BEFORE THE DEPARTMENT OF ENERGY
STATE OF NEW HAMPSHIRE

Case or Docket No. 23-____

COMMUNITY POWER COALITION OF NEW HAMPSHIRE

Complaint Against

Public Service Company of New Hampshire d/b/a Eversource Energy

June 13, 2023

NOW COMES the Community Power Coalition of New Hampshire (CPCNH or the "Coalition"), a non-profit corporation operating as a governmental instrumentality of 34 subdivisions of the State of New Hampshire[1] pursuant to RSA 53-A and 53-E and COMPLAINS that Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or "PSNH") is in violation of Public Utilities Commission Order No. 22,919 (5/4/98), RSA 362-A:9, II, RSA 53-E:3, and RSA 374-F:3, XII(c) as well as the express intent of RSA 374-F and petitions the Department for redress of the ongoing harm caused to the Coalition, its Members, and their prospective customers by Eversource's lack of compliance with these laws and PUC Order.

This complaint petition is made pursuant to RSA 365:1[2] regarding Eversource's acts and omission of actions needed to comply with these laws and PUC order, which act and omissions have substantially delayed the launch of the Coalition's power supply service (thereby foregoing

[1] City of Lebanon, Town of Hanover, City of Nashua, Cheshire County, Town of Harrisville, Town of Exeter, Town of Rye, City of Dover, Town of Warner, Town of Walpole, Town of Plainfield, Town of Newmarket, Town of Enfield, Town of Durham, Town of Pembroke, Town of Hudson , Town of Webster, Town of New London, City of Portsmouth, Town of Peterborough, Town of Canterbury, Town of Wilmot, Town of Sugar Hill, Town of Hancock, Town of Westmoreland, Town of Shelburne, Town of Brentwood, Town of Boscawen, City of Berlin, Town of Randolph, Town of Lyme, Town of Rollinsford, Town of Stratham and Town of Newport.

[2] RSA **365:1 "Complaint Against Public Utilities. –** Any person may make complaint to the department of energy by petition setting forth in writing **any thing or act claimed** to have been done or **to have been omitted by any public utility in violation of any provision of law**, or of the terms and conditions of its franchises or charter, **or of any order of the commission.**" [emphasis added]

A complementary complaint is being filed at the PUC under the Commission's authority pursuant to RSA 53-E:7, X and Puc 2205.12 concerning disputes between a CPA and a utility, and lack of compliance with the Puc 2200 rules and RSA 53-E. It is not clear that the Commission's authority to hear and decide complaints extends to those concerning acts or omission of acts pursuant to other statutes and PUC orders, at least not in the first instance prior to escalation pursuant to RSA 365:4 by the Department or complainant; hence the reason why this closely related and overlapping complaint is filed with the Department of Energy.

an estimated $4,380,000 cost savings for New Hampshire ratepayers and communities) and foreclosed the Coalition's ability to serve Net Metered customers or to offer advanced rate structures (both of which the Coalition is capable of providing as a power agency and are key benefits for NH ratepayers receiving value for participating in the energy transition with Distributed Energy Resource).

Eversource's non-compliance with these laws and order results in the Coalition's CPA default service[3] being treated in a number of discriminatory ways, small and large, that have the effect of giving an unfair advantage to utility default service counter to the realization of these statutory and regulatory purposes and directives. RSA 374-F:3, IV provides that "*the department should monitor companies providing transmission or distribution services and take necessary measures to ensure that no supplier has an unfair advantage in offering and pricing such services.*" RSA 374-F:3, VII entitled "Full and Fair Competition" provides that *"[c]hoice for retail customers cannot exist without a range of viable suppliers. The rules that govern market activity should apply to all buyers and sellers in a fair and consistent manner in order to ensure a fully competitive market.*" New Hampshire ratepayers are harmed when comparable meter data, rate, and billing options are not provided to CPA default service that Eversource provides to its own default and distribution service as expected by the relevant law and PUC order. There cannot be a range of viable suppliers without access to the same information for all parties.

In support of this complaint the Coalitions states as follows:

1. Introduction and Overview

1.1. The Coalition was formed by its municipal and county members to "jointly support the implementation and operation of their respective CPAs [Community Power Aggregations] and related energy programs" (JPA p. 2) and "to jointly exercise certain powers, privileges, and authorities granted to municipalities and counties pursuant to NH RSA 33-B, NH RSA 53-E, NH RSA 53-F, and NH RSA 374-D (and by reference NH RSA 33), all in accordance with NH RSA 53-A."

[3] RSA 374-F:2, I-a. states that "**'Default service' means electricity supply that** is available to retail customers who are otherwise without an electricity supplier and are ineligible for transition service and **is provided by electric distribution utilities under RSA 374-F:3, V or** as an alterative [sic], **by municipal or county aggregators under RSA 53-**E." RSA 53-E:6, III(c) requires electric aggregations plans to detail "[r]ate setting and other costs to participants, including **whether energy supply services are offered** on an opt-in basis or **on an opt-out basis as an alternative default service**." [emphasis added]

1.2. On March 6, 2023, CPCNH sent notice, via email, to the Commission, the NH Department of Energy (DOE), Office of the Consumer Advocate (OCA), and the 4 electric distribution utilities (EDUs) that ten CPCNH members[4] would commence CPA service no sooner that 45 days hence, pursuant to approved Electric Aggregations Plans (EAPs). Commencement of service notices were also sent on April 14, 2023 for 2 additional communities.[5]

1.3. The Puc 2204.02 anonymized individual customer data sets that Eversource has provided to CPCNH have thus far not included any negative usage data from Net Energy Metered (NEM) customers. Unlike the other utilities who did provide the information in the Puc 2204.02 data sets, the Eversource data only had zeros in such months when those customers presumably exported surplus power to the grid in excess of their behind the meter consumptions. This redacted or limited reporting is contrary to Puc 2204.02(a)(2) that requires the provision of monthly usage data, and Puc 2203.02(d) that requires that: *"[a]ll 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."*

1.4. Upon further inquiry CPCNH learned that Eversource would not provide CPAs with historic or ongoing negative usage data (monthly net exports, or any hourly data where reported) for NEM customers, directly contrary to the requirements of Puc 2203.02(d), Puc 2205.05(b), Puc 2205.13(a)(7), Puc 2205.15, RSA 362-A:9, II, the Declaration of Purpose of RSA 362-A:1, and expectations of EDI standards established pursuant to PUC Order No. 22,919[6].

1.5. Eversource has not explained how or when they will comply with Puc 2205.15(b) and RSA 362-A:9, II to account for NEM generation exported to the grid by CPA customer-generators *"as a reduction to the CPA's customers' electricity supplier's wholesale load obligation for energy supply as an LSE, net of any applicable line*

[4] City of Lebanon, City of Nashua, Town of Enfield, Town of Exeter, Town of Hanover, Town of Harrisville, Town of Peterborough, Town of Plainfield, Town of Rye, and Town of Walpole

[5] City of Portsmouth and Town of Canterbury

[6] Order No. 22,919 in DR 96-150 (DR standing for "Docket Restructuring") "Electric Utility Industry Restructuring, EDI Working Group Report": https://www.puc.nh.gov/Regulatory/Orders/1998ords/22919e.html.

loss adjustments, as approved by the commission." This obligation has existed since September 15, 2020 when Chapter 21, NH Laws of 2020, went into effect.

1.6. Eversource has had a responsibility and obligation under New Hampshire law to provide competitive suppliers, through their EDI system or otherwise, with negative usage data for net metered customer-generators for a quarter of a century, since PUC Order No. 22,919 in DR 96-150 and Chapter 261, NH Laws of 1998 became effective in 1998.

1.7. Furthermore, Eversource has also indicated that they do not intend to provide any Time of Use (TOU) usage data for TOU rate customers as required by the EDI Standards for New Hampshire established by Order No. 22, 919 and generally referenced in Eversource's tariff,[7] as well as under Puc 2205.13(a)(7), nor to identify such customers by a TOU rate class, such as R-OTOD, R-OTOD-2, G-OTOD, and EV-2 contrary to Puc 2205.13(a)(4) and EDI standards.

1.8. Eversource has also indicated that they do not have the capability to allow CPAs to use their TOU rate structure to offer a TOU supply rate to TOU rate customers, as was called for and expected by PUC Order No. 22,919 and as is implicit in Puc 2205.16(c)(2).[8]

1.9. In addition to these barriers to serving NEM and TOU customers Eversource has attempted to impose additional EDI testing requirements beyond those authorized by the EDI standards established by Order No. 22,919, threatening unnecessary delay in the launch of Coalition CPA services. After CPCNH's open letter of 4/20/23 to Eversource's management concerning their obstacles to our successful launch they did reverse course and drop the redundant EDI testing requirements for each municipality that served no practical purpose, an accommodation that we did

[7] For example, under NHPUC NO. 10, Electricity Delivery, Public Service Company of New Hampshire DBA Eversource Energy, "TERMS AND CONDITIONS FOR ENERGY SERVICE PROVIDERS" ¶2(a) at p. 32: "(a) Customer Usage Data[:] Suppliers will be provided with monthly usage data, at no charge, via an EDI transaction in accordance with the guidelines adopted by the Commission."

[8] Puc 2205.16(c)(2) provides in relevant part that "[t]erms and conditions provided by the utility for CPA billing services shall . . . (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 . . . provided that: . . . incremental costs incurred to provide any special . . . billing system modifications shall be assigned to and paid by the CPA. . . ." Thus, the rule assumes that if such temporal periods for the provision of meter data are the same as those defined in the utility tariff (and thus available for use in the billing system), then there should be no need for a special request and assignment of incremental costs to modify such time periods.

and still do very much appreciate as it narrowly averted tens of thousands of customer enrollments from being delayed into June instead of May that would have resulted in millions of foregone customer and community savings.

2. **Eversource's treatment of Net Metering is contrary to both NH law and PUC orders.**

2.1. Eversource's non-compliance with Puc 2200 rules makes it infeasible for CPCNH to enroll NEM customers successfully and to serve them responsibly as many of them would likely be financially harmed by losing the value of their net exports to the gird. Thus, Eversource continues an effective 25-year monopoly on the provision of net metering and TOU rate options contrary to legislative intent in RSA 374-F, RSA 362-A:1, RSA 362-A:9, II, and RSA 53-E and regulatory intent in NH PUC Orders 22,514[9], 22,875[10], and 22,919.

2.2. Eversource's monopolization of the provision of net metering through control of the metering data and refusal to supply negative usage data along with positive usage data as either part of Puc 2204.02 anonymized individual default service customer

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[9] 82 NH PUC 122, Re Statewide Electric Utility Restructuring Plan, DR 96-150, Order No. 22,514, (2/28/97) out of which the EDI Working Group was established in the plan context where the PUC noted the following:

- "the regulated status of distribution companies raises the possibility that such companies will utilize their privileged position to exercise market power." (at 137)
- "innovation and the introduction of new products should be stimulated as competitors vie for market share." (at 148)
- "As recognized by 374-F:3, III, to provide customers with meaningful choices, vertically integrated utilities must unbundle their retail services into generation, transmission, and distribution sub-components." (at 149)
- "Allowing retail customers the freedom to choose among power suppliers will promote economic efficiency" (at 150).
- "Successful large scale implementation of retail access will require, according to GSEC, the use of Electronic Data Interchange (EDI) standards to support all necessary data transactions, although it concedes many of these standards are not yet available. We accept the advice of GSEC on this matter and direct it to submit a proposal, within the timeframe established in Appendix B, to establish a data transfer working group which would prepare recommendations on appropriate EDI standards." (at 154)

[10] PUC DR 96-150, Order On Requests For Rehearing, Reconsideration And Clarification, Order No. 22,875 3/20/98: "our delegated mandate is to promote competition not to perpetuate monopolies. As the New Hampshire Supreme Court stated:

> …[L]egislative grants of authority to the PUC should be interpreted in a manner consistent with the State's constitutional directive favoring free enterprise. Limitations on the right of the people to 'free and fair' competition" ... must be construed narrowly, with all doubts resolved against the establishment or perpetuation of monopolies. RSA 374:26 thus should not be interpreted as creating monopolies capable of outliving their usefulness.

Appeal of PSNH, 141 N.H. 13, 19 (1996) (emphasis added) (internal citation omitted)." (at 23-24) data or on an ongoing basis for customers of CPAs pursuant to RSA Puc 2205.13(a)(7) and EDI standards and their lack of notice on when the company will implement a business process to comply with RSA 362-A:9, II combined with Eversource's significant default service Net Energy Metering tariff costs to all distribution system ratepayers through their NEM adder[11] and the nonbypassable Stranded Cost Recovery Charge (SCRC) constitute an omission, a failure act, contrary to their ongoing obligation under RSA 364-F :3, XII(c): ***"Utilities have had and continue to have an obligation to take all reasonable measures to mitigate stranded costs."*** This is an affirmative continuing obligation of Eversource to take all reasonable measures to mitigate the expected $21 million in NEM costs charged to customers through their SCRC.[11] It would certainly be reasonable for Eversource to enable competitive suppliers and CPAs to serve net metered customers to minimize this arguable cost burden on Eversource's non-NEM customers given they are being charged SCRC. Based on our experience a great many customers would switch to CPA service on both an opt-in and opt-out basis to receive the benefits of lower cost default service through CPCNH and by doing so would reduce the need for Eversource to continually add to their calculated cost of serving NEM.[12] Enabling CPA's to effectively serve NEM customers, as all the approved EAPs to date indicated they would like to do, would clearly mitigate those Eversource stranded costs and benefit NEM customers that wish to move to a CPA.

2.3. Eversource has known or should have known that municipalities launching supply services through CPCNH expected to be able to serve their utility default service NEM customers as their alternative default service provider as the State granted them authority

[11] Authorized in DE 20-136 in Order No. 26,450, the NEM SCRC adder includes all of the cost of the payments and credits Eversource makes for NEM exports to the gird ("customer sales"), including to group hosts. The currently approved adder is $0.0414/kWh designed to recover over $21 million in payments to NEM customers from January 2023 through January 2024 and over $10 million in prior period NEM expenditures to purchase exported power from NEM customers. *See* Order No. 26,768 in DE 22-039 and Exhibit 3, Attachment MBP-9 at Bates pp. 56-57.

[12] The number of NEM customers on default service that might be served by CPAs launching this spring is not insignificant, on the order of 2% of all default service customers or about 1,100 customer-generators on default service in the 9 communities served by Eversource that the Coalition is launching this spring: Nashua-578, Portsmouth-153, Peterborough-125, Rye-110, Canterbury-51, Harrisville-40, Plainfield-35, and Hanover and Enfield - 3 each. (Canterbury, Plainfield, Hanover, and Enfield are primarily served by other distribution utilities.)

to so do under RSA 362-A:9, II, RSA 53-E generally, and RSAs 53-E:3 and 53-E:6, III(c) and (f) specifically, simply because such intentions were clearly stated[13], and detailed[14], in most of the Electric Aggregation Plans filed with the PUC, OCA, DOE, and Eversource and subject to Eversource's comment on the extent of the Plan's compliance with statute and rules pursuant to RSA 53-E:7, II. The inability to do so has economically harmed the community members who are not able to operate as NEM CPA customers and has left municipalities in the unenviable position of explaining why and without the ability to provide meaningful solutions.

2.4. RSA 53-E:3 provides as follows:

"**Municipal and County Authorities**. –

Any municipality or county may:

I. Aggregate the retail electric customers within its boundaries who do not opt out of or who consent to being included in an aggregation program.

II. (a) Enter into agreements and provide for energy services, specifically:

(1) The supply of electric power and capacity.

(2) Demand side management. . . .

(b) Such agreements may be entered into and such services may be provided by a single municipality or county, or by a group of such entities operating jointly pursuant to RSA 53-A."

2.5. RSA 53-E:6 requires municipalities to develop and approve electric aggregation plans before implementing aggregation programs that must address certain issues such as in subsection III: *"(c) Rate setting and other costs to participants, including whether energy supply services are offered on an opt-in basis or on an opt-out basis as an alternative default service."* And *"(f)* ***How net metered electricity exported to the distribution grid by program participants, including for group net metering, will be compensated and accounted for.****"*

[13] For example, as stated in the Town of Rye's Electric Aggregation Plan (EAP) at 28 in compliance with RSA 53-E:7, II: "**Rye Community Power intends to provide new rates and terms that compensate participating customer-generators for the electricity supply component of their net metered surplus generation.**

[14] Exhibit A is an example of the explanation of existing net metering and how Community Power would serve those default service NEM customers which was filed with the PUC and Eversource pursuant to RSA 53-E:7, II on or about 1/7/22 in DE 22-001 as Attachments 5 and 6 to the Town of Rye's EAP.

2.6. In order to account for and compensate net metered electricity exported to the distribution grid by community power program participants the CPA will have to know those quantities, simply known as negative usage. This is metering data, half of the netting equation opposite positive usage, which Eversource has not provided and exclusively controls as a State franchised monopoly and contrary to properly adopted PUC rules[15] required by RSA 53-E:7, X, by its acts of omission, is thwarting implementation of properly approved EAPs, causing unnecessary customer confusion and consternation, and failing to meet their statutory obligation to take all reasonable measures to mitigate stranded costs under RSA 364-F :3, XII(c).

2.7. Complying with PUC rules and enabling statutory authorities of subdivisions of the state would allow Eversource to completely or nearly completely mitigate any and all claimed "stranded costs" created by payments for the exports to the grid by NEM default service customers and being paid by all Eversource customers. By complying with PUC rules and providing the data needed for their NEM customers to become CPA customers on an opt-out basis Eversource will reduce the SCRC charge from what it will otherwise be by not complying with the law and the rule, mitigating the financial burden caused by the SCRC to both NEM and non-NEM Eversource customers.

2.8. Furthermore, under RSA 53-E:7, II, *"after an aggregation plan is duly approved the electric distribution utility or utilities serving an adopting municipality . . . shall provide to such municipality . . . for such customers on utility provided default service, . . . any other information necessary for successful enrollment in the aggregation."* The PUC rules anticipated that some information not addressed in the rule may be needed for a successful enrollment but they did not anticipate the impact of a utility not complying with parts of the rule would have on whether enrollments could be successful. Coalition CPAs cannot successfully enroll NEM customers because they cannot serve them in accordance with their legislative body

[15] For example, Puc 2203.02 (d) broadly requires that: "[a]ll customer usage data provided by the utility shall include consumption power delivered to the customers and exports to the grid from customer generators in kWh for each reported interval."

and PUC approved EAPs and pursuant to their statutory authority resulting in likely significant financial harm NEM customers if they were enrolled in a CPA program before Eversource is able to comply with the PUC rules and relevant laws.

2.9. Related, CPAs cannot successfully enroll or serve NEM customers, without assurance from Eversource as to if, when, and how they will comply with the provision in RSA 362-A:9, II that requires that *"generation output exported to the distribution grid from eligible customer-generators [of community power aggregations] . . . shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply as a load service entity"*. Eversource's ability to comply with this law is critical to the economics of serving and successfully enrolling NEM customers for which RSA 53-E grants authority to CPAs as stated in RSA 362-A:9, II:

"Nothing in this paragraph shall be construed as limiting or otherwise interfering with the ***provisions or authority for municipal or county aggregators under RSA 53-E, including, but not limited to, the terms and conditions for net metering."***

3. The Origins of Net Metering and RSA 362-A:9, II and implications for Eversource's omitted actions.

3.1. In the spring of 1996, New Hampshire became the first state in the nation to enact electric utility restructuring legislation calling for a separation of the monopoly distribution utility function from the power generation and supply function that was to transition to a competitive market to be implemented pursuant to a statewide restructuring plan to provide for electric supply choice for all retail customers. Importantly, the Legislature explicitly recognized the vital roles of customer choice, renewable energy, and self-generation in achieving this transformation of the retail state's electricity markets. *See* RSA 374-F:3, II. The primary purpose in restructuring the electric utility industry was to *"reduce costs for all consumers of electricity by harnessing the power of competitive markets."* RSA 374-F:l, I. This legislative purpose was fully consistent with New Hampshire's Constitution, which expresses the state's *"fundamental preference for free enterprise."* Omni Communications, 122 N.H. at 862 (citing N.H. Const. art. 83, pt. II). In light of this constitutional mandate, the bill provided that competitive markets should *"provide* *electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, provide electricity buyers and sellers with appropriate price signals*" among other goals. RSA 374-F:1, II. In turn RSA 374-F:3, II emphasized the paramount role of customer choice, and specifically provided that; *"[c]ustomers should be able to choose among options such as levels of service reliability, real time pricing, and generation sources, including interconnected self generation."* RSA 374-F:3, VII addressed the principle of "Full and Fair Competition" providing that *"[c]hoice for retail customers cannot exist without a range of viable suppliers. The rules that govern market activity should apply to all buyers and sellers in a fair and consistent manner in order to ensure a fully competitive market."*

3.2. Within 5 months after the enactment of Chapter 129, NH Laws of 1996 (HB 1392) that created RSA 374-F the prime sponsor of that legislation, the Chair of the House Science, Technology, and Energy Committee (ST&E), then Rep. Jeb Bradley, and the 2nd sponsor of that legislation, then Rep. Clifton Below, became, respectively, the second and prime sponsors of HB 485, introduced in January 1997, to create net metering as an option and supply choice for retail customers, and to otherwise update RSA 362-A, the Limited Electrical Energy Producers Act (LEEPA), including by repealing certain provisions mandating the purchase of power from limited producers by utilities, in favor of a competitive market. As the legislative history indicates, Gary Long, a former President of Public Service Company of NH (PSNH) testified against the bill as introduced on behalf of PSNH.[16] This bill underwent extensive work over the course of 11 subcommittee work sessions, many or all of which were chaired by then Rep. Below as can be seen in the bill docket.[17] An amendment that completely replaced the original text had a public hearing on 10/17/97 and after a bit more committee work, was recommended for passage by a unanimous committee vote, followed by passage by the House on 1/15/98 and by

[16] The House legislative history on HB 485 enacted as Chapter 129, NH Laws of 1998 is found here: https://gencourt.state.nh.us/BillHistory/SofS_Archives/1998/house/HB485H.pdf. See page 18.

[17] https://gencourt.state.nh.us/bill_status/legacy/bs2016/bill_docket.aspx?lsr=976&sy=1998&sortoption=chapterno&txtsessionyear=1998&txtchapternumber=0261&txtbillnumber=HB485

the Senate on 5/21/98, both by voice vote, with only one vote recorded in opposition.

3.3. The amendment passed by the House and final legislation included an amended statement of purpose of RSA 362-A:1 that included the new language shown in bold italics (with emphasis added):

"362-A:1 Declaration of Purpose. It is found to be in the public interest to provide for small scale and diversified sources of supplemental electrical power to lessen the state's dependence upon other sources which may, from time to time, be uncertain***. It is also found to be in the public interest to encourage and support diversified electrical production that uses indigenous and renewable fuels and has beneficial impacts on the environment and public health. It is also found that these goals should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3. It is further found that net energy metering for eligible customer-generators may be one way to provide a reasonable opportunity for small customers to choose interconnected self generation, encourage private investment in renewable energy resources, stimulate in-state commercialization of innovative and beneficial new technology, enhance the future diversification of the state's energy resource mix, and reduce interconnection and administrative costs. . . ."***

3.4. The originally enacted RSA 362-A:9 that first created net metering in New Hampshire effective on 8/25/98 included the following provision:

"Electricity suppliers may voluntarily determine the terms, conditions, and prices under which they will agree to provide generation supply to and purchase net generation output from eligible customer-generators; however, electricity suppliers who provide default service or transition service to such a customer shall only bill for the net energy supplied as calculated in accordance with this section."

Clearly, the legislature expected electricity suppliers to be able to offer net metering "in a competitive environment pursuant to restructuring policy principles" with only electricity suppliers providing default service having a prescriptive requirement for how to bill NEM customers. Implicit in that policy choice, is the expectation that regulated distribution utilities as state franchised monopolies, to the extent that they exclusively control retail metering data, would have to provide net metering data (both positive and negative usage) to electricity suppliers to enable customer choice of suppliers by customer-generators, just like the provision of positive usage data to competitive suppliers is implicit in requiring general customer choice of suppliers, without the legislature spelling out that detail in statutory requirements. Positive and negative usage data from the utility meter is inherent to the concept of ***net*** metering and without access to both positive and negative usage information net metering is unable to be offered to NH ratepayers. The fact that both positive and negative usage data are required to be provided to suppliers is inherent in the fact that NH legislative policy on net metering, from the get-go in the same time frame as EDI standards were originally approved, anticipated that negative balances for kWh exported to the grid by customer-generators could be carried forward from month to month by the originally enacted language in RSA 362-A:9, IV(c) for utility default or transition service:

"(c) Where the electricity generated by the customer-generator exceeds the electricity supplied by the electric grid, the customer-generator shall be credited during the next billing period for the excess kilowatt hours generated in accordance with this section."

Chapter 129:11, NH Laws of 1998 reinforces the legislative expectation that net metering data would be made available to competitive suppliers by requiring the PUC to make a future report back to the legislature concerning "the results and effects of net energy metering arrangements to date, including a summary of information available from participating utilities, electricity suppliers, and eligible customer-generators . . . ."

3.5. PSNH was well aware of this legislation and its requirements. As the chair of the electric utilities subcommittee of ST&E in 1997 and 1998 and the prime sponsor of the legislation, the primary author of this complaint can attest to the fact the PSNH was represented at most, if not all of the 11 work sessions on this bill and actively expressed their view on proposed text in the bill throughout the legislative process. The House Legislative history (FN 8 at 24) indicates that "Dave Collins, Public Service Company of N.H." testified on the proposed committee amendment on 10/21/97 ("both supports and opposes") that included language nearly identical to the final version adopted by the legislature: *"[o]ther electricity suppliers may voluntarily determine the terms, conditions, and prices under which they will agree to provide generation supply to and **purchase net generation output from eligible customer-generators.**"* (*Id at 8)*

3.6. In 2010 the Legislature enacted Chapter 143 that did a complete repeal and replacement of RSA 362-A:9. The text explicitly expecting that suppliers be able to serve net metered customer-generators was moved to its own paragraph II and slightly updated to read:

"II. Competitive electricity suppliers registered under RSA 374-F:7 may determine the terms, conditions, and prices under which they agree to provide generation supply to ***and purchase net generation output from eligible customer-generators****."*

3.7. Chapter 21, NH Laws of 2020 (SB 166) substantially amended RSA 362-A:9, II to read:

"II. Competitive electricity suppliers registered under RSA 374-F:7 ***and municipal or county aggregators under RSA 53-E*** may determine the terms, conditions, and prices under which they agree to provide generation supply to and ***credit, as an offset to supply, or*** purchase [~~net~~] ***the*** generation output ***exported to the distribution grid*** from eligible customer-generators. ***The commission may require appropriate disclosure of such terms, conditions, and prices or credits. Such output shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply as a load service entity, net of any applicable line loss adjustments, as approved by the commission. Nothing in this paragraph shall be construed as limiting or otherwise interfering with the provisions or authority for municipal or county aggregators under RSA 53-E, including, but not limited to, the terms and conditions for net metering."*** [emphasis added]

Of note is the fact that this legislation addressed no other matter than this one paragraph expanding these provisions that expressly provided that electricity suppliers, other the utility, have the authority and have been expected to be able to provide service to net metered customers. And it went further by including for the first time the explicit requirement that exports to the grid by NEM customers with negative usage "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." In fact, the House ST&E Committee retained SB 166 that was originally introduced in 2019 and held 4 work sessions to develop the amendment enacted into law.

Once again it is clearly implicit here that state law expects distribution utilities subject to this law, to provide competitive suppliers, and now explicitly municipal and county aggregators pursuant to RSA 53-E, with the net metering usage data, both positive and negative, required to make the authorities granted and the requirement concerning how to account for exports to the grid in load settlement have any meaning or purpose whatsoever. Standard legislative interpretation and construction presumes that enactment of laws and specific statutory text have purpose, meaning, and consequence and in this case that would indicate that RSA 362-A:9, II and RSA 53-E:6, III(f) are not intended to just be hypothetical possibilities dependent on the voluntary discretion of a regulated monopoly that controls the necessary data to make the statute have any practical meaning or consequence.

3.8. To the extent that Eversource argues that these statutes do not specifically require them to provide negative usage data to CPAs and competitive suppliers that want to serve NEM customer-generators the Department and Commission should look at the statutory language and regulations as a whole, not merely "isolated words or phrases." In the Matter of Maves & Moore, 166 N.H. 564, 566-67, 101 A.3d 101 (2014). The relevant statutes here, RSA 362-A:1 and 9, including in the context of RSA 374-F, should not be read in isolation but in the context of the overall purpose and effect of RSA 53-E and the Puc 2200 rules as read in their entirety. *See, e.g., Appeal of N. New Eng. Tel. Operations, LLC*, 165 N.H. 267, 271 (2013) (legislative intent to be determined from words of the statute considered as a whole; statutes to be interpreted not in isolation but in the context of overall statutory scheme); *Appeal of Pennichuck Water Works*, 160 N.H. 18, 27 (2010) (various statutory provisions to be construed harmoniously insofar as reasonably possible); *Chase v. Ameriquest Mortgage Co.*, 155 N.H. 19, 22 (2007) (statutes to be construed in harmony with the overall statutory scheme).

RSA 53-E provides community power aggregators ("CPA") with the power to determine the terms, conditions, and prices under which they will supply generation and credit or purchase generation output exported to the distribution grid. Specifically, RSA 53-E:6 provides that municipalities or counties may develop a plan for an aggregation program for its citizens to provide universal access and reliability for all classes of customers. RSA 53-E:6 III (f) states that such plan shall detail how net metered electricity exported to the distribution grid by program participants, including for group net metering, will be compensated, and accounted for.[18]

[18] The inclusion of this requirement for electric aggregation plans supports the conclusion that that data regarding the amount of net metered electricity being exported to the distribution grid by program participants is both

The state has required incumbent distribution utilities to facilitate net metering through community aggregation. The state understands that sales of energy is an integral part of encouraging the development of renewable resources. In fact, RSA 362-A:1 states that these goals should be pursued in a competitive environment where small customers can participate in the energy market and municipal aggregators can incentivize such participation by developing pricing, terms, and conditions for the sale of energy that foster a welcoming environment for renewable resource development.

Pursuant to this requirement, the legislature provides municipal aggregators with the authority to develop aggregation plans to detail the accessible, reliable, and equitable provision of generation across all customer classes, and subsequently vested in utilities the obligation to provide the names, mailing addresses, and any other information necessary for successful enrollment in the aggregation for all electric customers taking utility default service in a municipal aggregator's service area, excluding those who opt-out of CPA alternative default service. NEM customers cannot be successfully enrolled in a CPA, absent the ongoing provision of net metering usage data (both positive and negative) because they cannot be served consistent with Commission approved Electric Aggregation Plans or statutory authorities and obligations. Doing so would likely incur substantial financial harm to many NEM customers contrary to the purposes of RSA 53-E, 362-A, and 374-F.

4. EDI Requirements Pursuant to PUC Order No. 22,919 (5/4/98)

4.1. In the Final Plan[19] for electric utility restructuring the PUC established "an Electronic Data Interchange (EDI) Working Group for the purpose of developing a consensual plan for the transmission of electronic information. On April 2, 1998, the Working Group filed with the Commission a report recommending the adoption of business rules and related standard transactions and formats for the electronic transfer of customer information."[20]

important and necessary for the provision of "universal access, reliability, and equitable treatment" of all classes of customers as described in RSA 53-E:6 II.

[19] PUC Order No. 22,514, 2/28/97.

[20] PUC Order No. 22,919, 5/4/98, available at: https://www.puc.nh.gov/regulatory/Orders/1998ords/22919e.html.

In Order No. 22, 919 issued May 4, 1998, the Commission stated that *"each distribution company is directed to implement the report's requirements"* and *"ORDERED, that the recommendations of the EDI Working Group as set forth in the above mentioned report and as clarified in this order are approved pending the outcome of a rulemaking to implement EDI standards; and it is FURTHER ORDERED, that each distribution company implement the report's requirements."* This was in anticipation of beginning customer choice of electricity suppliers as soon after a July 1, 1998 statutory deadline as possible. In 1997 PSNH, joined by other utilities, filed suit in federal court against the PUC to block implementation of their restructuring plan. On June 12, 1998 the federal court enjoined the PUC from implementing RSA 374-F for most utilities in NH so on July 1, 1998 the Commission issued Order No. 22,971[21] delaying the implementation of electric utility restructuring. Implementation of restructuring was delayed for PSNH by more than 2 years until after a settlement was reached with the state and enabled by the enactment of RSA 369-B: Electric Rate Reduction Financing and Commission Action by the passage of Chapter 249, NH Laws of 2000 (SB 249) of which the main author of this complaint was the prime sponsor and a principal negotiator.

This delay in the implementation of restructuring may account for why rules were apparently never developed for NH's EDI standards, as full restructuring in NH was delayed for several years and as a Massachusetts Electronic Business Transaction (EBT) Working Group was established and took the lead on EDI standards for utilities doing business in Massachusetts that included Unitil, PSNH's parent (then Northeast Utilities, now Eversource), and National Grid, then owner of Granite State Electric. Nevertheless, the PUC, utility tariffs, and supplier agreements all still reference the original NH EDI Working Group report and PUC Order No. 22,919 as establishing the applicable standards in New Hampshire.[22]

4.2. The EDI Standards approved by the PUC in Order No. 22,919 can be found at https://www.puc.nh.gov/Electric/edi.htm. Attached as Exhibit B are selective

[21] PUC Order No. 22,271, 7/1/98, available at: https://www.puc.nh.gov/Regulatory/Orders/1998ords/22971e.html.

[22] In at least one docket, DE 08-081, the Commission considered and approved by Secretarial Letter a request for a relatively minor change in the EDI Codes. EDI standards and certain implementation details were also approved in Puc 2000 rules in DRM 10-014 and DRM 16-853. EDI standards may also be addressed in PUC approved tariffs.

excerpts from those standards, starting with an index to the PUC web page on EDI information that shows the name of the files that download as PDFs. The Cover Letter notes that "Any proposed modifications to the standard transactions and formats described in the report would be subject to the approval of the Working Group and the Commission." The Cover Letter and Consensus Plan recommended and anticipated that the EDI Working Group would continue meeting for some period of time, if not indefinitely.[23] In its "Introduction" the Consensus Plan noted that: "the Commission issued on February 28, 1997 its Final Plan for restructuring New Hampshire's electric utility industry. The Final Plan establishes a market structure which provides **all customers the opportunity to purchase their power requirements directly from competitive suppliers.**" (Consensus Plan at 8)

4.3. The Working Group noted that the initial consensus "standard transactions satisfy the short-term needs of the competitive market while remaining flexible enough to accommodate the evolution of regional and national standards as they are further developed." (*Id* at 3-4.) In its discussion of the Change Control process the Working Group stated that "[i]t is anticipated that the EDI standards will be modified and enhanced as market or regulatory requirements dictate" and further noted that "there must be a process to modify such transactions in a timely manner, if the market is to function efficiently." (*Id* at 42.) At a minimum, requirements for proposing changes from the initial EDI standards stipulated that "the initiating party must: Document in advance the scope of the modification/enhancement and the affected EDI transaction sets, and Provide cost justification if appropriate, and Document proposed amendments, provide a test plan, test cases, EDI documentation and EDI transaction sets." These technical requirements were clearly within the wherewithal of the utilities, but not necessarily customer-generators or their potential suppliers at the time.

[23] *See, e.g.,* p. 42 of the Consensus Plan: "The EDI Working Group will meet on a regular basis and will be comprised of Competitive Supplier and Distribution Company representatives." When restructuring was delayed on 7/1/98 for several years by virtue of Federal Court injunction for much of the state it is not apparent that the NH EDI working group continued to meet.

4.4. **No part of the approved standard or working group report provides that a negative usage measurement should be converted to a zero.** One of the key pieces of data to be provided by the EDI is "Peak or Total Kilowatt Hour Usage" as defined on p. 10 of Exhibit B (Consensus Plan at 50) and noted on pp. 11-13 of Exhibit B (EDI Data Transaction Formats at D-13, D-15, and D-11). In the 810 transactions to "allow Distribution companies to send usage and billing information for electricity to the suppliers who have enrolled customers" this usage data is delivered through Segment ID "MEA" as shown in Exh. B at 15 (TS810 at 2). The purpose of this segment is described as "[t]o specify physical measurements or counts, including dimensions, tolerances, variances, and weights". At each detailed Data Element description for MEA there is a comment noting that "any measurement requiring a sign (+ or -), or any measurement where a positive (+) value cannot be assumed, use MEA05 as the negative (-) value and MEA06 as the positive (+) value. (Exh. B at 16-19.) This statement is preceded by a note "[w]hen citing dimensional tolerances" as the context seems to a generic EDI architecture also used for manufactured goods that was being adapted for utility use. While the field "MEA03" seems to have been initially enabled, based on the ">>" used in the first column, it is identified as only suitable when the value can only be positive, while MEA05 and MEA06 were to be used where a positive value cannot be assumed, perhaps not initially enabled as apparently indicated by an "X" in the first column. When utility meters used for net metering, which began in 1998, were to generate negative usage measurements for months in which more power was exported to the grid by customer-generator than consumed, the NH EDI necessarily needed to be modified in some way to deal with negative usage values. Nowhere in the EDI standards approved by the Commission is there any reference or authorization to convert negative values to zeros and place them in a field for positive only values, yet that is apparently what Eversource choose to do rather than modify or propose a change to the EDI to use the two fields in the basic architecture designated for positive and negative measurement values in 810 reports. We have been unable to locate Commission approval for such an approach as Eversource took,

4.5. In contrast, 867 transactions for "Use in Reporting Historical Electric Power usage for a given time period" are specified to use MEA 05 and MEA 06 for positive and negative values respectively, as seen in Exh. B at 21-22, yet again, Eversource only reports positive usage values in 867 reports and converts negative usage values to a zero, also apparently without authorization.

4.6. In the EBT test conditions described in "ebtstv11" at p. 16 (Exh. B at 26) there is actually an example of a test transaction in which a "-500" kwh is reported in the "Peak/Total KWH" field, which in turn generates a negative customer charge (or credit) and negative amount due supplier. This sample transaction is highlighted in yellow on the next to last line of the main table, columns 11-34 of which are excerpted here:

N	-500											15	19980723	-14	-14	0	0	0	0	-0.7	0	0	-14.7

The sum of amounts due supplier does indeed total $112.7268, including the negative credit for a negative usage figure as the sum of amounts in the last column (34). This does indicate that recording and sharing a negative usage entry with a resulting credit was in fact contemplated at the time. Although apparently used here to illustrate a bill credit with a canceled reverse usage entry (a negative number), it does suggest that the EDI system was intended to handle negative usage entries in some manner which suggests that functionality could be extended to providing actual negative usage data for exports to the grid by a customer-generator as apparently contemplated in 867 historic usage reports.

4.7. Enactment of net metering legislation, including provision for suppliers other than the utility to determine how they would compensate for negative usage, occurred in the same year as Order No. 22,919, just a couple of months apart from the originally anticipated start of customer choice. The delayed implementation of restructuring due to PSNH's lawsuit gave adequate time for PSNH to figure how the EDI implementation would accommodate negative usage data that the State expected suppliers to have access to so they could determine their own terms, conditions and prices to "purchase net generation output from eligible customer-generators" under a customer choice and competitive supplier market paradigm that the utility was expected to facilitate with essential sharing of meter data, once litigation was resolved.

4.8. It appears that instead of implementing the requirement called for in the PUC approved standard Eversource made a decision to turn a negative usage value into zero and place it in a field only intended for measurements that can be assumed to be a positive value. This change was not sanctioned or suggested by the standard or the PUC, did not follow the known process for making changes or updates to the EDI process, nor is it known to have been discussed through a NH working group or a formal proceeding for the benefit of NH ratepayers. value.

5. NH EDI Standards clearly indicate that Time-of-Use (TOU) meter data should be available to Suppliers that should be able to charge based on utility TOU periods through Consolidated Billing by the utility.

5.1. The glossary of EDI terms in the Consensus Plan (at 47-50, Exh. B at 8-10) define Peak, Off-Peak, and Shoulder kWh usage and "amounts" referring, respectively, to kWh used in the Distribution Company's peak, off-peak and shoulder periods, and to the "current billed amount for usage during the Distribution Company's [peak, off-peak, or shoulder] hours. At various points it is recognized that there may not be TOU period, in which case only the "peak" or "total" field is used, or if ther**e is TOU metering, it may be for "2 or 3 time-of-use periods" as noted at Exh. B at 8**.

5.2. **The EDI Data Transaction Formats (Exh. B at 11-13) and 810 "Usage/Billing Invoice" report** also clearly provide for 2 or 3-part TOU usage data for both Pass-through and Consolidated billing, as well as TOU billing information where the Supplier charges rates based on the Distribution Company TOU periods in Consolidated billing. (Exh. B at 14-20).

5.3. The 867 historical usage report also includes provisions for On Peak, Off Peak and Shoulder TOU usage data. (Exh. B at 21-22)

5.4. Page 2 of the test plan ("ebtstv11") there is line for the utility to supply TOU kWh usage data for Supplier to use in Pass-through or separate billing. (Exh. B at 25)

5.5. Page 7 of the test plan ("tplanv11", Exh B at 26) makes clear that Suppliers should be able to provide a TOU rate with different charges by TOU period (and also demand charges) demonstrating these are to be accommodated under Consolidated Billing in NH, yet this functionality has not been enacted by Eversource over the past quarter of a century.

5.6. Page 16 of the test plan ("tplanv11", Exh B at 27) also illustrates testing of the provision of on and off-peak data for pass through billing.

5.7. Page 19 of the Consensus plan notes that "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." Likewise, the Training Guide, Part 002 (Exh. B at 30) also states "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." The Training Guide Part 002 (Exh. B at 31), like current tariffs, supplier, or trading partner agreements, and Puc 2205.16(c)(2) (see FN 8) indicates that if a Supplier wants to use a rate structure other than what the utility system currently supports, then they may request such and be responsible for the cost after receiving a quote from the utility to enable such.

5.8. To the extent the distribution company's billing system is capable of generating charges based on TOU, regardless of the specific rate element, such as for distribution services, it would certainly seem to have been the intent of the EDI standards to enable sharing of that TOU usage data to the Supplier and, in the case of Consolidated Billing, to charge differential rates based on distribution utility defined TOU periods as PSNH was actually doing at the time NH EDI standards were being developed and in the years immediately preceding the start of customer choice. Exhibit C is a compilation of excerpts from PSNH's tariffs No. 37 and 38 showing examples of 2-part TOU rates for General Service Rate Class G (Optional Time-of-Day or OTOD rates) effective 12/1/96 and 6/1/97, as well as Large General Service Rate LG 2-part TOU rates effective 6/1/97, 12/1/98, 11/1/99, and 6/1/2000 all presented as an "Energy Charge" based on TOU meter data. While today Eversource only uses those TOU periods for their distribution charge, up until the inception of customer choice, it was an integrated "Energy Charge" that included power supply. Considering all the evidence it is reasonable to conclude that the expectation under Order No. 22,919 as well as the parties to the consensus EDI plan was that Competitive Suppliers and now CPAs pursuant to RSA 53-E:4, V and Puc 2200 rules should be provided with TOU meter data as collected by the utility and used in the billing system to able to offer supply rates based on the same, either through separate pass-through billing or consolidated billing.

5.9. Inability to process consolidated billing for CPAs with TOU rates or NEM rates does not exclude the utility from providing meter data in the correct positive and negative format where applicable. While the law and subsequent rules are clear that this billing option should be available today as well as available the last 25 years, the withholding of the metering information limits solutions that may be available to CPAs to correct this billing deficiency for the benefit of NH ratepayers.

6. **EDI requirements imposed by Eversource and proposed testing requirements exceed those required pursuant to PUC Order No. 22,919 and the plain language of its own tariff.**

6.1. Eversource Tariff NPUC No. 10 Original p. 36 (§3(a) under Terms and Conditions for Suppliers) states: "Supplier Service shall commence on the date of the Customer's next meter read date, provided that the Supplier has submitted the Electronic Enrollment to the Company at least two business days prior to the scheduled meter read date." This seems to indicate that an EDI enrollment (or drop) of a customer must be submitted not less than 2 days prior to a meter read date to be effective starting with that meter read. However, Eversource has reinterpreted that to mean that an enrollment must actually be submitted no later than 3 pm a minimum of 3 business days prior to the next scheduled meter read date to be effective starting with that meter read as illustrated in slide 27 from an EDI training deck presented this year as seen below and imposed on the Coalition's EDI provider.

EVERSOURCE ENERGY

Data Exchange Operating Schedule Continued

Effective Dates

All successfully processed enrollment, drop and change requests require a minimum of two (2) full business days window prior to the Customer's next scheduled meter read date.

The EDI must be received at least two **full** business days prior to the customer's next cycle read date.

In other words, the EDI needs to be received by us before the 3:00 PM cut off time with a minimum of **three (3) business days** to meet the two full business days requirement.

Ten (10) days is recommended to prevent the effective date of the next cycle bill date from being missed due to a rejection EDI for an incorrect name key name, account number, etc.

SCHEDULES

Electronic Interchange (EDI) Schedule

Daily Activity/Event	Approximate Completion Time
Receive Supplier EDI Input	00:00 - 15:00
Daily Billing Cycle Process	16:00 - 08:00 (Upload readings, post cash billing)
Bills printed/inserted/mailed	By 18:00
Transmit EDI Output to Suppliers	12:00 - 15:00

Meter Reading

- 2021 Meter Reading Schedule (PDF)

https://www.eversource.com/content/nh/about/about-us/doing-business-with-us/energy-supplier-information/electric---new-hampshire

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This is directly contrary to the EDI standards approved by PUC in Order No. 22,919 as detailed below.

6.2. The consensus plan approved by the PUC in that order under "Account Administration: Enroll Customer" provides that: *"[t]he Competitive Supplier must electronically notify Customer's Distribution Company of the selection no less than two (2) business days prior to the scheduled cycle meter-read date or the enrollment will be deferred until the following read date. See Transaction #1." (Exh. B at 4). Under "Scheduling" that plan provides that "on Company in order to develop a proposed baseline schedule. The recommended schedule for a normal business day is as follows:*

- *Supplier transactions must be received ready for Distribution Company processing by noon each work day.*
- *"Transactions received by noon of the current business day will typically be responded to by noon the following business day."* (Exh. B at 5)

This is further graphically illustrated at Exh. B, p. 6 (p.38 of the Consensus Plan) showing a cut-off from enrollment transfers 2 days prior to the meter read date, presumably at noon, but definitely not by 3 pm on the 3rd day prior as Eversource is now requiring (but not other distribution utilities).

6.3. After required EDI testing and certification by Eversource that is also required to be completed prior to initial registration of a CEPS with the Dept. of Energy pursuant to Puc 2006.01(k), Eversource has sought to and continues to require additional EDI testing prior to allowing enrollment of CPA customers, directly contrary to the EDI standards approved by the PUC in Order No. 22,919 and its own tariff that simply requires that the "Supplier shall satisfy all EDI Standards as approved by the Commission."[24] Exhibit B, at 24 (tplanv11 at 9) shows an illustrative EBT Test Acceptance Form that provides certification to the DOE that the supplier (CEPS) has successfully completed EDI testing, including the following statement: "Subject to finalization of bilateral agreements between [supplier] and [UDC] and fulfillment of all other registration requirements as directed by the New Hampshire Public Utility Commission, [supplier] may submit customer enrollment transactions electronically to [UDC] beginning on [date]." Eversource has sought to require repeat EDI testing by Calpine Community Energy, LLC, the Coalition's LSE and Calpine Energy Solutions, LLC, the Coalition's EDI provider (together "Calpine") for each Coalition Member we seek serve, over the course of additional weeks after they have already certified EDI testing as successfully completed. Calpine has indicated to CPCNH that each such EDI test is identical in all respects to originally

[24] PSNH Tariff NHPUC No. 10, Original p. 31 (effective 1/1/21) at §1 f, under "Obligations of Suppliers" under "Terms and Conditions for Energy Service Providers."

successfully completed EDI testing, except for the use of a different DUNS+4 identifier in a particular data field and going forward, Eversource has recently indicated that they would not require repeating "frame testing," and then only require "connectivity testing."

6.4. We appreciate part of Eversource's response to CPCNH's open letter complaining of Eversource's requirements beyond those authorized by applicable rules and tariffs, which threatened to delay enrollment of tens of thousands of customers to take advantage of millions in savings. Eversource did waive further EDI testing for the initial launch of multiple communities but in doing so did blame CPCNH and our EDI provider for the potential delay rather than acknowledging their own role in the delay[25] and has more recently advised that going forward they will require such additional testing for each community the Coalition seeks to serve with the same CEPS, LSE, and EDI provider already approved. In an email dated 5/31/23 from Aaron Downing of Eversource to CPCNH CEO Brian Callnan, Mr. Downing stated that "[t]o complete EDI setup with an existing supplier [for each new member CPA served], excluding the frame testing, the process takes approximately 1-2 weeks, but can take up to 3 or so weeks if the queue is particularly long (which usually isn't the case)." Under the Commission approved EDI standards, as shown in Exh. B at 23 (tplanv11 at 4) "A complete test cycle can typically be completed in two days, assuming no problems." Calpine has confirmed that this actual testing is quite expeditious.

7. CONCLUSION

Eversource should act to come into compliance with the statutes and PUC Orders as detailed herein, provide CPA's the opportunity to best serve its Members, and meet the needs of NH ratepayers in general.

Community Power Coalition of New Hampshire

Clifton Below

by CPCNH Chair Clifton Below

[25] Such as by their refusal to deal with CPCNH as supplier as explained in CPCNH's parallel complaint to the PUC and their unilateral imposition of additional EDI testing requirements beyond those authorized. In a written response to a Boston Globe reporter's inquiry regarding the Coalition's open letter, William Hinkle, speaking for Eversource was quoted as writing; "we have been proactively encouraging them to take the necessary steps to be able to enroll customers in a timely fashion. Despite those efforts, the required steps were not completed by the supplier in a timely manner in this instance," https://www.bostonglobe.com/2023/04/21/metro/some-nh-community-power-programs-facing-delay/.

LIST of EXHIBITS:

- EXHIBIT A is an example of the explanation of existing net metering and how Community Power would serve those default service NEM customers which was filed with the PUC and Eversource pursuant to RSA 53-E:7, II on or about 1/7/22 in DE 22-001 as Attachments 5 and 6 to the Town of Rye's EAP. BATES PAGE 26
- EXHIBIT B is a compilation of selective excerpts of EDI Standards approved by the PUC in Order No. 22,919. BATES PAGE 36
- EXHIBIT C is a compilation of excerpts from PSNH's tariffs No. 37 and 38 showing examples of 2-part TOU "Energy Charge" rates with effective dates from 12/1/96-6/1/00. BATES PAGE 68

Attachment 5: Overview of Utility Net Energy Metering Tariffs

Discussion of Utility Net Metering, Group Net Metering and Low-Moderate Income Solar Project Tariffs

Under the net metering process, customers who install renewable generation or qualifying combined heat and power systems up to 1,000 kilowatts in size are eligible to receive credit or compensation for any electricity generated onsite in excess of their onsite usage.

Any surplus generation produced by these systems flows back into the distribution grid and offsets the electricity that would otherwise have to be purchased from the regional wholesale market to serve other customers.

The credits and compensation customer-generators receive for electricity exported to the grid are defined under Net Energy Metering (NEM) tariffs offered by Eversource, Liberty Utilities, Unitil and the New Hampshire Electric Co-op (NHEC). Note that:

- NHEC is a member-owned cooperative and, as such, its rules and regulations are approved by its Board of Directors and are not subject to regulation by the Public Utilities Commission. Additional information regarding NHEC's Net Energy Metering tariffs may be found online under their "Terms and Conditions".
- The Public Utilities Commission regulates the distribution utilities' Net Energy Metering (NEM) tariffs in accordance with PUC Rule 900 and RSA 362-A:9 (refer to RSA 362-A:9, XIV specifically for Group Net Metering statutes).

The remainder of this chapter concerns NEM tariffs regulated by the Public Utilities Commission. Note that:

- NEM tariffs offered by the utilities underwent a significant change several years ago;
- Customer-generators that installed systems before September 2017 may still take service under the "NEM 1.0" tariff ("standard" or "traditional" NEM);
- Systems installed after August 2017 must take service under the "NEM 2.0" tariff ("alternative NEM")
- NEM 1.0 customers are allowed to switch to taking service under the NEM 2.0 tariff but cannot subsequently opt-back to NEM 1.0 (with limited exceptions, e.g., participation in certain pilot programs).

Under both tariffs, customer-generators are charged the full retail rate for electricity supplied by Eversource and receive credits for electricity they export to the grid for some (but not all) components of their full retail rate. Refer to the next subsection for tables comparing NEM 1.0 to 2.0 tariffs.

To appropriately measure and credit customer-generators taking service under a NEM tariff, the utility installs a bi-directional net meter that records each kilowatt-hour (kWh) supplied to the customer from the grid and also each kWh that flows back into the grid. This data is recorded and collected on a monthly billing-cycle basis.

For NEM 1.0 tariff systems (installed before September 2017), any kWh exported to the grid are netted against kWh consumed. If there is a net surplus of kWh at the end of the monthly billing period (i.e., more power was exported to the grid by the customer-generator than was consumed) those surplus or negative kWh are carried forward and can be used to offset future kWh consumption (so the customer only pays for their "net" energy consumption).

For NEM 2.0 tariff systems (installed after August 2017), all customer-generators receive a monetary credit for each kWh that is exported valued at 100% of their default electricity supply rate component for the month. Smaller systems (up to 100 kilowatts in size) additionally receive credits for 100% of the transmission component and 25% of the distribution component of their retail rate. (Larger systems, up to 1,000 kilowatts in size, only receive full credit for the electricity supply rate component.)

Note that most customer-generators in Rye Community Power are expected to be taking service under NEM 2.0 tariffs going forward.

Any credits that accumulate over time are tracked and used to offset the customer-generator's future electricity bills. Customers may also request to cash-out their surplus credit once a year, after their March billing cycle, if the balance exceeds $100 (or any balance in the event of moving or service disconnection). NEM 1.0 surplus balances are tracked as kWh credits and are converted to dollars at wholesale avoided costs, while NEM 2.0 surplus balances are tracked as monetary credits directly (in dollars). Note that these cash-outs are treated as taxable income by the Internal Revenue Service (IRS). Payments of $600 or more remitted to the customer are accompanied by a 1099 form for the IRS. Utilities may also issue IRS Form 1099s for smaller amounts.

Alternatively, Group Net Metering is a process that allows any customer-generator to share the proceeds of their surplus generation credits to directly offset the electricity bills of other customers, which is financially more advantageous and can increase the effective value of the system. All the members in the group need to be within the same distribution utility service territory but may be served by different suppliers. The credits are calculated based on the host site's NEM tariff and retail rate, and payments are credited to offset the electricity bills of each member directly by the utility (assuming the utility is billing the customers for supply). These allocations are governed by a Group Net Metering Agreement between the host customer-generator and group members, which is part of the registration process overseen by the Public Utilities Commission.

Note that larger systems (up to 1,000 kilowatts in size) actually have to register as group hosts in order to qualify for net metering in the event that the customer-generator exports more than 80 percent of the power produced onsite to the distribution grid. Additionally, if the electricity exported from larger systems exceeds the total electricity usage of the group on an annual basis, the credit for the residual amount (e.g., electricity exported in excess of the group's total usage) is re-calculated based on their utility's avoided cost of electricity supply. This rate is lower than the NEM credit based on the customer-generator's retail rate, and results in a downward payment adjustment issued by the utility to the host customer. Residential systems under 15 kilowatts, however, are not subject to this adjustment.

Most recently, a Low-Moderate Income (LMI) Community Solar Project option has been implemented under Group Net Metering. The program currently provides an incentive of 3 cents per kWh (dropping down to 2.5 cents after July 2021) in addition to the host site's NEM credits, and solar systems may be either rooftop or ground-mounted systems. To qualify, groups must include at least five residential customers, a majority of which are at or below 300 percent of the federal poverty guidelines, and non-residential customers cannot account for more than 15 percent of the total projected load in the group.

Lastly, all group hosts (except for residential systems under 15 kilowatts) must file an annual report with the Public Utilities Commission and their utility that includes the annual load of the host and members, annual total and net surplus generation of the host site system, and additional information for Low-Moderate Income Community Solar Projects.

In addition to NEM credits, all customer-generators have the option of selling the Renewable Energy Certificates (RECs) produced by their systems. This can provide an additional revenue stream to customer-generators, but requires a separate REC meter, registration and ongoing reporting requirement.

Alternatively, the Public Utilities Commission estimates the RECs that could be produced by all customer-generators who do not separately meter and sell their RECs and lowers the Renewable Portfolio Standard procurement requirements for all load-serving entities by an equivalent amount.

Comparison of Utility "Standard" and "Alternative" Net Energy Metering Tariffs

The tables below compare the two tariff structures, which offer different credits to customers depending on the size of their installed system:

Net Energy Metering (NEM) Credit on Net Monthly Exports to Grid

	NEM 1.0 *"Standard NEM"* *Offered prior to 9/1/2017*	**NEM 2.0** *"Alternative NEM"* *Effective 9/1/2017*
Large Systems *100 Kilowatts to 1 Megawatt*	Full credit (at the customer's retail rate) for electricity supply <u>only</u>	
Small Systems *≤ 100 Kilowatts*	Full credit for electricity supply, distribution, transmission, System Benefits, Stranded Cost & Storm Recovery charges	Full credit for electricity supply and transmission; 25% credit for distribution & no credit for other charges

As shown in the table above, levels of compensation for small customer-generators (with systems up to 100 kilowatts) were lowered, such that these customers no longer receive full compensation on their distribution rate component or several other small charges (e.g., the System Benefits, Stranded Cost and Storm Recovery charges).

Additionally, the NEM 2.0 tariff modified the type of credit, and the ways credits for surplus generation are tracked and refunded, for both small and large customer generators:

- Under NEM 1.0, any surplus generation would be tracked as a kilowatt-hour (kWh) credit, which was carried forward to offset the customer's consumption (and bill) in future months. For any kWh credits remaining on an annual basis (at the end of March each year), such customers have the option of either continuing to bank their credits to offset future usage, or to convert the kWh credit into a monetary credit, at a rate set by the Public Utilities Commission (typically ~3-4 cents per kilowatt-hour) and to apply the amount to their account or receive a check for the amount owed.

- Under NEM 2.0, kWh credits are automatically converted into a monetary credit every month, valued at the customer's retail rate for that specific month. Customers have the option of either carrying the credit forward to offset to their electricity bill in future months or may receive the refund directly as a check.

The crediting mechanism under NEM 1.0 was relatively more advantageous for customers in one respect. Solar systems generate more power in the spring and summer months relative to other seasons; consequently, the credits that customer-generators would accrue during the summer months would offset their consumption in the winter months on a one-to-one, kWh per kWh basis. This is advantageous because winter supply rates are above summer rates on average.

In another respect, NEM 2.0 offers an advantage to customers that accrue surplus credits over the course of the year, because the surplus is calculated based on components of the customer's retail rate — which is higher than the ~3-4 cents per kilowatt-hour value that is applied to convert NEM 1.0 kWh credits into a monetary credit whenever customers elect to cash-out their surplus.

These changes are summarized in the table below, and apply to all customer-generators regardless of system size:

NEM 1.0 *"Standard NEM"* *Offered prior to 9/1/2017*	**NEM 2.0** *"Alternative NEM" Effective 9/1/2017*
kWh credit carried forward. May be refunded at a rate calculated by the Public Utilities Commission (typically ~3-4¢ per kWh).	kWh converted to monetary credit automatically each month. Monetary credit carried forward as a bill credit or refundable.

Additional details may be found in the Eversource, Liberty Utilities and Unitil tariffs and the Public Utilities Commission website:

- Eversource Tariffs
- Unitil Tariffs
- Liberty Utilities Tariffs
- PUC overview of Net Metering
- PUC graphic explanation of NEM 1.0 vs. NEM 2.0.

Net Energy Metering Systems by Utility Territory

According to the most recent Energy Information Agency (EIA) Form 861m data, there are about 11,000 customer-generators taking service under Net Energy Metering tariffs in New Hampshire, with a cumulative installed capacity of approximately 140 megawatts (in terms of nameplate capacity in alternating current, or "AC"). Estimated numbers of customer-generators and installed capacity by technology are summarized below:

- Solar photovoltaics: ~120 megawatts (MW) and 10,760 customer-generators; note that:
  - Group Net Metering accounts for an additional ~1.5 MW serving 56 customers; and

- Sixteen residential customers, in addition to solar photovoltaics, also have battery storage systems with a cumulative capacity of 175 kilowatts (an average size of ~11 kilowatts per customer).

- Onsite wind: 412 kilowatts (kW) and 72 customer-generators.
- "Other" technologies (presumably, small hydro or qualifying combined heat and power systems, or "CHP"): ~17.5 megawatts (MW) and 55 customer-generators.

The table below provides the number of customer-generators in each distribution utility territory:

Number of Net Metered Customer-Generators by Technology

	Customer-Generators by Technology				Subsets of Solar PV Customers	
	Total	**Wind**	**Other (CHP or Hydro)**	**Solar PV**	**Group Net Metering**	**Battery Storage**
Eversource	7,949	37	52	7,860	21	0
Unitil	1,066	3	1	1,062	0	0
Liberty Utilities	724	1	0	723	22	16
NHEC	1,204	31	2	1,171	13	0
Total	10,943	72	55	10,816	56	16

The number of customer-generators by customer class with onsite solar photovoltaic systems, total installed capacity, and average solar system size in each utility territory are provided for reference in the tables below.

Note that these tables do not include Group Net Metered systems and participating customers within groups and reflect only installed solar photovoltaic system capacity (i.e., exclusive of onsite battery storage capacity).

Net Metered Solar Photovoltaic Systems: Number of Customer-Generators

	Residential	Commercial	Industrial	Total Customer-Generators
Eversource	7,195	630	35	7,860
Unitil	973	61	6	1040
Liberty Utilities	633	77	0	710
NH Electric Coop	1,065	81	4	1,150
Total	**9,866**	**849**	**45**	**10,760**

Net Metered Solar Photovoltaic Systems: Total Installed Capacity (MW-AC)

	Residential	Commercial	Industrial	Total Installed Capacity (MW-AC)
Eversource	54.15	29.66	5.09	88.91
Unitil	7.40	2.30	0.73	10.43
Liberty Utilities	4.78	5.12	0.00	9.90
NH Electric Coop	7.61	2.46	0.60	10.66
Total	73.94	39.54	6.42	119.90

Net Metered Solar Photovoltaic Systems: Average System Size (kW-AC)

	Residential	Commercial	Industrial	Average System Size (kW-AC)
Eversource	7.5	47.1	145.5	66.7
Unitil	7.6	37.8	121.2	55.5
Liberty Utilities	7.6	66.5	N/A	24.7
NH Electric Coop	7.1	30.3	149.0	62.2
Average	**7.5**	**45.4**	**138.6**	**52.3**

Attachment 6: Community Power Net Metering, Group Net Metering and Low-Moderate Income Solar Project Opportunities

Please refer to Attachment 5: Overview of Utility Net Metering Tariffs as context for this section.

RSA 362-A:9,II grants Community Power programs broad statutory authority to offer customer-generators new supply rates and terms for the generation supply component of Net Energy Metering (NEM). The relevant statutory authority is quoted in full below:

> *"Competitive electricity suppliers registered under RSA 374-F:7 and municipal or county aggregators under RSA 53-E 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. The commission may require appropriate disclosure of such terms, conditions, and prices or credits. Such output shall be accounted for as a reduction to the customer-generators' electricity supplier's wholesale load obligation for energy supply as a load service entity, net of any applicable line loss adjustments, as approved by the commission. Nothing in this paragraph shall be construed as limiting or otherwise interfering with the provisions or authority for municipal or county aggregators under RSA 53-E, including, but not limited to, the terms and conditions for net metering."*

Rye Community Power intends to offer a NEM generation rate and terms to customers with onsite renewable generation eligible for net metering from Eversource. Note that any non-supply related components of the Net Energy Metering tariff (e.g., credits for transmission and distribution) will continue to be provided to customer-generators directly by their utility.

How Rye Community Power calculates, accounts for, and provides NEM credits to participating customer-generators for the different types of eligible system sizes, customer types and group configurations will have a number of important financial and practical implications for the program and customers in the Town.

Rye Community Power also anticipates encountering practical challenges of an operational nature in administering net metering and group net metering programs. This is partly because net energy metering continues to evolve in response to new policy and regulatory requirements, and the day-to-day processes that govern the coordination between the program, participating customers, and Eversource are subject to refinement and change over time.

In particular, Rye Community Power will be one of the first default aggregation programs to launch in New Hampshire, and the process of transferring significant numbers of NEM customers may cause unanticipated issues due to the metering, billing, and data management requirements of this subset of customers. Rye Community Power will maintain close coordination with Eversource to expeditiously resolve any such issues that may occur.

For example, Rye Community Power may decide to separately issue supply bills to customers that have installed systems after September 2017.

The advantage in dual-billing this subset of customers stems from what is essentially an accounting irregularity in how utility billing systems currently treats customer-generators taking service under the NEM 1.0 tariff, which applies to systems installed before September 2017, versus the NEM 2.0 tariff, which applies to all systems installed after that date. As context:

- The cumulative surplus generation exports of net metered customer-generators will decrease the amount of electricity that Rye Community Power will have to purchase from the regional power market to supply other customers in the program. The surplus generation from both NEM 1.0 and NEM 2.0 customer-generators is tracked and netted out from the program's wholesale load obligations by Eversource for this purpose.
- However, for the purpose of netting out of the program's Renewable Portfolio Standard (RPS) compliance requirements, the surplus generation from NEM 1.0 customers is tracked and accounted for differently than it is for NEM 2.0 customers:
    - Surplus generation from NEM 1.0 customers is tracked as a kWh credit that is carried forward to offset the customer's future electricity supply requirements; these kWh credits will be counted as an offset that decreases the total electricity supplied by the program to retail customers in aggregate — which lowers the program's RPS compliance obligation.
    - Surplus generation from NEM 2.0 customers is tracked as a monetary credit that is carried forward to offset the customer's future electricity bills; even though the monetary credit is calculated each month based on every customer's kWh surplus generation, the monetary credit is treated as a resale or delivery of power generated by NEM 2.0 customer and provided to other participating customers through the program — it is not treated, in other words, as an offset that decreases the total electricity supplied by program to retail customers in aggregate — and therefore does not lower RPS compliance obligations in the same way.

  The practical consequence of this accounting treatment is that Rye Community Power would have to purchase Renewable Energy Certificates for the amount of surplus generation supplied by NEM 2.0 customer-generators (but not NEM 1.0 customer-generators) in the same way as if the program had imported that amount of electricity from the regional wholesale market.
- Taking on the responsibility of billing this subset of NEM 2.0 customers directly may allow Rye Community Power to track and account for the impact of their surplus generation in ways that lower the program's RPS compliance obligations and costs. Specifically, the program could credit customers currently on the utility's NEM 2.0 tariff in the same way that NEM 1.0 customers are credited (i.e., using kWh credits to track surplus generation on the supply portion of the bill). Note that RSA 362-A:9,II explicitly grants Community Power programs the flexibility to offer net metered customers either:
    - A "*credit, as an offset to supply*" for their surplus generation, which is equivalent to the NEM 1.0 tariff accounting; or
    - To "*purchase the generation output exported*", which is equivalent to how the NEM 2.0 tariff tracks surplus generation.

  Exercising the first option listed above, by offering NEM 2.0 customers a kWh credit tracked as an offset to supply, would allow Rye Community Power to harmonize the accounting treatment of NEM 1.0 and 2.0 surplus generation for the purpose of program RPS compliance reporting. This would lower program rates and is an option that the program may therefore find cost-effective to implement.

Additionally, certain customer-generators currently receiving IRS Form 1099 taxable income from monetary credits paid out by their utility under NEM 2.0 tariff may benefit financially from receiving kWh credits for the supply portion of their monthly surplus generation instead.

While dual billing is typically avoided — as it is less convenient for most customers to receive a separate bill from their utility and supplier — customers with onsite generation systems tend to be highly informed on energy issues and respond positively to more active engagement with both their utility and supplier.

Consequently, dual billing may enhance customer satisfaction, awareness and ongoing participation in the program for customer-generators. Furthermore, dual billing could be done electronically, which is more convenient for the customer and less costly for the program than sending paper bills.

Furthermore, Rye Community Power may be able to create additional value for customer-generators through a combination of dual billing, assistance with metering upgrades and time-varying rate structures. For example:

- Many customer-generators with solar systems may benefit from local programs that help them reduce their full energy bill costs;
- Providing the customer with a separate supply-only bill would allow Rye Community Power to also offer a time-varying rate (which may not otherwise be available through Eversource's billing system);
- Upgrading to an interval meter (if the customer does not have one) and installing onsite battery storage, combined with a time-varying rate, may enable the customer-generator to further lower their overall bill by shifting their pattern of electricity usage at times of high-power prices and constrained generation and transmission capacity. This could also help to manage and lower the program's electricity supply costs in aggregate as well, and thus benefits all participating customers.

Similarly, Rye Community Power may be able to streamline the process and cost of installing REC production meters, registering customer-generators, and purchasing their RECs for the onsite power generated to satisfy part of the program's overall RPS compliance requirements. This would allow the program to source RECs locally and would provide an additional source of revenue for customer-generators in the Town.

Rye Community Power also intends to evaluate ways to enhance the value of the NEM credits that customers receive overall, from both the program and Eversource. For example, customer-generators may benefit by becoming hosts in Group Net Metering, including by establishing a Low-Moderate Income Solar Project group. The program may be able to streamline the process required to do so, which entails:

- Matching customers interested in becoming members with prospective group hosts;
- Executing a Group Net Metering Agreement together;
- Registering the group with the Public Utilities Commission and Eversource; and
- Thereafter filing annual compliance reports.

Lastly, NEM tariffs are subject to revision and Rye Community Power, through the Coalition, intends to work with Eversource, participate in Public Utilities Commission proceedings, and engage at the Legislature on issues that impact how the tariffs evolve going forward.

Customers are increasingly adopting new energy technologies and expect to be offered rates and services that provide them with new choices and fair compensation based on their investment; the program's ability to assist customers in these ways is heavily dependent on how state policies and utility regulations evolve over time.

Rye Community Power will seek to represent the interests of our community and customers in these matters.

Excerpts from PUC EDI Standards and Guidelines

Index to PUC web page on EDI Information with correlation of hyperlinks to the name of file that downloads for each shown in [RED].

https://www.puc.nh.gov/Electric/edi.htm

Home > Electric > EDI Information

EDI Information

The following files represent the existing approved EDI standards and guidelines:
All files in PDF unless otherwise noted.

- Training Guide -
  - Part 001 - 4/22/98 [Downloads as "Part001.pdf"]
  - Part 002 - 4/22/98 [Downloads as "part002-nhguide v3.pdf]
- Cover Letter - 4/2/98 [Downloads as "nhpuccov.pdf"]
- Consensus Plan for the Transmission of electronic Data in New Hampshire's Retail electric Market - 4/2/98 [Downloads as "edirev53.pdf"]
- Edi Data Transaction Formats - 4/2/98 [Downloads as "format33.pdf" – "Printed 4/9/2004"]
- Transaction Set Test Plans -
  - ebtstv11 - 4/2/98 [ebtstv11.pdf]
  - tplanv11 - 4/2/98 [tplanv11.pdf]
- Usage Billing Invoice - 4/2/98 [TS810.pdf]
- Account Administration - 4/2/98 [TS814.pdf]
- Payment - Order/Remittance Advice - 4/2/98 [TS820.pdf]
- Draft Product Transfer Resale Report - 4/2/98 [TS867.pdf]

In accordance with Commission Order No. 22,919 the above standards and guidelines are to be used "pending the outcome of a rulemaking on the implementation of EDI standards." Completion of that process is pending.

Consensus Plan for the Transmission of Electronic Data in New Hampshire's Retail Electric Market

Docket DR 96-150
Electric Utility Industry Restructuring

Prepared for:
The New Hampshire Public Utilities Commission
8 Old Suncook Road
Concord, NH 03301
(603) 271-2431

Prepared by:
The Electronic Data Interchange Working Group

April 2, 1998

Company of NH, Unitil, the Commission staff, ALLEnergy, Enron, Green Mountain Energy, Strategis Energy Ltd, Wheeled Electric Power, Unitil Resources, Select Energy, PG&E Energy, Xenergy, Eastern Utilities Associates, and Granite State Energy.

One of the first actions of the Working Group was create two subgroups, the Business Rules Subgroup and the Implementation Subgroup. The task of the Business Rules Subgroup was twofold: to reach agreement on a standard set of data transactions that meet the basic informational needs of each market participant; and to formulate business rules for each standard transaction.
The Implementation Subgroup’s primary task was to review the technologies and services available for transferring large volumes of electronic data and to make recommendations which ensure the smooth and timely implementation of retail access in 1998. The subgroup was also responsible for developing recommendations on the format of the electronic files and for producing training and systems testing manuals for use by competitive providers.

Anticipated Business Relationships
In order to establish a set of mutually agreed upon standards, there first must be agreement on the business relationships which define how the market operates. The following represents the current understanding of these relationships:

Customers:
(i)Provide appropriate authorization to Competitive Suppliers for customer enrollment[3]. Such authorization may also be given by an agent acting on behalf of the Customer.

(ii) Responsible for evaluating and securing services from registered Competitive Suppliers and Competitive Service Providers. A Customer who has not been enrolled by a Competitive Supplier at least two (2) business days prior to the Customer’s first scheduled cycle meter-read date following the start date for retail competition shall automatically receive transition power service.

[3] Enrollment includes switching Competitive Suppliers.

Account Administration:
Enroll Customer
The Competitive Supplier shall submit customer enrollment after receiving the appropriate authorization for each account and after any rescission period has lapsed. Appropriate authorization can be submitted by the customer in writing, in electronic form, or be given orally to a qualified and independent third party.

The Competitive Supplier must electronically notify Customer's Distribution Company of the selection no less than two (2) business days prior to the scheduled cycle meter-read date or the enrollment will be deferred until the following read date. See Transaction #1.

The Distribution Company shall process enrollment requests in the order in which they are received at its VAN or alternative transfer mechanism.

Multiple Enrollments
In most cases, it is anticipated that a Customer will select a Competitive Supplier, the Competitive Supplier will allow the customer rescission period to lapse, and will enroll the Customer with the Distribution Company, as outlined above. In the event that a Customer selects more than one Competitive Supplier, and those suppliers attempt to enroll that Customer for the same cycle meter-read period, the Distribution Company shall respond as follows:

> The Distribution Company shall process the first valid enrollment transaction received during the enrollment period. Once received, any other enrollment transaction submitted for the same Customer during the enrollment period will be rejected.
>
> The enrollment period commences one (1) business day prior to the Customer's scheduled cycle meter-read date and ends two (2) business days prior to the Customer's next scheduled cycle meter-read date.

Multiple Services
Where more than one distribution service is assigned to a Customer account, a Competitive Supplier may submit one enrollment transaction for all services or one enrollment for each service. When a Competitive Supplier successfully enrolls a Customer with multiple services, a successful

Computer Operations Considerations:
This section deals with the operational issues (both manual and automated) that affect the efficiency and consistency of business processes. The Subgroup agreed on the following principles for computer operations:

- Processing of data must be reliable, predictable, accurate and efficient
- Transaction processing must be fair and verifiable
- Trading partners' daily operational schedules should be accommodated
- The process must be designed to detect and report errors without manual intervention
- There must be a clear assignment of responsibility at all stages of transaction processing

Computer operations issues have been categorized into the following topics:

1. Scheduling
2. File Handling
3. Error Handling
4. Recovery

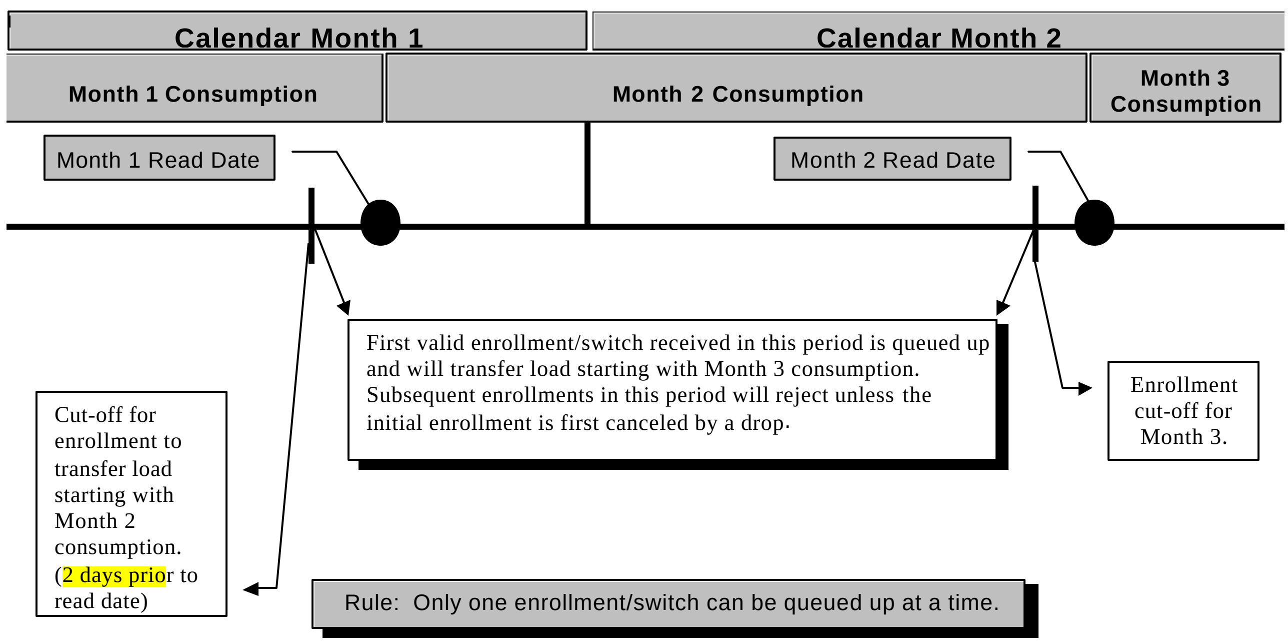
Scheduling
Each trading partner will have daily schedules that should be accommodated to the extent possible. Operating schedules cannot be standardized because of differences in daily transaction volumes, processing techniques, technology, etc. At the same time, there should be a baseline schedule that all trading partners can rely on and that does not place an undue burden on any trading partner.

The Subgroup has reviewed the daily computer operation schedules of each Distribution Company in order to develop a proposed baseline schedule. The recommended schedule for a normal business day is as follows:

- Supplier transactions must be received ready for Distribution Company processing by noon each work day.

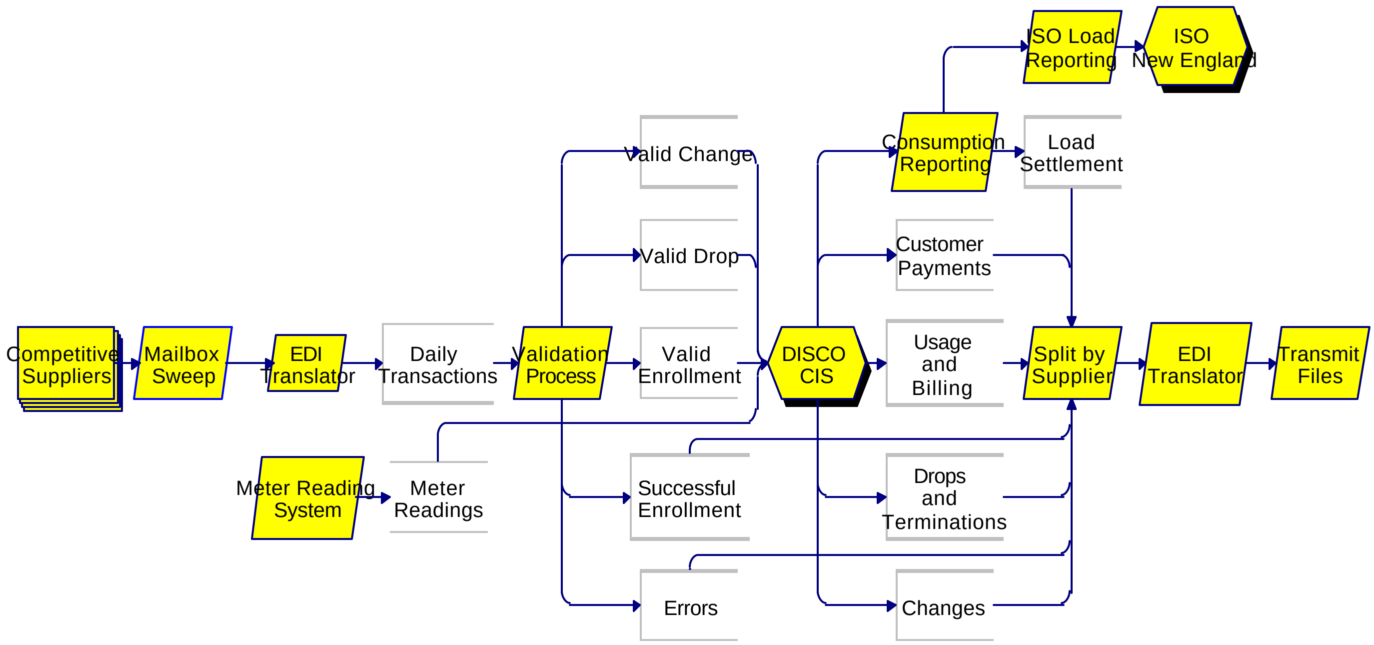
- Transactions received by noon of the current business day will typically be responded to by noon the following business day.

Exhibit A: Enrollment



This diagram illustrates the relationship between the Customer Enrollment/Change Supplier transaction and the Distribution Company meter reading dates for that customer.

Exhibit B: Electronic Business Transaction Process Flow



This diagram is a conceptual example only. It depicts the essential components (in terms of Competitive Supplier interfaces) of a theoretical Distribution Company computer operations processing cycle. The complete process occurs over a 24 hour period (noon to noon) and includes:

- Daily input and validation of Competitive Supplier input transactions (Enrollments, etc.)
- Distribution Company billing cycle ("Distribution Company CIS")
- ISO New England load estimating and reporting
- Daily output to the Competitive Suppliers (Successful Enrollments, Usage and Billing, Customer Payments, Errors, Load Settlement, etc.).

Billing Option for the Account: This field will indicate the billing method for the Customer. The Competitive Supplier may offer either 'Consolidated' or 'Passthrough' Billing, and the Customer will receive a separate bill from his Competitive Supplier (Passthrough) or one complete bill (Consolidated). Possible values are:

C = Consolidated (Complete)
P= Passthrough

Completion Status Code: After a set of transactions is processed by the Distribution Company, this field will be used to communicate the status of each detail record. See Appendix B for valid codes.

Consolidated Billing Option: A billing option whereby the distribution and generation charges are combined on one statement rendered by the Distribution Company.

Current Amount: The current amount billed for the Competitive Supplier for an individual service when there are multiple services per account, or for a single account when there is a single service for the account.

Current Customer Charge: The current Customer charges applied on the Competitive Supplier portion of the bill.

Current Demand Charges: The current billed amount for the Competitive Supplier total demand portion of the bill.

Current Off-Peak amount: The current billed amount for usage recorded during the Distribution Company's off-peak hours for the Competitive Supplier portion of the bill.

Current Peak Amount: The current billed amount for usage recorded during the Distribution Company's on-peak hours for the Competitive Supplier portion of the bill.

Current Read Date: The date the meter was read. The format of the date is CCYYMMDD.

Current Sales Tax: The current sales tax amount for the Competitive Supplier portion of the bill.

Current Shoulder Amount: The current billed amount for usage recorded during the Distribution Company's shoulder hours for the Competitive Supplier portion of the bill.

Data Exchange: The process of sending and receiving files over a computer network.

Demand Value Used by Distribution Company for Billing: This field is used for time-of-use accounts. It is the kW or kVa demand that was used by the Distribution Company to calculate the current demand charges. (Since there are 2 or 3 time-of-use periods, each with demand, this field tells the Competitive Supplier which demand was used for billing purposes).

Load Date: The day for which the kWh usage has been calculated by the load estimation system. The format of the field is: CCYYMMDD.

New Distribution Company Account Number: In certain circumstances the Distribution Company must change a Customer's account number. This field will be used to identify the new account number.

New Distribution Company Service Identifier: In certain circumstances the Distribution Company must change a Customer's service (i.e. replacement meter). This field will be used to identify the new service identifier.

New Distribution Company Customer Name: In certain circumstances the Distribution Company must change the Customer's name (i.e. marriage). This field will be used to notify the Competitive Supplier of the first four characters of the Customer's new name.

Net Dollars: This field will contain the total of the Payment/Adjustment amount field for the Competitive Supplier.

Number of Non-Metered Units: Number of billable units pertaining to the value listed in the type of service indicator field.

Off-Peak Demand: The highest demand measured in kilowatts during the Distribution Company's off-peak hours.

Off-Peak kVa Demand: The highest kVa demand measured in kilovolt-amperes during the Distribution Company's off-peak hours.

Off-Peak Kilowatt Hour usage: The total kilowatt hour use during the Distribution Company's off-peak hours.

Passthrough Billing Option: A billing option whereby the Customer receives two bills, one for distribution charges from the Distribution Company, and one for generation charges billed separately by the Competitive Supplier.

Payment/Adjustment Amount: The amount that was posted to the Customer's account for the Competitive Supplier portion of the bill.

Payment/Adjustment Code : This field will contain a code that identifies the record's function.

001 = Payment received from the Customer
002 = Transfer
003 = Bad Check
004 = Arrears Interest
005 = Sales Tax
006 = Adjustment

007 = Supplier Write-Off

Payment/Adjustment Posting Date: The date the transaction amount was posted to the Customer's account for the Competitive Supplier portion of the bill.

Peak or Highest kW demand: For non-time-of-use meters, this will contain the actual highest demand measured in kilowatts. For time-of-use meters, it is the highest demand measured in kilowatts during the Distribution Company's on-peak hours.

Peak kVa Demand: The actual peak demand measured in kilovolt-amperes during the Distribution Company's on-peak hours.

Peak or Total Kilowatt Hour Usage: For non-time-of-use meters, this is the total kilowatt hour usage for the billing period. For time-of-use, it contains the total kilowatt hour use during the Distribution Company's on-peak hours.

Previous Read Date: The date the meter was last read and used for billing. The format of the date is CCYYMMDD.

Primary Metering Indicator: The indicator telling the Competitive Supplier that the Distribution Company has metered Customer's service at primary voltage.

N = No Primary Metering
Y = Primary Metering
SPACE = No Primary Metering

Record Count: The number of detail records contained in this transmission.

Service Identifier: Some systems offer multiple types of services to a particular account. A Competitive Supplier may wish to offer different prices for the different service types. This field will be used in conjunction with the Type of Service Indicator to identify the specific service referenced by the transaction (it typically contains a meter number or an unmetered rate depending on the type of service).

Settlement Function: Single character on settlement record indicating the type of supply service included in the record. The values for the field are:

C = Competitive Supply
D = Transition Service

Shoulder kW Demand: The shoulder demand measured in kilowatts.

Shoulder kVa Demand: The total shoulder demand measured in kilovolt-amperes.

Shoulder Kilowatt Hour Usage: The total shoulder kilowatt hour usage.

Format II - USAGE & BILLING

DESCRIPTION	SIZE	TYPE
1) Detail Record indicator	1	A/N
2) Supplier account number	20	A/N
3) Distribution Co. account number	20	A/N
4) Supplier rate code	3	A/N
5) Type of service indicator	1	A/N
6) Service Identifier	10	A/N
7) Billing option for the account - Pass Through or Consolidated	1	A/N
8) Activity Code	2	A/N
9) Supplier pricing structure maintained by Distribution Co.	7	A/N
10) Current read date	8	DATE
11) Previous read date	8	DATE
12) Primary metering indicator	1	A/N
13) Peak or Total kilowatt hour usage	9	N0
14) Peak or Total kW demand	6	N1
15) Peak kva demand	6	N1
16) Off peak kilowatt hour usage	9	N0
17) Off peak kW demand	6	N1
18) Off peak kva demand	6	N1
19) Shoulder kilowatt hour usage	9	N0
20) Shoulder kW demand	6	N1
21) Shoulder kva demand	6	N1
22) Demand value used by Distribution Co. for billing	6	N1
23) Number of non-metered units	4	N0
FIELDS 24-35 ARE FOR CONSOLIDATED BILLING OPTION		
24) Billing cycle	2	A/N
25) Billing date	8	DATE
26) Current amount	11	N2
27) Current peak amount	11	N2
28) Current off peak amount	11	N2
29) Current shoulder amount	11	N2
30) Current demand charges	11	N2
31) Current customer charge	11	N2
32) Current Tax amount	11	N2
33) Arrears interest *	11	N2
34) Supplier arrears *	11	N2

Format II - CUSTOMER USAGE INFORMATION (Transaction 10)

From Distribution Co. to Supplier

DESCRIPTION	REQ	SIZE	TYPE	PSNH	NHEC	CVEC	UNITIL	GSEC
1) Detail Record indicator	MA	1	A/N					
2) Supplier account number	MA	20	A/N					
3) Distribution Co. account number	MA	20	A/N					
4) Supplier rate code	N/A							
5) Type of service indicator	OP	1	A/N	Y		Y	M	
6) Service Identifier	OP	10	A/N	I		Y	M	
7) Billing option for the account - Pass Through or Consolidated	MA	1	A/N					
8) Activity Code	MA	2	A/N					
9) Supplier pricing structure maintained by Distribution Co.	N/A							
10) Current read date	MA	8	DATE					
11) Previous read date	MA	8	DATE					
12) Primary metering indicator	OP	1	A/N	Y			IF A	
13) Peak or Total kilowatt hour usage	MA	9	N0					
14) Peak or Total kW Demand	OP	6	N1	IF A		IF A	IF A	
15) Peak kva demand	OP	6	N1	IF A		IF A	IF A	
16) Off peak kilowatt hour usage	OP	9	N0	IF A		IF A	IF A	
17) Off peak kW demand	OP	6	N1	IF A		IF A	IF A	
18) Off peak kva demand	OP	6	N1	IF A		IF A	IF A	
19) Shoulder kilowatt hour usage	OP	9	N0	I			IF A	
20) Shoulder kW demand	OP	6	N1	I			IF A	
21) Shoulder kva demand	OP	6	N1	I			IF A	
22) Demand value used by Distribution Co. for billing	OP	6	N1	IF A		IF A	IF A	
23) Number of non-metered units	OP	4	N0	IF A		IF A	IF A	
FIELDS 24-35 ARE FOR CONSOLIDATED BILLING OPTION								
24) Billing cycle	N/A							
25) Billing date	N/A							
26) Current amount	N/A							
27) Current peak amount	N/A							
28) Current off peak amount	N/A							
29) Current shoulder amount	N/A							
30) Current demand charges	N/A							
31) Current customer charge	N/A							
32) Current Tax amount	N/A							
33) Arrears interest	N/A							
34) Supplier arrears	N/A							

Format II - CUSTOMER USAGE and BILLING INFORMATION (Transaction 11)

From Distribution Co. to Supplier

DESCRIPTION	REQ	SIZE	TYPE	PSNH	NHEC	CVEC	UNITIL	GSEC
1) Detail Record indicator	MA	1	A/N					
2) Supplier account number	MA	20	A/N					
3) Distribution Co. account number	MA	20	A/N					
4) Supplier rate code	MA	3	A/N					
5) Type of service indicator	OP	1	A/N	Y		Y	M	
6) Service Identifier	OP	10	A/N	I		Y	M	
7) Billing option for the account - Pass Through or Consolidated	MA	1	A/N					
8) Activity Code	MA	2	A/N					
9) Supplier pricing structure maintained by Distribution Co.	MA	7	A/N					
10) Current read date	MA	8	DATE					
11) Previous read date	MA	8	DATE					
12) Primary metering indicator	OP	1	A/N	Y		Y	IF A	
13) Peak or Total kilowatt hour usage	MA	9	N0					
14) Peak or Total kW demand	OP	6	N1	IF A		IF A	IF A	
15) Peak kva demand	OP	6	N1	IF A		IF A	IF A	
16) Off peak kilowatt hour usage	OP	9	N0	IF A		IF A	IF A	
17) Off peak kW demand	OP	6	N1	IF A		IF A	IF A	
18) Off peak kva demand	OP	6	N1	IF A		IF A	IF A	
19) Shoulder kilowatt hour usage	OP	9	N0	I		I	IF A	
20) Shoulder kW demand	OP	6	N1	I		I	IF A	
21) Shoulder kva demand	OP	6	N1	I		I	IF A	
22) Demand value used by Distribution Co. for billing	OP	6	N1	IF A		IF A	IF A	
23) Number of non-metered units	OP	4	N0	IF A		IF A	IF A	
FIELDS 24-35 ARE FOR CONSOLIDATED BILLING OPTION								
24) Billing cycle	OP	2	A/N	NO	Y	Y	Y	Y
25) Billing date	MA	8	DATE					
26) Current amount	MA	11	N2					
27) Current peak amount	OP	11	N2	IF A		IF A	IF A	
28) Current off peak amount	OP	11	N2	IF A		IF A	IF A	
29) Current shoulder amount	OP	11	N2	I		I	IF A	
30) Current demand charges	OP	11	N2	IF A		IF A	IF A	
31) Current customer charge	OP	11	N2	IF A		IF A	IF A	
32) Current Tax amount	OP	11	N2	IF A		IF A	IF A	
33) Arrears interest *	OP	11	N2	IF A		IF A	IF A	
34) Supplier arrears *	OP	11	N2	IF A		IF A	IF A	

810 Usage/Billing Invoice

Functional Group ID=IN

Introduction:

This transaction will allow Distribution companies to send usage and billing information for electricity to the suppliers who have enrolled customers.

Notes:

ASSUMPTION: One 810 will be created for all of a Suppliers customers who receive electricity from this Distribution company for a given billing cycle. Each customers account for the specific Supplier defined by the N1 within will create looping at the IT1 segment level.

Heading:

	Pos. No.	Seg. ID	Name	Req. Des.	Max.Use	Loop Repeat	Notes and Comments
Must Use	010	ST	Transaction Set Header	M	1		
Must Use	020	BIG	Beginning Segment for Invoice	M	1		
Not Used	030	NTE	Note/Special Instruction	O	100		
Not Used	040	CUR	Currency	O	1		
Not Used	050	REF	Reference Identification	O	12		
Not Used	055	YNQ	Yes/No Question	O	10		
Not Used	060	PER	Administrative Communications Contact	O	3		
			LOOP ID - N1			1	
Must Use	070	N1	Name - Distribution Company	O	1		
Not Used	080	N2	Additional Name Information	O	2		
Not Used	090	N3	Address Information	O	2		
Not Used	100	N4	Geographic Location	O	1		
Not Used	110	REF	Reference Identification	O	12		
Not Used	120	PER	Administrative Communications Contact	O	3		
Not Used	125	DMG	Demographic Information	O	1		
			LOOP ID - N1			1	
Must Use	070	N1	Name - Supplier	O	1		
Not Used	080	N2	Additional Name Information	O	2		
Not Used	090	N3	Address Information	O	2		
Not Used	100	N4	Geographic Location	O	1		
Not Used	110	REF	Reference Identification	O	12		
Not Used	120	PER	Administrative Communications Contact	O	3		
Not Used	125	DMG	Demographic Information	O	1		
Not Used	130	ITD	Terms of Sale/Deferred Terms of Sale	O	>1		
	140	DTM	Date/Time Reference - File Creation Date	O	1		
Not Used	150	FOB	F.O.B. Related Instructions	O	1		
Not Used	160	PID	Product/Item Description	O	200		
Not Used	170	MEA	Measurements	O	40		

Not Used	180	PWK	Paperwork	O	25		
Not Used	190	PKG	Marking, Packaging, Loading	O	25		
Not Used	200	L7	Tariff Reference	O	1		
Not Used	212	BAL	Balance Detail	O	>1		
Not Used	213	INC	Installment Information	O	1		
Not Used	214	PAM	Period Amount	O	>1		
			LOOP ID - LM			10	
Not Used	220	LM	Code Source Information	O	1		
Not Used	230	LQ	Industry Code	M	100		
			LOOP ID - N9			1	
Not Used	240	N9	Reference Identification	O	1		
Not Used	250	MSG	Message Text	M	10		
			LOOP ID - V1			>1	
Not Used	260	V1	Vessel Identification	O	1		
Not Used	270	R4	Port or Terminal	O	>1		
Not Used	280	DTM	Date/Time Reference	O	>1		
			LOOP ID - FA1			>1	
Not Used	290	FA1	Type of Financial Accounting Data	O	1		
Not Used	300	FA2	Accounting Data	M	>1		

Detail:

	Pos. No.	Seg. ID	Name	Req. Des.	Max.Use	Loop Repeat	Notes and Comments
			LOOP ID - IT1			200000	
Must Use	010	IT1	Baseline Item Data (Invoice)	O	1		
Not Used	012	CRC	Conditions Indicator	O	1		
Not Used	015	QTY	Quantity	O	5		n1
Not Used	020	CUR	Currency	O	1		
Not Used	030	IT3	Additional Item Data	O	5		
Not Used	040	TXI	Tax Information	O	10		
Not Used	050	CTP	Pricing Information	O	25		
Not Used	055	PAM	Period Amount	O	10		
Must Use	059	MEA	Measurements - Peak/Total kilowatt hour usage	O	1		
	059	MEA	Measurements - Peak kW Demand	O	1		
	059	MEA	Measurements - Peak kva Demand	O	1		
	059	MEA	Measurements - Off Peak kilowatt hour usage	O	1		
	059	MEA	Measurements - Off Peak kW Demand	O	1		
	059	MEA	Measurements - Off Peak kva Demand	O	1		
	059	MEA	Measurements - Shoulder kilowatt hour usage	O	1		
	059	MEA	Measurements - Shoulder kW Demand	O	1		
	059	MEA	Measurements - Shoulder kva Demand	O	1		
	059	MEA	Measurements - Demand value used for Billing	O	1		
	059	MEA	Measurements - Number of Non-metered units	O	1		
			LOOP ID - PID			1000	

Segment: **MEA Measurements - Peak/Total kilowatt hour usage**
Position: 059
Loop: IT1 Optional (Must Use)
Level: Detail:
Usage: Optional (Must Use)
Max Use: 1
Purpose: To specify physical measurements or counts, including dimensions, tolerances, variances, and weights (See Figures Appendix for example of use of C001)
Syntax Notes:
1 At least one of MEA03 MEA05 MEA06 or MEA08 is required.
2 If MEA05 is present, then MEA04 is required.
3 If MEA06 is present, then MEA04 is required.
4 If MEA07 is present, then at least one of MEA03 MEA05 or MEA06 is required.
5 Only one of MEA08 or MEA03 may be present.
Semantic Notes: 1 MEA04 defines the unit of measure for MEA03, MEA05, and MEA06.
Comments: 1 When citing dimensional tolerances, any measurement requiring a sign (+ or -), or any measurement where a positive (+) value cannot be assumed, use MEA05 as the negative (-) value and MEA06 as the positive (+) value.

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
X	MEA01	737	**Measurement Reference ID Code** Code identifying the broad category to which a measurement applies Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 2/2
X	MEA02	738	**Measurement Qualifier** Code identifying a specific product or process characteristic to which a measurement applies Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 1/3
>>	MEA03	739	**Measurement Value** The value of the measurement Peak/Total kilowatt hour usage	X R 1/20
>>	MEA04	C001	**Composite Unit of Measure** To identify a composite unit of measure (See Figures Appendix for examples of use)	X
>>	C00101	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken KH Kilowatt Hour Refer to 003070UIG Data Element Dictionary for acceptable code values.	M ID 2/2
X	C00102	1018	**Exponent** Power to which a unit is raised	O R 1/15
X	C00103	649	**Multiplier** Value to be used as a multiplier to obtain a new value	O R 1/10
X	C00104	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 2/2
X	C00105	1018	**Exponent** Power to which a unit is raised	O R 1/15
X	C00106	649	**Multiplier** Value to be used as a multiplier to obtain a new value	O R 1/10
X	C00107	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in	O ID 2/2

			which a measurement has been taken Refer to 003070UIG Data Element Dictionary for acceptable code values.		
X	**C00108**	**1018**	**Exponent** Power to which a unit is raised	**O**	**R 1/15**
X	**C00109**	**649**	**Multiplier** Value to be used as a multiplier to obtain a new value	**O**	**R 1/10**
X	**C00110**	**355**	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken Refer to 003070UIG Data Element Dictionary for acceptable code values.	**O**	**ID 2/2**
X	**C00111**	**1018**	**Exponent** Power to which a unit is raised	**O**	**R 1/15**
X	**C00112**	**649**	**Multiplier** Value to be used as a multiplier to obtain a new value	**O**	**R 1/10**
X	**C00113**	**355**	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken Refer to 003070UIG Data Element Dictionary for acceptable code values.	**O**	**ID 2/2**
X	**C00114**	**1018**	**Exponent** Power to which a unit is raised	**O**	**R 1/15**
X	**C00115**	**649**	**Multiplier** Value to be used as a multiplier to obtain a new value	**O**	**R 1/10**
X	**MEA05**	**740**	**Range Minimum** The value specifying the minimum of the measurement range	**X**	**R 1/20**
X	**MEA06**	**741**	**Range Maximum** The value specifying the maximum of the measurement range	**X**	**R 1/20**
>>	**MEA07**	**935**	**Measurement Significance Code** Code used to benchmark, qualify or further define a measurement value 42 On-Peak Refer to 003070UIG Data Element Dictionary for acceptable code values.	**O**	**ID 2/2**
X	**MEA08**	**936**	**Measurement Attribute Code** Code used to express an attribute response when a numeric measurement value cannot be determined Refer to 003070UIG Data Element Dictionary for acceptable code values.	**X**	**ID 2/2**
X	**MEA09**	**752**	**Surface/Layer/Position Code** Code indicating the product surface, layer or position that is being described Refer to 003070UIG Data Element Dictionary for acceptable code values.	**O**	**ID 2/2**
X	**MEA10**	**1373**	**Measurement Method or Device** The method or device used to record the measurement Refer to 003070UIG Data Element Dictionary for acceptable code values.	**O**	**ID 2/4**

Segment: **MEA** **Measurements - Off Peak kilowatt hour usage**

Position: 059
Loop: IT1 Optional (Must Use)
Level: Detail:
Usage: Optional
Max Use: 1
Purpose: To specify physical measurements or counts, including dimensions, tolerances, variances, and weights (See Figures Appendix for example of use of C001)

Syntax Notes:
1. At least one of MEA03 MEA05 MEA06 or MEA08 is required.
2. If MEA05 is present, then MEA04 is required.
3. If MEA06 is present, then MEA04 is required.
4. If MEA07 is present, then at least one of MEA03 MEA05 or MEA06 is required.
5. Only one of MEA08 or MEA03 may be present.

Semantic Notes:
1. MEA04 defines the unit of measure for MEA03, MEA05, and MEA06.

Comments:
1. When citing dimensional tolerances, any measurement requiring a sign (+ or -), or any measurement where a positive (+) value cannot be assumed, use MEA05 as the negative (-) value and MEA06 as the positive (+) value.

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
X	MEA01	737	**Measurement Reference ID Code** Code identifying the broad category to which a measurement applies Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 2/2
X	MEA02	738	**Measurement Qualifier** Code identifying a specific product or process characteristic to which a measurement applies Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 1/3
>>	MEA03	739	**Measurement Value** The value of the measurement Off Peak kilowatt hour usage	X R 1/20
>>	MEA04	C001	**Composite Unit of Measure** To identify a composite unit of measure (See Figures Appendix for examples of use)	X
>>	C00101	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken KH Kilowatt hours Refer to 003070UIG Data Element Dictionary for acceptable code values.	M ID 2/2
X	C00102	1018	**Exponent** Power to which a unit is raised	O R 1/15
X	C00103	649	**Multiplier** Value to be used as a multiplier to obtain a new value	O R 1/10
X	C00104	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 2/2
X	C00105	1018	**Exponent** Power to which a unit is raised	O R 1/15
X	C00106	649	**Multiplier** Value to be used as a multiplier to obtain a new value	O R 1/10
X	C00107	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in	O ID 2/2

Segment:	**MEA** **Measurements - Shoulder kilowatt hour usage**
Position:	059
Loop:	IT1 Optional (Must Use)
Level:	Detail:
Usage:	Optional
Max Use:	1
Purpose:	To specify physical measurements or counts, including dimensions, tolerances, variances, and weights (See Figures Appendix for example of use of C001)
Syntax Notes:	**1** At least one of MEA03 MEA05 MEA06 or MEA08 is required. **2** If MEA05 is present, then MEA04 is required. **3** If MEA06 is present, then MEA04 is required. **4** If MEA07 is present, then at least one of MEA03 MEA05 or MEA06 is required. **5** Only one of MEA08 or MEA03 may be present.
Semantic Notes:	**1** MEA04 defines the unit of measure for MEA03, MEA05, and MEA06.
Comments:	**1** When citing dimensional tolerances, any measurement requiring a sign (+ or -), or any measurement where a positive (+) value cannot be assumed, use MEA05 as the negative (-) value and MEA06 as the positive (+) value.

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
X	MEA01	737	**Measurement Reference ID Code** Code identifying the broad category to which a measurement applies Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 2/2
X	MEA02	738	**Measurement Qualifier** Code identifying a specific product or process characteristic to which a measurement applies Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 1/3
>>	MEA03	739	**Measurement Value** The value of the measurement Shoulder kilowatt hour usage	X R 1/20
>>	MEA04	C001	**Composite Unit of Measure** To identify a composite unit of measure (See Figures Appendix for examples of use)	X
>>	C00101	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken KH Kilowatt hours Refer to 003070UIG Data Element Dictionary for acceptable code values.	M ID 2/2
X	C00102	1018	**Exponent** Power to which a unit is raised	O R 1/15
X	C00103	649	**Multiplier** Value to be used as a multiplier to obtain a new value	O R 1/10
X	C00104	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken Refer to 003070UIG Data Element Dictionary for acceptable code values.	O ID 2/2
X	C00105	1018	**Exponent** Power to which a unit is raised	O R 1/15
X	C00106	649	**Multiplier** Value to be used as a multiplier to obtain a new value	O R 1/10
X	C00107	355	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in	O ID 2/2

Segment:	**SAC** **Allowance, or Charge Information - Current Amount**
Position:	180
Loop:	SAC Optional
Level:	Detail:
Usage:	Optional
Max Use:	1
Purpose:	To request or identify a service, promotion, allowance, or charge; to specify the amount or percentage for the service, promotion, allowance, or charge

Syntax Notes:
1. At least one of SAC02 or SAC03 is required.
2. If either SAC03 or SAC04 is present, then the other is required.
3. If either SAC06 or SAC07 is present, then the other is required.
4. If either SAC09 or SAC10 is present, then the other is required.
5. If SAC11 is present, then SAC10 is required.
6. If SAC13 is present, then at least one of SAC02 or SAC04 is required.
7. If SAC14 is present, then SAC13 is required.
8. If SAC16 is present, then SAC15 is required.

Semantic Notes:
1. If SAC01 is "A" or "C", then at least one of SAC05, SAC07, or SAC08 is required.
2. SAC05 is the total amount for the service, promotion, allowance, or charge. If SAC05 is present with SAC07 or SAC08, then SAC05 takes precedence.
3. SAC08 is the allowance or charge rate per unit.
4. SAC10 and SAC11 is the quantity basis when the allowance or charge quantity is different from the purchase order or invoice quantity. SAC10 and SAC11 used together indicate a quantity range, which could be a dollar amount, that is applicable to service, promotion, allowance, or charge.
5. SAC13 is used in conjunction with SAC02 or SAC04 to provide a specific reference number as identified by the code used.
6. SAC14 is used in conjunction with SAC13 to identify an option when there is more than one option of the promotion.
7. SAC16 is used to identify the language being used in SAC15.

Comments:
1. SAC04 may be used to uniquely identify the service, promotion, allowance, or charge. In addition, it may be used in conjunction to further the code in SAC02.
2. In some business applications, it is necessary to advise the trading partner of the actual dollar amount that a particular allowance, charge, or promotion was based on to reduce ambiguity. This amount is commonly referred to a "Dollar Basis Amount". It is represented in the SAC segment in SAC10 using the qualifier "DO" - Dollars in SAC09.

Notes:
Summary value of any and all of the following that are applicable to this account.
SAC for Current Peak Amount
SAC for Current Off-Peak Amount
SAC for Current Shoulder Amount
SAC for Current Demand Charges
SAC for Current Customer Charges
SAC for Current Sales Tax Amount

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
>>	**SAC01**	**248**	**Allowance or Charge Indicator** Code which indicates an allowance or charge for the service specified C Charge Refer to 003070UIG Data Element Dictionary for acceptable code values.	**M ID 1/1**
X	**SAC02**	**1300**	**Service, Promotion, Allowance, or Charge Code** Code identifying the service, promotion, allowance, or charge Refer to 003070UIG Data Element Dictionary for acceptable code values.	**X ID 4/4**
	SAC03	**559**	**Agency Qualifier Code**	**X ID 2/2**

867 Product Transfer and Resale Report

Functional Group ID=PT

Introduction:

This Draft Standard for Trial Use contains the format and establishes the data contents of the Product Transfer and Resale Report Transaction Set (867) for use within the context of an Electronic Data Interchange (EDI) environment. The transaction set can be used to: (1) report information about product that has been transferred from one location to another; (2) report sales of product from one or more locations to an end customer; or (3) report sales of a product from one or more locations to an end customer, and demand beyond actual sales (lost orders). Report may be issued by either buyer or seller.

Notes:

For Use in Reporting Historical Electric Power usage for a given time period.

Heading:

	Pos. No.	Seg. ID	Name	Req. Des.	Max.Use	Loop Repeat	Notes and Comments
Must Use	010	ST	Transaction Set Header	M	1		
Must Use	020	BPT	Beginning Segment for Product Transfer and Resale	M	1		
			LOOP ID - N1			2	
Used	080	N1	Name	O	1		

Detail:

	Pos. No.	Seg. ID	Name	Req. Des.	Max.Use	Loop Repeat	Notes and Comments
			LOOP ID - PTD			>1	
Must Use	010	PTD	Product Transfer and Resale Detail	M	1		
			LOOP ID - N1			5	
Used	050	N1	Name - Consumer	O	1		
Used	090	REF	Reference Identification	O	20		
			LOOP ID - QTY			>1	
Used	110	QTY	Quantity	O	1		
Must Use	160	MEA	Measurements	O	40		
Used	210	DTM	Date/Time Reference	O	10		

Summary:

	Pos. No.	Seg. ID	Name	Req. Des.	Max.Use	Loop Repeat	Notes and Comments
			LOOP ID - CTT			1	
Used	010	CTT	Transaction Totals	O	1		n1
Must Use	030	SE	Transaction Set Trailer	M	1		

Transaction Set Notes

1. The number of line items (CTT01) is the accumulation of the number of LIN segments. If used, hash total (CTT02) is the sum of the value of quantities (QTY02) for each QTY segment.

Segment: **MEA** **Measurements**
Position: 160
Loop: QTY Optional
Level: Detail:
Usage: Optional (Must Use)
Max Use: 40
Purpose: To specify physical measurements or counts, including dimensions, tolerances, variances, and weights (See Figures Appendix for example of use of C001)
Syntax Notes:
1 At least one of MEA03 MEA05 MEA06 or MEA08 is required.
2 If MEA05 is present, then MEA04 is required.
3 If MEA06 is present, then MEA04 is required.
4 If MEA07 is present, then at least one of MEA03 MEA05 or MEA06 is required.
5 Only one of MEA08 or MEA03 may be present.
Semantic Notes: **1** MEA04 defines the unit of measure for MEA03, MEA05, and MEA06.
Comments: **1** When citing dimensional tolerances, any measurement requiring a sign (+ or -), or any measurement where a positive (+) value cannot be assumed, use MEA05 as the negative (-) value and MEA06 as the positive (+) value.

Data Element Summary

	Ref. Des.	Data Element	Name	Attributes
Used	**MEA04**	**C001**	**Composite Unit of Measure** To identify a composite unit of measure (See Figures Appendix for examples of use)	**X**
M/U	**C00101**	**355**	**Unit or Basis for Measurement Code** Code specifying the units in which a value is being expressed, or manner in which a measurement has been taken K1 Kilowatt Demand Represents potential power load measured at predetermined intervals K2 Kilovolt Amperes Reactive Demand Reactive power that must be supplied for specific types of customer's equipment; billable when kilowatt demand usage meets or exceeds a defined parameter KH Kilowatt Hour	**M ID 2/2**
Used	**MEA05**	**740**	**Range Minimum** The value specifying the minimum of the measurement range	**X R 1/20**
Used	**MEA06**	**741**	**Range Maximum** The value specifying the maximum of the measurement range	**X R 1/20**
Used	**MEA07**	**935**	**Measurement Significance Code** Code used to benchmark, qualify or further define a measurement value 41 Off Peak 42 On Peak 51 Total 66 Sales Shoulder	**O ID 2/2**

EBT Test Plan

Test File Processing

A total of six transaction sets (files) are needed to complete the test:

File ID	Simulated Date	Description
1A	7/2/98	1st file from supplier to Disco. Contains Enrollments.
1B	7/3/98	Disco's response to file 1A.
2A	7/3/98	2nd file from supplier to Disco. Contains Changes, Drops and more Enrollments.
2B	7/6/98	Disco's response to file 2A plus Changes, Moves and Drops.
3B	8/10/98	From Disco to supplier. Usage and Billing records for August cycle 6.
4B	8/25/98	From Disco to supplier. Payments and Adjustments.

The supplier may transmit files 1A and 2A without waiting to receive the first file from the Disco. The Disco will process File 1A and 2A as if they were actually transmitted on two separate days. A complete test cycle can typically be completed in two days, assuming no problems.

Account Number Tables

Each transaction contains the Distribution Company Account Number and the Supplier Account Number. Since the actual account numbers are not known at this time, the test transaction account numbers have been arbitrarily assigned. A translation table for each company will have to be developed to replace the test script account numbers with "real" account numbers. The Account Number Tables have been provided as a template for this. Note that a given account may be used in more than one test condition.

Service Identifier Table

Where the Service Identifier (i.e., meter number) is used, a translation table for each company will have to be developed to replace the test script Service Identifier with "real" ids (meter number, rate code, etc.). The Service Identifier Table is provided as a template for this.

Optional Fields

The distribution companies have documented their unique requirements as optional fields. This information is included in Appendix D of the EDI Working Group Report dated March __, 1998. Trading partners will have to work together to ensure that adequate testing of optional fields is performed.

EBT Test Plan

EBT Test Procedure Attachment 2: Test Acceptance Form

The undersigned agree that [supplier company] and [UDC] have successfully completed electronic interchange testing on [date].

Subject to finalization of bilateral agreements between [supplier] and [UDC] and fulfillment of all other registration requirements as directed by the New Hampshire Public Utility Commission, [supplier] may submit customer enrollment transactions electronically to [UDC] beginning on [date].

Supplier Company: ___________________________________

Supplier Business Contact Signature: _______________________________
Date of Test Acceptance: _____________

Supplier Technical Contact Signature: _______________________________
Date of Test Acceptance: _____________

Distribution Company: ___________________________________

Distribution Company Business Contact Signature:
____
Date of Test Acceptance: _____________

Distribution Company Technical Contact Signature:
____
Date of Test Acceptance: _____________

EBT Test Conditions
Test Condition Descriptions

A-013	Customer on the Complete bill option moves within Disco service territory. Note variation in format of address (apartment number is imbedded in line 1).	Disco sends a Move transaction and a final Usage and Billing transaction (Activity Code 3). The Move transaction identifies the customers' new account number, service id (meter), cycle and billing address.
A-014	Customer on Pass-Through bill option moves outside Disco service territory.	Disco sends a Drop transaction and a final Usage transaction (Note: This is the same action that would be taken if customer called Disco to drop the supplier).
A-015	Supplier changes price structure.	Disco should accept the Change transaction and update the Price Structure. No confirmation is returned but the next billing record should use the new price structure.
A-016	Supplier changes account number.	Disco should accept the Change transaction and update the account number. No confirmatin is returned but subsequent transactions should carry the new account number.
A-017	Customer currently getting separate bills (Pass-through) wants one bill. Supplier sends a change to the billing option, but doesn't specify the rate and price structure.	The Change transaction should be rejected. Disco should return an error record with two error codes in the Completion Code field: Code 109 (Invalid Rate Code) and Code 110 (Invalid Price Structure)
A-018	Enrollment submitted for an account that is already pending enrollment.	The Enrollment should be rejected. An Unsuccessful Enrollment transaction is returned with Completion Code = 164
B-001	Customer on Pass-through option; single service account - regular cycle bill.	Disco sends Usage record (Activity Code 0)
B-002	Customer on Pass-through option; multiple metered services on account - regular cycle bill.	Disco sends a Usage record for each service on the account (Activity Code 0)
B-003	Customer on Complete bill option; single service account - regular cycle bill.	Disco sends Usage and Billing record (Activity Code 0)
B-004	Customer on Complete bill option; multiple metered services on account - regular cycle bill. Note: This scenario does not apply to all Discos.	Disco sends Usage and Billing record for each service on the account. The last record in the set contains the total amounts. Activity Codes are = 0.
B-005	Estimated consumption (Pass-through)	Disco sends Usage record; Activity Code = 6
B-006	Estimated consumption (Complete bill)	Disco sends Usage and Billing record; Activity Code = 6
B-007	Customer disconnected by Disco (Final Bill)	Disco sends Usage and Billing record; Activity Code = 3. A Drop transaction is not sent.
B-008	Time of use (kwh and demand) - Pass-Through option	Disco sends Usage and Billing record with on and off peak fields filled in.
B-009	Primary metering	Disco sends Usage and Billing record with Primary Metering indicator = Y
B-010	Late payment charge - Supplier Arrears = $50.00	Disco sends Usage and Billing record with Supplier Arrears and Late Payment Charge fields filled in
B-011	Unmetered service bill	Disco sends Usage and Billing record with Number of Unmetered Units filled in
B-012	Cancel and rebill - net effect is to reduce previous consumption by 200kwh. Original bill was for 500kwh; revised bill is for 300kwh.	Disco sends two Usage and Billing records: one that reflects the adjustment (Activity Code = 1) and one that reflects the rebilling (Activity Code = 4)
C-001	Customer makes full payment.	Disco sends a Payment record that shows the suppliers' portion of the payment. The supplier should add this amount (it is signed) to the customer's balance.

EBT Test Conditions
Test Condition Descriptions

RATE KEY	Rate	Price Structure	KWH Price	KW Price	Off Peak KWH Price	Off Peak KW Price	Peak KVA Price	Off Peak KVA Price	Shoulder KWH Price	Shoulder KW Price	Shoulder KVA Price
G002000001	G00	2000001	$0.020000	$1.000000							
R011000001	R01	1000001	$0.028000								
R011000002	R01	1000002	$0.030000								
R021000002	R02	1000002	$0.022000								
TOU4000001	TOU	4000001	$0.350000	$2.500000	$0.018000	$0.750000					
U993000001	U99	3000001	$0.015000								

Tax Rate	Late Payment Charge Rate
5.00%	1.50%

EBT Test Conditions
Test Condition Descriptions

1	2	3	4	5	6	7	7a	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
H	***SUPP ID***	***DISC ID***	**19980810**									kWh																						
U	S0000000000009	D0000000000009		M	M000000015	P	0		19980710	19980610	N	350											6	19980710										
U	S0000000000010	D0000000000010		M	M000000017	P	0		19980710	19980610	N	1200	6.3										6	19980710										
U	S0000000000010	D0000000000010		M	M000000018	P	0		19980710	19980610	N	400	2.1										6	19980710										
B	S0000000000011	D0000000000011	R01	M	M000000019	C	0	R000001	19980710	19980610	N	600											6	19980710	16.8	16.8	0	0	0	0	0.84	0	0	17.64
B	S0000000000012	D0000000000012	G00	M	M000000021	C	0	G000001	19980710	19980610	N	1000	12.5								15		6	19980710	32.5	32.5	0	0	12.5	0				
B	S0000000000012	D0000000000012	G00	M	M000000022	C	0	G000001	19980710	19980610	N	500	3.1								4.5		6	19980710	13.1	13.1	0	0	3.1	0	0	0	0	45.6
U	S0000000000013	D0000000000013		M	M000000023	P	6		19980710	19980610	N	525											6	19980710										
B	S0000000000014	D0000000000014	R01	M	M000000025	C	6	R000001	19980710	19980610	N	650											6	19980710	18.2	18.2	0	0	0	0	0.91	0	0	19.11
B	S0000000000015	D0000000000015	R01	M	M000000027	C	3	R000001	19980710	19980610	N	47											6	19980710	1.316	1.316	0	0	0	0	0.066	0	0	1.382
U	S0000000000016	D0000000000016		M	M000000029	P	0		19980710	19980610	N	500	10.2		200	2.5							6	19980710										
U	S0000000000017	D0000000000017		M	M000000031	P	0		19980710	19980610	Y	115000	112.1	50.1	7000	86.1	30.2						6	19980710										
U	S0000000000017	D0000000000017		M	M000000032	P	0		19980710	19980610	Y	28750	25.1	50.1	6250	15.5	30.2						6	19980710										
B	S0000000000018	D0000000000018	G00	M	M000000033	C	0	G000001	19980710	19980610	N	500											6	19980710	10	10	0	0	0	0	0.5	0.75	50	11.25
B	S0000000000019	D0000000000019	U99	L	10116	C	0	U000001	19980710	19980610	N	1500										99	6	19980710	22.5	22.5	0	0	0	0	1.125	0	0	23.63
B	S0000000000020	D0000000000020	R01	M	M000000036	C	1	R000001	19980723	19980623	N	-500											15	19980723	-14	-14	0	0	0	0	-0.7	0	0	-14.7
B	S0000000000020	D0000000000020	R01	M	M000000036	C	4	R000001	19980723	19980623	N	300											15	19980723	8.4	8.4	0	0	0	0	0.42	0	0	8.82
T	**112.7268**																																	

Total Amount Due

H	***SUPP ID***	***DISC ID***	**19980810**		
P	S0000000000004	D0000000000003	001	19980810	-44.07
T	**44.07**	**980812**			

ACH Transfer Amount

ACH Transfer Date

[Excerpt from page 9 below to provide a key to the column headings above with corresponding numbers added above in red.]

Field Number
Field Description

1	2	3	4	5	6	7	7a	8	9	10	11	12	13	14	15	16	17	22	23	24	25	26	27	28	29	30	31	32	33	34
Detail Record Indicator	Supplier Account No.	Disco Account No.	Supplier Rate	Type of Service	Service Identifier	Billing Option	Activity Code	Supplier Price Struct.	Current Read Date	Previous Read Date	Primary Metering Indicator	Peak/Total KWH	Peak/Total KW	Peak KVA	Off Peak KWH	Off Peak KW	Off Peak KVA	Number of Unmetered Units	Billing Cycle	Billing Date	Current Amount	Current Peak Amount	Current Off Peak Amount	Current Shoulder Amount	Current Demand Charges	Current Customer Charge	Current SaleS Tax Amount	Arrears Interest	Supplier Arrears	Total Amount Due Supplier

Excerpts from Training Guide Part 002

C. SUPPLIER REGISTRATION

The purpose of the Commission's rules for providers of competitive electric services is to establish requirements for competitive electric suppliers seeking to sell generation service to retail customers in New Hampshire consistent with the promotion of full and fair competition among competitive electric suppliers.

As part of the NHPUC Supplier registration requirements, competitive Suppliers will be required to file an application with the NHPUC. That application requires suppliers to provide certain information including certification of compliance with ISO reliability requirements. To enable the electronic exchange of information, as well as to support the NHPUC billing options and other available opportunities, a Supplier will also have to sign a trading partner agreement with each Utility as well as communicate electronically with each utility.

1. REGISTRATION WITH STATE REGULATORY AUTHORITIES

A Supplier must register with the state regulatory authority, the **NHPUC**, as required by the Commission's administrative rules.

2. NEPOOL/ISO-NEW ENGLAND REPRESENTATION

NEPOOL Membership

A Supplier must obtain a Certificate of Compliance from NEPOOL stating that it has complied with the ISO reliability requirements. Suppliers can comply with those requirements by either becoming a NEPOOL member or establishing a contract with a NEPOOL member so that its bulk power supply facilities and resources are administered by NEPOOL. Such administration by NEPOOL provides reliability of wholesale supply in accordance with NERC and NPCC guidelines, NEPOOL reliability criteria and operation of the NEPOOL system by NEPEX currently, and by ISO New England under a restructured NEPOOL.

Membership in NEPOOL is open to any person or organization engaged in the electric utility business (the generation, transmission or distribution of electricity for consumption by the public, or the purchase, as principal or broker, of electric energy and/or capacity for resale at wholesale) whether the United States of America or Canada, or a state or province or a political subdivision thereof or a duly established agency of any of them, a private corporation, a partnership, an individual, an electric cooperative or any person or organization recognized in law capable of owning property and contracting with respect thereto.

If a Supplier elects not to be a NEPOOL Participant, its power supply must be treated by NEPOOL as part of a Participant's responsibility for energy and capacity. After a Supplier and a NEPOOL Participant have made their own bilateral agreement, they should inform NEPOOL that all transactions involving the Supplier will be treated as those of the NEPOOL Participant.

CREATION OF A TIELINE

In NEPOOL billing, a tieline is a connection, or combination of connections, across which energy flows between Participants. A tieline may be a combination of several actual connections. The NEPOOL Automated Billing System (NABS) Procedure for the Transfer of Capability and Energy Responsibility For Load Between NEPOOL Participants (NABS 18) describes the procedure for establishing tielines. It involves the Participants whose NEPOOL energy bills will be affected by the transfer, the Host Utility and NEPOOL Billing.

Suppliers should contact **both** NEPOOL and the Host Utility to establish and activate tielines prior to enrolling their first customer in that utility's service territory.

In general, each Host Utility will require the following supplier information to establish a tie line:

Host Utility
NEPOOL Participant
Participants Own Load Dispatch Number
Supplier's Name
Supplier's Contact Name, Telephone Number, and Address
NEPOOL Contact
Estimated Load Transfer
Estimated Load Transfer Date

3. SUPPLIER TRAINING ATTENDANCE

D. BILLING

This section outlines how Distribution Companies will handle billing in compliance with the NHPUC requirements. Similarities and differences in the approaches between Distribution Companies will be identified to facilitate the seamless exchange of information for the overall benefit of the customer.

1. Billing Options

In order to aid the provision of competitive electric generation services, Distribution Companies or their agents shall offer both Standard (Passthrough) and Consolidated billing services as described below:

Standard Billing Service - Passthrough (Separate Bills):

A Distribution Company shall offer a standard billing service to all Competitive Suppliers doing business in its service area. Standard billing service requires the Distribution Company to electronically transfer to a Customer's authorized Competitive Supplier the Customer's usage data within twenty four (24) hours of the Distribution Company's issuing a bill to that Customer. See Transaction #10. 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. See Transaction #11.

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.

2. Required Billing Information

Company	No. of Cycles	Billing Period	Billing Window	Usage Transmission after Validation	Activity Codes
Concord Electric					
Connecticut Valley Elec.					
Exeter & Hampton Elec.					
Granite State Electric					
New Hampshire Coop.					
Public Service Co./ N.H.					

Explanation of Data:

Billing period range: The number of days from one meter reading to the next which will produce a standard "monthly" bill.

Billing window: The maximum number of days after the reading date that an on-cycle bill may be generated. Bills rendered after this date will either be estimated or billed off-cycle.

Usage transmission: The elapsed day(s) that data will be sent electronically to the Supplier after the data has passed utility validation checks.

Activity codes: The usage type that is sent to the Supplier.

To facilitate the exchange of information, each Distribution Company will publish its meter reading schedule on its Web Site.

4. Rate Structures

In order to support the consolidated billing option, Suppliers must adhere to NHPUC-approved Customer class designations for each Distribution Company. Each Distribution Company will post currently effective tariffs on its Web site.

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.

The common Distribution Company transaction-processing schedule for a normal business day is as follows:

- Supplier transactions must be received by the processing Distribution Company by noon each working day.
- Transactions received by noon of the current business day will be responded to by noon the following business day.
- Validated usage transactions will be transmitted to Suppliers by noon of the day following the corresponding Distribution Company processing cycle.

File Handling

The operational Guidelines pertaining to file handling are based on the transaction and data transmission standards included elsewhere in this document.

- Distribution Companies will attempt to process all files sent by Supplier(s) unless specific action is taken by the Supplier(s) to avert processing (i.e., delete files, replace files). Refer to the Error Handling section for additional information.
- The recipient of a file (Supplier or Distribution Company) is responsible for reviewing (editing) file contents to prevent adverse impact on the recipient's operations or systems (data errors, duplicate files, illogical conditions, etc.). The recipient of a file has the right to reject the file in whole or in part due to content or protocol errors. In the event that a file is rejected, the detail transactions will not be processed.
- The creator of a file is responsible for the accuracy and authenticity of the contents.
- All data exchanges will be done in a pre-established manner to ensure data security and integrity.
- Each file will have one recipient, and should contain transactions intended only for that recipient. A file may contain multiple transactions of the same or different type for the same customer account.
- Files will be processed by the recipient according to the recipient's operating schedule. Distribution Companies will sweep the input queue at least once each business day and will process all files that are available by the cut-off and up to the time of the last sweep.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

GENERAL SERVICE RATE G

SUMMARY OF CHANGES
TO TARIFF NHPUC NO. 37 EFFECTIVE JUNE 1, 1997

Monthly Rate	Tariff 37 Effective 12/1/96(1)	Tariff 37 Effective 6/1/97(2)
Customer Charge		
Single-Phase	$ 9.80 per month	$ 9.80 per month
Three-Phase	$19.61 per month	$19.61 per month
Customer's Load Charge	$ 9.16/KW over 5.0 KW	$ 9.16/KW over 5.0 KW
Energy Charges		
First 500 KWH	14.129¢ per KWH	14.514¢ per KWH
Next 1,000 KWH	9.802¢ per KWH	10.187¢ per KWH
All Additional KWH	8.606¢ per KWH	8.991¢ per KWH
Uncontrolled Water Heating Rate		
Meter Charge	$1.96 per month	$1.96 per month
All kilowatt-hours	11.194¢ per KWH	11.579¢ per KWH
Controlled Water Heating Rate*		
Meter Charge	$3.91 per month	$3.91 per month
All kilowatt-hours	6.864¢ per KWH	7.249¢ per KWH

* Closed to new customers.

Space heating service is available under Transitional Space Heating Service Rate TSH to customers served under Rate G or GV at locations which were receiving space heating service under the space heating provisions of General Service Rate G on May 31, 1992 and which have continuously received such service since that date. The charges under Rate TSH are:

Meter Charge	$1.96 per month	$1.96 per month
Energy Charge	12.893¢ per KWH	13.278¢ per KWH

GENERAL SERVICE OPTIONAL TIME-OF-DAY RATE G-OTOD

SUMMARY OF CHANGES
TO TARIFF NHPUC NO. 37 EFFECTIVE JUNE 1, 1997

Monthly Rate	Tariff 37 Effective 12/1/96(1)	Tariff 37 Effective 6/1/97(2)
Customer Charge		
Single-Phase	$22.87 per month	$22.87 per month
Three-Phase	$32.67 per month	$32.67 per month
Customer's Load Charge	$ 9.16 per KW	$ 9.16 per KW
Energy Charges		
On-Peak KWH	9.581¢ per KWH	9.966¢ per KWH
Off-Peak KWH	6.966¢ per KWH	7.351¢ per KWH

(1) Energy charges include a Fuel and Purchased Power Adjustment Clause rate of (0.848)¢ per KWH, and a Nuclear Decommissioning Charge above base of 0.019¢ per KWH.

(2) Energy charges include a Fuel and Purchased Power Adjustment Clause rate of (0.481)¢ per KWH, and a Nuclear Decommissioning Charge above base of 0.037¢ per KWH.

LARGE GENERAL SERVICE RATE LG

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for high voltage electric service. It is available upon the signing of an agreement for such service at specified delivery points to customers whose loads are larger than those that would be permitted under Rate GV of this Tariff, except that customers with loads in excess of 500 kilowatts who utilize electric thermal storage equipment or other equipment approved by the Company may take service under this rate. Service rendered hereunder shall exclude all backup and standby service provided under Backup Service Rate B. Outdoor area lighting is available under Outdoor Lighting Service Rate ML. Substation foundations and structures, and suitable controlling, regulating, and transforming apparatus, all of which shall be acceptable to and approved by the Company, together with such protective equipment as the Company shall deem necessary for the protection and safe operation of its system, shall be provided at the expense of the customer.

CHARACTER OF SERVICE

Service supplied under this rate will be three-phase, 60 hertz, alternating current, at a nominal delivery voltage determined by the Company, generally 34,500 volts or higher. A reasonably balanced load between phases shall be maintained by the customer.

RATE PER MONTH

Customer Charge.................................. $392.10 per month

Demand Charge.................................. $8.50 per kilovolt-ampere of maximum demand

Energy Charges:

	Per Kilowatt-Hour
On-Peak Hours (7:00 a.m. to 8:00 p.m. weekdays excluding holidays as defined in Section 12 of the Terms and Conditions of this Tariff)	
First 150 hours' use of the maximum demand	9.432¢
All additional kilowatt-hours	7.865¢
Off-Peak Hours (all other hours)	
All kilowatt-hours	7.212¢

Issued: June 2, 1997

Issued by: Gary A. Long
Gary A. Long

Effective: June 1, 1997

Title: Vice President Customer Service and Economic Development

Authorized by Order No. 22,604 dated May 27, 1997 in Docket No. DR 97-014 and by Order No. 22,593 dated May 12, 1997 in Docket No. DR 97-087

LARGE GENERAL SERVICE RATE LG

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for high voltage electric service. It is available upon the signing of an agreement for such service at specified delivery points to customers whose loads are larger than those that would be permitted under Rate GV of this Tariff, except that customers with loads in excess of 500 kilowatts who utilize electric thermal storage equipment or other equipment approved by the Company may take service under this rate. Service rendered hereunder shall exclude all backup and standby service provided under Backup Service Rate B. Outdoor area lighting is available under Outdoor Lighting Service Rate ML. Substation foundations and structures, and suitable controlling, regulating, and transforming apparatus, all of which shall be acceptable to and approved by the Company, together with such protective equipment as the Company shall deem necessary for the protection and safe operation of its system, shall be provided at the expense of the customer.

CHARACTER OF SERVICE

Service supplied under this rate will be three-phase, 60 hertz, alternating current, at a nominal delivery voltage determined by the Company, generally 34,500 volts or higher. A reasonably balanced load between phases shall be maintained by the customer.

RATE PER MONTH

Customer Charge .... $365.12 per month

Demand Charge .... $7.92 per kilovolt-ampere of maximum demand

Energy Charges:

Per Kilowatt-Hour

On-Peak Hours (7:00 a.m. to 8:00 p.m. weekdays excluding holidays as defined in Section 12 of the Terms and Conditions of this Tariff)

First 150 hours' use of the maximum demand ...... 9.614¢

All additional kilowatt-hours .... 8.155¢

Off-Peak Hours (all other hours)

All kilowatt-hours .... 7.547¢

Issued: December 2, 1998

Issued by: Gary A. Long

Effective: December 1, 1998

Title: Vice President Customer Service and Economic Development

Authorized by Order No. 23,073 dated December 1, 1998 in Docket No. DR 98-197

LARGE GENERAL SERVICE RATE LG

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for high voltage electric service. It is available upon the signing of an agreement for such service at specified delivery points to customers whose loads are larger than those that would be permitted under Rate GV of this Tariff, except that customers with loads in excess of 500 kilowatts who utilize electric thermal storage equipment or other equipment approved by the Company may take service under this rate. Service rendered hereunder shall exclude all backup and standby service provided under Backup Service Rate B. Outdoor area lighting is available under Outdoor Lighting Service Rate ML. Substation foundations and structures, and suitable controlling, regulating, and transforming apparatus, all of which shall be acceptable to and approved by the Company, together with such protective equipment as the Company shall deem necessary for the protection and safe operation of its system, shall be provided at the expense of the customer.

CHARACTER OF SERVICE

Service supplied under this rate will be three-phase, 60 hertz, alternating current, at a nominal delivery voltage determined by the Company, generally 34,500 volts or higher. A reasonably balanced load between phases shall be maintained by the customer.

RATE PER MONTH

Customer Charge .... $365.12 per month

Demand Charge .... $7.92 per kilovolt-ampere of maximum demand

Energy Charges:

Per Kilowatt-Hour

On-Peak Hours (7:00 a.m. to 8:00 p.m. weekdays excluding holidays as defined in Section 12 of the Terms and Conditions of this Tariff)

First 150 hours' use of the maximum demand ...... 9.658¢

All additional kilowatt-hours .... 8.199¢

Off-Peak Hours (all other hours)

All kilowatt-hours .... 7.591¢

LARGE GENERAL SERVICE RATE LG

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for high voltage electric service. It is available upon the signing of an agreement for such service at specified delivery points to customers whose loads are larger than those that would be permitted under Rate GV of this Tariff, except that customers with loads in excess of 500 kilowatts who utilize electric thermal storage equipment or other equipment approved by the Company may take service under this rate. Service rendered hereunder shall exclude all backup and standby service provided under Backup Service Rate B. Outdoor area lighting is available under Outdoor Lighting Service Rate ML. Substation foundations and structures, and suitable controlling, regulating, and transforming apparatus, all of which shall be acceptable to and approved by the Company, together with such protective equipment as the Company shall deem necessary for the protection and safe operation of its system, shall be provided at the expense of the customer.

CHARACTER OF SERVICE

Service supplied under this rate will be three-phase, 60 hertz, alternating current, at a nominal delivery voltage determined by the Company, generally 34,500 volts or higher. A reasonably balanced load between phases shall be maintained by the customer.

RATE PER MONTH

Customer Charge .... $365.12 per month

Demand Charge .... $7.92 per kilovolt-ampere of maximum demand

Energy Charges:

Per Kilowatt-Hour

On-Peak Hours (7:00 a.m. to 8:00 p.m. weekdays excluding holidays as defined in Section 12 of the Terms and Conditions of this Tariff)

First 150 hours' use of the maximum demand ..... 9.658¢

All additional kilowatt-hours .... 8.199¢

Off-Peak Hours (all other hours)

All kilowatt-hours .... 7.591¢

Issued: June 7, 2000

Issued by: /s/ Gary A. Long
Gary A. Long

Effective: June 1, 2000

Title: Senior Vice President

Authorized by Order No. 23,505 dated June 6, 2000 in Docket No. DE 00-105