COMMUNITY POWER COALITION OF NEW HAMPSHIRE

For communities, by communities.

c/o Sustainability Director
Town of Hanover,
41 S Main Street
Hanover, NH 03755

March 28, 2022

Daniel C Goldner, Chairman
New Hampshire Public Utilities Commission
21 South Fruit Street
Concord, NH 03301-2429

Re: DRM 21-142, Community Power Coalition of New Hampshire Petition for Rulemaking to Implement RSA 53-E for Community Power Aggregations by Public Stakeholders - CPCNH Reply Comments on Initial Proposal for Puc 2200 Municipal and County Aggregation Rules

Dear Chair Goldner,

The Community Power Coalition of New Hampshire (CPCNH), joined by the Office of the Consumer Advocate (OCA) and Clean Energy New Hampshire (CENH), hereby submit reply comments on the Commission's Initial Proposal for Puc 2200 Municipal and County Aggregation Rules.

We appreciate the opportunity to reply to the initial comments of other stakeholders in this proceeding and that the Department of Energy convened a stakeholder work session to encourage the parties to narrow their differences.

We concur with other stakeholders, including the NH Utilities (Eversource, Liberty, and Unitil) and New Hampshire Electric Cooperative (NHEC) that expeditious adoption of these administrative rules is in everyone's best interests.

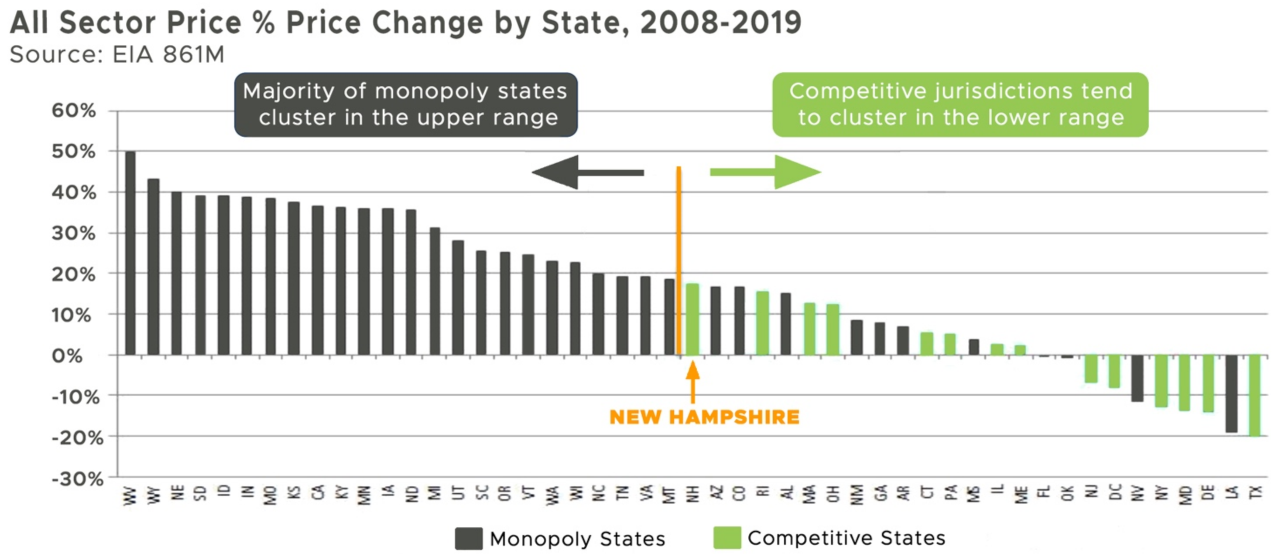
To that end, we propose certain modifications and clarifications to the initial proposal for the Commission's consideration in preparing a final proposal. Our reply comments:

- Provide introductory context, and an overarching view of how critically-important it is for the Commission to enable the authorities of CPAs in these rules to re-invigorate New Hampshire’s competitive market.
- Provide our response to the general framing advanced by the NH Utilities and the New Hampshire Electric Cooperative (NHEC) in opening comments; and
- Discuss our perspective and recommendations regarding specific rule changes under consideration.

Generally, we concur with the comments and specific suggestions filed by Clean Energy New Hampshire, Colonial Power Group (CPG), NRG, and the Department of Energy (DoE) and will note any exceptions in comments on specific proposed rules.

Introduction

More than two decades after the Legislature enacted the Electric Utility Restructuring Act in 1996, New Hampshire's retail electricity market remains only partially restructured. New Hampshire has, in fact, fallen behind every other state with a restructured electricity market in terms of price competition:



Credit: Retail Energy Supply Association, 2020.

The reason is that the competitive market has stalled:[1]

- The "mass market" of residential and small commercial customers — approximately four out of every five customers — remains on default service provided by the distribution utilities.
- Residential customers are not offered many rate options or clean technology innovations today. Out of the 29 competitive suppliers currently offering service in New Hampshire, only nine offer service to residential customers.
- Moreover, the market is both highly concentrated (indicating a lack a competition) and fragmented (e.g., only four of the 29 competitive suppliers serve customers in every distribution utility territory).
- Regulated distribution utilities have consequently been relied upon to provide services that are not natural monopolies and could therefore be available by competitive means — such as default electricity supply, metering, meter data management, billing, and other retail customer services (e.g., demand response and energy storage for smaller customers).

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[1] For explanatory context and data, refer to DE 19-197, Testimony of Samuel Nash Vautier Golding on behalf of the Local Government Coalition, 17 August 2020. Available online: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TESTIMONY/19-197_2020-08-18_LEBANON_LGC_REV_TESTIMONY_GOLDING.PDF.

- The continued reliance on utilities to provide these customer-facing services has necessitated state regulation of many aspects of the retail customer market that could plausibly be deregulated.
- Utility regulation relies on administrative regulatory proceedings, which are necessarily more slow-moving and unable to respond to changing customer technologies and wholesale market dynamics (such as the increased price volatility caused by higher levels of renewable generation) compared to the nimbler, market-based framework envisioned under the Electric Utility Restructuring Act.

New Hampshire's Community Power law was passed to achieve the goals of the Electric Utility Restructuring Act — and to finally deliver the benefits of restructuring for residential and small commercial customers.

A recent article by the Consumer Advocate (Don Kreis) provides particularly relevant insights regarding the near-term financial benefits of fully enabling CPAs.[2] He contrasts the winter supply rates for Unitil (17.5 cents/ KWh) to the New Hampshire Electric Cooperative (9.8 cents/KWh), and goes on to explain that the co-op actively manages their energy portfolio, whereas:

> "*The IOUs do not actively manage the power portfolios used to provide their default energy service. They simply seek competitive bids, twice a year, from wholesale power suppliers that agree to charge the IOU a predetermined price during each month of the contract. The prices get locked in over the six months even as wholesale market prices fluctuate – and . . . the suppliers thereby take on considerable market risk that nudges their bids to the IOUs upward.*"

The Consumer Advocate then noted that the Coalition intends to contract for and actively manage an energy portfolio for its CPA members — and recommended that customers "*get your city or town to become a CPCNH municipality, and then work hard to launch these community power programs*."

The Community Power Coalition of New Hampshire (CPCNH) is comprised of local governments that represent ~20% of the state's population, each of which are actively planning on launching Community Power Aggregations in the next year or two. The Coalition's members and supporters have been engaged in developing the proposed rules for almost two years now.

Unfortunately, and as explained at length herein, the distribution utilities — Eversource, Unitil, Liberty, and the New Hampshire Electric Cooperative — have proposed sweeping changes to the initial proposal in opening comments that would (1) artificially increase supply costs and risk for CPAs and (2) effectively foreclose CPAs from offering innovation in retail customer pricing and services. Furthermore:

- On the subsequent stakeholder call convened by DoE last week, the utilities (1) disclosed that they would be unable to provide CPAs with the data required to effectively serve net metered customers under the initial rules as-proposed, and

[2] Don Kreis, *"As Your Electric Bill Soars, Some Ideas for Fighting Back"*, 9 October 2021. Available online: https://indepthnh.org/2021/10/09/as-your-electric-bill-soars-some-ideas-for-fighting-back/

(2) repeatedly insisted that data which they hold outside of their Electronic Data Interchange (EDI) systems is inaccessible and cannot be provided to CPAs — which is nonsensical on its face, as such data is stored in customer information systems, meter data management systems or other utility systems.

- **The utilities' competitive supplier agreements and associated terms and conditions — which we reviewed in relation to recommendations made by the utilities in in opening comments — appear to be non-compliant with Order No. 22,919** (the May 4, 1998 decision in which the Commission adopted the recommendations of its EDI Working Group) and other applicable determinations of the PUC adopting the standards and guidelines proposed by the EDI Working Group report.[3] Not coincidentally, the utilities appear non-compliant in ways that will:

    - Prevent CPAs and competitive suppliers from offering innovative rate structures and services to mass market customers — such as by not honoring requests to make reasonable changes to utility billing systems at the CPA's or competitive suppliers' expense; and

    - Degrade the accuracy of load forecasting by withholding data — such as the actual hourly loss factors used in estimating load on an hourly basis for daily ISO-NE reporting for wholesale market settlements — that will be critical to disclose to CPAs preparing to provide default service on an opt-out basis to customers.

  These and other related areas of apparent non-compliance are explained and addressed at length in our "Responses to Specific Rule Proposals" below.

  Additionally, in reviewing the utilities' agreements we have observed that:

    - Not all of the utilities' competitive supplier agreements and associated terms and conditions currently in use have actually been approved by the Commission. Furthermore, the remainder appear to have been "approved" only insofar as the Commission ordered the utilities to submit tariff demonstrating compliance with specific, narrow matters (e.g., payment hierarchies) or as part of much broader proceedings that did not focus much — if at all — on competitive supplier issues (e.g., base rate settlement agreements).

    - All of the distribution utilities should propose and disclose updated service fees for CPAs serving customers on a default, opt-out basis. Not all of the utilities' current competitive supplier agreements and associated terms and conditions disclose service fees, and those that do are obviously outdated and not reflective of costs in key regards (such as the provision of interval metering data).

Our goal in this rule development process is to free municipalities from the worry that utilities will tie the provision of CPA competitive services to the utility's monopoly services in ways that artificially inflate costs and erect barriers to innovation — *which is precisely what the changes proposed by the utilities would*

[3] *See* PUC Order No. 22,919: https://www.puc.nh.gov/regulatory/Orders/1998ords/22919e.html.
See also EDI Standards: https://www.puc.nh.gov/electric/edi.htm.

do, in many instances by representing their non-compliance with extant market requirements as grounds to NOT implement key rules for CPAs.

As the default provider of competitive electricity service to retail customers, CPAs must have the practical ability to exercise the full authorities provided under RSA-53E.

In practice, this will require the utilities to (1) provide CPAs with sufficient data to inform energy procurement and rate setting to an industry-standard degree of diligence (including for customers with solar photovoltaics, electric vehicles, etc.), and (2) work with CPAs to modify their systems in reasonable ways to accommodate new rate structures and innovative services to CPA customers — the vast majority of which expect to receive a single bill from the utility for both generation supply and distribution charges.

The simple example below serves to illustrate how critical the alignment of meter data management, billing systems, and load settlement processes — all of which the utilities control — are in terms of enabling market-driven innovation:

- A CPA could lower capacity and transmission charges and shift a portion of electricity usage to low-priced wholesale market intervals for residential customers using smart thermostats or water heaters — and may find that it is so cost-effective to do so that participating customers could be provided with discounted or even no-cost thermostats (and/or a discounted supply rate) for opting into the service.
- However, the CPA will find it has no practical ability to offer or monetize such an innovative service in the event that:
    - Its customers' meters and/or the utility's current meter reading communications and meter data management system is incapable of providing interval usage data; and
    - The utility's billing system is (currently) not set up to effectively use this interval usage data when calculating rate charges and billing CPA customers; and/or
    - The utility's wholesale settlement processes still rely on statistically-estimated class-average load profiles (instead of the actual interval usage data of CPA customers) to calculate the CPA's wholesale market settlement charges.

Relevant here is the fact that there are latent opportunities for CPAs to enable innovation in time-varying rates and distributed energy services across EVERY utility territory — and that this opportunity could be readily exploited simply by better utilizing the common infrastructure which ratepayers have paid millions of dollars to deploy over recent years:

- Unitil has deployed an Advanced Metering Infrastructure (AMI) network to provide automated daily readings and validation of all retail electric customers meters — which are capable of recording Time of Use (TOU) intervals but are not currently utilized in this regard — and has invested in a billing system that could readily accommodate new time-varying rates.

- The NHEC has also deployed an Advanced Metering Infrastructure (AMI) network to provide automated daily readings of (practically) all retail electricity customers' meters, and to validate the hourly interval data that the meters produce, and has demonstrated the ability to provide time-of-use and critical peak pricing rate structures to customers in its territory (on an opt-in basis, and for electric vehicles, etc.).
- Liberty mainly has a legacy AMR system without interval metering (except for G1 accounts) but has begun to use AMI type interval meters with cellular data VPN connectivity for daily meter reading for GI and battery/TOU pilot accounts. It is our understanding that Liberty is in the planning stages for full AMI deployment in NH starting at some as yet unscheduled future year after deploying new SAS enterprise systems, including a new customer information system, which should enable new functionalities at lower incremental costs than their legacy systems.
- Even Eversource's Advanced Meter Reading (AMR) meters — often portrayed by the utility as incapable of basic functions like Time of Use — are actually capable of supporting "bidirectional (net) metering, time-of-use, demand with remote reset capability, event logs, programmability, self-monitoring/error/tamper codes, and similar features. [4] Enabling this functionality requires that the meter data is collected on a daily basis using a field network, instead of the monthly "drive-by" truck collection process the utility currently relies upon in New Hampshire.

  Eversource may deploy this functionality in New Hampshire on a territory-wide basis (as proposed in Connecticut), and/or CPAs may find it cost-effective to work with the utility to deploy field data collection systems (e.g., such as in cities, perhaps overlayed with municipal communication infrastructure deployments). T

Unfortunately, CPAs will be unable to explore these opportunities, and exploit this enabling infrastructure for the benefit of ratepayers, to any notable degree if the Commission accepts the recommendations submitted by the utilities in opening comments.

The Commission's final proposal will directly determine whether and to what extent (1) utilities finally comply with state law and long-standing PUC orders, and (2) Community Power Aggregators are afforded the practical ability to re-invigorate New Hampshire's competitive market.

In our view, the reason why the market has failed to benefit the vast majority of customers is self-evident: the utilities have demonstrated a consistent disinterest in tightening up the "nuts and bolts" of market operations to a degree that would permit any party — other than the utilities themselves — to perform straight-forward tasks such as offering new rate structures to residential customers, accessing interval meter data in a timely fashion for market operations, properly accommodating the more intensive data and billing requirements for net metered customers and electric vehicles, and so on and so forth.

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[4] Docket No. DE 19-057, "Rebuttal Testimony of Penelope McLean Connor", 3 March 2020. At pp. 17. Available online: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-057/TESTIMONY/19-057_2020-03-04_EVERSOURCE_REBUTTAL_TESTIMONY_CONNER.PDF

On behalf of our communities across the state, and for the benefit of all ratepayers, we petition the Commission to adopt our recommendations — and allow CPAs the opportunity to bridge the operational gaps required to make New Hampshire market work in practice.

General Comments on Utility Proposals

Data Platform

The first general comment of the NH Utilities is that standards for aggregating and anonymizing data in these rules should conform to standards adopted in the approved settlement agreement in DE 19-197 for incorporation into the online data platform at issue in that proceeding, arguing that parties to that settlement included "*individuals that comprise the Community Power Coalition of New Hampshire*."

In reality, the Community Power Coalition of New Hampshire does not consist of individuals; it is comprised of subdivisions of the state. More importantly, the DE 19-197 settlement agreement does not state or even imply that the standards for anonymizing data for general public access through the data platform should be or would be applicable to Electric Aggregation Committees or community power aggregations (CPAs) created pursuant to RSA 53-E or administrative rules adopted to implement that chapter.

While the municipal interests appearing in DE 19-197 as the "Local Government Coalition" did testify and argue that the data platform should be designed to meet various data needs of CPAs, the utilities generally argued otherwise and made the case that the platform in its initial stages should be designed as a "minimally viable product" (MVP) based on the Green Button Connect My Data standard.

Indeed, the Logical Data Model described in Appendix B of the DE 19-197 Settlement Agreement is premised upon the expectation that the platform "*will also provide the ability for an authorized user to retrieve aggregated data sets containing multiple utility customers*." (Id at 31.) Users seeking access only to aggregated data under the minimum of 100 customers per data set standard, which are deemed to be "*low or zero risk Data Sets*", would have minimal cyber security risk controls with only basic registration requirements. (Id at 39.)

The data needs for planning and implementing a CPA were not in any way expressly addressed in the Settlement Agreement in DE 19-197 [5] and the NH Utilities proposal that the standard of a minimum of 100 customers per data set per municipality should apply in these rules would seriously hamstring the efforts of CPAs to plan for and implement CPAs. While, perhaps in most cases, any given utility will

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[5] The only reference to municipal aggregation in the Settlement Agreement is the designation of one seat on the Platform Governance Council for "one representative of New Hampshire municipalities either participating in or with an aggregation plan developed for community power aggregation pursuant to RSA 53-E" to be initially filled by Clifton Below (at p. 9). His participation is not with an expectation that this minimally viable product will meet any of the data needs of CPAs in the near future, but rather to recognize that it is a starting point that is intended to be "extensible" and "adaptable to functionalities that may be desirable in the future" and I hope to be able to help advance to that end.

have 100 or more customers in any given rate or customer class, there are likely to be many instances where there are far fewer. For example, in the electric aggregation plan approved by the town of Harrisville and filed in DE 21-141, the total number of all Commercial & Industrial (C&I) customers taking utility default service is only 90, using 3,210 MWh/year, with another 20 on competitive supply using 242.5 MWh/year.[6] In the City of Lebanon's plan filed in DE 21-143, there were only 13 large C&I customers (in Liberty's G-1 rate class) on default service, using 9,762 MWh annually and 44 on competitive supply in the most year 12-month period.[7] Information on this distinct rate class is important because it is the only rate class that typically has hourly interval metering.[8] With just these two aggregated data points (customer count and annual load), it seems impossible that anyone could tease out any confidential customer data, even when the customer counts is relatively small.[9]

Moreover, while some 130 municipalities are served by only one electric distribution utility there are some 116 municipalities served by two or more distribution utilities. There could be many cases in which a given utility serves far fewer than 100 residential or non-residential customers in a given municipality. Indeed, even with the proposed 10 residential and 4/50 non-residential aggregation thresholds the NHEC in its comments notes "there are multiple towns in which the Co-op serves fewer than 10 residential and fewer than 4 non-residential members." (At p. 4.)

Consequently, as a practical matter, setting a data set threshold at 100 customers could make it very difficult for planning and implementing CPAs, as an understanding

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[6] www.puc.nh.gov/Regulatory/Docketbk/2021/21-141/INITIAL%20FILING%20-%20 at p. 6

[7] www.puc.nh.gov/Regulatory/Docketbk/2021/21-143/INITIAL%20FILING%20-%20PETITION/21-143_2021-12-01_LEBANON-REQUEST-APPROVAL-COMMUNITY-POWER-ELECTRIC-AGG-PLAN.PDF at p. 3.

[8] When large load customers have hourly interval metering that data is used by the utilities for load settlement. The load shape of a small subset of large C&I customers remaining on default service could be quite different than the class average load shape measured across the utilities service territory, so access to such data is essential to accurately, efficiently, and cost effectively pricing a CPA supply offering for such customers.

[9] Standards for anonymization of data sets were discussed in the rebuttal testimony of C. Below in Exhibit 15 in DE 19-197, pp. 75-76: ". . . the Illinois standard for release of anonymized data sets of customer data (not just aggregation) seem appropriate for adoption. Illinois has been an early leader in making multi-tenant energy data available to commercial building owners for benchmarking and other purposes. They have also enabled access to large quantities of anonymized AMI meter data. Their standard for the release of actual individual customer data sets, provided anonymously, is that there is required be a minimum of 15 sets of data with no one data set representing more than 15% of the load. That may be reasonable for NH. A few other states use a similar 15/15 standard for the release of anonymized data. The New York Public Service Commission found that to be too restrictive of community level commercial account data and have lowered their standard for such aggregated data, such as for publicly available community level data by rate class, to require a minimum of 6 customers in a data set with no one customer accounting for more than 40% of the total, so NY has adopted a 6/40 standard for aggregation of commercial customers, while maintaining a 15/15 standard for aggregation of residential customer data. [FN 18]

For the release of whole building energy data that includes tenant meter data, the New York PSC approved a 4/50 standard where "aggregated customer usage data is considered sufficiently anonymous to share publicly if (1) the aggregated group contains at least 4 individual accounts, and (2) no one account represents more than 50% of the total load. Where a set of data fails to pass the 4/50 standard, the building owner may only receive the data with tenant consent." For commercial class customers, we suggest that standard would also be appropriate for community level aggregated data, considering that small numbers of such C&I rate class customers in some New Hampshire towns.

of the load and number of customers that might be served and knowing something about what their load shape might be (by using class average load shapes disclosed by utilities on their websites) is essential to getting cost effective pricing to set adequate rates to enable a successful launch of the program.

While acknowledging that CPAs are subject to RSA 363:37 and 363:68 the NH Utilities seem to caution against allowing CPA access to any more data than is "essential to municipal aggregation operations" with a very narrow conception of what that is, as discussed below. New Hampshire's municipalities and counties continuously collect, store, and protect from disclosure or misuse large quantities of sensitive personally identifiable information of the most personal and private sorts, most of it digitally on government computer networks and those of qualified vendors, maintaining cybersecurity 24/7. For example, municipalities collect income and asset information from residents to qualify them for general assistance (welfare), elderly tax exemptions, and other programs, and in many cases utility data for water, sewer, and solid waste services; criminal records and investigation files are routinely protected by counties and municipalities; personal health information is protected by counties that operate nursing homes and jails and by municipalities that handle workers compensation claims of employees and collect health information in providing emergency and public health services.[10]

It does seem likely that energy and customer data provided by utilities to CPAs will generally be handled by qualified vendors that are experienced in working with such data, especially initially, although the Coalition anticipates that as it matures it will bring more data services in-house, but the point is that NH municipalities and counties, and their instrumentalities operated pursuant to RSA 53-A and 53-E, should be presumed to be competent, qualified, and trusted to receive and handle confidential customer information.

It also should be noted that RSA 53-E:4, VI authorizes CPAs to "*use individual customer data . . . for research and development of potential new energy services to offer to customer participants*", while RSA 363:37, III.(c) authorizes CPAs (as service providers) to use individual customer data as a primary purpose in *"[r]esearching, developing, and implementing new rate structures and tariffs, demand response, customer assistance, energy management, or energy efficiency programs."*

The "Core Functionality Approach" (or, the "Outdated Massachusetts Model")

Expanding on the idea of limiting CPA access to only data that is "essential" — under a so-called "*Core Functionality Approach (CFA)*" — the NH Utilities note their "*extensive experience supporting aggregations*" and opine that " *at no point in supporting those aggregations has the level of information requested in the Initial Proposal been necessary for those aggregations to launch and successfully develop.*"

Perhaps what the NH Utilities fail to understand is the relatively arrested state of development at which most Massachusetts aggregations are mired. Almost all of the

[10] For example, Lebanon's emergency medical services are provided by Lebanon's firefighters who are also EMTs (mostly advanced) and paramedics, operating ambulance service for Lebanon and some surrounding towns. With support from DHMC the City also employs two community nurses and a community paramedic that daily collect and protect personal health information.

municipal aggregations in Massachusetts (except the Cape Light Compact) have been stuck in the "CCA 1.0" model:

- The "CCA 1.0" model is the most basic community choice aggregation framework, under which a town engages a broker that packages up the aggregation for the town and puts the load out to bid to suppliers (i.e. load serving entities or "LSEs") which bid fixed prices that are locked in for a term, perhaps a year or two.
- This broker/bid model mimics how the utilities put default service load out to bid for fixed terms but can often beat the utility price due to flexible market timing and terms that brokers can take advantage of.

In contrast, the "CCA 2.0 and 3.0" models move community power into a much more holistic role in building a portfolio of supply resources that proactively manages risk and cost-effective procurement of a diversified portfolio of supply resources and providing a variety of other services to customer and communities to help them achieve their energy, economic, and environmental goals. For a more extensive discussion of what a CCA 2.0 and 3.0 [11] model might entail, please also see the testimony of Dr. Amro Farid in DE 19-197.[12]

2021's NH HB 315, as introduced (and originally drafted by Eversource), would have relegated and limited municipal aggregation in NH to the Massachusetts broker/bid model.

Fortunately, HB 315 was heavily amended — with near unanimous bipartisan support in both the House and Senate — and preserves and clarifies much more expansive governmental authorities granted to CPAs under RSA 53-E than Massachusetts aggregations operate under.[13]

These expanded authorities, unique to New Hampshire, include contracting for and providing "energy services", specifically:

1. The supply of electric power and capacity.
2. Demand side management.

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[11] Samuel Golding, "Understanding the Community Choice Energy (R)evolution in California", 15 October 2018. Available online: https://www.linkedin.com/pulse/understanding-community-choice-energy-revolution-samuel-golding/

[12] See in particular Dr. Farid's discussion of the "Shared Integrated Grid as a Realization of Legislative Objectives" starting on p. 6 (Bates p. 134) of his testimony found here: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TESTIMONY/19-197_2020-08-18_LEBANON_LGC_REV_TESTIMONY_FARID.PDF, and his Attachment C, "Accelerating the Shared Integrated Grid through an eIoT eXtensible Information Model: A Dartmouth-LIINES & EPRI Collaboration." Invited Presentation. Stanford University Digital Grid Series. Stanford, CA. July 15th 2020. Bates p. 189, and Attachment D, Faruqi, Ahmad, "Refocusing on the Consumer: Utilities need to prepare for the "prosumer" revolution." Regulation. Spring 2020. pp. 20-26. Bates p. 253, found at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TESTIMONY/19-197_2020-08-18_LEBANON_LGC_REV_ATT_TESTIMONY_FARID.PDF.

[13] The Cape Light Compact was formed through a joint powers agreement by most of the communities on Cape Cod. As the first municipal aggregation they aspired to and achieved something of a CCA 2.0 model, where they operate programs in-house, with their own staffing, including ratepayer funded energy efficiency programs. However, subsequent MA CCAs have generally not progressed beyond the broker/bid simple CCA 1.0 model.

3. Conservation.
4. Meter reading, with commission approval for meters owned or controlled by the electric distribution utilities or used for load settlement.
5. Customer service for aggregation provided services.
6. Other related services.
7. The operation of energy efficiency and clean energy districts adopted by a municipality pursuant to RSA 53-F and as approved by the municipality's governing body.

Further, CPAs can operate as "*self-supporting enterprise funds including the use of revenue bonds pursuant to RSA 33-B and RSA 374-D*", under which they can "*design, develop, acquire, and construct small scale power facilities*" and sell that power; and — singly or jointly (such as through the Coalition) — CPAs can become load serving entities and NEPOOL members.

With that in mind, we recognize that many of the data elements sought in the initial proposal are not currently readily available as the NH utilities and NHEC note in their assertions that the provision of such data would be costly and difficult for them.

Consequently, for most of the data elements in the initial proposal, the utility are only required to provide such data "*if known and readily available*" — so the rules do not impose burdensome time commitments or significant uncompensated costs.

Although "*readily available*" is not a defined phrase, commonly understood meanings are applicable:

- "*Readily*" can be defined as "*promptly; quickly; easily; without any problem.*"
- "*Readily available*" can be defined as meaning "*able to be used or obtained quickly and easily*."

However, there are a few important data elements that are needed to enable the NH model of Community Power to be able to cost-effectively price and secure power supply, particularly in the realm of load shape impacts at the municipal aggregation level. These include the utility's hourly estimated class load profiles (which is available through utility websites for CEPS, so does not need to be addressed in these rules) and actual customer interval load data where that is used for load settlement, actual load adjustment factors used for load settlement (at least on an annual average basis), excess net metered generation, residual or unaccounted for energy, and any other factors that the utility relied upon in calculating actual load on an hourly basis for daily ISO-NE reporting and market settlements.

This is essential data for pricing CPA default energy service accurately and efficiently, and for constructing retail rates (including net metering supply rates) in ways that minimize or avoid shifting costs across customers participating in the aggregation. It is also data that the utilities should readily have available, and the provision of this data should be a basic service of the distribution system operator supporting customer choice and competitive retail power supply markets. It is necessary to support demand side management and to realize appropriate price signals in electricity supply that support economic and technical efficiency and innovation — as called for by RSA 374-F.

Refer to 2204.02(a)(2) for additional discussion and our recommendations.

Cost Recovery for Retail Metering and Associated Infrastructure

This issue is discussed under Puc 2205.14 in specific rule comments.

Billing

The concerns about billing in 2205.16 are addressed in rule specific comments.

Net Metering and Limited Capabilities of NHEC

NHEC raises the point that they are not subject to RSA 362-a:9 concerning net metering. As this is true pursuant to RSA 362:2, II, we suggest that a simple solution would be to add a new paragraph under section 2201.02, Application of Rules, that reads:

> (e) Puc 2204.02(a)(4), Puc 2205.13(a)(9), and Puc 2205.15 shall not apply to CPAs where their customers are served by a rural electric cooperative for which a certificate of deregulation is on file with the commission, except by voluntary agreement of such a rural electric cooperative.

The reference to Puc 2205.13(a)(9) is to a revised section Puc 2205.13 recommended below that pertains to net metering in a way not applicable to NHEC.

At the NHEC is not generally subject to rate regulation and plenary oversight by the PUC pursuant to RSA 362:2, II, it may be appropriate to enable a specific waiver process for them where the cost to comply with the rules is not reasonably practicable at a reasonable cost to them or a CPA. Such language might also be added following the suggested (e) above under 2201.02, Application of Rules:

> (f) The commission shall waive the application of any particular rule in this part to a rural electric cooperative for which a certificate of deregulation is on file with the public utilities commission pursuant to RSA 301:57 if it finds upon petition of such a cooperative that compliance is not reasonably practical at a reasonable cost to the cooperative or CPA or CPAs requesting information or services from the cooperative.

Responses on Specific Rule Proposals

- **2202.02** Definition of "Anonymized" Both the NH Utilities and NHEC recommend that a specific standard for achieving anonymization be incorporated into the definition. Such a change would move it beyond being a definition into specifying a "substantive requirement" — which is not properly part of a definition according to the *New Hampshire Drafting and Procedure Manual* approved by the Joint Legislative Committee on Administrative Rules.[14]

- **2202.07** Definition of "Confidential customer information" The NH Utilities suggest deleting part of the definition. The proposed definition is identical to that in Puc

[14] Drafting and Procedure Manual for Administrative Rules EFFECTIVE 5/1/16, AS AMENDED EFFECTIVE 8-1-19, p. 108.

2002.09, virtually identical to that in Puc 3002.08, and is more protective of customer privacy than what the NH Utilities propose.

- **2202.11** Definition of "Electronic data interchange" The NH Utilities suggest referencing “EBT standards” (the term used in Massachusetts for EDI) that are “in place in NH” (presumably the one approved in PUC Order No. 22, 919 on May 4, 1998), which the utilities are arguably out of compliance with. We note that the proposed definition is the same as in Puc 2202.14, with the additional reference to CPAs pursuant to RSA 53-E:4, V. Again, "substantive requirements" are not supposed to be part of definitions.

- **2202.01** Notification of Formation of a CPA Committee
    - **2202.01(b)** The NHEC's suggestion seems appropriate and could be achieved by striking the words "the person or persons" in mid-sentence.
    - **2202.01(c)** We concur with clarifying the time frame to "10 ***business*** days".
    - **2202.01(d)** We do not object to requiring contact information to be updated when changed, however a requirement of every 6 months, presumably in perpetuity, is unnecessarily burdensome, especially since there is no requirement to maintain an electric aggregation committee after an electric aggregation plan has been approved by the subdivision's legislative body.

- **2203.02** Request for Usage Information from Utilities
    - **2203.02(b)** We concur with clarifying the time frame to be "30 ***calendar*** days", but does not agree, as NHEC suggests, that this basic aggregated data need only be supplied if known and readily available. That is a very low discretionary bar and should not apply to basic data needs that are known to the utility.
    - **2203.02(b)(1)** The NH Utilities suggest specifying a standard data format and method of transfer that would be required. Because the amount of such aggregated data is limited in quantity, we are ambivalent to the format used to provide the data, so long as the data is provided in machine readable format, and in regard to the method of transferring the data, which could be via secure email exchange or Secure File Transfer Protocol (SFTP). Currently we understand some utilities to use CSV format, while others may use PDF or Excel files. The data platform Settlement Agreement at p. 29 states that for aggregated data "[i]ndustry standard file formats such as CSV, XML, or JSON will also be considered." It would seem wise to leave the format question to the discretion of the utilities for this purpose, as the formats and methods of transference used presently vary and may change over time.

      NHEC suggests that such aggregated data be only supplied as "residential" or "non-residential," which would be highly problematic for planning purposes, as the NH Utilities split the "non-residential" (a.k.a. C&I) classes between the small customer group (typically C&I without demand meters, lumped in with residential customers) and the large customer group (some with and some without interval meters in the case of Liberty and Eversource). The NH utilities provide different default service products to these two groups and provide different load shapes for these two groups, as well as more granular rate class average load shapes. At a minimum, CPAs need to understand the number of customers and amount of load in each of the rate classes for which a utility provides class average load shapes. This could be accomplished by adding a clarifying paragraph, probably following (b) or (c) (with the remaining paragraphs renumbered) that reads:

> (x) Each customer rate class shall mean, as a minimum, each rate class or group of rates classes for which the utility publicly provides class average load shapes.[15]

The NH Utilities also suggest this be limited to 12 months of data. The text already provides a fallback to 12 months if 24 are not available. The Settlement Agreement in DE 19-197 calls for "at least 24 months of historical data" if available (at p. 7).

- **2203.02(b)(3) and (4)** The main body of the NH Utilities' opening public comments clearly includes these two items, counts of net metered customers and those participating in the Electric Assistance Program, in their CFA Report 1, outlined on p. 3 of their comments. Their redlined version of the rules states that their CFA does not include these elements. When asked about this at last Wednesday's stakeholder meeting, the utility representatives were unsure of what their collective position actually is, which will probably be clarified in their reply comments. We believe this a reasonable request and will be valuable for communities in planning and designing their aggregation plans.

- **2203.02(b)(5)** Absent a POR program this is critical information needed to plan and price electricity supply, especially since current receivable of competitive suppliers (and CPAs) are at the bottom of the waterfall payment system where CPAs would be paid for current electricity supply after all other receivables are paid. (The NH Utilities suggest this not be provided and that instead "*POR be in place prior to aggregation to avoid this need*" yet at the same time they ask to not have any requirement as to when they would be required to file a POR proposal with the Commission by striking 2205.15 from the proposed rules. We understand that providing this information on a municipality specific basis may be difficult for utilities. However, we note that Eversource's Electric Supplier Services Master Agreement states that the utility can provide suppliers with reports regarding "*the status of the customer's account with the Company as either subject to (a) a budget billing plan with the Company, (b) a payment plan with the Company, or (c) neither a budget billing nor a payment plan with the Company*."[16] As a middle ground, we offer the following clarifying language at the end of this sentence:

> (5) Until such time as the utility offers a Commission approved purchase of receivables program pursuant to RSA 53-E:9, revenues billed, actual receipts, and past due accounts receivable for utility default service for each rate class or by small customer group and large customer group for each of

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[15] NHEC provides load shapes for 5 rate class groups: COMLGE, COMMERCL, PRIMARYG, RESIDENT, and STREETLT, found here: https://www.nhec.com/electric-choice/supplier-information/. Liberty provides load shapes for 9 rate classes or groups linked to at the bottom of this page: https://new-hampshire.libertyutilities.com/londonderry/commercial/data.html. Eversource provides load shapes for 6 rate classes, found here: https://www.eversource.com/content/nh/residential/about/doing-business-with-us/energy-supplier-information/electric---new-hampshire. Unitil provides load shapes for 4 rate classes found here: https://unitil.com/suppliers/energy-supplier-resources.

[16] Eversource CEPS Agreement, Section A, 2. Available online: https://www.eversource.com/content/docs/default-source/doing-business/electric-supplier-master-agreement.pdf?sfvrsn=800bea62_14

the most recent 12 months available**, if readily available, and if not, then the utility shall provide such information on a system wide basis for a recent 12-month period."**

- **2203.02(c)** The NH Utilities suggest inserting the word "monthly" before interval. For this section of the rules that is not necessary as 2203(b)(1) clearly states that the usage data is "monthly usage data," though just to be sure the word "reported" could be inserted in front of "monthly usage data in 2203(b)(1). Referencing the "reported interval" more generically is important for 2204.02(2) and 2205.13(o) (in the initial proposal, or 2205.13(a)(7) in a recommended revision detailed below) where hourly interval data that is used for load settlement is very important in cost effective pricing of power due to load shape impacts and as a potential billing determinant for customers and to inform demand side management and rate innovation offerings. NHEC raises a concern because of how they uniquely define "consumption." To clarify and make more generic we suggest amending this section to read:

  (c) All customer usage data provided by the utility shall include ~~consumption~~ **power delivered to customers** and exports to the grid **from customer-generators** in kWh for each reported interval.

- **2203.02(e)** NHEC expresses concern that the language does not address the situation where a single customer has multiple accounts. The adjective "distinct" qualifies the word "customer" here meaning that the minimum count of customers is for "clearly separate and different" customers. If there are only 5 non-residential accounts in a given community and 3 of them are the same (or closely related) customers, then the 4 "distinct" customers threshold would not be met.

- NHEC also suggests clarifying the phrase "50 percent of the total usage." We support such clarification, preferably to "over the most recent 12-month period" here and elsewhere similar language appears.

- The opening line refers to "the monthly load data" which would better read "the monthly **usage** data", as shown below:

  (e) With respect to the monthly ~~load~~ **<u>usage</u>** data required to be provided pursuant to (b)(1) above:

- The NH Utilities concerns about the standard for anonymization here being different than in the data platform are addressed in our general comments above.

- To address the comment of NHEC about how to deal with situations where the minimum thresholds are not met even after grouping all residential or nonresidential accounts together, we suggest adding new subparagraphs as follows:

  (3) If there are fewer than 4 distinct non-residential customers or fewer than 10 distinct residential customers, such usage data shall be reported together without identifying the type of customer, provided that the overall group contains at least 10 distinct customers and no one customer constitutes more than 25% of the total usage over the most recent 12-month period.

  (4) If the criteria in subparagraph (3) above are not met and there are at least 4 distinct customers, the total annual usage of all such customers (rather than monthly) shall be

> provided for the most recent 12-month period available without identifying the number of such customers (other than “less than 10 customers”); and if not, than no usage or customer counts shall be provided (other than “less than 4 customers”).

- **2203.02(f)** NHEC's suggestion that the data request be not more frequently than every 6 months, rather than every 3 months, is reasonable and amenable. After a CPA launches such requests will be moot.

- **2204.01(b)** Submission of EAPs We support qualifying "the first 21 days" as "the first 21 **calendar** days" (3 weeks).
- **2204.02** Request for Anonymized Customer-Specific Information from Utilities
  - **2204.02(a)** We recommend that the reference to 30 days be clarified to "30 calendar days".

    We recommend against qualifying all data under this paragraph as only provided if readily available. Some of this data is critical to determining load shapes and wholesale billing determinants to cost-effectively price power supply to achieve the lowest cost retail rates for customers.
  - **2204.02(a)(1)** Each customer's (or account's) ICAP capacity tag is an essential billing determinant in purchasing power through the ISO New England wholesale electricity market. Along with LMP and ancillary services, it is a primary determinant of the cost of providing service. NHEC says ICAP tags are not stored in their billing system, but they must be stored somewhere in the load settlement system they use, as they are required for each LSE's meter/customer domain account to settle their load, so they should be able to extract and report data subsets (as they acknowledge doing for competitive suppliers upon request). When a customer (and their account and meter) switches suppliers, their individual ICAP tag goes with them, as does that determinant of the cost to serve them. There should not be a charge to provide this essential data. We understand that the utilities do not retain past year or know next power year capacity tags before the start of that year, and if they did, such data wouldn't be readily available. As such, the language in the initial proposal should not be a problem for the utilities, and maybe someday this might be enabled.
  - **2204.02(a)(2)** We recommend clarifying language along the lines recommended by Colonial Power Group, but with further modification based on feedback received at the stakeholder workshop hosted by DoE on 3/23/22, during which the NH Utilities’ clarified that excess net metered generation is not included in customer usage data files — but is an input into the utilities’ load profile construction process that determines hourly loads for ISO-NE reporting and wholesale settlements:

    > (2) The most recent 24 months, if available, or 12 months otherwise, of usage data in kWh for each monthly interval for accounts reported in monthly intervals for load settlement, and for each hourly interval for accounts reported in hourly intervals for load settlement.

    All of this is essential data for pricing CPA default energy service accurately and efficiently, and this dataset is what CPA power procurement solicitations will be based upon. CPAs (and Competitive Electric Power Suppliers) should have access to the most accurate load shape data for customers they are preparing to serve. To the extent that customer-specific hourly interval data is used for load settlement, it should be provided to the CPA. This is done for CEPS serving large C&I accounts. If only monthly meter data is used, shaped by class average load shape, then only monthly usage data is needed for pricing. Similarly, CPAs should be provided with the actual inputs that have gone into calculating aggregate load profiles for wholesale settlement reporting — including excess generation from net metered accounts, which is data that the CPA also requires to accurately estimate the cost to serve this subset of customers, and to set net metering supply rates in a manner that minimizes or avoids shifting costs to other customers participating in the aggregation.

There should not be a charge for this data or to modify systems to extract and report it. It is a basic service of the distribution system operator supporting customer choice and competitive retail power supply markets and is necessary support demand side management and to realize appropriate price signals in electricity supply that support economic and technical efficiency and innovation, as called for by RSA 374-F.

Lastly, NHEC's objection to providing usage data because their "*MDM [meter data management] system does not store energy provider name and cannot determine which accounts are default service*" should be disregarded. We observe that this would presumably be a barrier to providing ANY of the datasets required under 2204.02. Similar to the NHEC's objection to 2204.02(a)(1), the required data is held by the utility and stored in a different system (e.g., their billing system and customer information system). NHEC will simply need to export and cross-reference the datasets from these systems in order to prepare a dataset.

- **2204.02(a)(3)** We recommend clarifying this text by having it read along these lines:

  (3) The meter reading **date or utility reference number for the read** cycle for each customer account;

2204.02(a)(4) As NHEC is exempt from the net metering statute, RSA 362-A:9, and apparently only has one set of terms in their tariff, we recommend exempting them from compliance with this provision by adding a new paragraph under section 2201.02 as discussed in our general comments above.

In response to the NH Utilities' comments, what is being sought here is an understanding of the kWh usage or load shape of customer-generators based on whether they get kWh credits for net exports to the grid under the original form of net metering in effect before September 1, 2017 (NEM 1.0) when new "Alternative Net Metering Tariffs" went into effect in accordance with PUC Order No. 26,029 (NEM 2.0). This information is essential to enable CPAs to determine "the terms, conditions, and prices under which they agree to provide generation supply to and credit, as an offset to supply, or purchase the generation output exported to the distribution grid from eligible customer-generators" as provided for in RSA 362-A:9, II. Clarifying language might read:

(4) Whether the customer net meters and, if so, ~~under which~~ **whether under original** net energy metering terms~~, whether set forth in tariff or otherwise~~ **available prior to September 1, 2017, or new alternative net metering terms and tariffs that have been available since September 1, 2017, or any subsequent successor terms and tariffs**.

Note that this matter is further discussed under 2205.03 below.

- **2204.02(a)(5)-(8)** Generally, the term "account" might be substituted for "customer" here to the extent any of this data is tracked by account rather than customer. While these data elements would be desirable and useful in planning possible value-added energy service options, they are not essential to launching CPAs and early development, which is why three (out of four) state that the data only needs to be provided if "known and readily available." Subparagraph (6) is the exception, and that provision, "if known and readily available," could be added:

  (6) Whether a group net-metered customer-generator operates as a low-moderate income solar project pursuant to RSA 362-F:2, X-a and the Commissions PUC 900 rules**, if known and readily available**.

- **2204.02(b)** The initially proposed language here gives utilities the greatest latitude in determining what digital format works best and is most cost effective and/or secure for them, which we know already varies and may change over time, as noted in the discussion under 2203.02(b)(1) on p. 11. CSV could be added to the list of examples, in response to NHEC's concern regarding spreadsheet limitations. PDF formats used by NHEC for many reports should be okay if they are more digital text than scanned images, i.e., text can be captured from the file without having to run OCR on an image, such as PDFs that can be exported to Word or Excel format. The following clarifying language may suffice:

  b) The information required to be provided pursuant to (a) above shall be provided in **machine-readable** digital electronic format, such as a database, **comma-separated value** or spreadsheet file, but not in the form of scanned images.

- **2204.02(d)** See the comments under 2203.02(e) on p. 13. We recommend the same two additional subparagraphs proposed on p. 13 be added under this paragraph. Also, adding the phrase "over the most recent 12-month period" after the phrase "50 percent of the total usage" in subparagraph (1) makes sense too.

- **2204.02(e)** NHEC's suggestion that the data request be not more frequently than every 6 months, rather than every 3 months, is reasonable and amenable to the Coalition. After CPA launch such requests will be moot.

- **2204.03** Request for Names, Address, and Account Numbers of Customers
  - **2204.03(a)(3)** While this item is not essential, it may be helpful in assisting a customer with multiple meters figure out which account goes with which meter when deciding to enroll some of their loads in a CPA, but not others. It could be qualified with "if known and readily available" or deleted. Also "meter identification" could be dropped or qualified with "meter identification **number**."
  - **2204.03(a)(6)** We support Colonial Power Group's suggested addition of new subparagraph (6) for the reasons they explain:

(6) whether the account is receiving default service from the utility or supply service from a CEPS.

- **2204.03(b)** Refer to the discussion under 2204.02(b) above. We recommend the following language:

  b) The information required to be provided pursuant to (a) above shall be provided in **machine-readable** digital electronic format, such as a database, **comma-separated value** or spreadsheet file, but not in the form of scanned images

- **2204.03(c)** We recommend "15 **calendar** days" (half a month).

- **2204.03(d)** In this instance we recommend not adopting NHEC's recommendation that a CPA may only request the dataset once every six months (instead of every three months). This is relatively small amount of data that should be relatively easy to extract after it is done the first time and if a CPA launch is delayed by 3 to 5 months from what is anticipated at the time of an initial request, they will need to refresh this data to comply with RSA 53-E:7, III.

- **2204.04(b)** Days should be calendar days, not business days.

- **2204.05(g)** NHEC expresses concern about required notice to the utility of a customer transfer back to utility default service. That concern seems to be addressed by the phrase "with adequate notice in advance of the next regular meter reading by the distribution utility, in the same manner as if they were on utility provided default service". To address that fact that NHEC does not do off-cycle meter reads the next to last sentence could be added to so it reads:

  "Customers requesting transfer of supply service upon dates other than on the next available regular meter reading date may be charged an off-cycle meter reading and billing charge, **if such a service is available from the utility.**"

- **2205.01** Provision of Electricity Supply Service

  - **2205.01(a)** There is some confusion over this text. We believe the intent was to indicate that, as a whole, a CPA may be served by more than one LSE, such as how the NH Utilities use more than one LSE to serve their default service load, not that any one customer account could be served by more than one LSE at a time, so clarifying language is in order.

    We strongly object to NHEC's recommendation that CPAs be allowed to use only one LSE for EVERY customer in the aggregation and protest the NHEC's current practice of restricting each supplier to only using "one asset per metering domain".

    We agree that each account (each separate customer meter) can and should only be served by one LSE at a time and the time to switch between LSEs is at the regular meter reading date, with adequate notice through the EDI system.

    However, there is no compelling reason why any given CPA — which may or may not be registered as an LSE itself — should not be able to offer customers service through different LSEs, or assign subsets of customers as load assets registered to different subaccounts of one or more LSEs. Separately bidding the small customer and large customer groups, as the utilities do with their default service, and is sometimes done under the broker/bid model, may achieve lower rates. Further, more innovative rate options that might be offered on an opt-in basis, such as dynamic hourly pricing that some large C&I customers opt for, may require a CPA to use a separate LSE from the one (or more) used to provide their fixed price default energy service — or such programs might be most cost-effectively delivered by registering participating customers under a discrete subaccount of the CPA's LSE for load settlement purposes. Consequently, we strongly recommend the Commission to afford CPAs with maximum flexibility in these regards.

With regard to the NH Utilities' confusion over a very simple concept around CPAs providing all requirements service and in full compliance with ISO New England policies and NH law: the proposed rules simply recognize that if a CPA or their LSE is purchasing power from a distributed generation or storage source — that is not a participant in wholesale electricity markets administered by ISO-NE, meaning that it is going to less than 5 MW in rated capacity and is interconnected to the NH utility distribution grid — then it is going to be treated as a load reducer for purposes of determining the balance of load that must be settled in the ISO-NE market.

As the utilities know, "*ISO New England Operating Procedure No. 14 - Technical Requirements for Generators...*" sets forth technical requirements for generating facilities under the control/jurisdiction of ISO-NE. It expressly provides that a "*generating facility*" less than 5 MW in capacity interconnected below 115 kV (on the state jurisdictional distribution grid) "*may elect to not register [with the ISO as a generator] if not participating in any New England Markets other than as a load reducer*." The way ISO-NE defines "*generating facility*" includes battery storage. Treated as a load reducer, such distributed generation or storage ("DG" or "DERs") reduces the amount of energy, capacity, and ancillary services that must be purchased through the ISO-NE wholesale market, that is, it looks like a load reduction.

CPAs have the authority to purchase such power from such DERs pursuant to RSA 53-E, RSA 374-D, RSA 362-A:2-a, and RSA 362-A:9, II expressly provides that power exported to the grid by customer-generators of CPAs (and CEPS) "*shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply as a load service [sic] entity, net of any applicable line loss adjustments, as approved by the commission*." So, to provide a simple illustrative example:

- Normally, if a supplier is selling 20 MW of power to their customers as measured (or estimated) during a given hour, and none of that was supplied by DG (including customer-generators), and the line loss adjustment factor is 5% (for example) then that LSE would need to purchase 21 MW of power through ISO-NE.
- If, on the other hand, customer-generators (and potentially other DG that the CPA purchases power from) are supplying 1 MW of power onto the same utility's distribution grid during that same hour (metered or estimated), then the apparent retail load will look like 19 MW, and without any credit for reduced

transmission losses given by the PUC, that supplier's load settlement with ISO-NE would be 19.95 MW (19 X 1.05).

We recommend this clarifying language:

> (a) A CPA, including a CPA operating as an LSE, may use more than one LSE to serve their customers, provided that each CPA customer account shall be served by only one LSE at any given time. CPAs shall be responsible for providing all-requirements service to meet each CPA customer's full load requirements, which may include as an offset to each LSE's wholesale load settlement obligation with ISO-NE any electricity exported to the grid of the utility distributing the electricity by distributed generation and storage, including customer-generators of the CPA, that are not participants in wholesale electricity markets administered by ISO-NE, except as an alternative technology regulation resource (ATRR) to the extent ATRRs are deemed by ISO New England to function as retail or network load reducers for all other ISO New England purposes, and that are selling or providing their power to the LSE, with any adjustments for line losses as approved by the commission.

- **2205.02** Application of Puc 2000 to CEPS When Providing Electricity Supply to CPA Customers The NHEC notes 3 Puc 2000 provisions that are not included in this section. The first, Puc 2004.11 concerning solicitation of customer is entirely inappropriate for CEPS that are serving CPAs. CPAs are controlled by public bodies and are accountable to the citizens in the communities they serve through the elected governing bodies and the legislative bodies of their municipality or county. In turn, any CEPS acting in their capacity serving a CPA, will be under contract with and accountable to the CPA rather than individual customers. The second, Puc 2004.12, concerns off-cycle meter reading and seems entirely appropriate to include in 2204.02, so is a good catch by NHEC. The third, Puc 2004.14 doesn't seem appropriate as a CEPS serving a CPA as an LSE will be under contract with the CPA and not the individual customers as is generally presumed in the Puc 2000 rules.

- **2205.03** Utility Services to CPAs.

The Coalition and the OCA strongly object to NHEC's recommendation that CPAs not be permitted to choose consolidated billing or dual-billing service on a customer specific basis.

As a threshold matter, the fact that NHEC is apparently forcing suppliers to choose between dual-billing or consolidated billing service for ALL customers served by the supplier "*at the time of the supplier's registration with NHEC*" is non-compliant with the standards and guidelines made by the Electronic Data Interchange Working Group report made effective by PUC Order No. 22,919 and other applicable regulations of the PUC.[17]

Specifically, the Supplier Guide — which is referenced in the Working Group report and is one of the documents that comprise the EDI Standards — was clearly written to accommodate dual-billing and consolidated billing service on an individual, customer-specific basis (emphasis added):

> *Standard Billing Service - Passthrough (Separate Bills): Standard billing service requires the Distribution Company to electronically transfer to a Customer's authorized Competitive Supplier the Customer's usage data within twenty*

[17] EDI Standards: https://www.puc.nh.gov/electric/edi.htm.

four (24) hours of the Distribution Company's issuing a bill to that Customer . . . After receiving the data, the Competitive Supplier can issue a separate bill for energy services provided.

Consolidated Billing Service: Under this option, a Competitive Supplier or its agent must provide the Distribution Company with its price schedule for the relevant Customer or customer class. Using these prices and metered usage data, the Distribution Company can calculate the Customer's energy service bill and include this on a single bill together with Distribution Company's unbundled transmission, distribution and stranded cost charges.[18]

We observe that the other utilities appear to properly accommodate dual-billing and consolidated billing on a customer-specific basis. Eversource, for example, allows that *"Once an agreement for provision of consolidated billing service is effective, the Supplier can specify on a customer by customer basis which customers it wants to receive consolidated billing service from the Company."*[19]

As a practical matter, forcing CPAs to choose between EITHER consolidated billing OR dual-billing service for ALL customers would result in the CPA electing consolidated billing service for all customers. The vast majority of mass market customers do not want to receive two bills and would find it confusing. It would also cause the CPA to incur significant and needless expense.

However, the NHEC's proposed rule would effectively preclude CPAs in ANY utility territory from dual-billing select groups of customers, such as those with distributed generation, or the more the larger commercial and industrial customers still left on utility default supply service. This would be a particularly acute problem that could compromise a CPA's ability to cost-effectively serve net metered customers in practice. Attachment 6 to the City of Lebanon's and town of Rye's electric aggregation plans filed with the PUC in DE 21-143 and DE 22-001, respectively, explain the issues and possible solutions for CPAs to serve net metered customers.[20]

Furthermore, suppliers that are already serving customers in NHEC's territory on a pass-through billing basis would be effectively precluded from participating in CPA solicitations — which would diminish competition and increase rates for customers – due to the fact that the NHEC would be apparently unable to allow the same supplier to serve individual customers on a pass-through basis while serving CPA customers on a consolidated billing basis.

- **2205.04** County CPAs That Contain Municipalities with Adopted or Planned CPAs NHEC's suggestion on this proposed rule seems okay, but not necessary, so we don't have any language to suggest.

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[18] EDI Standards, Supplier Guide: https://www.puc.nh.gov/electric/EDI/part002-nhguide%20v3.pdf.

[19] Eversource CEPS Agreement, Section A, 1. Available online: https://www.eversource.com/content/docs/default-source/doing-business/electric-supplier-master-agreement.pdf?sfvrsn=800bea62_14.

[20] The City's plan is linked to in footnote 8. Rye's is at: www.puc.nh.gov/Regulatory/Docketbk/2022/22-001/INITIAL%20FILING%20-%20PETITION/22-001_2022-01-07_RYE_COMMUNITY-POWER-ELECTRIC-AGG-PLAN.PDF.

- **2205.05** New Utility Service Customers
    - **2205.05(b)** Not clear why this is unclear to NHEC, as the paragraph starts off with "Upon request of a CPA" so there is no obligation of the utility to automatically send the data, only upon request.
- **2205.12 Complaints and Dispute Resolution.**
    - **2205.12(b)** We concur with the NH Utilities that the reference should be to RSA 53-E:7, X.
- **2205.13** Individual Customer Billing Information In general we concur with CPG's suggestion to differentiate between the more essential elements that can readily be provided now or could be with only a modest effort and should be available without charge, and those which should only be required to be available if known and readily available or if CPAs pay for the cost to make them available. In the former category should be the data fields listed in the initial proposal under: (a), (c), (d), (i), (l), and (o). Here is our recommendation for a rewrite of this section:

Puc 2205.13 Individual Customer Billing Information.

(a) Once an individual utility customer has become a customer of a CPA, the utility shall provide to the CPA the following information, which may be provided through EDI access or otherwise, for each such customer, to the extent applicable:

(1) name and mailing address,

(2) utility account number or numbers,

(3) service address,

(4) utility rate class or code for each account,

(5) name key,

(6) the meter reading date or utility reference number for the read cycle for each account,

(7) the most recent 24 months, if available, or 12 months otherwise, of usage data in kWh for each monthly interval for accounts reported in monthly intervals for load settlement, and for each hourly interval for accounts reported in hourly intervals for load settlement,

(8) ICAP capacity tag or the current power year, and for the next power year, when known and if readily available,

(9) whether the customer net meters and, if so, whether under original net energy metering terms available prior to September 1, 2017, or new alternative net metering terms and tariffs that have been available since September 1, 2017, or any subsequent successor terms and tariffs.

(10) any other information typically made available to CEPS through the utility EDI.

(b) Once an individual utility customer has become a customer of a CPA, the utility may provide to the CPA the following information, which may be provided through EDI access or otherwise, for each such customer, to the extent applicable, known, and readily available:

(1) Name of customer contact, if different from customer name;

(2) Home or company phone number;

(3) Mobile phone number;

(4) Email address;

(5) Preferred billing and communication method;

(6) Form or type of meter reading or meter model and communication module identifier;

(7) The size in kW-AC of any such distributed generation located behind the customer's meter;

(8) Whether the customer is a group net metering host or member with on-bill crediting;

(9) Whether the customer's distributed generation facility has been determined to be a low-moderate income community solar project;

(10) Whether the customer participates in the Liberty Utilities battery storage pilot program or any other battery storage program;

(11) Whether the customer is currently enrolled in the electric assistance program; and

(12) Whether the customer is currently on a payment plan or a budget billing plan.

Note that item (a)(9) listed above uses the same language we have proposed for 2204.02(a)(4).

Note also that items (b)(2), (b)(3), and (b)(4) listed above are among the "minimally viable product" (MVP) Data Fields for the Utility Logical Data Model in the Settlement Agreement in DE 19-197 (at p. 34).[21]

- **2205.14** Enabling Meter Reading Authority and Access to Interval Meter Data

The NH Utilities and NHEC seriously misconstrue proposed Puc 2205.14 as imposing costs and requirements on them when in fact, all of the "requirements" (1) derive from RSA 53-E:4. The current language of Puc 2205.14(a)(1), and (2) merely allow a CPA to propose certain metering and meter reading arrangements subject to utility approval in the first instance, and with such utility approval, to then seek Commission approval in an adjudicated proceeding. Without such utility approval, while a CPA could propose a metering arrangement in an adjudicative proceeding the burden of proof would be on the CPA to demonstrate to the Commission's satisfaction that the proposal "is for the public good and the terms and conditions of the agreement are just and reasonable."

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[21] Available online: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/LETTERS-MEMOS-TARIFFS/19-197_2021-04-28_EVERSOURCE_JT_SETTLEMENT_AGREEMENT.PDF

- **2205.14(a)** The purpose statement and much of detail that follows that the NH Utilities and NHEC object to merely mimics and fleshes out what RSA 53-E:4, IV expressly states:

  > *"IV. For the purpose of obtaining interval meter data for load settlement, the provision of energy services, and near real-time customer access to such data, a municipal and county aggregator may contribute to the cost of electric utility provided meter upgrades, jointly own revenue grade meters with an electric utility, or provide its own revenue grade electric meter, which would be in addition to a utility provided meter. . . ."*

  The five subparagraphs **(a)(1)-(5)** that follow elaborate on statutory authority, but all are subject to approval by the utility and then approval by commission, in an adjudicated proceeding, and a finding that such agreement between the CPA and a utility is for the public good.

- **2205.14(a)(3) and 2204.14(a)(4)** These develop the idea of allowing CPA to contribute to the incremental cost of interval meters over and above what utilities are budgeting for and purchasing as replacement legacy meters that aren't capable of interval metering and may soon be obsolete.

  This is an idea that was suggested by former PUC staff as part of their grid modernization recommendations as a way to help support more appropriate price signals through rate innovations that have considerable economic value to customers and grid as a whole. Please see "*Expanding Customer Choices in a Renewable Energy Future*" by Ahmad Faruqui, Principal, and Mariko Geronimo Aydin, Senior Associate, The Brattle Group, found at Bates and PDF page 44 in Exhibit 15 in DE 19-197.[22]

- **2205.15** Net Metering by CPAs

  This language simply reiterates what is stated in RSA 362-A:9, II, which NHEC is not subject to. We recommend that NHEC be exempted from this rule, as discussed in regard to 2204.02(a)(4) above. As described under 2205.01(a) above, ISO-NE policy is to treat small scale DG, such as net metered generation, that is not registered with them as a generator or otherwise, as a load reducer relative to ISO-NE markets.

- **2205.16** Billing Services and Purchase of Receivables for CPAs

  - **2205.16(a)** NHEC asserts that any given LSE must choose to serve all customers through either separate (dual) or consolidated billing, while this is apparently not a problem for the NH Utilities. This is a non-trivial obstacle to customer and community choice of how a CPA may want to serve different customers with different needs, such as is described under 2205.03 and 2205.01(a). We suppose the Commission could create a carve out for NHEC here, but we strongly recommend that the Commission not impose limitations on this option because one distribution company's systems doesn't support it.

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[22] Available online: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TRANSCRIPTS-OFFICIAL EXHIBITS-CLERKS REPORT/19-197_2021-05-05_EXH_15.PDF

- **2205.16(c)** The Coalition and OCA strongly objects to the NH Utilities' removal of this section in its entirety.

  Regarding 2205.16, c, 1: it should be non-controversial that customers contacting the utility for CPA-related inquiries be provided with the CPA's customer service number. This was, in fact, proposed by the utilities as a compromise in response to the Coalition's initial suggestion that the customer's call be directly transferred by the utility to the CPA. (The utilities represented that they wouldn't know how to transfer the call.)

  Regarding 2205.16, c, 2: The NH Utilities' assert that it is *"[u]nclear why utilities should modify terms and conditions as described and be committed to implementing individualized "pricing options and rate structures""*.

  We would like to clarify that the reason why utilities MUST modify their terms and conditions as described is because all of the utilities' competitive supplier agreements and associated terms and conditions appear to be non-compliant with the standards and guidelines made by the Electronic Data Interchange Working Group report made effective by PUC Order No. 22,919 (May 4, 1998) and other applicable regulations of the PUC.[23]

  Specifically, the Supplier Guide — which is referenced in the Working Group report and is one of the documents that comprise the EDI Standards — requires the utilities to accommodate reasonable requests to implement new rate structures and associated modifications to their billing and metering systems at the suppliers' expense:

  > *In order to support the consolidated billing option, Suppliers must adhere to NHPUC approved Customer class designations for each Distribution Company… If a Supplier makes a written request to add a pricing/rate structure not currently supported by a Distribution Company, the Distribution Company will consider making reasonable changes to its billing system. The requesting Supplier will be responsible for any costs incurred to make the designated changes, which will be quoted by the Distribution Company to the Supplier in advance of any changes. A different price structure may also require the installation of a different meter.* [24]

  The only limitation to this billing system change request process is as follows (emphasis added):

  > *Competitive Suppliers who select the Consolidated Billing Option are limited to the rate structures, customer class definitions and availability requirements that are within the capabilities of the Distribution Company's billing system."*[25]

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[23] *See* PUC Order No. 22,919: https://www.puc.nh.gov/regulatory/Orders/1998ords/22919e.html

See also EDI Standards: https://www.puc.nh.gov/electric/edi.htm

[24] EDI Standards, Supplier Guide, Section III, D, 4. Available online: https://www.puc.nh.gov/electric/EDI/part002-nhguide%20v3.pdf.

[25] Ibid., Section III, D, 1.

Despite this, the utilities have apparently either explicitly forced suppliers to use the utility's distribution rate structures, or incorporated language that would inappropriately allow the utility to refuse to consider making reasonable changes.

Below are a selection of relevant excerpts taken from each of the utility's competitive supplier agreements and/or associated terms and conditions (emphasis added):

1. The New Hampshire Electric Cooperatives tariff explicitly limits suppliers to using the distribution utility's rate structures:
    a. "Competitive suppliers who select Consolidated billing <u>are limited to the rate structures, customer class definitions and availability requirements that the Cooperative utilizes for billing</u> its unbundled delivery charges."[26]
2. Liberty Utilities' competitive supplier agreement (see "a" below) flatly prohibits suppliers from using rate structures other than those in use by the utility, and their associated terms and conditions for competitive suppliers (see "b" and "c" below) further stipulate that demand and time-of-use billing determinants must be the same as the distribution utility uses for its own rate structures:
    a. *"Supplier rates and pricing options <u>must conform to the rate structure in use by Company</u> for each specific rate class service and be supported by meters in place."*[27]
    b. *"Billing Demand: Units of billing demand <u>shall be as defined in the Company's applicable Rate Schedule</u>."*[28]
    c. *"On-Peak / Off-Peak Period Definitions: The on-peak and off-peak periods <u>shall be as defined in the Company's applicable Rate Schedule</u>."*[29]
3. Unitil's terms and conditions (see "b" and "c" below) appears to comply with Commission direction, but the utility's competitive supplier agreement (see "a" below) only allows suppliers relying on consolidated billing services to change <u>rate levels</u> using the utility's distribution rate structures:
    a. "Supplier rates and pricing options <u>must conform to the rate structure in use by Company</u> for that specific tariffed Distribution Service and be supported by meters in place."[30]
    b. *"If a Competitive Supplier requests different customer classes or rate structures than are offered by the Company, <u>the Company shall</u>*

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[26] NHEC Tariff No. 21, Section 5.4, c (2nd revised page 9). Available online: https://www.nhec.com/wp-content/uploads/2016/12/tariff-document-member-responsibililties.pdf

[27] Liberty Utilities, Competitive Electric Supplier Trading Partner Agreement, Section VII, B, 2. Online: https://www.dropbox.com/s/02jnopxh9ryjzfz/Liberty_CEPS%20Agreements%20with%20Exhibits.doc?dl=0

[28] Liberty Utilities, Terms and Conditions for Competitive Suppliers, Section 62, v, 1 (original page 84). Available online: https://new-hampshire.libertyutilities.com/uploads/Rates%20and%20Tariffs/Electric%202017/Tariff_May_2017.pdf

[29] Ibid., Section 62, v, 2 (original page 84).

[30] Unitil, Competitive Electric Supplier Trading Partner Agreement, Section VII, A, i (original page 85). Available online: https://unitil.com/sites/default/files/2021-05/Trading%20Partner%20Agmt.pdf

accommodate changes to the billing system, if reasonably possible, at the Competitive Supplier's expense. The costs of making the designated changes shall be quoted by the Company to the Competitive Supplier and payment must be received by the Company prior to the start of programming."

  c. *"Competitive Suppliers may define on-peak and off-peak periods differently from those above; however, they will be required to make special metering arrangements with the Company to reflect different on-peak and off-peak definitions. Any costs incurred to provide the special metering arrangements shall be assigned and billed to the Competitive Supplier."*

4. Eversource's competitive supplier agreement (see "a" below) does not explicitly require suppliers to conform to distribution utility rate structures — and could be interpreted as being in compliance with Commission direction — but the utility's terms and conditions (see "b" below) inappropriately stipulates that any changes to (for example) rate structures would have to be provided entirely "*at [Eversource's] option*".

  a. *"Supplier rates and pricing options must be supported by meters in place and the Company's billing systems."*[31]

  b. "*The Company shall also provide, at its option, Billing and Payment Service for Supplier pricing options which require programming changes to the Company's billing systems.*"[32]

  This is clearly non-compliant with the EDI Standards Supplier Guide — which actually requires utilities to evaluate any supplier request for new rate structures, and provide the supplier with a quote for the expense of the required programming, so long as the requested rate structure is "*within the capabilities*" of the utility's billing system to accommodate. (In other words, utilities are NOT supposed to have the "option" of declining to make reasonable changes to their billing systems upon request!)

On the basis of the lack of clarity and apparent range of non-compliance with PUC Order No. 22,919 — and also because the utilities, over the course of the rule development process including in their opening comments, have strongly indicated an aversion to accommodating CPA requests for different rate structures — we urge the Commission to retain 2205.16(c) in order to ensure that all distribution utilities are brought into compliance.

To more completely align 2205.16(c) with the letter and spirit of PUC Order No. 22,919, and also to explicitly address NHEC's concern's regarding limitations to their ability to re-configure the registers of their Advanced Metering Infrastructure (AMI) smart meters — along with related issues regarding the dual use of common network infrastructure (e.g., resolving potential conflicts between distribution and supply billing determinants) — we recommend that the following language be added:

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[31] Eversource CEPS Agreement, *A, 2 (p.7):*

[32] Eversource T&Cs, 2, d:

(c) Terms and conditions provided by the utility for CPA billing services shall:

(1) Require that customers contacting the utility regarding the billed amount for CPA services or any other CPA issue are provided with the CPA's customer service number; and

(2) Allow a CPA to define on-peak, mid-peak, and off-peak periods or other pricing options and rate structures that are different from those defined in the utility's applicable tariffs on file with the commission, and to request enhanced metering services for customers to participate in programs and services beyond the provision of basic electricity supply service, provided that**:**

> **a. The requested rate structures, customer class definitions and availability requirements are within the capabilities of the utility's billing system, customer information system and/or meter data management system;**
>
> **b. the requested modifications do not preclude collection of billing determinants required by the utility, or else are implemented subject to the commission finding it is in the public good; and**
>
> **c.** all incremental costs incurred to provide any special metering, data management, or billing system modifications shall be assigned to and paid by the CPA, in which case such costs shall be:
>
> > 1. estimated by the utility to the CPA prior to the start of implementing such changes; and
> >
> > 2. if approved for implementation by the CPA, shall be charged to and paid by the CPA.

- **2205.16(d)(1)** While we have understood that this is not currently an option available to CEPS through the utility EDI and was not required as part of PUC Order No. 22,919, we note that that order did require utilities to provide usage data to suppliers and the original architecture of the EDI, contemplated numerous options where "SAC" or service, promotion, allowance, or charge amounts could be denominated in dollars and exchanged between supplier and utility as current customer charges. See for example pp. 48 - 49 and pages following in "ts810" found in the original "810 Usage/Billing Invoice" transaction system that was not specifically enabled as part of the PUC's approval.[33]

  Clarifying whether this functionality already does, in fact, exist within the EDI architecture, and if not, enabling, this functionality in current EDI systems, would solve a host of issues, including allowing most all types of rate innovation and services to be billed through cost effective consolidated billing, with the CPA or CEPS separately providing the customer with the billing determinants and charge calculation electronically or through other means to customers that opt-in to better rate structures and service options while maintaining the convenience of a single electric bill.

  We note that this functionality is commonly referred to as "bill ready" consolidated billing, whereas the practice of providing rates to the utility to use to calculate

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[33] On the PUC's (or now DoE's) EDI Information page, https://www.puc.nh.gov/Electric/edi.htm under "Usage Billing Invoice - 4/2/98".

customer supply bills is referred to as "rate ready" consolidated billing. Other markets, such as New York and California, allow both options through EDI systems.

- **2205.16(d)(2)** The NHEC objects on the basis that their "*billing system cannot handle a custom rate code for every member*". We observe that CPAs, as a default supplier, are NOT expected to provide custom rates for EVERY individual participating customer. However, CPAs have the authority to offer opt-in products to subsets of customers as well as custom retail rates to select individual customers (e.g., larger commercial customers with distinct load shapes, onsite generation and/or controllable loads, etc.), in order to expand customer choice and value — just as competitive suppliers do. CPAs should not be unfairly disadvantaged in this regard. Consequently, we recommend not modifying the proposed rule.
- **2205.16(e)** Oddly, the NH Utilities propose striking this provision to set a deadline for filing of POR proposals as "unnecessary, as utility proposals are in progress" suggesting that they would beat the deadline. We join in the comment of NRG and CPG as to importance of this for successfully launching and operating CPAs.

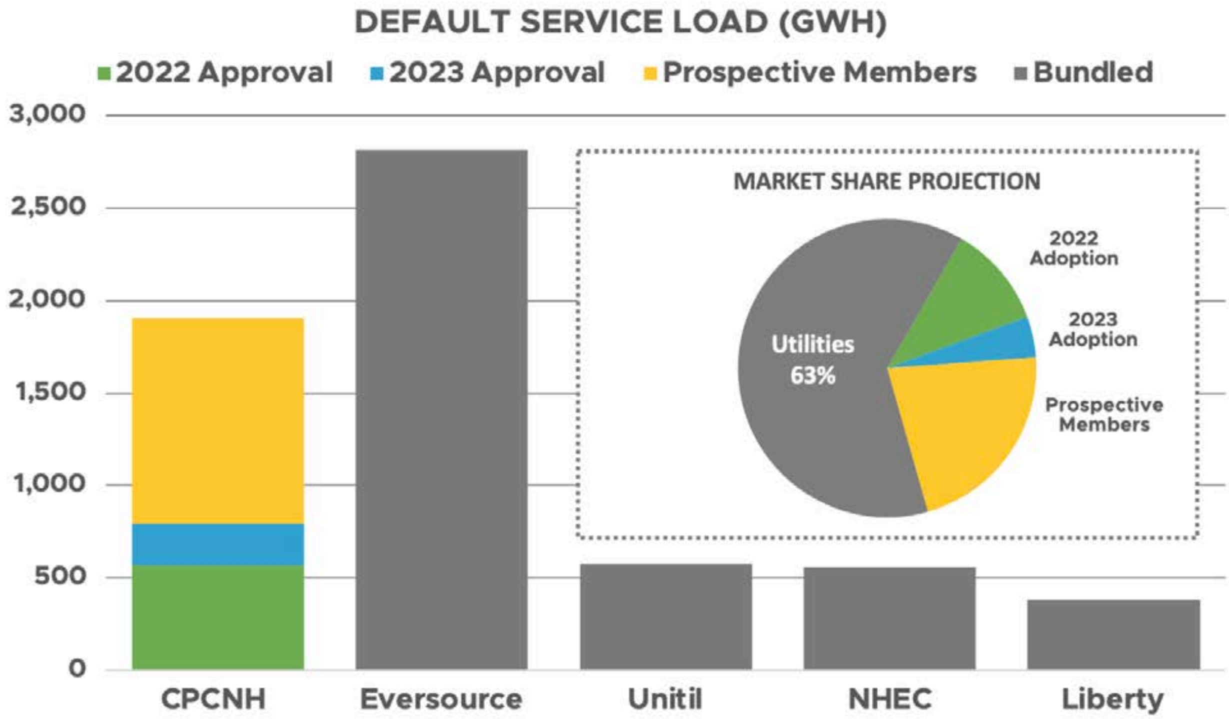
Conclusion

Extending the benefits of competition to the 'mass market' of residential and small commercial customers — and animating New Hampshire's broader retail choice market in the process — is a relatively straight-forward process from our perspective.

Community Power Aggregations represent a ready means to break the regulated utilities' monopoly over the provision of default supply. Provided that the utilities are made to disclose sufficient data in a timely fashion, CPAs will be able to arrange for the credit support and services required to structure and actively manage diversified portfolios of financial and physical energy products on a competitive basis while structuring rates for default service and net metered customers reflective of cost causation.

The Community Power Coalition of New Hampshire's current 19 local government members represent ~20% of the state's population. More than two dozen additional municipalities are currently expressing interest in joining our Joint Powers Authority.

The graph below puts the near-term scale of this transition to competitive supply in context:



The next few years, in other words, have the very real potential to usher in the largest transference of customer accounts to competitive supply that the state has ever seen.

Past this point, the ability of CPA programs to effectively innovate and create new value — in regard to time varying rate structures and new billing options, enabling services that assist customers in adopting and utilizing intelligent energy technologies and services, and a wave of capital investments in customer- and community-sited distributed energy resources of every kind — hinges upon the ability of CPAs to be afforded fair and "open access" to the retail customer network functions (chiefly metering, data management and billing) that New Hampshire's distribution utilities own and operate on behalf of all ratepayers.

New Hampshire is at a fork in the road: we are confident that our proposed rules will fulfill the Legislature's intent and secure a more resilient, locally determined, and cost-effective clean energy future for the state as a whole, whereas the distribution utilities' recommendations will perpetuate their apparent disregard of complying with long-standing state policy and PUC precedent.

We petition the Commission to adopt our recommendations, in order to secure our communities' energy future in alignment with the Electric Utility Restructuring Act (RSA 374-F).

We additionally urge the Commission to consider taking proactive steps — which are long overdue, from our perspective, such as reconvening the EDI Working Group — to modernize the competitive market and ensure that Community Power Aggregators and Competitive Electricity Powers Suppliers are able to create new value for customers in the context of the increasingly-rapid pace of technological change and market disruptions taking shape across all organized electricity markets.

Pursuant to current Commission policy, this filing is being made electronically only.

Yours truly,

Clifton Below

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