

THE STATE OF NEW HAMPSHIRE  
PUBLIC UTILITIES COMMISSION

DE 16-576

ELECTRIC DISTRIBUTION UTILITIES

Development of New Alternative Net Metering Tariffs and/or  
Other Regulatory Mechanisms and Tariffs for Customer-Generators

City of Lebanon, NH

Direct Testimony of Clifton C. Below

ORIGINAL	
N.H.P.U.C. Case No.	DE 16-576
Exhibit No.	# 25
Witness _____	
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1    **I.      Introduction**

2    **Q.      Please state you name, business address and position with regard to the docket.**

3    A.      My name is Clifton C. Below and my office address is 1 Court Street, Suite 300,  
4    Lebanon, NH 03766. I am a Lebanon City Councilor and Chair of the Lebanon Energy Advisory  
5    Committee created by the Council. Earlier this year the Lebanon City Council voted  
6    unanimously to authorize me to represent the City in this proceeding, as well as in IR 15-296,  
7    Investigation into Grid Modernization, on a volunteer basis.

8    **Q.      Please describe your background and experience with regard electric utility  
9    regulation and energy policy.**

10   A.     My interest in electric power and utilities began when I toured hydroelectric and nuclear  
11   power stations on the Susquehanna River while in Elementary School. That inspired me to try  
12   to construct a hand cranked electric generator out of wood, wire and magnets for a science fair in  
13   6<sup>th</sup> grade. While the needle on the meter I installed wiggled back and forth, I think that was more  
14   from vibration of the contraption than actual AC current. In 1980 I graduated from Dartmouth  
15   College with distinction in my major of Geography and Environmental Studies. My course work  
16   included New England Energy Futures, Environmental Systems, Environmental Policy  
17   Formulation, and engineering courses in Community Systems (e.g. electric and water utilities)  
18   and Principles of Systems Design. In 1985 I earned an M.S. in Community Economic  
19   Development from Southern NH University, with course work in such areas as accounting,  
20   financial and organizational management, financing, and business development. During this  
21   time I became a sweat-equity partner in the development of two commercial buildings on  
22   urban renewal parcels that helped to revitalize downtown Lebanon. I continue to operate and  
23   manage one of those two buildings and with a modicum of success in that regard it enabled to  
24   begin serving in the New Hampshire legislature for 12 years starting in 1992 and do this  
25   volunteer work.

26       At the start of my first term I was appointed to the House Science Technology and  
27   Energy Committee. The first study committee that I was appointed to was the “Small Power  
28   Producers and PSNH Renegotiations Legislative Oversight Committee” that gave me a crash  
29   course into LEEPA and PURPA issues, as well as the tension between competition and

30 regulation, as over-market contracts with independent power producers (QFs) were being  
31 renegotiated. Those contracts and the PUC rate order approving them were originally justified  
32 by the same load and rate projections that were used to justify continued investment in the  
33 Seabrook nuclear station.

34 In 1995 I Chaired the Policy Principles, Social and Environmental Issues Subcommittee  
35 of the Retail Wheeling and Restructuring Study Committee. In that role, I worked closely and  
36 collaboratively with then ST&E Chair Rep. Jeb Bradley and many other legislators and  
37 stakeholders to craft a consensus report and recommendations that became the foundation for  
38 NH's Electric Utility Restructuring statute, RSA 374-F, the enactment of which enjoyed broad  
39 bi-partisan support. In 1996 Rep. Bradley and I provided joint written and in-person testimony  
40 before the Energy & Power Subcommittee of the U.S. House Committee on Commerce on  
41 State-Federal issues related to electric utility restructuring on behalf of the NH House of  
42 Representative. In 1997 I sponsored HB 485 with my co-sponsor Rep. Bradley that reformed  
43 the NH LEEPA statute, RSA 362-A, and first established net energy metering in New  
44 Hampshire in 1998.

45 After I was elected to the New Hampshire State Senate in 1998 I was approached by  
46 Attorney Tom Rath and the CEO of Northeast Utilities and was asked to be the prime sponsor  
47 of (then controversial) securitization legislation that NU saw as critical to resolving PSNH's  
48 litigation against NH's electric utility restructuring. I did so and in 2000 I was part of the team  
49 that negotiated a resolution of PSNH's litigation with the enactment of RSA 369-B with strong  
50 bipartisan support that enabled restructuring to proceed in New Hampshire. Throughout my 12  
51 year tenure in the legislature I always served on the policy committees that dealt with energy  
52 and electric utility issues and became active in regional and national forums. For example,  
53 from 1997-2004 I served on the Advisory Council on Energy of the National Conference of  
54 State Legislatures (NCSL), including 3 years as Chair and the Energy & Electric Utilities  
55 Committee, Assembly on Federal Issues, where, as Chair in 2000-2001, I facilitated a  
56 consensus based comprehensive update of NCSL's National Energy Policy (and other policies)  
57 used for lobbying the federal government on behalf of all state legislatures. I testified before  
58 the United States Senate Committee on Energy and Natural Resources on "Electric Industry  
59 Restructuring," with a particular focus on transmission issues, on behalf of NCSL. I also

60 served as a member of the National Council on Electricity Policy, Steering Committee from  
61 2001-2004.

62 After not seeking reelection to the State Senate Governor Lynch nominated me to the  
63 NHPUC, where I served over 6 years as a Commissioner from the end of 2005 into 2012. I  
64 read reams of testimony, participated in examination of witnesses and the adjudication of some  
65 360 cases with public hearings. I was active in ISO New England stakeholder processes and  
66 other regional and national forums on behalf of the NHPUC and the State. I served on the  
67 National Association of Regulatory Utility Commissioners (NARUC) Energy Resources &  
68 Environment Committee for 6 years including 3 as a Vice-Chair. I also served on the FERC-  
69 NARUC Smart Grid and Demand Response Collaborative, 2008-2011 and on the Electric  
70 Power Research Institute (EPRI) Advisory Council, 2009-2011 and its Energy  
71 Efficiency/Smart Grid Public Advisory Group, 2008-2010. I also served as President of the  
72 New England Conference of Public Utility Commissioners (NECPUC) from 9/2010 to 9/2011.  
73 A more detailed statement of my background and experience is attached as Appendix A.

74 **II. Overview of Issues and Summary of Proposal**

75 **Q. What is the City of Lebanon's interest in future net metering tariffs?**

76 A. In 2012 the Lebanon Planning Board and City Council adopted an updated Master Plan  
77 with an Energy Chapter that serves as official public policy for the City. Our Master Plan calls  
78 for Lebanon to be “a leader in energy efficiency, renewable energy reliance, and innovation  
79 across municipal, commercial, institutional, and residential sectors.”<sup>1</sup> A key outcome is for the  
80 City to rely “upon as much local renewable energy as possible” (p. 13-18) and our strategies  
81 include pursuit of opportunities on City sites and encouraging the residential and business  
82 sectors to invest in renewable energy. Our purpose is to reduce both the carbon impact and the  
83 long-term cost of our energy consumption and to make our energy systems more resilient and  
84 sustainable to support the long-term prosperity of our local economy and the City.

85 Specifically the City has a number of sites suitable for net metered and group net  
86 metered facilities including the possibility of generating up to 1 MW from landfill gas that is

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<sup>1</sup> From p. 13-17 of City of Lebanon Master Plan, 2012. Energy Chapter available at:  
<http://planning.lebnh.net/home/master-plan/implementation/chapter-13>.

87 now being flared, and so is ready to convert to power production, and on the order of 2 MW or  
88 more of potential solar PV sites, as well as a bit of hydro, some potential for heat led combined  
89 heat and power production, and some significant storage and demand response opportunities,  
90 all of which largely depend on net metering tariffs being developed in this docket. Lebanon is  
91 an electric customer of Liberty Utilities with approximately 85 meters and accounts and  
92 consumes approximately 5 million kWh per year. We estimate that within a couple of years  
93 we could be producing roughly twice what the City itself consumes from renewable resources  
94 on City sites.

95 During the course of 2015 one thing that LEAC and the City did in furtherance of its  
96 objectives to support residential investment in renewable energy was to support a “Solarize  
97 Lebanon-Enfield” effort, that, although sidetracked by Liberty Utilities’ hitting its net metering  
98 cap, has resulted in an increase in small PV installations in the City, from about 16 to 46 and  
99 from about 81 kW installed capacity at the start of the program to approximately 320 kW or  
100 more now, a four-fold increase. One of the things that we learned from this experience,  
101 besides the need for stable net metering policies, is that there are a significant number of  
102 residents who would like to invest in or purchase solar power, but do not have suitable sites at  
103 their own homes, hence indicating a need and opportunity for community solar projects.

104 **Q. As the original sponsor of NH’s net metering legislation nearly 20 years ago,  
105 generally how do you view the expectations set forth in HB 1116, Chapter 31, Laws of  
106 2016 that initiated this proceeding?**

107 A. After the Solarize Lebanon-Enfield campaign was stopped dead in its tracks last  
108 summer by the interconnection cap, I got involved in both DE 15-271, concerning queue  
109 management for interconnection of net metered customer-generators, and the development of  
110 the legislation that became Chapter 31, NH Laws of 2016. I testified in support of HB 1116  
111 and its Senate companion bill in both chambers. As both Sen. Bradley and I stated at those  
112 hearings, the original net metering statute was recognized as a rough justice for early adopters  
113 of emerging renewable technologies for behind the meter generation. Today, we are past the  
114 early adopter stage as distributed renewable generation has become more cost-effective and  
115 popular as an important means to act to reduce the climate risk from burning fossil fuels and

116 promote energy independence and local resources. We need a net metering policy that results  
117 in a more refined and granular justice for all involved.

118 It is important to view the work in this docket in the context of the purpose statement in  
119 Chapter 31:1, which starts by stating that to “meet the objectives of electric industry  
120 restructuring pursuant to RSA 374-F, including the overall goal of developing competitive  
121 markets and customer choice to reduce costs for all customers . . . the general court finds that it  
122 is in the public interest to continue to provide reasonable opportunities for electric customers to  
123 invest in and interconnect customer-generator facilities” while ensuring fairness in the  
124 allocation of costs and benefits. It goes on to state that the “general court continues to promote  
125 a balanced energy policy that” promotes “a modern and flexible electric grid that provides  
126 benefits for all ratepayers” among other things.

127 This proceeding, and I believe the City of Lebanon’s proposal for piloting a real time  
128 net metering tariff set forth below, is an opportunity to significantly advance some of the yet to  
129 be fully realized goals of RSA 374-F in a way that will benefit all utility customers and the  
130 resiliency of the electric grid and industry itself.

131 **Q. Could you elaborate on those “yet to fully realized goals of RSA 374-F” and how**  
132 **that relates to the City’s proposal?**

133 A. Yes. I think it will be helpful to consider some of goals and principles expressed in  
134 RSA 374-F, enacted into law over 20 years ago, to help inform the weight to be given to  
135 various rate design principles in evaluating proposed tariffs in this case (with emphasis added):

136 **374-F:1 Purpose. –**

137 I. The most compelling reason to restructure the New Hampshire electric utility industry is to  
138 **reduce costs for all consumers of electricity by harnessing the power of competitive**  
139 **markets.** The overall public policy goal of restructuring is to develop a more efficient industry  
140 structure and regulatory framework that results in a more productive economy by reducing costs  
141 to consumers while maintaining safe and reliable electric service with minimum adverse impacts  
142 on the environment. **Increased customer choice and the development of competitive markets**  
143 **for wholesale and retail electricity services are key elements in a restructured industry . . .**

144 II. A transition to competitive markets for electricity is consistent with the directives of part  
145 II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition  
146 in the trades and industries is an inherent and essential right of the people and should be  
147 protected against all monopolies and conspiracies which tend to hinder or destroy it."  
148 **Competitive markets should** provide electricity suppliers with incentives to operate efficiently

149 and cleanly, **open markets for new and improved technologies, provide electricity buyers**  
150 **and sellers with appropriate price signals,** and improve public confidence in the electric utility  
151 industry.”

152 **374-F:3 Restructuring Policy Principles. – . . .**

153 II. Customer Choice. . . . **Customers should be able to choose among options such as . . .**  
154 **real time pricing,** and generation sources including interconnected self generation . . .”

155 While good rate and tariff design requires the balancing of a variety of principles and  
156 objectives, New Hampshire policy clearly gives considerable weight to customer choice, the  
157 development of competitive markets, including, of note, for retail electricity services, and the  
158 provision of “appropriate price signals.” In this context it seems apparent that “appropriate price  
159 signals” include those that achieve economic and operational efficiency and help achieve express  
160 public policy goals such as “maintaining safe and reliable electric service with minimum adverse  
161 impacts on the environment.” New Hampshire statutory policy calls out specifically for  
162 customers to have the choice of real time pricing. Even as that concept and practice was still  
163 relatively new and limited to wholesale markets two decades ago, it was apparent to legislators  
164 that enabling retail load (customers) to respond to temporal price signals in supply markets is  
165 important to economic efficiency and productivity. While considerable effort has gone into  
166 developing wholesale supply markets in New England, we can do a better job connecting  
167 wholesale market price signals to retail consumption and supply markets and enabling small  
168 customers and customer-generators to have greater participation in retail electricity market  
169 choices.

170 **Q. Are there other rate design principles that inform your testimony?**

171 A. Yes, many of the principles first developed by James Bonbright and Alfred Kahn  
172 remain relevant today. Rates should yield the revenue required for regulated monopoly  
173 services in a stable and predictable manner. Rates should reflect cost causation, avoid undue  
174 discrimination and fairly apportion costs among customer classes, and, I’d say increasingly, in  
175 this day and age, among individual customers. Furthermore rates should promote  
176 economically efficient consumption and investment, and promote innovation in supply and  
177 demand. Rates that are forward looking and reflect marginal costs, especially long-term  
178 marginal costs when long-term investments are involved, can efficiently harmonize utility and  
179 customer investments, choices and benefits. Better translating existing wholesale market

180 prices signals for both generation services and transmission services to load could be key in  
181 this regard.

182 **Q. Could you summarize your alternative net metering tariff proposals?**

183 A. Yes, first I'll summarize what would be ideal, but can't be implemented in the near  
184 term due to limitations of current utility metering and billing systems. Then I'll summarize our  
185 proposed work-around in the form of a real time pricing (RTP) net metering (NM) pilot.  
186 Finally I'll summarize some recommendations for new NM tariffs that can work with existing  
187 meters and billing systems as a part of default service. More detailed discussions then follow.

188 Ideally a RTP NM tariff option would be offered on an opt-in basis as a secondary  
189 form of default service. During each RT interval when power is exported to the distribution  
190 grid it would receive credit at NH load zone Real Time Locational Marginal Prices (RTLMPs)  
191 plus all generation related ancillary services that are also billed with LMPs (and hence avoided  
192 when the load at the wholesale meter point is turned down from what it would otherwise be),  
193 adjusted for avoided line losses. Likewise, whenever power is imported from the grid it would  
194 be charged at the same RT Prices (RTPs) plus a mark-up to cover related billing and overhead  
195 (but not hedging services). Likewise FCM charges would be incurred or credited as avoided,  
196 based on the net load or production at the hour of New England wide coincident peak (CP) for  
197 each year.

198 Monthly transmission charges that are based on the monthly CP (of the "local"  
199 transmission network, either the whole NU or National Grid system in New England in NH's  
200 case), would be charged or credited based on each RTP NM customer's actual load during  
201 those monthly CPs. Distribution rates would be modified on a revenue neutral basis so that  
202 each customer class' composite or average load profile would produce the same revenue, but  
203 demand charges would be either based largely on share of CP, or customer peak on limited  
204 number of hours that are highly likely to be when the coincident peak occurs in a given year.  
205 Volumetric distribution rates would likewise be modified in a revenue neutral manner so that  
206 most costs are recovered during a limited number of pre-defined hours when system peaks are  
207 most likely to occur, say when demand might exceed 90% of annual peak. There would be  
208 decoupling of the distribution revenue requirement from net changed volumetric load (and  
209 shifting demand) compared with assumed or forecast load.

210        In order to facilitate a **RTP NM pilot work-around** of existing utility metering and  
211    billing limitations, the Lebanon City Council voted unanimously on Oct. 5<sup>th</sup> to designate the  
212    Lebanon Energy Advisory Committee (upon LEAC's recommendation) as Lebanon's Electric  
213    Aggregation Committee pursuant to RSA 53-E:6, I to develop a plan for an aggregation  
214    program, subject to future approval by the Council. I've attached a copy of RSA 53-E for  
215    convenient reference as Appendix B. I'll return to the significance of this later. The pilot  
216    would work outside of default service. The pilot would be administered with the assistance of  
217    a competitive energy supplier, two of which have indicated a strong interest in working with  
218    the City if this is approved. RTP NM for supply would be provided similar to what is  
219    described above. Load above and beyond that produced by NM DG would also be available at  
220    RTPs plus a modest retail mark-up. Either a secondary revenue grade interval meter with  
221    communications or an upgrade to the existing utility meter would be paid for by participants as  
222    described in the next section. Secondary meter data would be made available to Liberty  
223    Utilities at no charge. Participation in PPAs or even direct investment in off-site DG such as  
224    for community solar would likely be available to participants.

225        Transmission and distribution services would continue to be directly billed by Liberty,  
226    but there would be a transmission tariff rider in which pilot participants, through their supply  
227    bill, would receive a credit or additional transmission charge for their interval measured  
228    percentage deviation from customer class average load shape, i.e. the percentage of their  
229    monthly load (or surplus generation) that occurs on the hour of monthly coincident peak. The  
230    sum of differences would be settled monthly with Liberty through their Transmission Cost  
231    Adjustment Mechanism (TCAM) reconciliation account. Either distribution charges would  
232    simply be billed monthly for any net loads consumed over the billing period by customers,  
233    with no credit for net monthly exports, or with a pilot tariff for coincident peak demand  
234    charges and/or TOU volumetric components, distribution charges could be incurred for any  
235    hour in which there is net consumption across a meter (instead of the whole month) with no or  
236    limited credit for exports. The City would need for this pilot to be approved for a long  
237    duration, say through 2040, as long-term investments in landfill gas generation, community  
238    solar and other NM DG facilities are anticipated, but the pilot could be limited to Lebanon and  
239    contiguous municipalities within Liberty Utilities' Lebanon area service territory.

240        For a new NM tariff that will work with existing default service and meters,  
241 considering the value of solar NM generation as I discuss in the respective sections below, I  
242 propose that a volumetric credit continue to be allowed to be carried forward for default  
243 service and transmission charges, but not for distribution services and other minor charges, at  
244 least for solar. However, a customer that generates and sells RECs for their entire production  
245 (as opposed to only their net annual exports) would pay an RPS compliance adder equal to  
246 that included in default service rates for any carried forward volumetric net metering credit.  
247 NM tariffs that work with default service are of interest to the City because some residents and  
248 businesses that may want to invest in NM renewable energy system, which we want to  
249 encourage, but may not want to participate in a RTP NM pilot, or wait for it to launch, even if  
250 it is approved.

251 **III. Metering Issues**

252 **Q. How do current metering and information systems constrain options within this  
253 docket?**

254 A. First and foremost, throughout the informal discovery processes that have preceded  
255 initial filings in this case, it has been apparent that the lack of interval data, including load  
256 research data concerning net metered and other customers has limited the analytical ability of  
257 the parties to better understand the temporal attributes and impacts of customer-generators  
258 compared with the diversity of load shapes and impacts of other customers. For instance there  
259 has been very little “before and after” load shape data on customer generators. The NH  
260 Electric Cooperative was able to undertake an analysis in support of new net metering tariffs  
261 that clearly and substantially benefited from a body of detailed customer interval data. For  
262 instance their “‘Above the Cap’ Net Metering Staff Analysis & Recommendations”<sup>2</sup> reports  
263 that “we found that, on average, we could attribute an increase in usage of about 52% to the  
264 PV accounts” (p. 3) negating some of what might otherwise be under-recovery of delivery  
265 charges. This seems to be evidence of PV adopters also adopting new forms of electrification,  
266 such as heat pumps and/or electric vehicles. The report also states that they “performed  
267 detailed analysis of the PV systems’ contribution during each peak hour during the prior two

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<sup>2</sup> [http://www.nhec.com/filerepository/nhec\\_above\\_the\\_cap\\_net\\_metering\\_recommendationsstaff\\_analysis\\_2.pdf](http://www.nhec.com/filerepository/nhec_above_the_cap_net_metering_recommendationsstaff_analysis_2.pdf)

268 years and concluded that, under current net metering, the annual demand related Regional  
269 Access [transmission] costs attributable to members with PV installations was reduced by  
270 34%.” (p. 4). Further “[d]etailed analysis of the last two summers determined that members  
271 with PV installations reduced their contributions to NHEC’s load at the time of the FCM peak  
272 by 60%.” (p. 5). They indicated that they planned to update these analyses annually.<sup>3</sup>

273 Recognizing that NHEC has indicated that they do not want to be involved in this  
274 proceeding, perhaps little weight can be given to their analysis, but it is indicative of the kind  
275 of analysis that is made possible with interval data that could be made available through a pilot  
276 such the City of Lebanon is proposing, in advance of widespread AMI deployment. The key  
277 here is to find a revenue grade metering solution that can be implemented on an affordable  
278 basis even for smaller accounts, such as for residential net metering, and it looks like  
279 competitive market forces are providing them. Existing interval metering options under utility  
280 tariffs are simply cost-prohibitive for all but the largest accounts. The current annual cost per  
281 meter for Liberty Utilities, for example, to retrieve, store and access interval data could cost up  
282 to \$740-\$772.<sup>4</sup>

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<sup>3</sup> A summary of resulting rates can be found at:

[http://www.nhec.com/filerepository/nhec\\_above\\_the\\_cap\\_net\\_metering\\_summary\\_2.pdf](http://www.nhec.com/filerepository/nhec_above_the_cap_net_metering_summary_2.pdf).

<sup>4</sup> Under **Liberty Utilities** Tariff No. 19, at p. 72, their “Optional Interval Data Service Provision” to subscribe to access to interval data over the internet requires an annual fee of \$309 or \$277 for each additional retail delivery account requested at the same time. However, this option also requires equipment (including a modem) to allow the utility to read the interval data over a telephone line for a one-time fee of \$155 to \$247. A basic dedicated phone line for this purpose through FairPoint can cost a total of about \$38.55/mo. (\$25.13 for a business line plus \$13.42 in taxes and fees on local service) or about \$463/year. Combined with the subscription charge this totals \$740-\$772/year. It may be possible that a dedicated phone line would not be necessary, or it might be obtained at less expense if part of a VOIP network, so the annual cost might be as low as the subscription cost, which is still a lot for a smaller accounts and would not provide anything resembling real time data.

**Eversource** does not have an annual subscription cost and instead only charges a one-time fee of \$148 per phone line, that can read up to 5 meters at one location but they do require that “the Customer or Supplier provides and maintains a dedicated, dial-up, analog telephone line to the meter under their Tariff No. 9 at p. 34 under “Extended Metering Service.” So this could cost about \$463/year/phone line.

**Unitil** currently has a one-time cost of \$220.11 for residential service (or \$8.97 monthly) and \$361.61 for general service (or \$14.73 monthly) to obtain enhanced metering service that includes interval data and requires the customer at its own expense to install and operate telephone lines and service for the company to read the customer’s meter. (Unitil Tariff No. 3, pp. 44-45) These lump sum costs are proposed to increase to \$742.11 (\$32.24 monthly) for residential service and \$928.61 (\$40.34 monthly) for general service in DE 16-384. It is not clear if the required phone line must be dedicated. For “Interval Data Service” (p. 46) where only Large General Service G1 customers can obtain web-based access to interval data (but then only after standard monthly data reads), there is an additional \$335.05 monthly subscription fee (proposed to increase to \$455.14 in DE 16-384).

283   **Q.      Short of waiting for utility roll-out of AMI, what work-around do you see for the**  
284   **high cost of simple interval data?**

285   A.     In contrast to the high cost utility options current available, technology and software  
286   innovation driven by market forces for lower cost sub-metering and DG monitoring and  
287   renewable energy credit production seems to have resulted in a variety of potential solutions, if  
288   customers, or a municipal aggregator, are allowed by this Commission to install a secondary  
289   revenue grade meter behind the utility meter on the customer premises. RSA 53-E:3, II(a)  
290   authorizes municipal aggregators to enter into agreements for “Meter reading” and “other related  
291   services” in the context of a statute whose purpose is to “allow municipalities to aggregate retail  
292   electric customers, as necessary, to provide such customers access to competitive markets for  
293   supplies of electricity and related services” finding “that aggregation may provide small  
294   customers with similar opportunities available to larger customers” and “to encourage voluntary,  
295   cost effective and innovative solutions to local needs.” (RSA 53-E:1) There would be no point  
296   to authorizing independent meter reading services, just to get the same data that the utility  
297   already has and gives to customers, if a meter that was secondary or different from the one  
298   owned by the utility wasn’t legally possible. Just to be clear though, the City of Lebanon is not  
299   opposed to working with Liberty to find an affordable upgrade that could be owned by them and  
300   used in their meter socket. However we are past the point when once a day dial-up telephone  
301   modems make sense for data retrieval, especially when near real time meter data solutions are  
302   available that can securely use existing communication networks. The City of Lebanon has  
303   already invested in a municipally owned fiber optic network that is located just below the electric  
304   lines on utility poles and connects all of the City’s significant facilities. We have dark fiber that  
305   could be a cost-effective resource as part of a Liberty smart grid communications system.

306       At least one company, EKM Metering, Inc. offers an affordable revenue grade electrical  
307   meter and communications system that is designed to tie directly into local routers. Their EKM  
308   PUSH device securely pushes data to secure cloud storage once per minute, by default, but is  
309   capable of pushing real time data as often as once per second. For a one-time cost of \$100 their  
310   system includes permanent secure storage and customer controlled secure access to data, with a  
311   very open and flexible API (applications programming interface). This approach to meter data is  
312   much like that recently approved by this Commission in REC 16-215 and REC 16-474 for

313 PowerDash, Inc. and Solar-Log. Attachment C is an affidavit from Jameson Brouwer, CTO of  
314 EKM Metering Inc. responding to a series of questions about their system that are relevant to  
315 how it might be used for this pilot.

316       Should this pilot be approved, the City likely would use a competitive procurement  
317 process, such as an RFQ or RFP, to select a revenue grade metering vendor and would work with  
318 the PUC and Liberty to see that any concerns can be addressed, assuming a Liberty provided  
319 solution can't be found. We recognize that third party metering, even for a pilot, may need a  
320 waiver or amendment to certain Puc 300 rules as they assume only the utility will provide  
321 metering services. Besides EKM, there are other meter providers who might provide viable  
322 alternatives, including Solar-Log<sup>5</sup> that has both socket and other meters than can use LAN or  
323 cellular networks and a company called Powercom.<sup>6</sup>

324 **IV. Generation (Electricity Supply)**

325 **Q. If the City of Lebanon is proposing a pilot through which an aggregation program,  
326 in conjunction with a competitive electricity supplier is arranging to buy and sell electricity  
327 outside of default service, is any tariff or action needed by this Commission with regard to  
328 such transactions?**

329 A.       No, probably not. RSA 362-A:9, II does provide that: "Competitive electricity suppliers  
330 registered under RSA 374-F:7 may determine the terms, conditions, and prices under which they  
331 agree to provide generation supply to and purchase net generation output from eligible customer-  
332 generators." Puc 903.02(d) mimics this statutory provision. Of course other rate elements for  
333 net metering under such an arrangement still need to be addressed.

334 **Q. With regard to a new default service NM tariff, wouldn't it just be simple and fair,  
335 to pay for any net exported electricity during any interval that can be metered or billed at  
336 PURPA avoided costs for QFs, while requiring customer-generators to buy back power at  
337 subsequent times or billing cycles at default service rates?**

338 A.       It might be simple, especially if RTLMPS are simply averaged, but I do not believe it  
339 would be fair. At least with regard to solar, which is, by far, the dominant technology used for

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<sup>5</sup> <http://www.solar-log-america.com/us/home.html>

<sup>6</sup> <http://www.powercom.co.il/Templates/PRODUCT/PRODUCT.aspx?folderid=129&lang=EN>.

340 net metering,<sup>7</sup> and the only technology that I've seen hourly data for in New Hampshire, that  
341 would under value the contribution made by solar. The times that PV produces have tended, on  
342 average, to be distinctly above the average value for LMPs and ancillary services over the last 5  
343 years according to available data. Comparing the value of solar for energy (RTLMPs plus  
344 ancillary services) plus capacity, using the annual Avoided Energy Cost calculations by NHPUC  
345 staff for purposes of Puc 903.02(i) to compensate annual net surplus generation, with the  
346 average value for all hours, it has been estimated that solar production occurs during hours that  
347 resulted in 35% higher value than average for the year ending 3/31/12, 19% higher for 2013,  
348 13% higher for 2014, 12% higher for 2015, and 5% higher for 2016. These calculations  
349 however appear to substantially underestimate the value of solar because they used PV Watts  
350 modeled production for an assumed typical system, instead of actual PV production data. The  
351 PV Watts model uses typical weather data so it produces reasonably accurate projections of total  
352 average annual or even monthly production. It does this by using typical weather data drawn  
353 from actual historic dates. This necessarily results in a random mismatch of weather data, hourly  
354 solar insolation in particular, with actual conditions. High price hours in New England summers  
355 are correlated with high load hours, which in turn correlate with high solar insolation days which  
356 drive, in particular, air conditioning loads in building that heat up more when the sun shines.

357 For the 12 months ending 3/31/16 I used available actual data from 20 PV systems  
358 supplied by NESEA as part of informal discovery, plus 5 more systems that I collected data for,  
359 and ran them in the spreadsheet model attached hereto as my Schedules 1.1 through 1.3. My  
360 spreadsheets also used actual NH hourly values for generation related ancillary services instead  
361 of the \$1/MWh that had been assumed by the staff calculation. The average percentage by  
362 which the value of PV production from these 25 systems exceeded the average of all hours was  
363 27%, ranging from a low of 5% to a high of 67%. Obviously the 127% average value of solar is  
364 quite a bit more than the 105% value of solar compared with the average for all hours computed  
365 using modeled generation data. In addition I computed the load weighted average value for all  
366 hours of that year and this solar sample group still produced during hours that averaged 10%

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<sup>7</sup> Note that PURPA rules do allow differentiation of compensation rates by technology: CFR § 292.304 (c)(3)(ii) provides that purchase rates “[m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.”

367 more in value and reached as high as 44% greater value. To the extent that a customer-generator  
368 either offsets their own load and/or generates surplus during higher than average hours, it means  
369 that their hours of net consumption will be significantly lower than what they would otherwise  
370 have been. In other words, the PV customer-generator appears, from this sample, to  
371 significantly improve their load profile, and hence that of the default service group that they are  
372 in, from a cost of energy service perspective. If they are not credited for the actual value of  
373 energy they produce, then any difference in value is being transferred to other default service  
374 customers, or possibly the default service provider or distribution utility.

375 I would like to note the significant diversity in the RT value of individual systems.  
376 Generally, western oriented and tracking systems produce at higher value times than more  
377 eastern oriented systems, yet current homogenized rates or credit mechanisms give no price  
378 signal in this regard. A significant part of this value is coincidence with FCM peak. For better  
379 economic efficiency more granular rates, specifically RTP, will create better price signals.

380 **Q. Doesn't PURPA limit the authority of the NHPUC to require compensation of NM  
381 generation at more than PURPA avoided costs?**

382 A. If an alternative NM tariff required the distribution utility to purchase exported power for  
383 resale, then it seems like it would; however that is not being proposed. Also, while a NM  
384 eligible customer-generator under NH law may qualify to be recognized as a QF under PURPA I  
385 don't believe that makes them QFs and subject to QF related provisions of PURPA if they are  
386 not seeking to sell power at wholesale to a utility for resale to other customers, as may be the  
387 case for required compensation for net surplus generation that is permanently sold to a utility. In  
388 fact, the federal Energy Policy Act of 2005 directed state utility commissions to consider  
389 implementing a net metering standard, if they hadn't already done so, which New Hampshire  
390 had. The current net metering statute and ones like it in other states have not been struck down  
391 as contrary to PURPA, logically since PURPA also calls for states to consider adopting such  
392 policies. It logically follows that this Commission can modify net metering into forms that may  
393 lie between the current full volumetric credit and compensation limited to PURPA avoided costs  
394 for QFs.

395 **Q. Why do you suggest it might be fair to allow NM generation to be credited at default  
396 service rates when there is surplus to carry forward to a future period to be consumed?**

397 A. A number of cost components go into default service rates. The low bid of the  
398 competitive energy supplier incorporates the wholesale market costs plus some considerable  
399 amount for hedging to turn those dynamic and ultimately uncertain market costs into a fixed  
400 price for fixed period, with the additional risk of uncertain total load and load shape to be served.  
401 Plus there is the competitive supplier's own overhead and profit. Beyond that there is the  
402 distribution utilities' cost of administering the procurement including regulatory approval,  
403 perhaps a bit of credit and working capital cost, and more significantly, RPS compliance costs.  
404 When suppliers bid on the default service load, it is net of net metered loads and transactions, so  
405 they aren't figuring on buying the surpluses from one month to sell back at mark-up in a later  
406 month. The utilities' cost of administering the default procurement doesn't vary incrementally  
407 with net metering flows and the recovery base is figured net of net metered loads, as it should be.  
408 Hence the main variable is RPS compliance costs, which are becoming more significant over  
409 time. If a NM customer-generator produces and sells RECs for all their generation, essentially  
410 monetizing and selling off the renewable attribute, then I think it would be fair for that customer  
411 to pay for RPS compliance costs (which might go to purchase their RECs) whenever they take  
412 power back from the grid over a billing period, even if they had NM surplus to carry forward. On  
413 the other hand if they don't produce RECs for their behind the meter and net consumption, then  
414 other default service load benefits by getting credit for that renewable generation pursuant to  
415 RSA 362-F:6, II-a at no cost. Thus for such a customer-generator, full default service credit for  
416 episodic surpluses against future consumption seems more than fair to other customers, since the  
417 contribution of having that customer pay for RPS compliance would likely be far less than the  
418 cost of purchasing RECs for all that NM generation. However, a single credit rate for NM PV  
419 gives no price signal the value of western oriented or tracking systems.

420 Finally it is important to note that all ratepayers benefit from the demand reduction  
421 induced price effect (DRIPE) of having what is essentially price taking net metered generation,  
422 which lowers the demand for wholesale market generation whenever it is producing power from  
423 what it would otherwise be. The New England wholesale markets, both day ahead and real  
424 time, clear a bid stack of supply offers at constant intervals of time. Whenever demand across  
425 wholesale meter points, the real time load obligation, drops from what it would otherwise be,  
426 whether as a result of energy efficiency, demand response, such as shifting load to lower cost

427 hours, or distributed generation that doesn't bid into the supply market, that reduced demand will  
 428 lower the market clearing price (subject to the bid increments), benefitting all ratepayers.

429 While the DRIPE used in the last Core Program docket for energy efficiency might  
 430 approximate this value, another anecdotal indication of the magnitude of this effect comes from a  
 431 March 15, 2016 Bloomberg news story about a new ICF International study that found that Solar  
 432 PV would be depressing prices in wholesale power markets by as much as \$2 Billion by 2019.  
 433 For New England Bloomberg reported that "Generators stand to lose as much as \$716 million in  
 434 New England's auction, where demand for conventionally-generated power has been cut by 390  
 435 megawatts, according to ICF. It's a figure that takes into account both the amount of new solar  
 436 expected to be in use by 2019, and estimates for the power lost when the sun isn't shining."<sup>8</sup>  
 437 Unfortunately the source report doesn't seem to be publicly available, or at least I haven't been  
 438 able to track it down, but what it describes as bad news for generators is also savings and good  
 439 news for load and ratepayers.

440 The DRIPE effect also matters in the forward capacity market, where even modest  
 441 increments of increasing system peak demand can cause big increments of increase in next year's  
 442 forward capacity auction clearing price as has recently been experienced. ISO New England, in  
 443 this year's CELT report estimated that 40% of behind the meter (BTM) solar PV capacity (AC  
 444 nameplate) was reducing the summer seasonal peak load in 2015 from what it would otherwise  
 445 be. As the table below shows their 10 year forecast projects continued contribution to summer  
 446 peak load reduction, albeit at a slowly declining rate as increasing amounts of PV slowly shifts  
 447 the afternoon peak a bit later in the day each year (on average).<sup>9</sup>

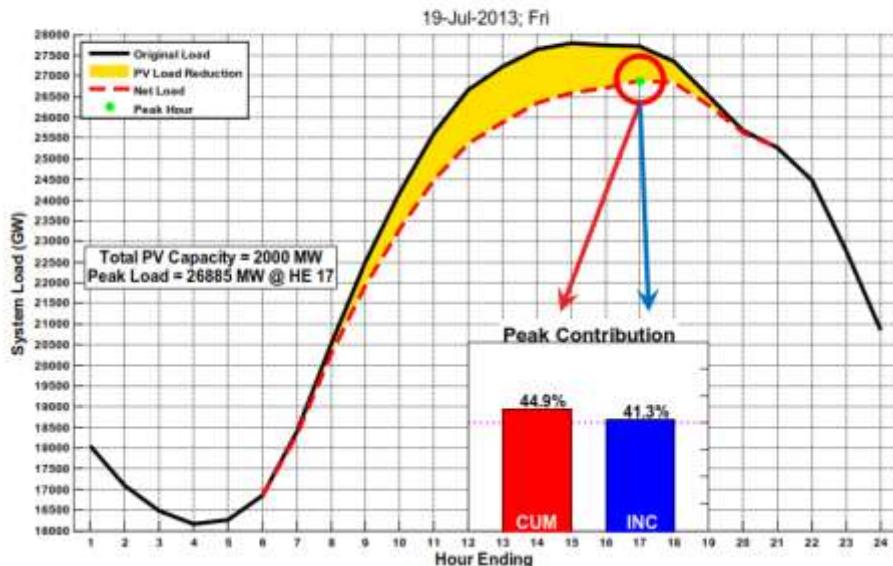
3.1.2 - Forecast of Cumulative BTM Solar PV Estimated Summer Seasonal (July 1st) Peak Load Reduction by State												
Category	States	Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Behind-the-Meter PV	CT	61.0	92.1	123.9	153.6	181.0	207.7	230.6	247.6	262.8	275.7	288.2
	MA	194.0	249.4	295.6	312.6	320.4	324.0	327.9	332.5	337.1	341.8	346.2
	ME	5.4	7.3	9.0	10.6	12.2	13.7	15.2	16.6	17.8	19.1	20.3
	NH	6.8	12.7	16.7	18.7	19.9	21.1	22.2	23.4	24.6	25.8	26.9
	RI	2.5	3.7	7.0	11.3	15.2	18.7	20.6	21.3	21.8	22.3	22.7
	VT	44.2	57.8	67.4	75.4	83.0	90.5	97.7	104.5	110.9	117.1	123.3
Total	Cumulative	313.9	422.9	519.5	582.2	631.6	675.6	714.3	745.9	775.0	801.7	827.6
Estimated Summer Seasonal Peak Load Reduction - % of BTM AC nameplate		40.0%	39.4%	38.2%	37.3%	36.7%	36.1%	35.6%	35.2%	34.8%	34.5%	34.1%

<sup>8</sup><http://www.bloomberg.com/news/articles/2016-03-16/-2-billion-loss-for-generators-as-a-million-u-s-roofs-get-solar>

<sup>9</sup> From tab 3.1.2, [https://www.iso-ne.com/static-assets/documents/2016/05/2016\\_celt\\_report.xls](https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls)

449           The cause of this effect can be illustrated with a slide from ISO New England's 2016  
450   Solar Forecast,<sup>10</sup> seen below:

## July 19, 2013 Net Load Profile 2000 MW PV



451  
452   A series of slides illustrates how increasing level of BTM PV (with static load) slowly shifts the  
453   expected afternoon peak, which has moved from around 2-3 pm in the past to an hour ending  
454   around 4 or 5 pm more recently. However the growth of installed PV still has the effect of  
455   significantly reducing the peak from what it would otherwise be absent the PV so there is  
456   persistent benefit and value to the system and all ratepayers from continued avoidance of  
457   substantial investments in T, D & G capacity from what otherwise would be required.

## 458   **V.      Transmission**

459   **Q      Please explain your ideal concept for a retail transmission tariff that supports NM  
460   and is fair to all customers.**

461   A.     The ideal would be to translate through to retail load the forward looking long-term  
462   marginal price signal that is charged at wholesale under FERC jurisdictional rates implemented  
463   by the ISO New England OATT (Open Access Transmission Tariff). While most of the current

<sup>10</sup> Slide # 80 [https://www.iso-ne.com/static-assets/documents/2016/09/2016\\_solar\\_forecast\\_details\\_final.pdf](https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf)

464 cost of operating the transmission grid consists of what are now relatively fixed and embedded  
465 costs from past investment in transmission capacity and capabilities, in the form of physical  
466 plant, nearly the entire revenue requirement for both PTF (pool transmission facilities) recovered  
467 through RNS (regional network service) rates and non-PTF or Local Network Service Rates are  
468 recovered through what is, in effect, a monthly demand charge, based on each distribution  
469 utility's share of coincident peak of the "local" transmission network that serves them. In New  
470 Hampshire's case, we are but a small part of the two local networks that serve us, namely  
471 National Grid that serves Liberty, which in March accounted for 28% of total New England  
472 network load, with NH network load constituting about 1% of that 28%, and NU serving  
473 Eversource and UES, which in March accounted for 35% of the NE network load, with NH load  
474 constituting 9% of that 35%.

475       Transmission rates are fully reconciling such that the full revenue requirement is always  
476 meet through apportionment of that revenue requirement by shares of monthly coincident peaks.  
477 With all other things being equal a reduction in NH share of coincident peaks will shift the vast  
478 majority of that "under-recovery" to ratepayers in other states. Ideally we would pass these  
479 shares of peak demand charges through to individual customers based on their individual  
480 contribution to these coincident peaks. As a matter of retail rate design NH does exactly the  
481 opposite. We translate what is a monthly coincident peak demand charge into a flat volumetric  
482 kWh charge for all customers with no temporal differentiation. This is pretty much the opposite  
483 of an appropriate price signal as it gives no transparency to cost causation and does nothing to  
484 promote economic efficiency and efficient investment in new or improved transmission capacity  
485 to accommodate growth in peak demands. Ironically, as I understand it, here in NH wholesale  
486 transmission charges are apportioned between rate classes based on each class' share of  
487 coincident peak before being translated to flat volumetric rates within each class. For the class  
488 there is an element of cost causation, but it is so dilute when translated to each individual  
489 customer in that rate class as to become invisible.

490 **Q. Aren't most transmission investments for reliability as opposed to load growth?**

491 A. While there are variety of aspects to reliability, growth in peak demands is a central  
492 driver of reliability investments. Both transmission and distribution facilities tend to be under  
493 the greatest stress and risk of failure when they are most heavily loaded. Power lines sag the

494 most and equipment like transformers tend to experience their greatest wear and tear and failure  
495 rates when they are most heavily loaded, especially when ambient temperatures are high, such as  
496 on hot summer days. To ensure reliability capacity margins need to be maintained.

497 In its 2015 Regional System Plan ISO-NE introduces the issues for northern New  
498 England Transmission as follows (p. 87):

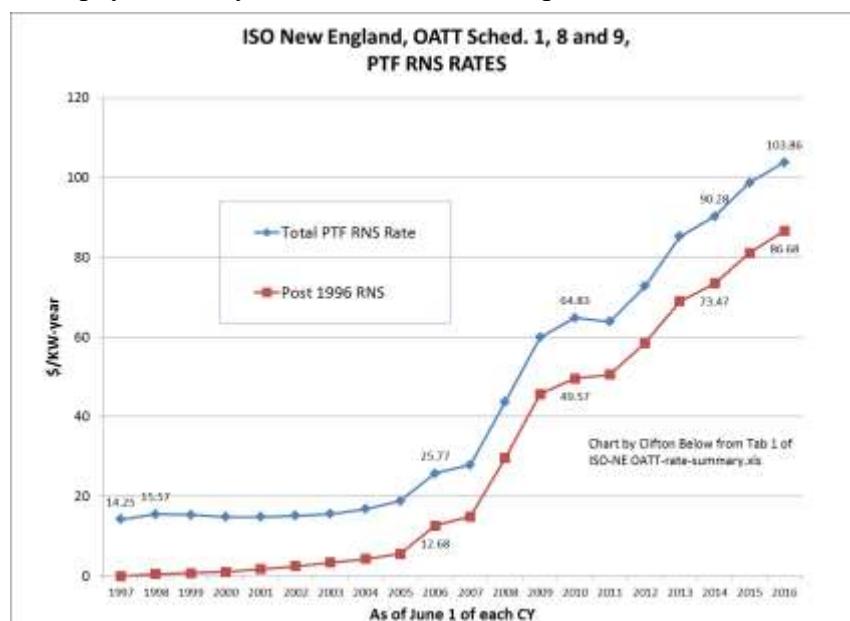
499 The transmission system throughout northern New England is limited in capacity; it is weak in places and  
500 faces numerous transmission security concerns. Underlying the limited number of 345 kV transmission  
501 facilities are a number of old, low-capacity, and long 115 kV lines. These lines serve a geographically  
502 dispersed load, as well as the concentrated, more developed load centers in southern Maine, southern New  
503 Hampshire, and northwestern Vermont.

504 The two most significant issues facing the area have been to maintain the general performance of the long  
505 345 kV corridors, particularly through Maine, and to ensure sufficient system security to meet demand. The  
506 region faces thermal and voltage performance issues and stability concerns. The system of long 115 kV lines,  
507 with weak sources and high real- and reactive-power losses, is exceeding its ability to integrate generation  
508 and efficiently and effectively serve load. Also, in many instances, the underlying systems of 34.5 kV, 46 kV,  
509 and 69 kV lines are exceeding their capabilities, and some are being upgraded, placing greater demands on an  
510 already stressed 115 kV system.

511 **Q. Historically transmission costs have been a small part of retail rates, so why is this a  
512 concern now?**

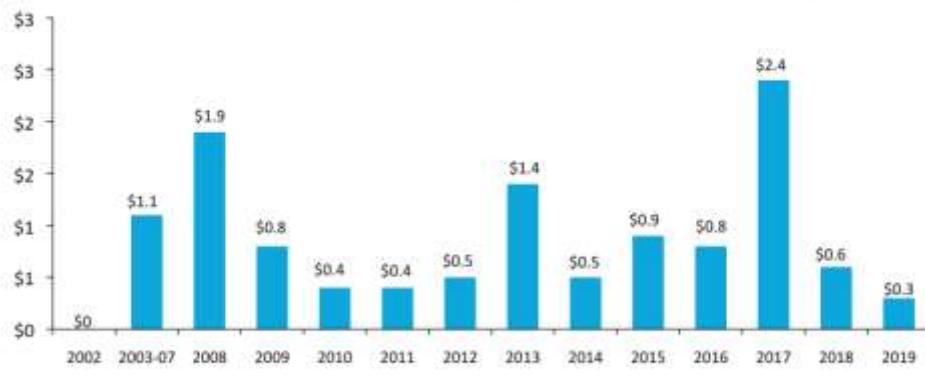
513 A. Perhaps so, but in recent years transmission rates in New England have risen rapidly and  
514 if current trends continue New Hampshire ratepayers will be paying proportionately more for  
515 new transmission investment than ratepayers in any other state. Let me explain with a few  
516 graphics. The chart at right  
517 shows the growth in RNS  
518 rates over the last two  
519 decades, during which the  
520 RNS rate has increased more  
521 than 7 fold.

522 Following are two slides from  
523 a 2015 presentation at  
524 NESCOE ([http://nescoe.com/wp-content/uploads/2015/12/CLG\\_Doc2015.pdf](http://nescoe.com/wp-content/uploads/2015/12/CLG_Doc2015.pdf))



## Transmission Investment in New England

Since 2002, about \$12 billion in reliability Tx placed in service, under construction or in planned/proposed phase



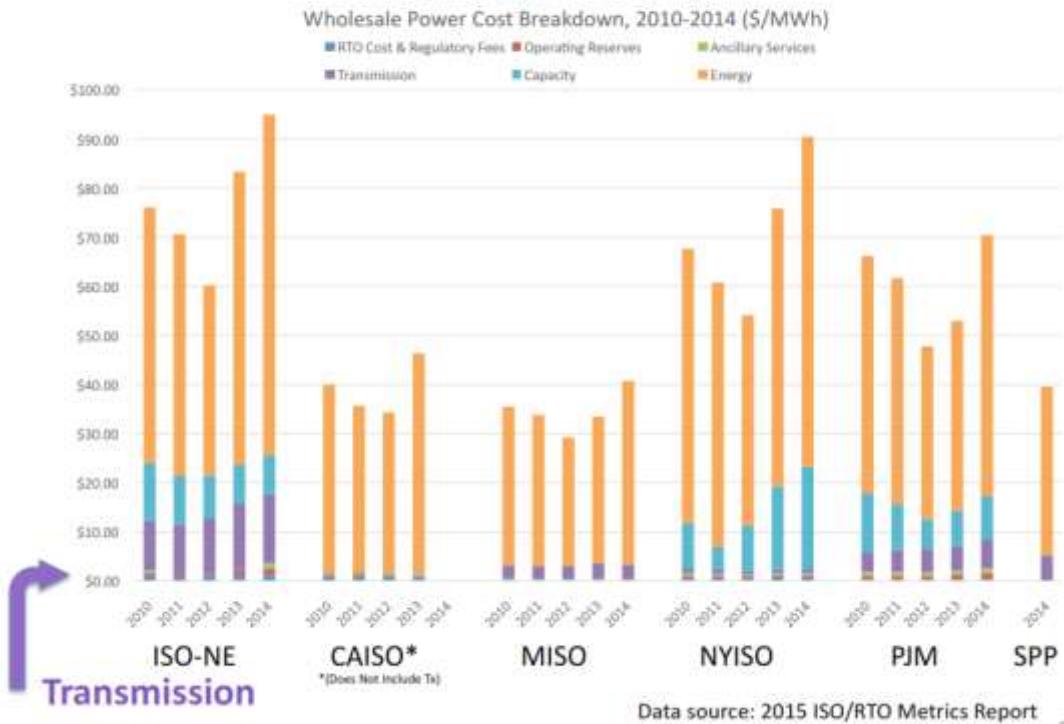
Source: ISO-NE

Cumulative Investment through June 2015	\$7.2 billion
Estimated Future Investment through 2019	\$4.8 billion

4

526

## A Comparative Look: Market Pricing Components, Including Transmission



527

5

528 Note how the absolute size, proportion and rate of growth of transmission rates in ISO-NE  
529 compared with other organized markets. Now here is the kicker, New Hampshire has seen a  
530 substantial decline in its load factor from the decade ending in the year 2000, when it averaged  
531 66.9%, to the decade ending in 2015, when it averaged only 57.1%, a nearly 10% drop. That  
532 means that in the past the average system load was about 67% of the summer NH coincident  
533 peak while it had dropped to about 57% in recent years. That means ratepayers are paying  
534 significantly more per kWh of electricity to support increasing T&D capacity for relatively fewer  
535 hours per year of high peak demands.

536 Now to make matter even worse, ISO-NE's latest load forecast (from [http://www.iso-](http://www.iso-ne.com/static-assets/documents/2016/04/isone_fcst_data_2016.xls)  
537 [ne.com/static-assets/documents/2016/04/isone\\_fcst\\_data\\_2016.xls](http://www.iso-ne.com/static-assets/documents/2016/04/isone_fcst_data_2016.xls), tab 2) projects that New  
538 Hampshire gross coincident summer (annual) peak demand (kW, 50/50 forecast) will grow at a  
539 compound annual growth rate (CAGR) of 1.4% for the next decade compared with a CAGR of  
540 1% for New England as a whole, only 40% higher than average. But wait, it gets worse, after  
541 netting out projected BTM PV and PDR (passive demand response, i.e. energy efficiency) from  
542 gross load, New England's projected peak demand CAGR falls to 0.2% while New Hampshire's  
543 only falls to 1.1%, more than 5 times the regional rate and more than double any other state,  
544 some of which are projected to see negative CAGR in net peak demand, like Vermont that is  
545 projected to have a -0.4% CAGR. That means we will have a disproportionately larger impact  
546 on the need for more transmission (and generation) capacity than any other state (cost causation)  
547 and our share of those costs will increase proportionately more than any other state.

548 And just to top this problem off our projected CAGR in load (GWh) is projected to be  
549 only 0.5%, while New England as a whole is projected to have a negative CAGR for load for the  
550 next decade of -.3%. (tab 10N) Most other states are projected to have negative or near zero net  
551 growth in load over the next decade. If it comes true that our peak demand grows at more than  
552 double the rate of our load over the next decade that will mean a further decline in our overall  
553 load factor and more costs for capacity (T, D and G), existing and new, per kWh. The best way  
554 to avert these rate increase impacts is likely to be to send appropriate price signals, aligned  
555 across all 3 rate components that there is value to reducing and shifting load off peak or  
556 generating more DG on those peaks, such as from western oriented and tracking solar PV.  
557 Reducing such growth in NH peak demand will benefit all ratepayers by reducing the drivers for

558 new T & D investments and reducing our share of RNS, LNS and FCM charges for embedded  
559 costs from what they would otherwise be.

560 **Q. So what are your tariff concepts for new default service NM tariffs and your RTP  
561 NM pilot?**

562 A. For default service, the simplest thing might to give monthly net exports of NM power  
563 full volumetric credit for transmission charges as an interim measure. The next step might be to  
564 redesign existing demand charges on a revenue neutral basis (before price response) to focus on  
565 the hours of the month or year when coincident peaks are most likely to occur. Volumetric rates  
566 can be similarly focused on a TOU basis. Ultimately interval data can sharpen the price signal.  
567 For our pilot where we would expect to have actual interval data for every load of any significant  
568 size, we would work with Liberty to design a tariff rider for participants that would be revenue  
569 neutral before price response and provide credit (or additional charge) in proportion to the  
570 extent that each customer deviates from class average load shape relative to the target interval  
571 hours for either monthly coincident peak for annual likely high demand hours.

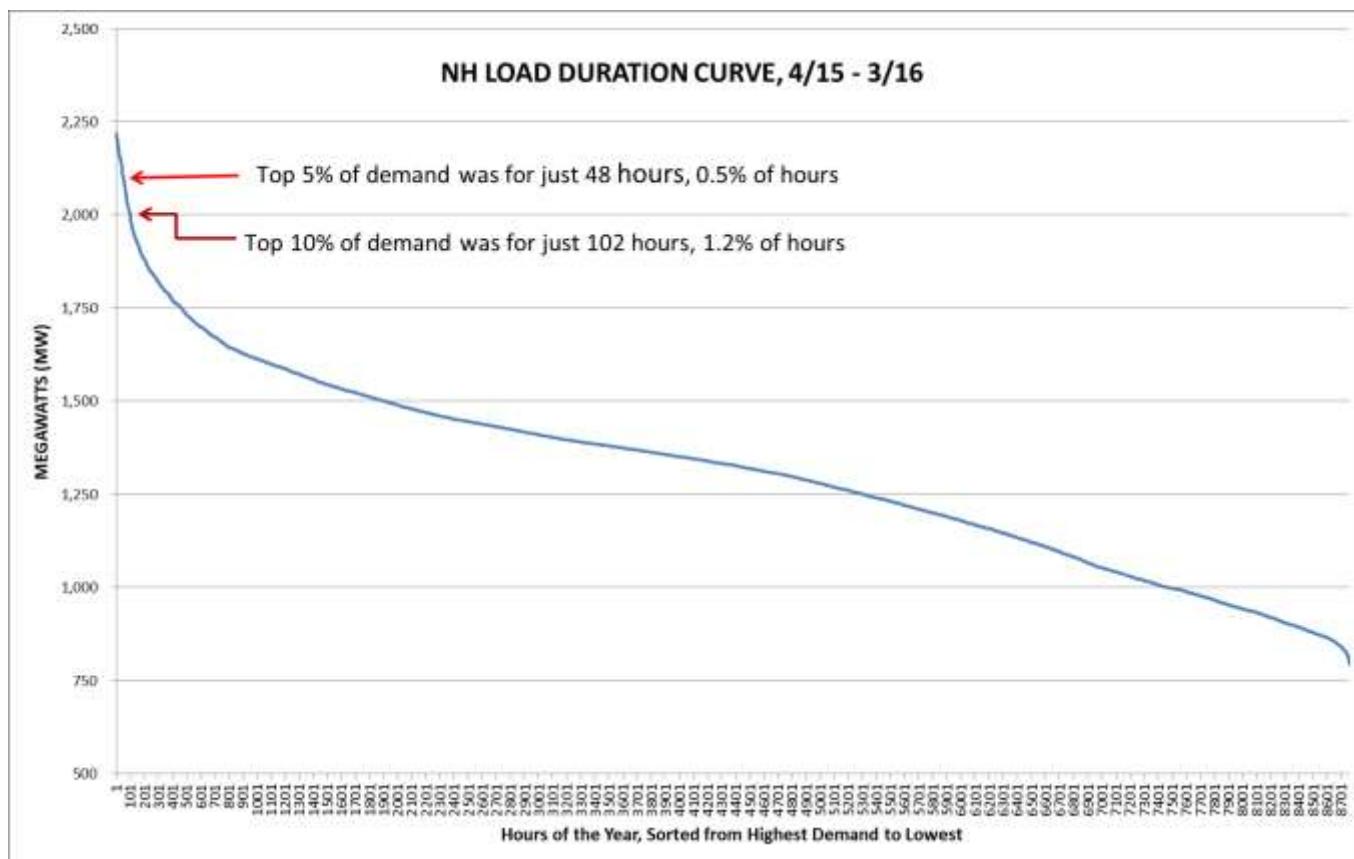
572 **VI. Distribution**

573 **Q. How would proposed NM distribution tariffs be different from transmission rates?**

574 A. Fundamentally there are many similarities to transmission in terms of how coincident  
575 peak demand growth stresses distribution systems and causes the need for future increased  
576 investment to increase capacity and reliability. However, it makes sense that NM customers who  
577 export power at certain times and take it back at other times or in other locations (such as with  
578 group NM or community solar) should pay to use the distribution grid to move power around  
579 town or “store” or bank it for later use. Therefore a simple interim step for use with existing  
580 meters and default service would be to simply charge regular distribution rates for any net  
581 imports in one month and not give distribution credit (volumetric or in dollars) for net monthly  
582 exports. A next step would be modify existing demand charges for larger C&I customers on a  
583 revenue neutral basis (before price response) so that they are concentrated during TOU or limited  
584 hours when high system coincident peak demand is most likely to occur. The same could be  
585 done for volumetric distribution rates. There will need to be volumetric/demand decoupling to  
586 make up revenues lost to price response that lowers peak demand. In the short term this may

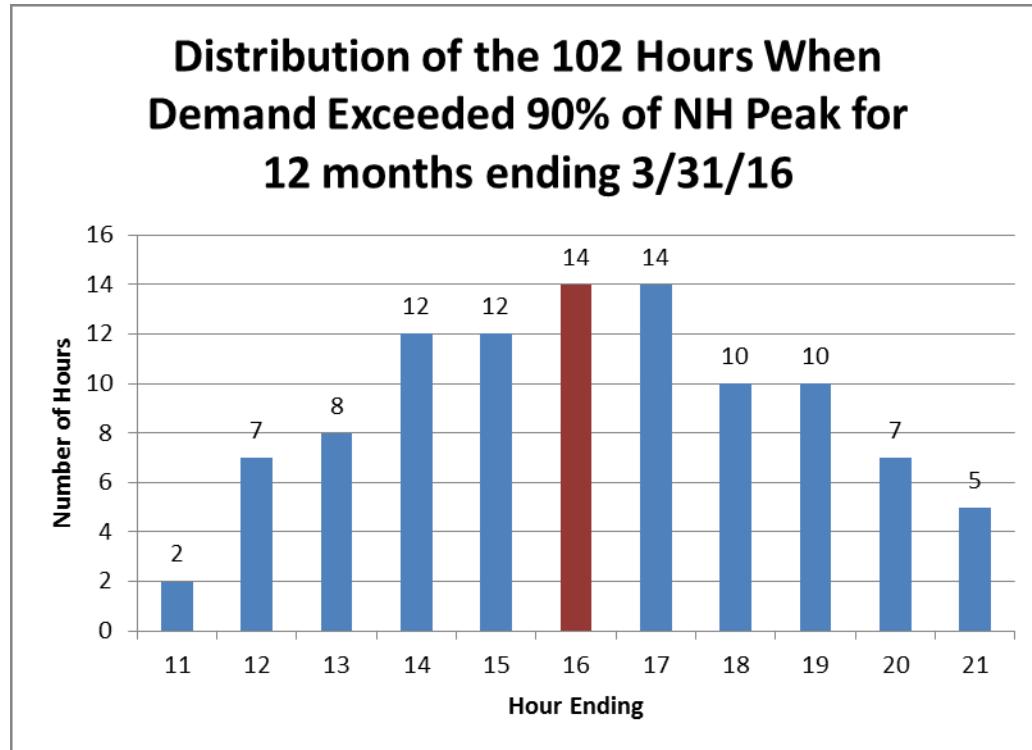
587 slightly increase rate for other customers, but in the long run it will help avoid growing peak  
588 demands and investments needed for more peak capacity and reliability investments for stressed  
589 distribution components. This will tend to improve load factors over time and lower distribution  
590 costs per kWh of load and demand for all customers from what they would otherwise be. The  
591 City of Lebanon would like to pilot some of these concepts as part of a RTP NM distribution  
592 tariff rider. This could be a collaborative effort with Liberty to improve the integration of non  
593 wire alternatives (NWA) into distribution system planning.

594 Below is a load distribution curve for NH. It is interesting to note the concentration of  
595 high demand in relatively few hours.



596  
597 Of the 102 hours where demand exceeded 90% of peak, all of them were between the hours  
598 ending 11 am and 9 pm in the months of May-September. Below is a chart showing the  
599 distribution of those hours. The average peak demand for those 102 hours was just slightly later

600 than the hour ending at 4 pm. Western oriented and tracking PV can have a very good  
601 coincidence with most of these hours.



602

## 603 **VII. Other Rate and Regulatory Issues**

604 If we get the price signals correct and there is no undue or unfair cost shifting with likely  
605 net benefits for all ratepayers from reducing peak demand growth and hence improving load  
606 factors and avoiding costly future investments for a very limited number of hours of high  
607 demand and stress, there is no good reason to limit such future Net Metering tariffs or the size of  
608 systems at any one location relative to the site load, especially if new NM systems continue to  
609 pay for the cost of interconnection.

610 There are issues with regard to how current inverters may affect power quality and  
611 system stability when NM generation starts to increase in proportion to load on local areas of the  
612 grid. There is great deal of effort going into technology and standards innovation to enable the  
613 use of smart meters that can improve grid stability and power quality rather than diminish it.  
614 Countries like Germany and states like California and Hawaii have already moved to better  
615 incorporate smart inverters, both those that act autonomously and those that can be addressed by

616 the utility. I'd encourage the Commission and utilities to closely follow developments in this  
617 rapidly evolving field. The City of Lebanon would be interesting in possibly piloting the use of  
618 smart inverters as part of its RTP NM pilot. Here are three good resources on the topic:

- 619 1. A somewhat dated presentation at ISO-NE: [https://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/prtcnts\\_comm/pac/mtrls/2014/jul112014/california\\_smart\\_inverter\\_working\\_group.pdf](https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcnts_comm/pac/mtrls/2014/jul112014/california_smart_inverter_working_group.pdf)
- 620 2. An excellent webinar set of slides from NREL that overview the issues with plenty of links  
621 for additional information: [http://www.nrel.gov/tech\\_deployment/pdfs/2016-04-28-adv-inverter-deploy.pdf](http://www.nrel.gov/tech_deployment/pdfs/2016-04-28-adv-inverter-deploy.pdf)
- 622 3. And a recent joint white paper by EPRI and SEPA entitled "Rolling Out Smart Inverters:  
623 Assessing Utility Strategies and Approaches," found at:  
624 <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002007047>

625 **VIII. Pilot Proposal Next Step and Conclusion**

626 **Q. What do you see at the next steps in your proposal and do you have any concluding  
627 thoughts?**

628 As you can see there are no actual proposed tariffs being submitted as part of this  
629 testimony. We are looking for approval of this concept and work with Liberty Utilities and other  
630 interested parties to collaborative on an next stage for further development and implementation.,  
631 which may include seeking limited rule waivers necessary to enable aspects of the pilot. These  
632 could evolve into rules changes.

633 I can mention that both Competitive Energy Services, the City's current energy supply  
634 procurement vendor and Freedom Energy Logistics, which supports the Town of Hanover in  
635 their self-supply RTP for town loads through direct market participation, have expressed strong  
636 interest in collaborating in this pilot. I have meet with Peter Kulbacki, Director of Public Works  
637 for the Town of Hanover who is responsible for their RTP program and supports Sustainable  
638 Hanover's Green Power Challenge where participants bought 4.5 million kWh of Green-E  
639 certified power (RECs) last year  
640 ([http://www.hanovernh.org/sites/hanovernh/files/uploads/new\\_faq - final.pdf](http://www.hanovernh.org/sites/hanovernh/files/uploads/new_faq - final.pdf)). However some  
641 participants and the town have been frustrated in the lack of available local RECs and Peter  
642

645 believes there may be considerable interest in this kind of pilot, including the possibility of  
646 participation in community solar PPAs and even possibly some direct investment. We are  
647 planning further meetings after I file this testimony to explore the possibility of collaboration,  
648 which RSA 53-E expressly provides for.

649 Finally I'd like to mention that I have spoken with a couple of Dartmouth College faculty  
650 and an administrator about this possible RTP NM pilot in light of the College's recent  
651 announcement of the creation of the Arthur L. Irving Institute for Energy and Society, a major  
652 new interdisciplinary institute "to prepare future generations of energy leaders and advance  
653 humanity's understanding of the field, driving change in the intelligent production, supply, and  
654 use of energy." Their initial response was that this pilot could provide significant test bed  
655 research opportunities for the Institute, potentially involving faculty and students from the Thayer  
656 School of Engineering, the Tuck School of Business, computer sciences, where Dartmouth has  
657 significant cybersecurity expertise, and a variety of humanities and social sciences. On the other  
658 hand that might just complicate things.

659 **Q. Does that conclude your testimony?**

660 A. Yes it does. Thank for your attention and interest. I could go on, but I'm out of time –  
661 real time peak load management challenges.