**THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION**

EXHIBIT
#20
DE 17-189

LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP. d/b/a LIBERTY UTILITIES
PETITION TO APPROVE BATTERY STORAGE PILOT PROGRAM

Docket No. DE 17-189

October 22, 2018

Technical Statement Regarding Time-of-Use (TOU) Model

by

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& Clifton Below, for the City of Lebanon

The time-of-use (TOU) model used in this settlement was developed collaboratively by Lon Huber, Heather Tebbetts and Clifton Below, with input from PUC staff and other parties in this proceeding. Many iterations and options were considered before a settlement consensus developed around the TOU rates proposed herein.

A core principle of any rate design is to ensure the rates being charged to customers reflect cost causation. Each of three main rate components: generation ("G" which is default energy service in this model, although customers may take competitive energy supply of their choice), transmission ("T"), and distribution ("D") were designed to reflect underlying cost causation allocated among logical break points in time-of-use. For residential customer classes (as well as the small commercial class, G-3) rates are currently designed on a flat volumetric basis ($/kWh) that typically only change or adjust annually for T&D and twice annually for default energy service G (or as provided by competitive supply). With a TOU rate, multiple volumetric levels must be developed for the rate design reflecting different TOU periods. As such, a methodology must be developed to ensure the costs assigned to each TOU period are appropriate. The development and application of TOU rates can be thought of as a progression from a very rough justice of allocating costs equally across all hours to a more granular and refined justice of allocating costs to blocks of time in each day, week, and season that reflect strong underlying temporal differences in cost drivers and result in more appropriate and economically efficient price signals to electric customers.

As originally proposed in this proceeding by Liberty, there are 3 primary TOU periods: off-peak (OP or OPP), which is generally the largest and lowest load and cost period covering overnight hours, holidays and weekends, a mid-peak period (MPP, previously referred to as "on-peak" in this proceeding) of higher loads and prices during non-holiday weekdays, and a critical-peak period (CPP) of the highest load levels and costs during the late afternoon and early evening non-holiday weekday. During settlement discussion consideration was given to splitting weekends and holidays into off-peak and mid-periods and a seasonal split for TOU rates based on dividing the default service procurement time periods in half, with May through October being the summer period and November through April being the winter period. Both of these refinements were adopted as part of this settlement as further explained below.

Recent Historic Experience Cost Causation Method for Generation

There are generally four components to generation or default energy service costs. These are: 1) the actual underlying energy costs (locational marginal cost or LMP) and related ancillary service costs that vary by hour throughout the year and which are usually the marginal cost for supply, which may be modified by bi-lateral arrangements between generators and suppliers in some cases, 2) Forward Capacity Market (FCM) costs based on annual system peak hour and resulting capacity tags to load, 3) RPS compliance costs, charged on a volumetric basis, 4) other costs including supplier overhead, profit, and hedging costs as well as Liberty's cost to administer default service procurement, including working capital and related bad debt expense.

For the first component of generation TOU the most recent calendar year (2017) of hourly real time prices (NH LMP) and volumetric ancillary services charges from the NHPUC calculations for "Net Metering Utility Avoided Cost Rates for Energy" were used along with Small Customer Group[1] (SCG) loads for 2017 to calculate load weighted average hourly costs that could then be allocated into various TOU periods, including accounting for holidays and weekends, as well as seasonal periods, to yield load weighted average cost per TOU period for the energy cost components.

For the 2nd component, FCM costs for the current period were estimated by using the overall SCG capacity tag (the 2017 average from Liberty's SCG data) times ISO New England's most recent forecast of the net cost to load (NH load zone) for the current period – capacity year beginning 6/1/18, net of prior year reconciliations from Liberty's most recent default service filing. This estimated FCM cost imbedded in the default service rate was then allocated to the TOU periods based on the portion of annual system peaks that occurred during each TOU period over the last 10 years (2008-2017), which happen to be all non-holiday weekdays during the summer seasonal period.

For the 3rd component, RPS compliance costs, the estimated average cost per kWh from Liberty's most recent default energy service filing (DE 18-041) was used and applied equally across the TOU periods.

These 3 rate components were then summed and multiplied by the 2017 TOU period SCG load

[1] The Small Customer Group consists of the following rate classes with their proportions of the SCG overall load in 2017: D - Domestic Service-71%, D-10 - Residential Time-Of-Use-2%, G3 - Small C&I-22%, M - Street Lighting-1%, T - All-Electric Living-5%, V - Business Space Heating-0.1%. Default service is procured and has equal rates for the SCG as a whole.

scaled to load forecast for the SCG in Liberty's most recent default service filing. This created a "base" revenue estimate for each TOU period. The difference between the base revenue estimate and total estimated revenue requirement for SCG default service (by seasonal period), representing the 4th set of "other" cost components, was then allocated to each TOU period in the portion that such period "base revenue" bears to the whole, to reflect the overall mix of volumetric and load weighted temporal cost causation elements.

The result, with the assumed SCG load shape and recent history temporal cost elements, produces the same revenue as the flat default service rate. If customers on TOU rates shift load off the critical-peak period when energy and capacity costs are highest, to off- or mid-peak periods, then the underlying load shape and capacity tag for the SCG should change accordingly and should proportionately affect future costs to serve this load group as reflected in default service bids.

Historic Experience Cost Causation Method for Transmission

Cost causation for transmission costs is relatively simple. ISO New England and transmission utility tariffs allocate FERC jurisdictional transmission revenue requirements (Regional Network Service or RNS and Local Network Service or LNS) based on each distribution utility's share of the monthly coincident hour of peak load for the whole system (for RNS) and of their transmission provider's LNS peak. Liberty's transmission provider (at the LNS connection/wholesale meter point) is National Grid, which uses the N.E. system monthly peak for their LNS as well as RNS.

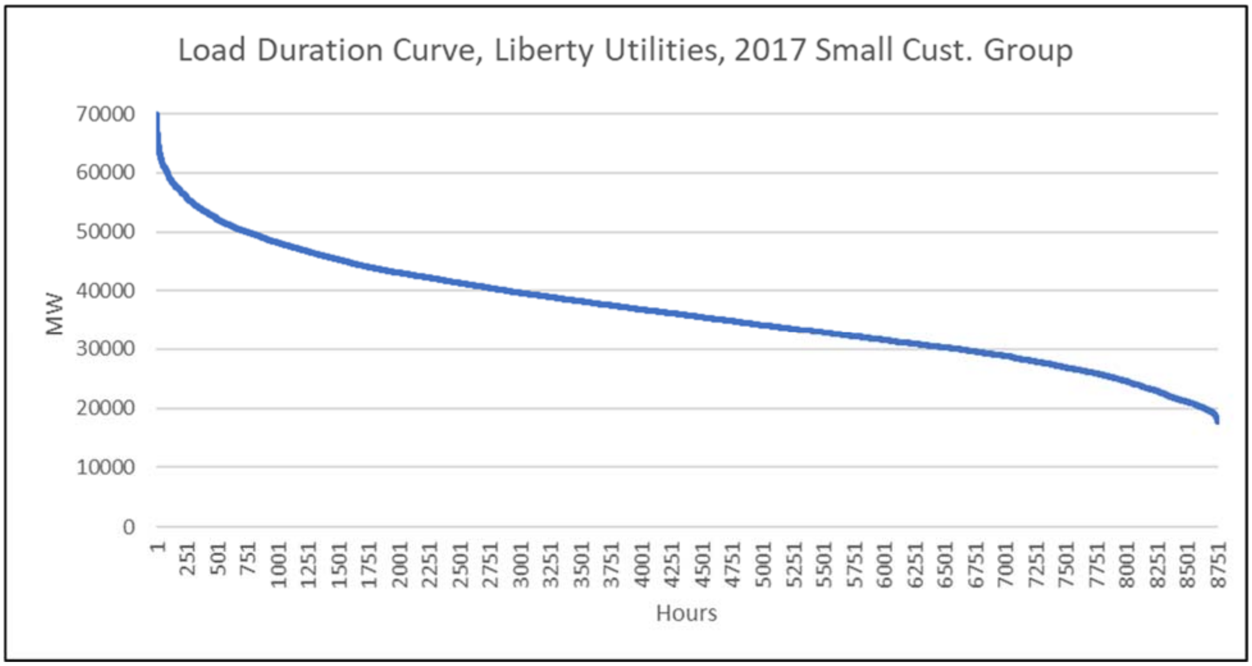
The probability of the monthly coincident peak hour (CPH) occurring during any particular TOU period is assumed to correspond to the historic experience over the most recent 10 years (ending 5/18 for this model) split into winter and summer seasons for 60 data points in each season. Those hourly probabilities based on historic experience were then consolidated into the TOU periods. For the summer period this resulted in a 77% assumed probability of the CPH occurring in the CPP, 23% in the MPP, and 0% in the OPP; and in the winter period 95% probability in the CPP, 3.3% in the MPP, and 1.7% in the OPP.

The current volumetric transmission rate (form DE 18-051) was then divided into two components: current transmission charges, allocated as described above, and various reconciliations, mostly prior period under-recovery, which were allocated on a flat volumetric basis to all TOU periods (since the prior period charges to all SCG customers were also on a flat volumetric basis). Current transmission charges were apportioned to the TOU periods based on the assumed probability of monthly CPHs, the cost causation, occurring during each period. These were also scaled to the overall current load forecast for the SCG.

Cost Duration Method for Distribution

The "cost duration method" was developed by Lon Huber to better link the recovery of distribution system costs to the time periods during which system assets are being utilized. In doing so, the resulting rates are intended to accomplish two goals: 1) send a time-differentiated price signal to customers to encourage peak demand reduction, 2) ensure rates for each TOU period reflect the costs of the underlying assets used to meet demand at those times (i.e. cost causation).

The load duration curve represents the MW of system demand for each hour of an entire year (8760 hours), ranked in order, and provides a time-differentiated demand profile that can be used as the basis of this methodology.



Close examination of a utility's system load duration (whether for individual customer classes, groups of classes, as seen above, or the entire system) reveals several features. For example, it is readily apparent that there are a small number of "peak" hours during which system assets necessary to meet demand are used very infrequently. Thus, it would be appropriate to assign a significant share of costs for these peaking assets to the hours that rank highest on the load duration curve. Similarly, there is a minimum load or "baseload" demand which all hours of the year exceed. Thus, there is some portion of system costs which should be assigned equally to all 8760 hours of the year. The cost-duration method is designed to capture these features by assigning a share of system costs to each hour in a way that reflects the usage as illustrated by the load duration curve. The assignment of costs to specific hours can be further systematized through the basic steps outlined below, which are described for an entire year. The seasonal rate model requires additional steps by apportioning hours and the overall D revenue requirement between the two seasons, the latter of which was done simply by the portion of kWh in each seasonal period.

Developing the Cost-Duration Curve

- *Step 1: Identify the costs and load duration curves to be used:*

Liberty's current revenue requirements for distribution service are to be allocated to each TOU period. Since residential customers often share distribution circuits with small commercial customers and are treated as in the same load and cost group for default energy service purposes the small customer group (SCG) load duration curve was used to allocate those costs, with the final rates scaled to the portion of the SCG specifically attributable to the residential class. Fixed (non-volumetric) customer charges and the revenue requirements related thereto were not modified.

- *Step 2: Identify the average cost of system capacity for each load duration curve:*

Total system costs are divided by the peak MW of the load duration curve to find an average cost per MW of system capacity. For example, in Liberty's case the total residential revenue requirement is $13,259,732 and SCG peak demand in 2017 was 70,004 MW, leading to an average residential cost of $185,605/MW.

- *Step 3: Divide the load duration curve into marginal MW blocks:*

The system load duration curve is sliced horizontally into 8760 individual MW blocks. Each block represents the incremental (marginal) MW of system capacity needed to serve the next highest hour of system demand. For example, in this case the 1st (highest) ranked hour requires 751 MW of additional capacity over the 2nd ranked hour to meet its needs. The 2nd hour requires just 0.2 MW over the 3rd hour. The 3rd hour requires 12 MW over the 4th hour, and so on. The lowest ranked hour will have an incremental MW value considerably higher than others since it represents the base load above 0 MW, or the minimum load, which in this case is 17,669 MW.

- *Step 4: Divide MW block costs between appropriate hours:*

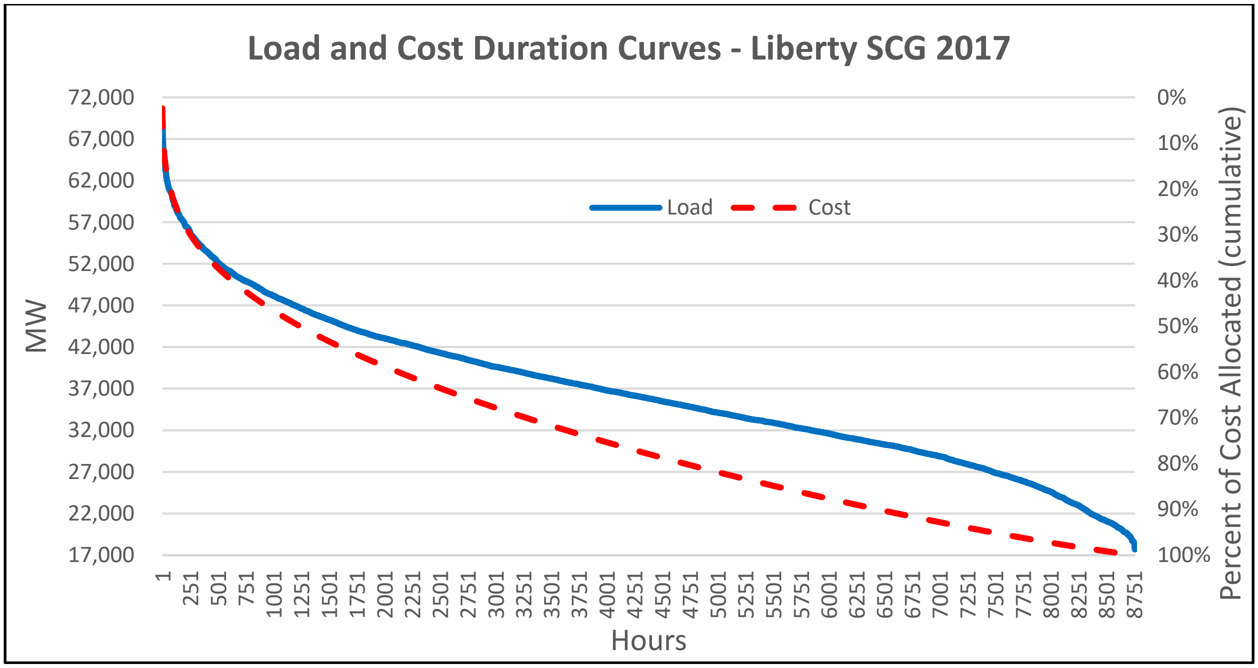
A cost weight for each 1 MW block is generated by dividing the average cost per MW derived in Step 2 by the number of hours at or above that load. For example, the 1st MW block costs are assigned solely to the 1st ranked hour. Meanwhile, the 2nd MW block costs are divided between hours 1 and 2. The 3rd MW block costs are divided between hours 1, 2 and 3, and so on until the base load block costs are divided between all hours because all hours contain the base load.

- *Step 5: Apply cost weights to each marginal MW block:*

Cost weights are allocated to each hour by multiplying the MWs of incremental load by the cost weight for that hour derived in Step 4.

- *Step 6: Add up the assigned MW block costs for each hour:*

For each hour of demand, the assigned portion of costs from each MW block are summed. This reflects a portion of the marginal MW block costs to serve that hour, plus a portion of the MW block costs for each hour below it on the load duration curve. This ensures that the cost assigned to each hour reflects not only any incremental "peak capacity" needs but also any underlying "baseload" or "intermediate" capacity needs. The resulting cost structure will appropriately assign costs for each incremental MW to the hours when those MW of capacity are being used to serve load. As illustrated below the costs are spread to each hour in a manner that closely resembles the load duration curve, with somewhat more weight given to the peak hours of demand (the steep part of the curve), and therefore reflects system use. This spread of costs to each hour is known as the "cost duration curve."



Once cost portions have been assigned to each hour, which are in the form of percentages of total D costs that sum to 100%, these hourly cost assignments can be readily used to construct a time-of-use rate. After the TOU time periods have been selected, the portion of D costs assigned to each hour within each TOU period are totaled (with the revenue requirement scaled to match what would be earned under the current rate structure and common load assumptions). The TOU period costs are then divided by the billing determinant (i.e. MWh of assumed/projected load) associated with the hours of the TOU period to figure the rate/kWh by TOU period.

In this model, a critical-peak period selection of 3-8 pm on non-holiday weekdays results in an allocation of 32% of the total summer D costs and 27% of winter D costs to the CPP, which comprises 14.5% of all hours in the summer and 14.3% of all hours in the winter and 17.9% of summer (S) load and 17.1% of winter (W) load. For the OPP, which comprises 50% of all hours and 44%S to 44.5%W of load, the allocated share of D costs are 30% (summer) and 33% (winter). The mid-peak period, which comprises 35.5% of all S hours and 35.7% of all W hours and 38.2%S to 37.4%S of load, the allocated share of D costs are 38% (summer) and 40% (winter).

Consideration Given to Keeping Weekends & Holidays All Off-Peak

There was serious consideration given to keeping weekends and holidays entirely off-peak for the sake of simplicity in customer understanding of the TOU rate structure., rather than splitting them equally between off- and mid-peak. Traditionally, with only two time-of-use periods weekends and holidays have been part of the off-peak period, such as with Liberty's D-10 rate. However, with three TOU rate periods, this resulted in the D component of the rate for the off-peak period being significantly more than the mid-peak rate during both summer and winter, to the extent that during the winter period the overall variable rate during the mid-peak period would be 14.4¢/kWh, nearly half a cent less than the overall off-peak rate of 14.8¢/kWh. This could be very confusing to customers and send an inappropriate price signal during winter weekdays that it would be better to shift flexible load and charge batteries during the day from 8 am to 3 pm than during the night from 8 pm to 8 am, when loads and energy LMPs are actually lower. The fact that by moving 8 am to 8 pm hours on weekends and holidays from off-peak to mid-peak results in winter mid-peak rates for D & G and overall going up with comparable winter off-peak rates going down along with the summer D rate and LMP component of G rates for off-peak going down and those components for the summer mid-peak going up, confirms that those daytime and early evening hours on weekends and holidays more closely resemble weekday mid-peak hours (8 am to 3 pm) than off-peak in terms of overall cost causation particularly in the winter (due to loads and energy LMPs rather than coincident peaks).

The trade-off with splitting weekends between off-peak and mid-peak is that during the summer period there is a somewhat weaker coincident peak price signal during the weekday mid-peak period because the overall mid-peak rate drops from 19.3¢/kWh to 15.3¢/kWh due to weekday coincident peak price signals, mainly for the hour from 2-3 pm, being diluted over more hours by the shift of 8 am to 8 pm on weekends and holidays, when no coincident peaks have occurred in the past 10 years, to the MPP. However, the summer off-peak rate also drops from 7.9¢/kWh to 6.8¢/kWh, maintaining a strong incentive to shift flexible loads from both mid- and critical-peak periods to off-peak. Moreover, looking forward as more behind the meter PV is added in New England the chance of coincident load peaks occurring at the hour ending 3 pm is likely to diminish.

Conclusion

The end results of the model using settlement consensus parameters are further detailed on the following pages, along with some of the detail of supporting calculations. These are intended to be illustrative of what the TOU rates would be using the model and agreed upon parameters (time periods, data, and other assumptions) for the current default energy service period (8/1/18 through 10/31/18 for the summer period and 11/1/18 through 1/31/19 for the winter period. The model should be updated twice per year for the default energy services rates (including RPS compliance costs) resulting in 4 rates per in year that are constant for 3-month seasonal periods over the TOU periods. The load data, energy cost data (NH hourly LMP and ancillary service charges), FCM costs and annual coincident peak hours, and rolling past 10 years of CPH for transmission charges, as well as transmission costs, should be updated on an annual basis. Probably the best time to do these updates would be with the default energy service procurement filings (twice annually) for that component, with the annual TCAM filing for transmission costs, and with any annual or other adjustment of distribution rates that pertain to the SCG. Most, but not all calculations will also be applicable to the G-3 rate class, with customized elements relative to the T & D revenue requirements for that rate class scaled to their share of the SCG load.

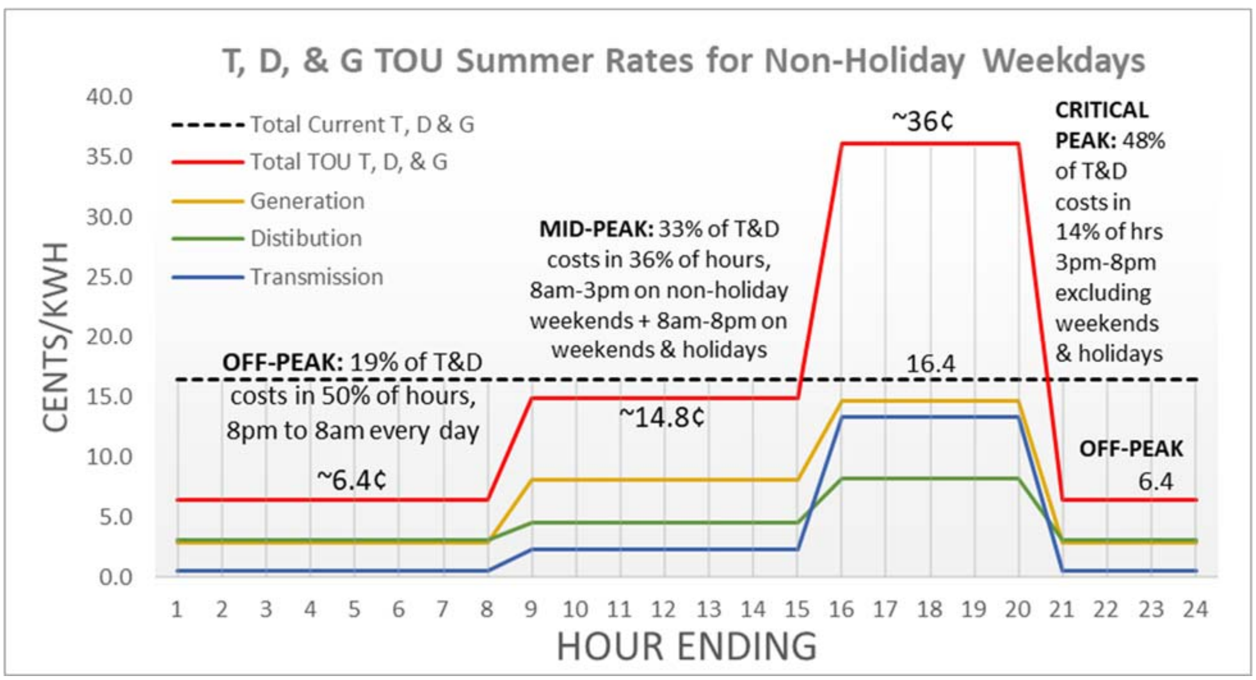
This TOU model is about 16 MB in size and contains 13 tabs, with the last 4 pages of this technical statement all from the first TOU Rate Summary tab. It retains toggles and data sets to calculate various modeling options. The second and third tabs (for summer and winter) that calculate the D portion of the rates using the Cost Duration Method developed by Lon Huber contain proprietary intellectual commercial property that should be kept confidential, but which Liberty, the OCA, PUC staff, and the City of Lebanon are given permission to retain and use solely in conjunction with Liberty proposing or implementing TOU rates both in this docket and other potential Liberty TOU rate proceedings in New Hampshire in the future. The full model is not being filed as evidence in this proceeding but has been provided to PUC staff.

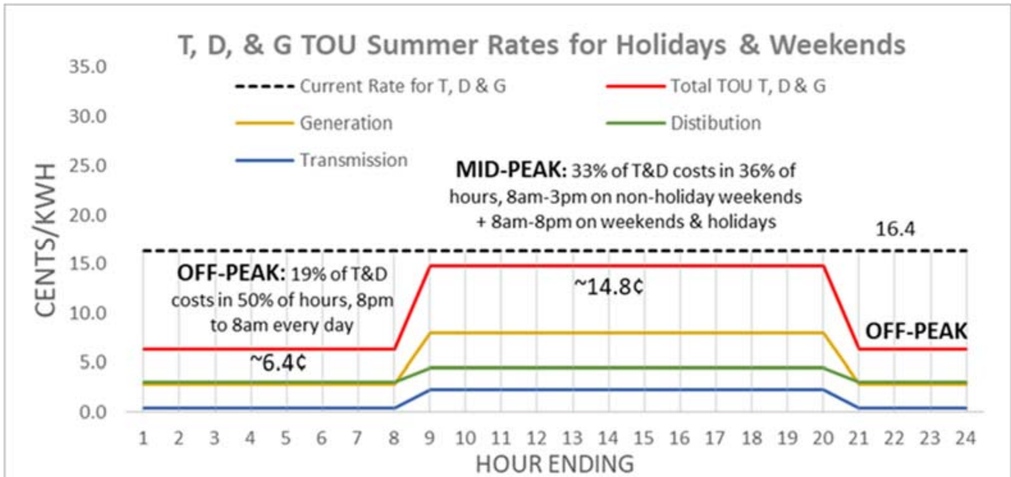
The illustrative rates for the period from 7/1/18 through 1/31/18 using settlement consensus parameters and assumptions are summarized below, rounded to the nearest 1/10 of a cent:

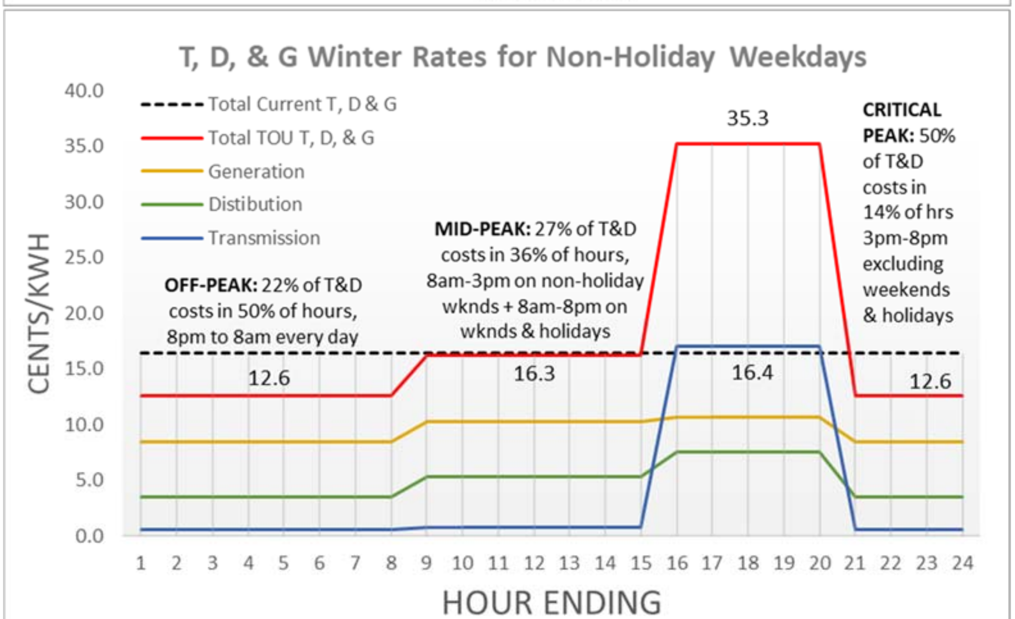
Rates are cents per kWh	Critical-Peak	Mid-peak	Off-peak	Current
Summer Energy (G) Rate =	14.6	8.1	2.9	8.3
Summer Distribution (D) Rate =	8.1	4.5	3.1	4.7*
Summer Transmission (T) Rate =	13.3	2.3	0.5	3.5
SBC and other minor charges/credits =	0.4	0.4	0.4	0.4
TOTAL SUMMER Variable Rate =	**36.4**	**15.3**	**6.8**	16.8
Winter Energy (G) Rate =	10.6	10.3	8.5	8.3
Winter Distribution (D) Rate =	7.5	5.3	3.5	4.7*
Winter Transmission (T) Rate =	17.1	0.7	0.6	3.5
SBC and other minor charges/credits =	0.4	0.4	0.4	0.4
TOTAL WINTER Variable Rate =	**35.7**	**16.7**	**13.0**	16.8

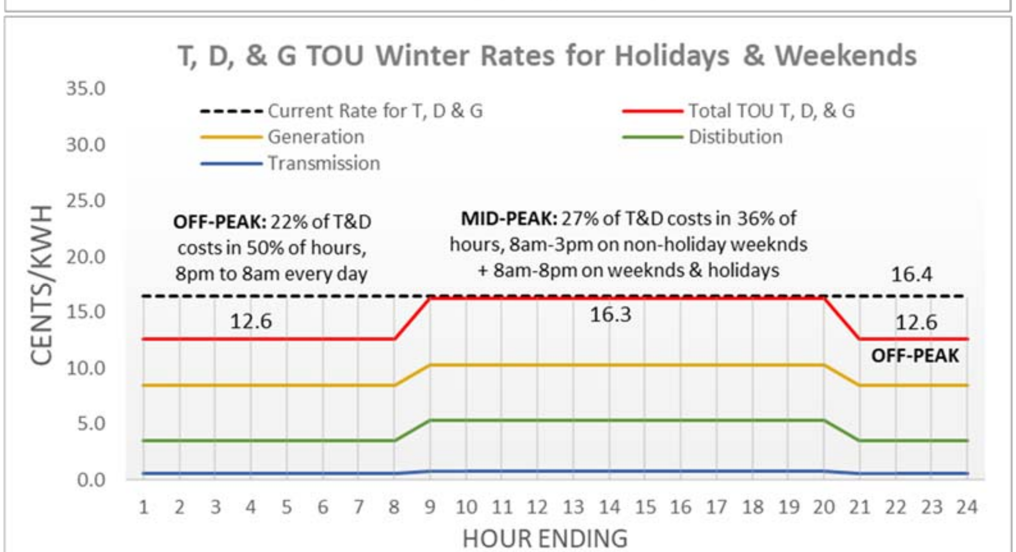
*The average distribution component of current rates is calculated using an assumed 650 kWh monthly load as there is a change in this tiered rate from $0.04299/kWh for the first 250 kWh to $0.04883/kWh for monthly consumption more than 250 kWh.

These rates (excluding SBC and other minor charges or credits) can be viewed graphically as follows:




T, D, & G TOU Summer Rates for Holidays & Weekends
Current Rate for T, D & G
Total TOU T, D & G
Generation
Distibution
Transmission
MID-PEAK: 33% of T&D costs in 36% of hours, 8am-3pm on non-holiday weekends + 8am-8pm on weekends & holidays
16.4
OFF-PEAK: 19% of T&D costs in 50% of hours, 8pm to 8am every day
~14.8¢
~6.4¢
OFF-PEAK
CENTS/KWH
HOUR ENDING


T, D, & G Winter Rates for Non-Holiday Weekdays
Total Current T, D & G
Total TOU T, D, & G
Generation
Distibution
Transmission
35.3
CRITICAL PEAK: 50% of T&D costs in 14% of hrs 3pm-8pm excluding weekends & holidays
MID-PEAK: 27% of T&D costs in 36% of hours, 8am-3pm on non-holiday wknds + 8am-8pm on wknds & holidays
OFF-PEAK: 22% of T&D costs in 50% of hours, 8pm to 8am every day
12.6
16.3
16.4
12.6
CENTS/KWH
HOUR ENDING


T, D, & G TOU Winter Rates for Holidays & Weekends
Current Rate for T, D & G
Total TOU T, D, & G
Generation
Distibution
Transmission
OFF-PEAK: 22% of T&D costs in 50% of hours, 8pm to 8am every day
MID-PEAK: 27% of T&D costs in 36% of hours, 8am-3pm on non-holiday weeknds + 8am-8pm on weeknds & holidays
16.4
12.6
16.3
12.6
OFF-PEAK
CENTS/KWH
HOUR ENDING

	A	B	C	D	E	F	G
1	**SUMMER SEASONAL PERIOD (May 1 to October 31)**			**USING Small Customer Group (SCG) load for D&G TOU**			
2	TOU Rates For Liberty Utilities		**Wkends & Holidays split between OP & MP**				
3		Hour Beginning (for n-H weekdays):	3:00 PM	8:00 AM	8:00 PM		
4		Hour Ending (for n-H weekdays):	8:00 PM	3:00 PM	8:00 AM		
5		Energy Service Rate Calculation:	**CPP**	**Mid-Peak**	**Off-Peak**	**Total**	
6		2017 LOAD in kWh =	13,598,454	28,996,692	33,337,355	75,932,500	
7		LOAD SCALED TO DE 18-041 forecast	14,072,501	30,007,528	34,499,509	78,579,538	
8		Portion of FCM allocated to Period =	50%	50%		(from FCM Peaks TAB)	
9		RTP + Gen. Related Ancil. Svcs =	$ 0.05109	$ 0.03342	$ 0.02430	FCM/Total ES Rate row 11/19	
10		Ave. RPS Costs for E.S. to 1/19 =	$ 0.00481	$ 0.00481	$ 0.00481	CPP	MPP
11		FCM Cost, net of prior yr recon. =	$ 0.09172	$ 0.04301	$ -	62.7%	53.4%
12		Subtotal E.S. TOU Rate =	$ 0.14762	$ 0.08124	$ 0.02910		
13		Base Revenue =	$ 2,077,330	$ 2,437,716	$ 1,004,010	$ 5,519,056	
14		Portion of Base Revenue =	37.6%	44.2%	18.2%		
15		Revenue Requirement DE 18-041 =				$ 5,469,025	
16		Balance to make up =				$ (50,031)	
17		Portions =	$ (18,831)	$ (22,098)	$ (9,101)	$ (50,031)	
18		Additional Rate =	$ (0.00134)	$ (0.00074)	$ (0.00026)	**Current Rates**	as of 8/1/18
19		**Total E.S. TOU Rate =**	**$ 0.14628**	**$ 0.08050**	**$ 0.02884**	0.08299	
21		**Distribution Rate =**	**$ 0.08139**	**$ 0.04491**	**$ 0.03052**	0.04658	Ave for 650 kWh*
22	For T:	Historic Odds of a Monthly Peak =	76.67%	23.33%	0.00%		
23	Gradual %	Rev Target for C.P. Demand % =	$ 1,798,293	$ 547,306	$ -		
24	0%	Transmission Rate for C.P. D.% =	$ 0.1278	$ 0.0182	$ -		
25		Transmission Rate for Fixed/kWh =	$ 0.0048	$ 0.0048	$ 0.0048		
26	CD Meth?	**Total Transmission Rate =**	**$ 0.13254**	**$ 0.02299**	**$ 0.00475**	$ 0.03460	
27	No	Total T,D & G Rate =	**$ 0.36021**	**$ 0.14840**	**$ 0.06411**	$ 0.16417	
28		Storm Recovery Adjustment =	$ -	$ -	$ -		
29		Stranded Cost Charge =	$ (0.00095)	$ (0.00095)	$ (0.00095)	$ (0.00095)	
30		System Benefits Charge =	$ 0.00457	$ 0.00457	$ 0.00457	$ 0.00457	
31		Electricity Consumption Tax =	$ 0.00055	$ 0.00055	$ 0.00055	$ 0.00055	
32	**TOTAL SUMMER Residential Variable Rate =**		**$ 0.36438**	**$ 0.15257**	**$ 0.06828**	**$ 0.16834**	
33							
34		Fixed Customer Charge/Month =	$14.54	$14.54	$14.54	$14.54	
35	Revenue Check (TOU compared with current rates):						
36		$ 12,061,583	$ 5,127,721	$ 4,578,303	$ 2,355,559	$ 13,228,394	
37	Dist Est.	$ (3,546,029)	$ (1,145,403)	$ (1,347,711)	$ (1,052,915)	$ (3,660,549)	*See note
38		$ 8,515,554	$ 3,982,318	$ 3,230,592	$ 1,302,644	$ 9,567,845	
39	Total revenues, net of D estimate (summer & winter should be looked at together):				-10.998%	=difference	
40	*NOTE: Subtract out Distribution component as the current rate is only an estimated average rate due to change in rates at 250 kWh.						

	A	B	C	D	E	F	G
41							
42	**WINTER SEASONAL PERIOD (November 1 to April 30)**			**USING Small Customer Group (SCG) load for D&G TOU**			
43	TOU Rates For Liberty Utilities		**Wkends & Holidays split between OP & MP**				
44		Hour Beginning (for n-H weekdays):	3:00 PM	8:00 AM	8:00 PM		
45		Hour Ending (for n-H weekdays):	8:00 PM	3:00 PM	8:00 AM		
46		Energy Service Rate Calculation:	**CPP**	**Mid-Peak**	**Off- Peak**	**Total**	
47		2017 LOAD in kWh =	15,057,549	33,014,472	40,124,308	88,196,329	
48		LOAD SCALED TO DE 18-041 forecast	14,945,076	32,767,870	39,824,600	87,537,546	
49							
50		RTP + Gen. Related Ancil. Svcs =	$ 0.06597	$ 0.06328	$ 0.05165		
51		Ave. RPS Costs for E.S. to 1/19 =	$ 0.00481	$ 0.00481	$ 0.00481		
52		FCM Cost, net of prior yr recon. =	$ -	$ -	$ -		
53			$ 0.07077	$ 0.06809	$ 0.05645		
54		Base Revenue =	$ 1,057,717	$ 2,231,060	$ 2,248,221	$ 5,536,998	
55		Portion of Base Revenue =	19.1%	40.3%	40.6%		
56		Revenue Requirement DE 18-041 =				$ 8,318,125	
57		Balance to make up =				$ 2,781,127	
58		Portions =	$ 531,271	$ 1,120,618	$ 1,129,238	$ 2,781,127	
59		Additional Rate =	$ 0.03555	$ 0.03420	$ 0.02836	**Current Rates**	as of 8/1/18
60		**Total E.S. TOU Rate =**	**$ 0.10632**	**$ 0.10229**	**$ 0.08481**	0.08299	
61							
62		**Distribution Rate =**	**$ 0.07540**	**$ 0.05296**	**$ 0.03533**	0.04658	Ave for 650 kWh*
63	For T:	Historic Odds of a Monthly Peak =	95.00%	3.33%	1.67%		
64	Gradual %	Rev Target for C.P. Demand % =	$ 2,482,346	$ 87,100	$ 43,550		
65	0%	Transmission Rate for C.P. D.% =	$ 0.1661	$ 0.0027	$ 0.0011		
66		Transmission Rate for Fixed/kWh =	$ 0.0048	$ 0.0048	$ 0.0048		
67	CD Meth?	**Total Transmission Rate =**	**$ 0.17085**	**$ 0.00741**	**$ 0.00584**	$ 0.03460	
68	No	Total T,D & G Rate =	**$ 0.35257**	**$ 0.16265**	**$ 0.12598**	$ 0.16417	
69		Storm Recovery Adjustment =	$ -	$ -	$ -		
70		Stranded Cost Charge =	$ (0.00095)	$ (0.00095)	$ (0.00095)	$ (0.00095)	
71		System Benefits Charge =	$ 0.00457	$ 0.00457	$ 0.00457	$ 0.00457	
72		Electricity Consumption Tax =	$ 0.00055	$ 0.00055	$ 0.00055	$ 0.00055	
73	**TOTAL WINTER Residential Variable Rate =**		**$ 0.35674**	**$ 0.16682**	**$ 0.13015**	**$ 0.16834**	
74							
75		Fixed Customer Charge/Month =	$14.54	$14.54	$14.54	$14.54	
76	Revenue Check (TOU compared with current rates):						
77		$ 15,981,051	$ 5,331,493	$ 5,466,338	$ 5,183,219	$ 14,736,421	
78	Dist Est.	$ (4,269,095)	$ (1,126,850)	$ (1,735,271)	$ (1,406,974)	$ (4,077,849)	*See note
79		$ 11,711,956	$ 4,204,643	$ 3,731,068	$ 3,776,245	$ 10,658,572	
80	Total revenues, net of D estimate (summer & winter should be looked at together):				9.883%	=difference	
81	*NOTE: Subtract out Distribution component as the current rate is only an estimated average rate due to change in rates at 250 kWh.						
82							
83		**OVERALL REVENUE CHECK (S +W):**	CP	MP	OP	Current Rates	
84		$ 28,042,633	$ 10,459,214	$ 10,044,641	$ 7,538,778	$ 27,964,814	
85	Dist Est.	$ (7,815,124)	$ (2,272,253)	$ (3,082,982)	$ (2,459,889)	$ (7,738,398)	*See note
86		$ 20,227,509	$ 8,186,961	$ 6,961,659	$ 5,078,889	$ 20,226,416	
87		Total revenues, net of D estimate are about equal:			**0.005%**	**=difference**	

	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1	**TOU Model for Liberty Utilities DE 17-189, Summer FCM and T Cost Calculators**													
2	**Weekend & Holiday hours split between Off-and Mid-Peak**													
3														
4		**FCM Cost (Generation Capacity) TOU Allocation Calculator**												
5			Est. Cost to Load / kW-mo.	$ 9.36	From ISO-NE 3/19/18 Net Cost to Load "nrcp_forecast_ccp_2018-2019.pdf"									
6			X # of months in period =	6										
7			X Ave. 2017 Cap. Tag for SC in kW =	74,658.57	From: https://liberty-utilities.com/nh/electricsupply/documents/ICAP_Tags_Rec.xls									
8			X Gross up for Dist. Loss Factor =	1.05025										
9			Est. FCM Cost @ 2017 Cap. Tag =	$ 4,192,826		From: www.puc.nh.gov/Regulatory/Docketbk/2018/18-041/TESTIMONY/18-041_2018-06-18_GSEC_ATT_TECH_STATEMENT_URBAN_SIMEK.PDF , p. 128								
10			Less Prior period reconcilliation =	$ 1,611,336	$ 0.00970	& 133								
11				$ 2,581,490	$ 5.49	/kW-mo= close to historic average AND long term conservative (low) forecast								
12		**Coincident Hourly Peak Demand Transmission Cost Allocator for Summer Period (May-Oct.)**												
13				For the 10 years ending 5/18, the % of 60 summer period months that the system peak occurred for transmission charges										
14			H.E. =	11	12	13	14	15	16	17	18	19	20	21
15				0.00%	1.67%	0.00%	6.67%	15.00%	11.67%	41.67%	6.67%	15.00%	1.67%	0.00%
16		CPP	76.67%	0.00%	0.00%	0.00%	0.00%	0.00%	11.67%	41.67%	6.67%	15.00%	1.67%	0.00%
17		Mid-Peak	23.33%	0.00%	1.67%	0.00%	6.67%	15.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18		Off-Peak	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19			100.00%											
21														
22					Current Transmission Rate for Rate Class D =	$ 0.03460	/kWh							
23					C.P. Demand portion of rate =	$ 0.02985	(Current Transmission Charges from DE 18-051)							
24					Fixed/kWh portion of rate =	$ 0.00475								
25							(Various reconcilliations, mosly prior period under-recovery from flat kWh rate, from DE 18-051)							
26					% of C.P. Demand part of rate moved to Fixed =	0%								
27					Gradualized C.P. portion of rate =	$ 0.02985						Use D cost/load duration method for all T:	No	
28					Gradualized Fixed/kWh portion of rate =	$ 0.00475				CP =	0.0401	0.0626763		
29										MP =	0.02354	0.036793		
30					Forecast Load for this Group =	78,579,538	kWh			OP =	0.01524	0.0238201		
31					Revenue Target for C.P. Demand Portion =	$ 2,345,599	with gradualization			scaling factor =		1.563		
32					Revenue Target for Fixed/kWh portion =	$ 373,253	$ 0.0048			(to meet same revenue)				
33					Overall Revenue Target =	$ 2,718,852	$ 2,718,852			(Source = Lon Huber model run)				
34														
35		LOAD FORECAST in Default Service Proceedings												
36			Feb-18	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	JAN
37	321,327,841	=Total	27708614	26838427	23234825	22196348	24762926	30469617	30078218	25145803	23355517	24831311	30158660	32547575
38			Summer Total =	156008429		78,579,538	=Summer Total in 2nd Half of 2017 (Aug-Oct)					47.3%		
39			Winter Total =	165319412		87,537,546	=Winter Total in 2nd Half of 2017 (Nov. -Jan. 2019)					52.7%		
40				321327841		166,117,084								
41														

	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
42	**TOU Model for Liberty Utilities DE 17-189, Winter T Cost Calculator**													
43	**Weekend & Holiday hours split between Off-and Mid-Peak**													
44														
45		**[FCM Calculator Not Used for Winter Period]**												
46														
47														
48														
49														
50														
51														
52														
53		**Coincident Hourly Peak Demand Transmission Cost Allocator for Winter Period (November - April)**												
54				For the 10 years ending 5/18, the % of 60 winter period months that the system peak occurred for transmission charges										
55			H.E. =	11	12	13	14	15	16	17	18	19	20	21
56				0.00%	1.67%	0.00%	0.00%	1.67%	1.67%	0.00%	48.33%	35.00%	10.00%	1.67%
57		CPP	95.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.67%	0.00%	48.33%	35.00%	10.00%	0.00%
58		Mid-Peak	3.33%	0.00%	1.67%	0.00%	0.00%	1.67%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
59		Off-Peak	1.67%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.67%
60			100.00%											
61														
62														
63					Current Transmission Rate for Rate Class D =	$ 0.03460	/kWh							
64					C.P. Demand portion of rate =	$ 0.02985	(Current Transmission Charges from DE 18-051)							
65					Fixed/kWh portion of rate =	$ 0.00475								
66							(Various reconcilliations, mosly prior period under-recovery from flat kWh rate, from DE 18-051)							
67					% of C.P. Demand part of rate moved to Fixed =	0%								
68					Gradualized C.P. portion of rate =	$ 0.02985						Use D cost/load duration method for all T:	No	
69					Gradualized Fixed/kWh portion of rate =	$ 0.00475				CP =	0.0401	0.0626763		
70										MP =	0.02354	0.036793		
71					Forecast Load for this Group =	87,537,546	kWh			OP =	0.01524	0.0238201		
72					Revenue Target for C.P. Demand Portion =	$ 2,612,996	with gradualization			scaling factor =		1.563		
73					Revenue Target for Fixed/kWh portion =	$ 415,803	$ 0.0048				(to meet same revenue)			
74					Overall Revenue Target =	$ 3,028,799	$	3,028,799		(Source = Lon Huber model run)				
75					Total S + W T rev. target =	$ 5,747,651	= Rev. Target with non-seasonal model							
76		REV FORECAST in Default Service Proceedings												
77			Feb-18	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	JAN
78	13,787,150	=Total							1,949,069	1,752,411	1,767,545	1,800,518	2,712,470	3,805,137
79			Summer Total =	5469025		5,469,025	=Summer Total in 2nd Half of 2017 (Aug-Oct)					39.7%		
80			Winter Total =	8,318,125		8,318,125	=Winter Total in 2nd Half of 2017 (Nov. -Jan. 2019)					60.3%		
81				13,787,150		13,787,150								