance

Compliance Exceptions

Compliance exceptions are actions which violate the authority limits or directives set forth herein or in the EPRM Regulations as developed and adopted pursuant hereto by the RMC.

Reporting of Exceptions

Exceptions to mandated policies, procedures and regulations shall be reported to the RMC within two business days after they are identified, and the Front Office shall prepare a full report for review and discussion at the next RMC meeting.

Independent Performance Evaluations

Compliance with this EPRM Policy, and with the specific requirements of the EPRM Regulations instituted pursuant to this policy, shall be subject to examination by CPCNH's independent auditors or by such other reviewers that CPCNH may appoint to evaluate the effectiveness of mandated controls. Pursuant to CPCNH's Joint Powers Agreement:

1. The RMC shall commission an independent agent to conduct and deliver to the Board and to the Members at the Annual Meeting an evaluation of the operational performance of CPCNH relative to the Enterprise Risk Management Policy (including this EPRM Policy) and as otherwise requested by the Board.

2. CPCNH shall budget an amount necessary for the evaluation as determined by the RMC, which shall cause to be hired a firm or individual that has no other direct or indirect business relationship with CPCNH.
3. The evaluation shall be conducted at least once every two years, starting within three years of the initial provision of electricity supply to a Member CPA.
4. No individual or firm may be hired to conduct more than two consecutive evaluations.

Reserves

Reserve levels shall be reviewed monthly by the Finance Committee.

Internal Systems, Tools, and Staff Training

CPCNH employees who are authorized to perform energy risk management functions on behalf of CPCNH shall be provided with the necessary systems and tools to support all risk management processes.

Commensurate to the level of portfolio risk management functions performed by CPCNH staff:

- Provision shall be made in the budget for the acquisition and maintenance of computer systems, software, communications equipment, data services and other analytical, measurement and reporting tools.
- Provision shall also be made in the budget for managers and staff to attend seminars and courses in risk management on a regular basis.

RETAIL RATES POLICY

Purpose

This Retail Rates Policy outlines the requirements, objectives, rate setting authorities, rate setting processes, Member rate product and Discretionary Reserve adder election procedures, and different types of rate structures, products, and content of the Community Power Coalition of New Hampshire (CPCNH).

Requirements and Objectives

Member Electric Aggregation Plans typically require the CPA to offer default rates to one or more customer groups that are lower than or competitive with utility default rates at the time of launch. CPCNH shall only launch new Member CPAs subject to meeting any such requirements.

Thereafter, CPCNH will strive to maintain default service rates that are lower than or competitive with utility default service rates on average and over time — acknowledging that utility rates may dip below CPCNH rates on occasion, for short periods of time, due to market volatility and other factors.

Rates will be set at a level such that revenues from CPA customers are projected to meet or exceed CPCNH's ongoing operating and capital costs, inclusive of financial reserve targets, and other requirements set by the Board.

- Rate setting will be performed in concert with hedge decision making, as different rate structures may impact the appropriate hedging approach, in accordance with the procedures and methodologies summarized in the Energy Portfolio Risk Management Regulations (EPRM Regulations).
- CPCNH shall strive to provide innovative rate structures and offers that maximize choice and create value for CPA customers and for the Members, while aligning to the extent beneficial, allowable, and practical within and across CPA service territories.
- Changes to CPCNH default service rates shall be set and publicly noticed at least 30 days in advance of any rate change.
- Pursuant to RSA 53-E, CPCNH rate setting shall ensure the equitable treatment of all classes of customers, subject to any differences arising from varying opportunities, tariffs, and arrangements between different electric distribution utilities in their respective franchise territories when setting default service rates.
- Pursuant to Puc 2204.05, CPCNH shall provide for the proper advance notice of rates to new customers, and update customer rate information whenever it changes, but no less frequently than once per month, on the New Hampshire Department of Energy's Shopping Comparison website.

CPCNH shall comply with all other applicable statutory and rule requirements.

Electric Assistance Program Discounts

Income eligible households can qualify for discounts on their electric bills under the Electric Assistance Program. CPCNH will support income eligible customers who enroll in the Electric Assistance Program to receive their discount. Discounts are funded by all ratepayers as part of the System Benefits Charge, which is charged to all customers and collected by the distribution utilities. At present, the Public Utilities Commission and utilities only support provision of the discount to individual customers when the customer's electricity supply charges are billed through the distribution utility. CPCNH will therefore elect utility consolidated billing to bill all customer accounts know to be enrolled in the Electric Assistance Program.

Policy Amendments

The Board must approve amendments to this Policy. Advance written notice of Board meetings at which changes to this Policy are proposed shall be sent to the principal executive officers of each Member by the CEO. Subsequently, prompt written notice of the effective date of such amendment shall be sent to the principal executive officers of each Member by the CEO.

Default Rate Setting Process

The CEO, in consultation with the Risk Management Committee and the Finance Committee — or in the absence of the CEO, the Risk Management Committee, in consultation with the Finance Committee — shall recommend default rates to the Board for approval with sufficient notice to be implemented commensurate with regulated default utility rate changes, or otherwise as deemed necessary to support the requirements and objectives of this Policy.

The Risk Management Committee and Finance Committee shall each convene at least one public meeting to provide for deliberation and public input regarding changes to default rates.

Advance written notice of Board meetings at which changes to default rates are proposed shall be sent to the principal executive officers of each Member by the CEO . Subsequently, prompt written notice of approved default rate changes shall be sent to the principal executive officers of each Member by the CEO.

Member Elections of Rate Products and Discretionary Reserve Adders

Pursuant to this policy, individual Members will be provided the opportunity to elect to offer different rate products on a default and opt-in basis and to elect to adjust their CPA's default and opt-in rates to include an adder for the accrual and use of Discretionary Reserves, as provided for under the Financial Reserves Policy.

Any such elections of rate products and/or Discretionary Reserve adders must be approved by both the CEO and the Member's governing body, or the Member's Representative or other individual authorized pursuant to a delegation of such authority by the Member's governing body or approved Electric Aggregation Plan, in advance of or during the meeting at which changes to default rates are approved by the Board.

Emergency Default Rate Adjustment Authority

This Policy acknowledges that, while rate structures or levels may be expected to persist for an expressed and/or intended period of time, unexpected events may warrant an immediate indefinite or temporary rate adjustment. Sound portfolio risk management will in most cases prevent the necessity of such action. However, risk factors such as market price risk may lead to a situation for such action to mitigate cash reserve constraints.

The Board must approve emergency rate adjustments as necessary to maintain the financial integrity of CPCNH. Prompt written notice of emergency rate adjustments shall be sent to the principal executive officers of each Member by the CEO.

Rate Structure Types

CPCNH may offer CPA customers the following rate structures:

Discount to Utility Tariff Rates

A rate structure that is discounted relative to utility rates ensures customer savings. This rate structure mitigates attrition risk. It will be based upon an expressed percentage discount to the rates offered by a customer's incumbent utility.

Fixed Price Cost of Service Based Rates

A rate structure that is based upon a budget build-up of cost of service, and/or another method whereby CPCNH offers a defined fixed price rate, is different than a discount to a utility rate. While it may be lower than a utility rate at inception and/or intent, a fixed rate could move above the utility rate due to wholesale market price movements, non-energy cost changes and/or regulatory changes impacting prices.

Time of Use (TOU) Rates

Time of use rates are rates that employ different pricing based on periods of time during a given day (e.g., daytime, nighttime) and/or weekday (e.g., weekday, weekend). Time of use rates incent customers to consume electricity at times that are lower cost and/or more environmentally friendly.

Net Metering Rates

Net metering rates allow a customer to benefit from behind-the-meter generation and possibly electricity storage capabilities through periodic meter reads where, at the end of the billing period the customer is charged for their net positive load (consumption) or if they have net exports to the grid at the end of the billing period they are either: 1) credited for those net exports to the grid on a kWh basis, such that they can carry forward a negative kWh balance to offset future consumption, or 2) get paid a rate for the surplus kWh exported to the grid and zero out their net kWh usage. This rate construct is typically indifferent to the time of behind-the-meter generation, production, or customer consumption, but may be provided with TOU rates.

Generation in excess of a customer's usage each month is accounted for as a reduction to the CPA's wholesale load obligations by the utility, net of any applicable line loss adjustments, as approved by the Public Utilities Commission.

Customer-generators will continue to receive any non-supply related components (e.g., transmission and distribution credits) directly from their utility, as specified under the terms of their applicable net energy metering (NEM) tariff.

Index Plus Adder Rates (Pass-Through)

Index rates take hourly (or, as contemplative of technology that may allow, subhourly) consumption and multiply a loss adjustment factor and an ISO-NE New Hampshire Zone power price, plus a CPCNH administrative adder, to arrive at an effective monthly cost based predominantly on market-based prices. Index rates should typically not be hedged, and the customer should bear all price risk under such arrangement, provided, however, that a collar or sleeve product that sets an upper and lower limit to such index prices for some period of time may be available for a price that covers the cost and risk of such a hedge. Demand flexibility options may be priced and included in the product.

Fixed & Index Blend and/or Variable Term Rates

Likely of particular interest to non-residential customers, a Fixed & Index blended rate would be a combination of a fixed price rate as expressed above and an index rate as expressed above. The offering could be fixed to 50/50 or some other risk sharing split of the fixed and index portion. CPCNH should only hedge the fixed portion. Non-residential customers may also be interested in such rate for varying term lengths, such as for 12- or 24-month periods, which may be subject to meeting certain contractual, creditworthiness, and/or collateral posting requirements. Demand flexibility options may be priced and included in the product.

Other Rate Structures

This policy precludes CPCNH from offering rate structures not expressly authorized herein, such as tiered rate structures (progressive or regressive), total dollar "all-you-can-consume" fixed cost offers, and rate structures that utilize a demand charge. Board approval is required to authorize additional rate structures.

Rate Product Types and Approval Authorities

CPCNH is authorized to provide or offer CPA customers the following rate products:

Default Service

Default Service shall be the default rates selected to offer CPA customers in each utility territory, priced relative to the prevailing utility default rate, and, if practical, based upon the same or a comparable structure as the prevailing utility rate structure, as approved by the Board.

Member Default Service Election

The Member Default Service Election is an exception to the Default Service Offer that would extend a default rate to the residents and/or businesses of a Member CPA different than other communities or CPCNH customers at large. Community offers may be rates that are higher or lower than the Default Service Offer, to reflect a different product content (e.g., higher or lower renewable and/or carbon-free content).

CPCNH shall provide Members with a schedule by which to request Community Default Service Offer Elections, which are subject to Board approval in consultation with the Risk Management Committee.

Local Power Offer

The Local Power Offer acknowledges and integrates the rate impact of local generation projects (e.g., a local community solar project), community investment programs (e.g., investment in EV charging stations), or other programs or projects benefiting a targeted community.

Subject to the terms of a Project Contract, or Board approval in the absence of governing terms in a Project Contract, the Local Power offer may extend a default or custom rate to the residents and/or businesses of a Member CPA different than other communities and customers.

Alternate Customer Rate Options (Opt-Up or Opt-Down)

Customers may select an optional rate extended by CPCNH through expressed choice of an alternative rate offer instead of Default Service. The option is held by the customer and CPCNH shall not move customers to an alternative rate without customer consent.

Alternative Customer Rate Options will be subject to Board approval at the same time as Default Service rates. Alternative Customer Rate Options shall be offered under the same rate structure as Default Service and may additionally be offered as a time-of-use rate.

Net Energy Metering Offer

CPCNH will provide new rates and terms that compensate or credit participating customer-generators for the electricity supply component of their net metered surplus generation.

For group net metering, to the extent CPA default rates are lower than utility default rates, it may be most advantageous for the host customer-generator to remain a utility default service customer, while the other group members may enroll in CPA supply and continue to receive on-bill credits for their participation in the group.

Additionally, CPCNH will pursue additional development of NEM rates and programmatic enhancements that benefit and encourage customers to adopt distributed generation.

Net Metering terms, conditions, and rates for compensating and crediting different types of NEM customer generators will be set by the Board and fully disclosed to all prospective NEM customers through the program's enrollment notification process and thereafter.

Non-Residential Additional and Custom Offers (Opt-In)

CPCNH may offer non-residential customers Index Plus Adder (Pass-Through) Rates, Fixed & Index Blend Rates, and/or Variable Term Rates thereof. Demand flexibility options may be priced and included in the product, to encourage and incentivize customers to shape their electricity usage patterns, including for the objective of lowering peak charges.

Rate Product Content and Member Elections

CPCNH shall offer the following rate products and contents:

PRODUCT	CONTENT *	MEMBER ELECTIONS
Granite Basic	Minimum RPS Content (23.4%)	Default, opt-down/in, or N/A**
Granite Plus	33% Renewable or Carbon Free	Default, opt-up/in, or N/A**
Clean 50	50% Renewable or Carbon Free	Opt-up/in or N/A
Clean 100	100% Renewable or Carbon Free	Opt-up/in or N/A

* Specified percentages are minimums (floors).

** One of these two products must be offered as Default Service

Member Elections

Each Member shall be provided the opportunity to elect whether to offer "Granite Basic" or "Granite Plus" as a default product, by customer class or as otherwise determined by the Board and will be advised on the cost implications of such elections by the CEO. Absent any election, "Granite Basic" shall be the default product.

Each Member that elects "Granite Plus" as their default product may also elect to offer "Granite Basic" as an opt-down choice for customers seeking the most affordable rate product. Absent any election, "Granite Basic" shall be offered as an opt-down/in product.

Each Member shall be provided the opportunity to elect whether to offer "Clean 50" and/or "Clean 100" as opt-up/in products. Absent any election, "Clean 50" and "Clean 100" shall be offered as opt-up/in products.

Product Content

Carbon-free content is power that is reported as carbon-free on an Environmental Disclosure label pursuant to Puc rule 2205.11.

Renewable content that is in addition to the minimum requirements of the New Hampshire Renewable Portfolio Standard shall be provided by Renewable Energy Credits pursuant to RSA 362-F, with a preference for sourcing Renewable Energy Credits from in-state generation.

FINANCIAL RESERVES POLICY

Purpose

This Financial Reserves Policy establishes minimum, target, and maximum levels of cash reserves that will be jointly accrued, used, maintained, and monitored by CPCNH, on behalf of all Members ("Joint Reserves"), and provides for the collection of Joint Reserves in excess of the maximum target joint reserve level to be applied at the discretion of individual Members ("Excess Reserves"). Separately, the policy allows for the collection and use of additional reserves at the sole discretion of each individual Member ("Discretionary Reserves").

Joint Reserves, Excess Reserves, and Discretionary Reserves are collectively referred to herein as "reserves".

Objectives

Reserves are accrued and maintained by CPCNH on behalf of and for the benefit of Member CPAs. The establishment of Joint Reserves, pursuant to this policy, is intended to secure the following objectives:

1. **Protect against emergency default rate adjustments.** Reserves can help minimize the risk that rates, after being set for a given period, would need to be quickly adjusted upwards due to market volatility (power supply shocks), weather impacts on demands, economic downturns, emergencies (such as natural disasters), and regulatory changes.
2. **Strive to adjust rates gradually over time.** In a rising price environment, reserves may be used to spread out the impact of price increases on customers over multiple rate setting periods. For example, if market prices are expected to increase over the medium-term, deciding to collect additional reserves over the near-term (when prices are lower) would later allow more funds to be used to offset rate increases in later periods, thereby adjusting rates more gradually and predictably for customers over time.
3. **Ensure cash availability when net revenues are unavailable.** To bridge seasonal times of the year that normally see temporary low or negative net revenues, which would otherwise require CPCNH to have sufficient credit to maintain liquidity.
4. **Lower and avoid interest expenses.** To avoid interest expense to cover short-term cash shortfalls, first by accruing reserves sufficient to execute a credit facility for CPCNH, and subsequently by having sufficient reserves to use in place of credit or debt instruments. CPCNH intends to negotiate and directly execute a credit facility on behalf of Member CPAs within the first year of operations.
5. **Enable the development of local energy projects.** Project developers typically seek to contract with entities that are willing and able to commit to paying for electricity over a 10 year or longer period. The accrual of financial reserves

hereunder is intended to provide CPCNH with the financial stability required to be a creditworthy counterparty for the purposes of soliciting and entering into long-term contracts to develop local energy projects on behalf of participating Members.

6. **Achieve a credit rating and maintain good standing with rating agencies.** After accruing sufficient reserves, CPCNH can apply for a credit rating, which would allow power to be secured at lower costs, that is, without posting credit enhancements, for the benefit of all Member CPAs. CPCNH intends to achieve and maintain strong financial performance metrics sufficient to receive an investment-grade credit rating within three-to-five years after launch.
7. **Manage risks identified in the Energy Portfolio Risk Management Policy**, such as those associated with market prices, counterparty credit and performance, load volumes and net revenues, gross margin levels, liquidity and collateral requirements, regulatory and legislative policy changes, and gross margin levels.
8. **Establish clear expectations between the Board of Directors, staff, contractors, and suppliers of electricity to CPCNH.** A formal reserve policy creates a shared understanding of the proper level and use of reserves.

Rights of Members to Reserve Contributions

Member Reserve & Cost Allocation Accounting

Reserve contributions shall be tracked and accounted for on behalf of each Member CPA. For each Member, reserves accrued shall be adjusted to reflect the equitable allocation of costs between Members pursuant to Cost Sharing Agreements.

To the extent that provisions in this policy are inconsistent with the Cost Sharing Agreements entered into by Members, the Cost Sharing Agreements shall control.

Member Accrual and Usage of Discretionary & Excess Reserves

Individual Members that request to adjust their CPA's default and opt-in rates to include an adder for the accrual of Discretionary Reserves, pursuant to the Rates Policy, will accrue reserves that are separate from Joint Reserves. Such reserves shall be tracked, accounted for, and transferred to the individual Member or otherwise applied or held by CPCNH as directed by the individual Member’s governing body.

Joint Reserves that accrue in excess of the Maximum Operating Reserve Level hereunder are Excess Reserves, which shall be allocated back to Members for use as Discretionary Reserves.

Members may use such Excess and Discretionary Reserves to invest in developing new local energy projects, or to fund programs benefiting their customers specifically, or for other uses as determined solely by each individual Member.

Member Reserve Settlements Upon Withdrawal or Termination

If a Member withdraws from CPCNH or is involuntarily terminated, the balance of any reserves accrued by the Member will be distributed or applied as directed by the Member's governing body, after satisfaction of the Member's contractual obligations with CPCNH and in accordance with any applicable law and regulation.

Joint Reserve Target Levels Established

Joint reserves will be used to honor financial commitments and will be used to cover the operations of CPCNH over a number of days in the event of emergencies or other significant unforeseen events, amongst other goals outlined in this policy.

For purposes of this policy, Joint Reserve levels are defined as a projected or estimated amount accrued at the conclusion of a forecasted period.

Three target levels of Joint Reserves are defined below, which shall be in addition to any financial covenants entered into by CPCNH, relative to the forecasted expense of operations as reflected in CPCNH's budget:

1. Minimum Operating Reserve: reserves sufficient to cover 60 days of operations.
2. Target Operating Reserve: reserves sufficient to cover 120 days of operations.
3. Maximum Operating Reserve: reserves sufficient to cover 180 days of operations.

Rates shall be set to accrue Joint Reserves sufficient to meet the target levels on a forecasted basis, as follows:

1. To reach the Minimum Operating Reserve level within 3 years.
2. To reach the Target Operating Reserve within 5 years.
3. The Maximum Reserve level would provide strong protections against any significant adverse events and represents a longer-term goal.

Joint Reserve Target Levels Maintained

Replenishment of Minimum Reserves

Once Minimum Reserves levels are initially achieved, should CPCNH drawdown reserves below the Minimum Operating Reserve level, CPCNH will implement plans to return reserves to their minimum targets within two (2) years on a rolling forecast basis. The CEO shall oversee the preparation and submittal of such plans in subsequent budget and rate discussions with the Board.

Reserves between Minimum and Maximum

To the extent that reserves are above the Minimum and below the Target Operating Reserve level, continued consideration should be given to the rate that reserves are accumulating toward the Target Operating Reserve.

To the extent that reserves are above the Target Operating Reserve and below the Maximum Operating Reserve level, no action by CPCNH would be required.

Joint Reserve Forecasting, Reporting, and Evaluation

Regular Forecasting of Reserve Levels

The conditions for use of reserves, being expressed as a percentage of the reserve level at the conclusion of a rolling 12-month forecast basis, require the reserve level to be regularly updated on a projected basis.

The reserve level forecast methodology shall be approved by Risk Management Committee, reviewed by the Finance Committee, and periodically assessed and updated as required to ensure appropriate reserve levels are maintained and funded.

The Risk Management Committee, supported by staff and contractors, shall ensure that the reserve level forecast is updated and reported to the Finance Committee and Board of Directors at each regular meeting.

The Treasurer shall report the reserve level in quarterly and annual financial reports.

Periodic Review of Reserve Target Levels

Reserve target levels shall be periodically reviewed for consistency with industry standards by the Risk Management Committee. If significant risk factors are eliminated or significant new risks emerge as a result of changes in the industry, legislation, or economic conditions, the basis of the reserve policy shall be reviewed, and the funding level shall be adjusted accordingly. Unless the Reserves are lower than 120% of the minimum levels, formal Reserve funding discussions with the Board may be deferred until the next budget process.

Annual Consideration of Forecasted Reserve Levels and Targets

An analysis of over or under forecasting of reserve levels during the fiscal year shall be made in conjunction with year-end financial results. These results will be reported to the Board of Directors as part of the year-end financial report presentation.

The Board shall review and consider the target reserve levels defined in this Policy, in the context of CPCNH's overall financial condition and taking under consideration changes to the industry and/or CPCNH's exposure to the risk factors defined in the Enterprise Risk Management Policy.

Conditions for Use of Joint Reserves

A temporary reduction in cash consistent with the expected peaks or dips in revenues and expenditures are normal cyclical occurrences to be expected over the course of any 12-month period, and do not constitute an expenditure of Joint Reserves.

The use of Joint Reserves is defined as an expenditure that is forecasted to result in a more than 10% reduction of the reserve level, relative to its then-prior forecasted level at the conclusion of the fiscal year, or $10 million, whichever is greater.

The use of Joint Reserves is subject to approval by the Board. However, the CEO has the authority to use reserves for operating liquidity in emergency situations in consultation with the Board Chair and either the Vice Chair or Treasurer, and such actions must be noticed to the Board in the next meeting.

Board and Membership Authority to Amend

The Board may, by resolution, modify or suspend any provision of this Policy for any duration at any time, except that the provisions under this section, '"Board and Membership Authority to Amend," and under "Rights of Members to Reserve Contributions" may only be modified or suspended by a written amendment unanimously approved by the votes cast at a meeting of the Membership at which a quorum is present.

The CEO or Board Chair shall send written notice of any proposed amendments to or suspension of the provisions under this section and under Rights of Members to Reserve Contributions to the Member Representatives and principal executive officers of each Member at least fourteen (14) days prior to such meeting at which it is to be acted upon. Subsequently, prompt written notice of the effective date of such amendment or suspension shall be sent to the Member Representatives and principal executive officers of each Member by the CEO or Board Chair.

Definitions

- "Board" means the Board of Directors of CPCNH.
- "CEO" means the Chief Executive Officer of CPCNH, or, in the absence of a CEO, the Board Chair (unless where otherwise provided for in the policies).
- "Cost Sharing Agreements" means the agreements entered into by CPCNH and individual Members pursuant to Article V, Section 3 of the CPCNH Joint Powers Agreement.
- "CPA" means Community Power Aggregation.
- "CPCNH" means the Community Power Coalition of New Hampshire.
- "EPRM Policy" means the Energy Portfolio Risk Management Policy.
- "EPRM Regulations" means the Energy Portfolio Risk Management Regulations.
- "ERM Policy" means the Enterprise Risk Management Policy.
- "GAAS" means generally accepted auditing standards.
- "ISO-NE" means ISO New England, Inc., the entity serving as the regional transmission operator and which oversees the operation of New England's bulk electric power generation and transmission system and administers the regional wholesale markets for electric energy and other electricity products, or its successors.
- Financial power or gas swap or futures. Includes fixed-for-floating swaps, basis swaps, exchange-traded futures contracts. Swaps and futures are financial settled instruments based on the difference between a fixed and floating reference price times a contracted volume. CPNCH could be the fixed side or float side of the settlement depending upon whether is buying or selling financial power.
- Financial power or gas option. The buyer of an option pays a premium to have the right, but not obligation, to exercise the option prior to expiry and receive a financial settlement.
- "Financial Transmission Rights (FTRs) obligations": An FTR provides the FTR holder a revenue stream that equals the quantity of the FTR multiplied by the hourly price difference (day-ahead) between the source and sink locations specified in the FTR. An FTR can be used by CPCNH as a Load Serving entity to hedge congestion risk between a load zone and a supply location such as a generator or hub. The payoff of a FTR can be positive or negative,
- "Financial Transmission Rights (FTRs) options": FTR option buyers pay a premium to have the right, but not the obligation to exercise the payoff of an FTR settlement.

- "Gross Margin at Risk" is a measure of the potential adverse changes in net revenues for a given time period and confidence level.
- "IBT" or "Internal Bilateral Transaction" is a contract tool that transfers the ISO load obligation between the buyer and the seller. Participants with load or generators often sign bilateral contracts with each other to obtain price certainty rather than risking the uncertain energy market price. A Buyer's load obligation decreases and therefore pay less to the ISO while a Seller's load obligation increase and pay more to the ISO.
- "Load Serving Entity (LSE)" means an entity that is registered with ISO-NE as a market participant and secures and sells electric energy and related services, which may include transmission service if not provided by the distribution utility, to serve the demand of end-use customers at the distribution level.
- "MTM" or Mark-to-Market is a measure of the current replacement value of physical or financial contracts based on prevailing market forward curves, rather than the book value.
- "NRSRO" means nationally recognized statistical rating organization.
- "Physical Power Purchases and Sales": see IBT.
- "Potential Future Exposure for counterparty credit risk" means the maximum MTM counterparty exposures for a given time period and confidence level.
- "Potential Collateral Exposure" means the maximum of collateral that CPCNH may have to post for a given period and time horizon with a given counterparty.
- "Rates at Risk" is a measure of the potential adverse changes to CPCNH's rate competitiveness, relative to the four default utility supply rates, for a given time period and confidence level.
- "RMC" means the CPCNH Risk Management Committee.
- "Financial Reserve Uncertainty" is a measure of the potential adverse change in reserves for a given time period and confidence level.
- "Stress tests" refer to analysis of portfolio performance under stress scenarios of material risk drivers. Used to understand the potential variability in CPCNH's projected procurement costs and resulting retail rate impacts and competitive positioning.