Unitil

DE 20-170: EV TOU Rates Technical Session

01/19/2021

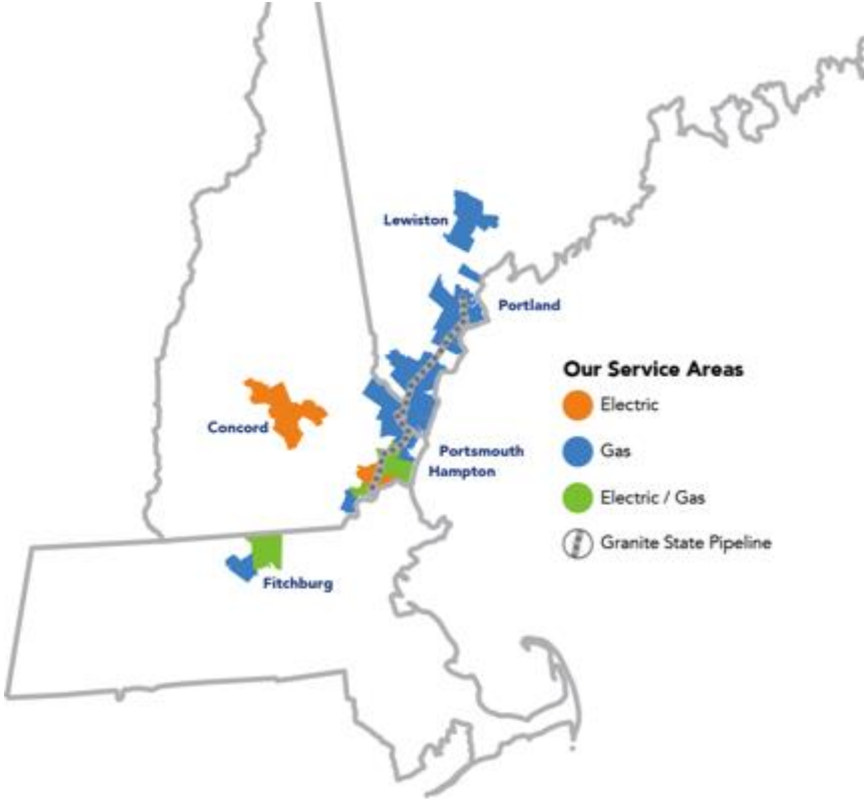
ABOUT UNITIL

Company Overview

- Natural gas and electric distribution utility with **operations in three states** serving ~186,000 customers

  ~30,000 electric and 16,000 gas in MA

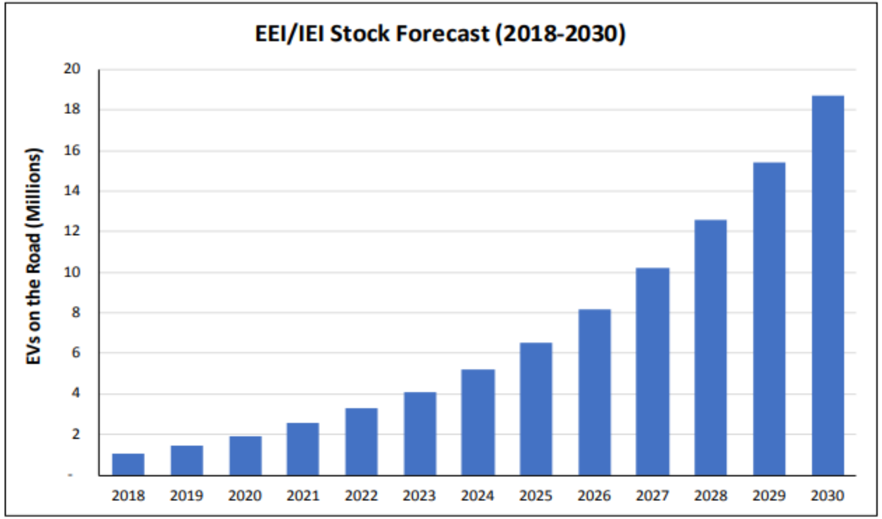
- 500+ full-time employees
- We provide **energy for life**, safely and reliably delivering natural gas and electricity in New England



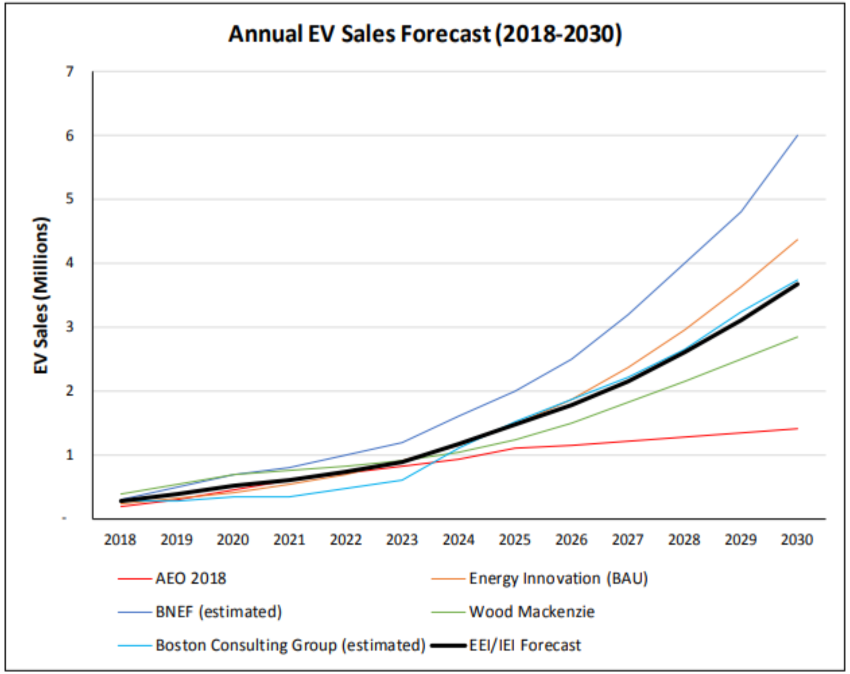
Overview

- EV Sales and Projections
- EV Energy Usage
- Where Will EV Charging Happen?
- EV Charging Demand
- DE 20-170 Unitil Comments
- Unitil Metering Systems
- Alternative Metering Assessment
- Unitil Next Steps

EV Sales and Projections



Credit: EEI



Credit: EEI

Following EEI forecast, Unitil NH could have +17,000 EVs on the system in 2030

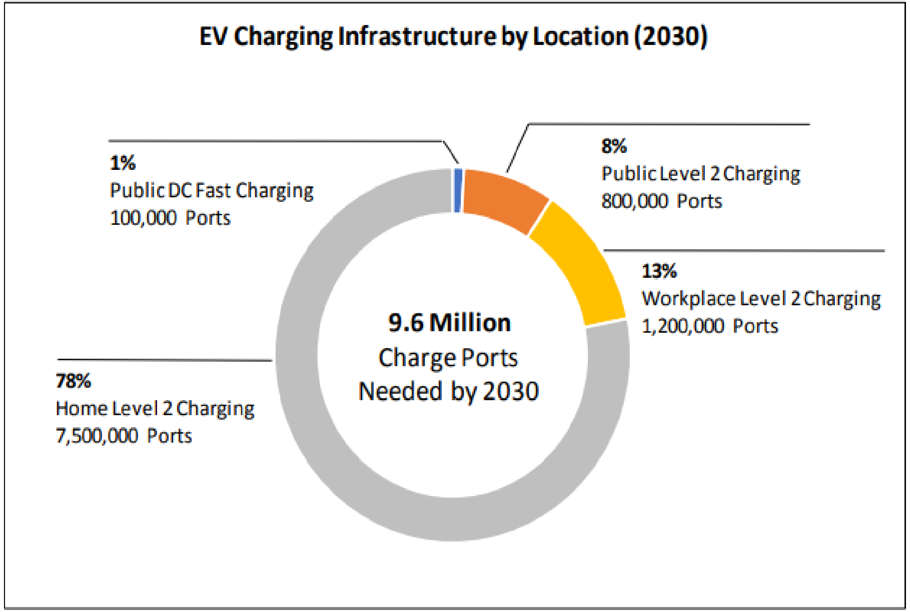
EV Energy Usage

- Looking at the most popular EVs available today, what are the added electrical loads?
- Assume: 85% charging efficiency factor, 12,000 mi/year

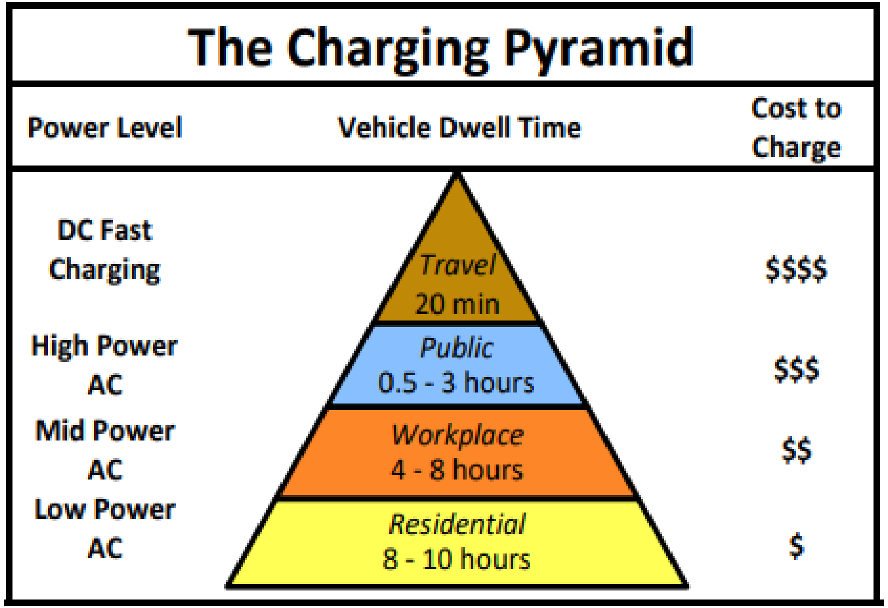
Credit: James Lipman, Motortrend

~3,500 kWh/year per EV

Where Will EV Charging Happen?



Credit: EEI



Credit: M. Prokin, M. Cabarkapa, J. Stojkovic

EV Charging Demand

- Comparing the different charging standards, how do these methods impact electricity demand? (Avg. home design w/o electrification = ~3-5 kW load)

Level 1 (120V)

Home
+3-5 mi/hour

+1.8 kW

Credit: Kyle Field, CleanTechnica

Level 2 (240V)

Home/Work/Public
+20-50 mi/hour

+12 kW

Credit: Soleil Energy Solutions

DC Fast Charge

Public Corridor
+75-300 mi/hour

+150 kW

Credit: ABB & Electrify America

Unitil DE 20-170 Comments

- Unitil supports the development of TOU rates for EV charging
- No single option will be suitable for all customer types and use cases
- Unitil intends to offer a suite of TOU rates
  - Whole-facility TOU
  - Separately-metered EV TOU for Residential
  - Separately-metered EV TOU Small C&I
  - Separately-metered EV TOU “high demand” Large C&I

Unitil DE 20-170 Comments

- EV TOU rates should be based on cost of service rate design principles to ensure economic efficiency and limit cost shifting
- Critical peak pricing (CPP) and demand reduction approaches are also worthy of consideration in addition to tariff-based EV TOU rates
- A utility's distribution-related costs are fixed in nature and are incurred to meet customers' non-coincident peak demands and do not necessarily exhibit time-varying cost characteristics
- In most cases, demand charges for C&I customers better reflect the manner in which a utility's costs are incurred to serve such larger customers

Unitil DE 20-170 Comments

- TOU rate options should create beneficial outcomes for the customer (through lower rates and electric bills) and for the utility (through a reduction in system costs over time)
- Should evaluate how customers are responding to the utility's TOU rate options in order to make periodic refinements to the TOU rate design and identify how the utility's load shape and resulting costs will likely change over time
- Incorporate considerations into the design of EV TOU rates that may be non-cost causative in the near term may provide an opportunity to gauge the resulting longer-term impact of EV adoption on the electric distribution system

Unitil Metering Systems

- Unitil has AMI, CIS, and data management systems in place today to offer TOU rates
- Customers with legacy TS2 AMI meters can still move to TOU rates
- The company is in the process of upgrading customers to next generation PLX AMI meters which provide 15 minute interval data
- Any EV customer on a TOU rate would receive a PLX AMI meter to enhance data sharing capability
- The Company plans to explore leveraging existing TS2 AMI technology for shadow billing

PLX vs TS2 Capabilities

Feature	TS2	PLX
Deployment	3 days	Within 24 hours
Reconfiguration	3 days	Within 24 hours
Reading Frequency	Daily	3 times per day
Load Profile	One hourly	One 15-min (res) Two 15 min (C&I)
Data storage of readings	30 days at collector	45 days of LP readings 30 days at the collector
TOU	4 periods 1 - 2 days to receive	4 periods 8 to 12 hours to receive
Remote Disconnect	20 commands per hour	288 commands per hour
Validation of Commands	2 days	20 - 25 minutes
Outage/Restoration Notification	20 minutes	Within 10 minutes
Voltage Readings	Available	Available

Data Types and Frequencies

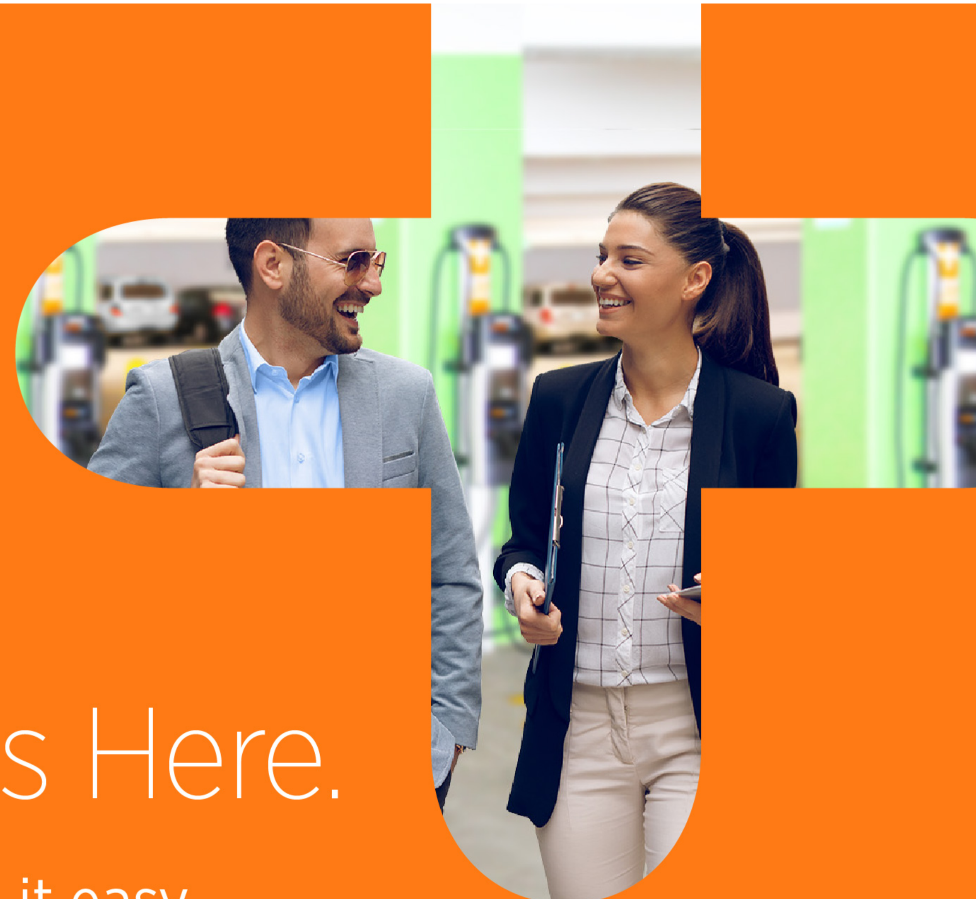
Data Type	TS2	PLX
kWh Del	Daily	3x/day
kWh Rec	Daily	3x/day
kWh Net	Daily	3x/day
TOU Register Read (kWh & Peak)	Daily	3x/day
kWh Interval	Daily	3x/day
kW Peak/Time	Daily	Interval Data 3x/day
Demand kW, kVar, kVA	Daily	3x/day
Power Factor	Daily	3x/day
Momentary Outage Count	Daily	3x/day
Min Voltage/Time of Occurance	Daily	3x/day
Max Voltage/Time of Occurance	Daily	3x/day
Ave Voltage	Daily	3x/day
Tamper Detection	Daily	3x/day
Disconnect Status	On Demand	On Demand
Meter Diagnostics	Daily	3x/day

Alternative Metering Assessment

- The goal is to assess accuracy, availability, format, interface capabilities, data sharing, testing, privacy, and cyber & physical security considerations related to EVSE
- Leveraging information for billing determinants, including disaggregation
- Unitil is in the process of engaging with EVSE equipment providers to understand these issues and develop a roadmap within the rate case
- Current thinking is to offer an incentive to customers to purchase and install smart, managed EVSE
- Unitil would develop a “standard” for qualifying equipment requiring internet connectivity, DR capability, and data sharing
- Analyze 3rd party EVSE metering data, report back to PUC & stakeholders

Unitil Next Steps

- File for EV TOU rates in the Company's upcoming base rate case based on guidance from Order 26,394 and issues derived from this proceeding, DE 20-170
- The three regulated utilities are at different points in their development of EV TOU rates
  - Liberty Utilities has a residential EV TOU rate
  - Eversource Energy has agreed to file an EV infrastructure proposal, residential rate, and demand charge alternative in a separate proceeding as per the settlement agreement in DE 19-057
- Transportation electrification requires a comprehensive strategy – rates, infrastructure, communications, vehicles



The Electric Revolution Is Here.

Our obsession? Making it easy.

EV Charging Embedded Metering

Matthew Deal, Manager, Utility Policy

January 19, 2021

EVSE and Grid Modernization

+ EV charging can be beneficial to the grid
+ Managed charging and/or use of dynamic rates if implemented effectively can result in meaningful customer savings
+ Embedded metering enables near-term EV charging opportunities at a lower cost to customers
+ AMI is not necessary to utilize embedded metering, but embedded metering can complement a modernized grid

Embedded Metrology of EVSE

Embedded Meter Capabilities

+ 1% accuracy across all supported current and temperature ranges
+ Measures energy delivered to vehicle only
+ 15-minute clock aligned interval data
+ Capable of remote firmware updates
+ Real-time power monitoring
+ Secure communication channel between station and server
+ Local storage of data on the charging station for 90 days
+ Will meet cybersecurity requirements

Benefits to Customers

- No need to purchase a second meter
- Opportunity to participate in TOU, dynamic rates, and/or managed charging programs
- Could realize additional fuel cost savings
- EV load can be separated from house load
- Seamless experience since the EVSE communicates w/utility
- Near-term program deployment potential

EVSE Embedded Metering – Pilots

+ Commission and utilities should pursue pilots to test deployment of charging stations with embedded metering
+ Pilots would confirm the accuracy of metering, work through service and business policies, and trial different methods to educate and engage with customers
+ Pilots can test managed charging programs, demand response, and TOU tariffs.
+ Appropriate for utilities to receive regulatory support and cost recovery for pilots due to the potential for broader ratepayer benefits.
+ PUC, if necessary, can grant waivers from metering requirements to facilitate the pilots.

EVSE Embedded Metering – Pilot Design

+ Phase I (Jan – March):
  - Develop pilot objectives, concept and scope
  - Identify criteria to meet billing, metering, and IT requirements
  - Perform an assessment of market-available EV charging products that meet minimum functional requirements
    - One possible pathway would be to conduct an RFI that would allow vendors to provide details about the capability of product offerings followed up with product demonstrations
  - Draft and issue an RFP for technology vendors to meet the objectives and scope of the pilot project
  - Engage with stakeholders to solicit feedback
+ Phase II:
  - April 30: Utilities file limited term pilot program for Commission approval.

Thank You

For further information on this topic,
please contact Matthew Deal:
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Appendix

NIST HB 44 Provides Guidelines for Embedded Meters

- National Institute of Science and Technology (NIST) Handbook 44 Sec 3.40 provides the basis for EVSE internal meter calibration
- 1% lab / 2% field accuracy
- NIST HB 44 metering guidelines may be adopted by state Weights and Measures (CA, others)
- Enables consistency across U.S. so companies are not building state-specific products
- Aligns with N.H Code Admin. R. PUC 305.02(a) statutory standard for meters (2%)

https://www.nist.gov/pml/weights-and-measures/publications/nist-handbooks/other-nist-handbooks/other-nist-handbooks-2-2

Utilities Currently Using Embedded Metering for Billing

+ San Diego Gas & Electric - Power Your Drive
+ Xcel Energy Minnesota – Home Program
  - State passed legislation requiring utilities to establish EV TOU rates
  - Originally Xcel Minnesota required all EV TOU customers to purchase a second meter and pay for installation of it
  - Many customers were unwilling to pay this extra cost and sign ups for the TOU tariff were very low
  - Xcel then developed a successful pilot using embedded metering for the TOU tariff
  - The Commission recently approved an expansion

Utilities Currently Using Embedded Metering for Billing

+ Baltimore Gas & Electric – EV-Only TOU
  - Required offering per Commission Order
  - Existing whole-home TOU for EV customers had low participation
  - Smart charger interval data aggregated into on-peak and off-peak charging by third-party
  - Subtractive billing
+ Smart charging incentives and active load management solutions
  - Valuable alternative or complement to time varying rates

Development of TOU Rate Model for Liberty Utilities Battery Pilot

by Clifton Below, Asst. Mayor, City of Lebanon

Docket No. DE 17-189

September 14, 2018

Technical Statement Regarding Time of Use (TOU) Model
by
Heather Tebbetts, Liberty Utilities
Lon Huber, Navigant, for the Office of Consumer Advocate
& Clifton Below, for the City of Lebanon

https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_TECH_STATEMENT_TOU.PDF

RAP®

FEBRUARY 2020

Rate Designs That Work for a Modern, Customer-Oriented Grid

A Look at New England Rate Design: Issue Brief #3

David Littell and Joni Sliger

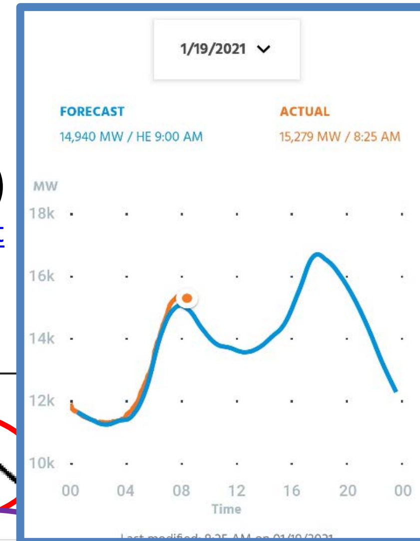
"The Liberty storage pilot rate design accepted by the New Hampshire PUC is the most advanced modern rate design in New England . . ."

https://www.raponline.org/knowledge-center/rate-designs-that-work-for-a-modern-customer-oriented-grid/

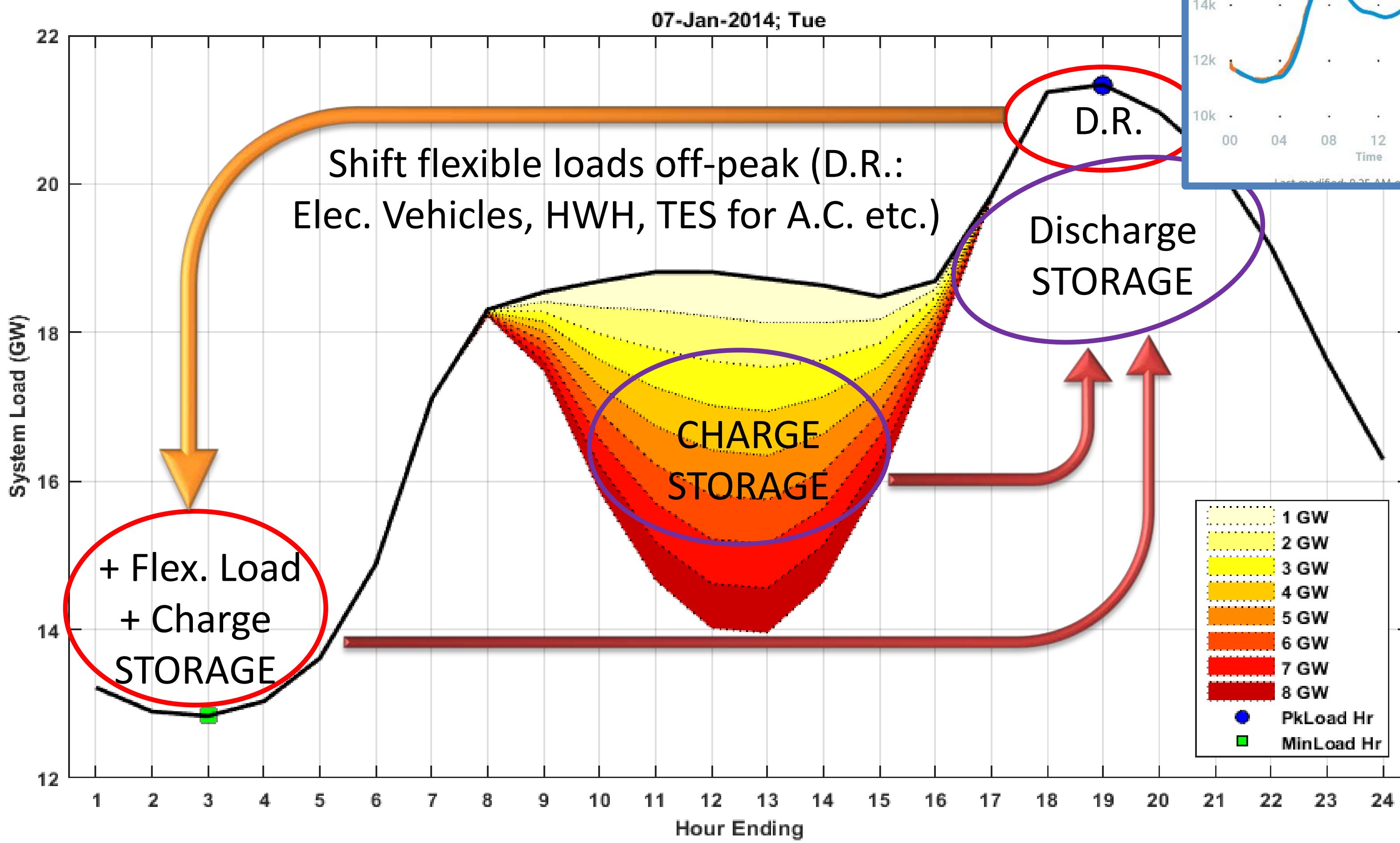
The Need for Time Varying Rates

Illustrative Winter Impact of Solar at Different Levels of Dev. (from ISO-NE)

from: https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact



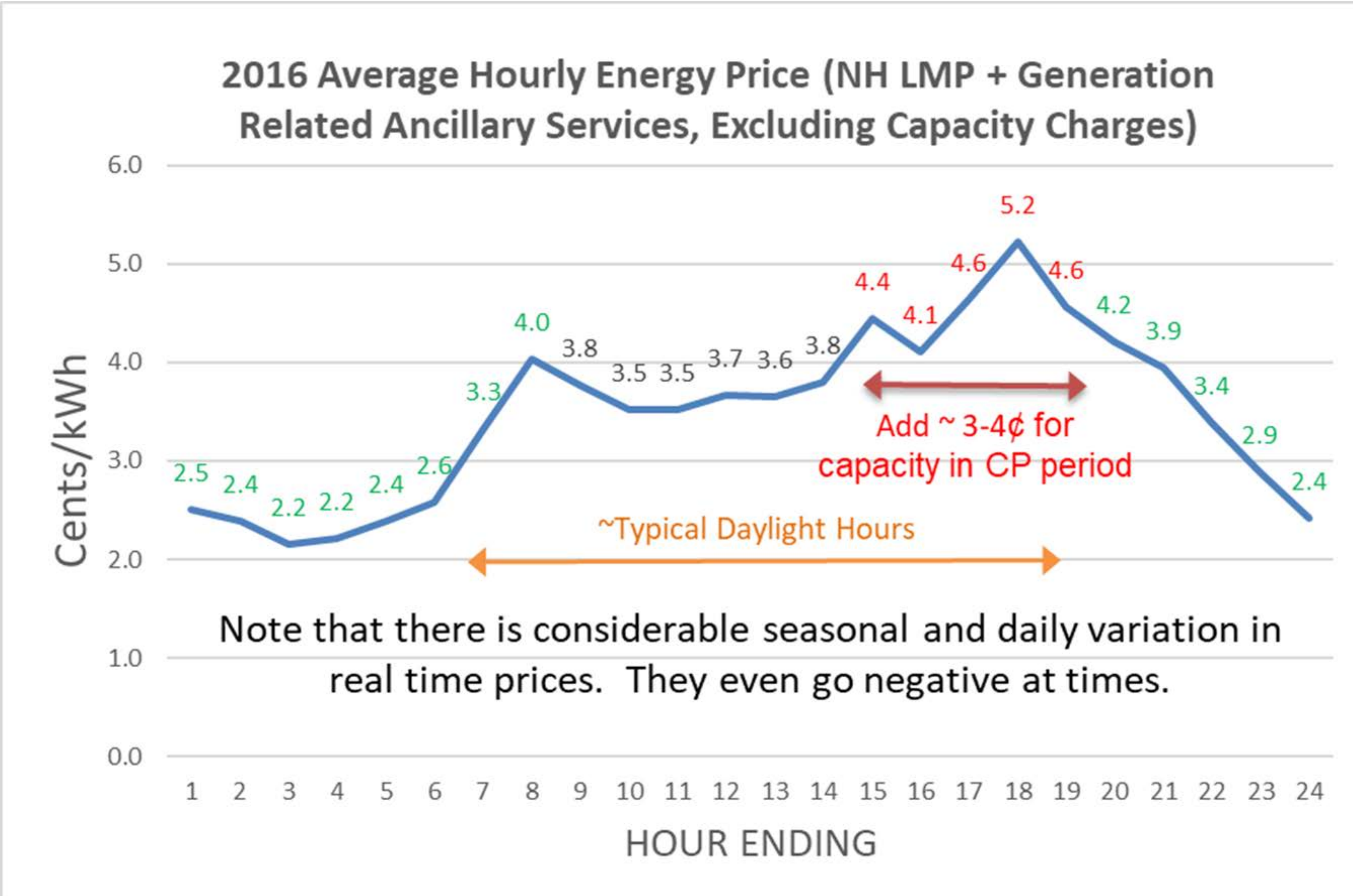
New England's Duck Curve



Rate Elements & Methods in Brief

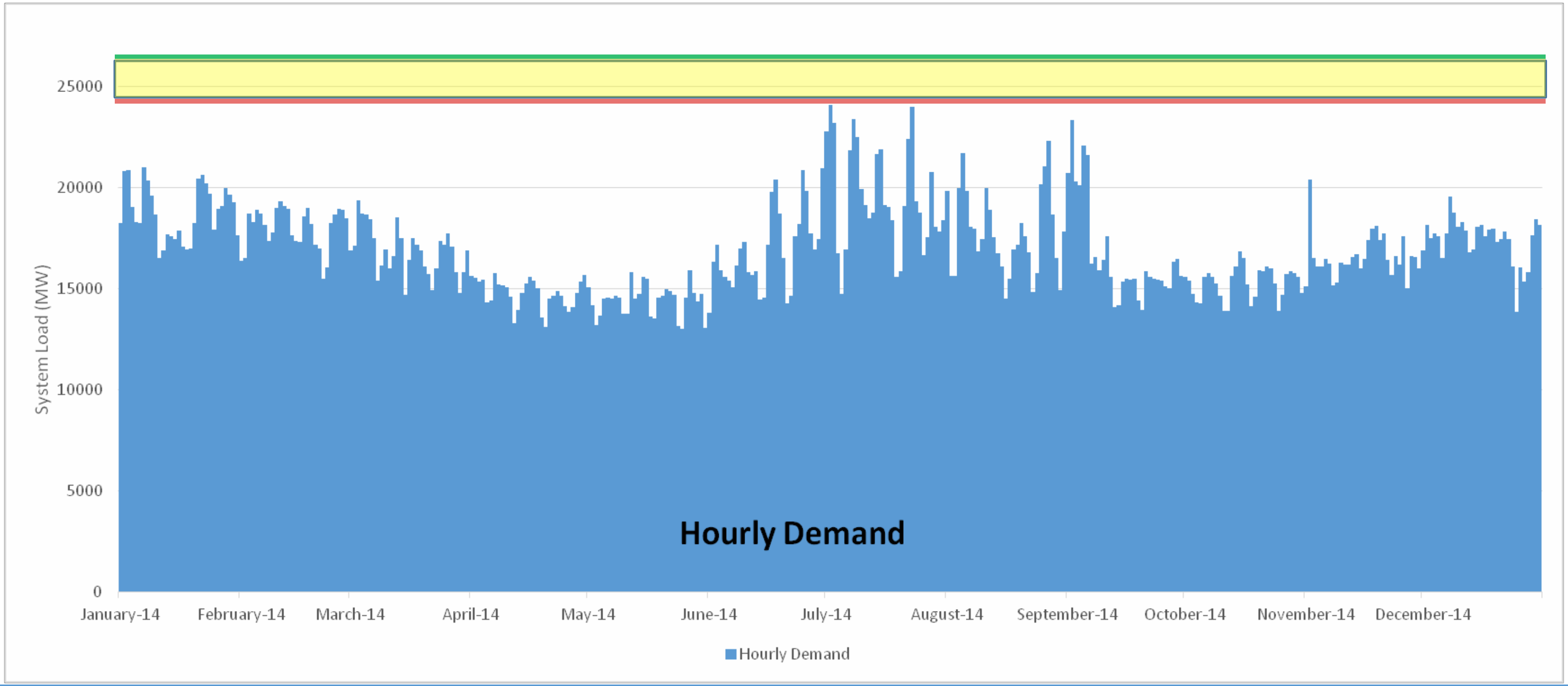
- **Recent Historical Cost Causation Method for Generation** (Energy, Ancillary Services, FCM)
- **Historic Experience Cost Causation Method for Transmission** – based on how transmission costs are allocated to distribution utilities
  - probability of Monthly Coincident Peak occurring during any given hour
  - Winter/Summer seasonal differentiation

Average LMPs by Time of Day



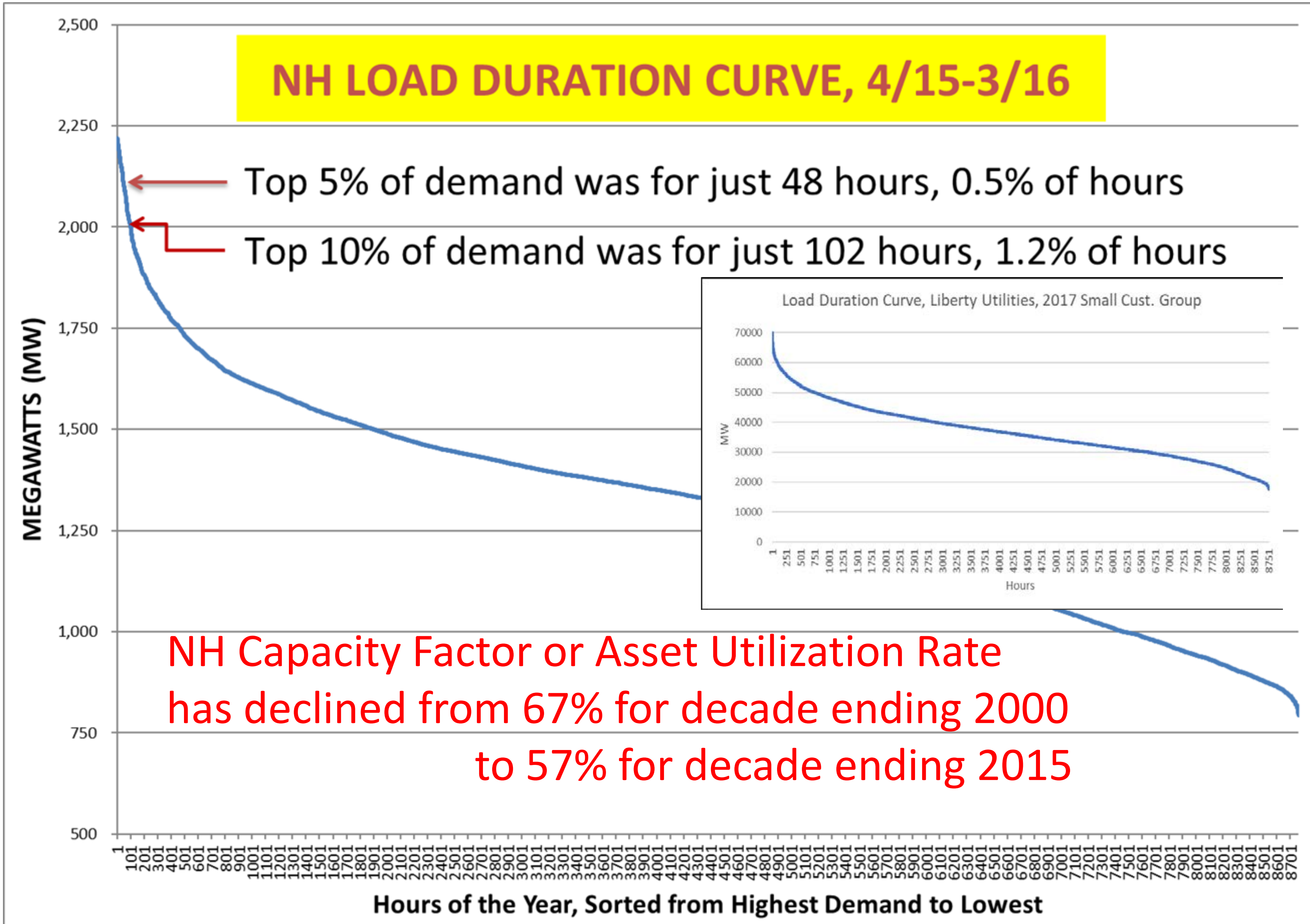
Electric Grid is Sized for Highest Hour of Demand

Whole Energy System (T, D & G) Sized to Meet Peak Demand, With a Safety Margin



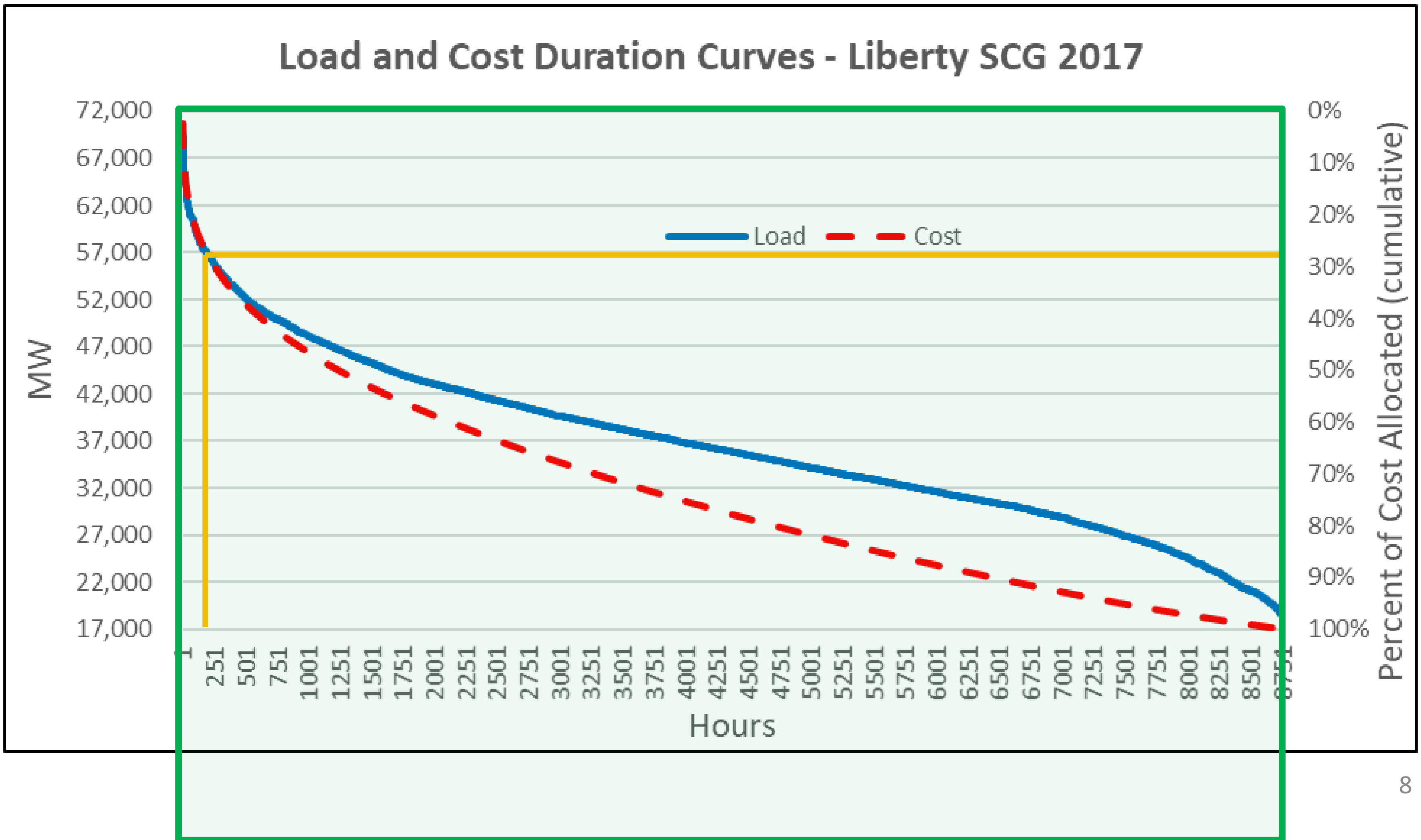
Top 1% of Hours accounts for 8% of Massachusetts Spend on Electricity
Top 10% of Hours accounts for 40% of Electricity Spend

Slide borrowed and adapted from MA Energy Storage Initiative 9/27/16 presentation: https://www.mass.gov/files/documents/2016/09/xd/9-27-16-storage-presentation.pdf


NH LOAD DURATION CURVE, 4/15-3/16
Top 5% of demand was for just 48 hours, 0.5% of hours
Top 10% of demand was for just 102 hours, 1.2% of hours
NH Capacity Factor or Asset Utilization Rate
has declined from 67% for decade ending 2000
to 57% for decade ending 2015
MEGAWATTS (MW)
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
Hours of the Year, Sorted from Highest Demand to Lowest
Load Duration Curve, Liberty Utilities, 2017 Small Cust. Group
MW
70000
60000
50000
40000
30000
20000
10000
0
Hours

Cost Duration Method for Distribution

Developed by Lon Huber, now V.P. for Rate Design and Strategic Solutions at Duke Energy Corporation

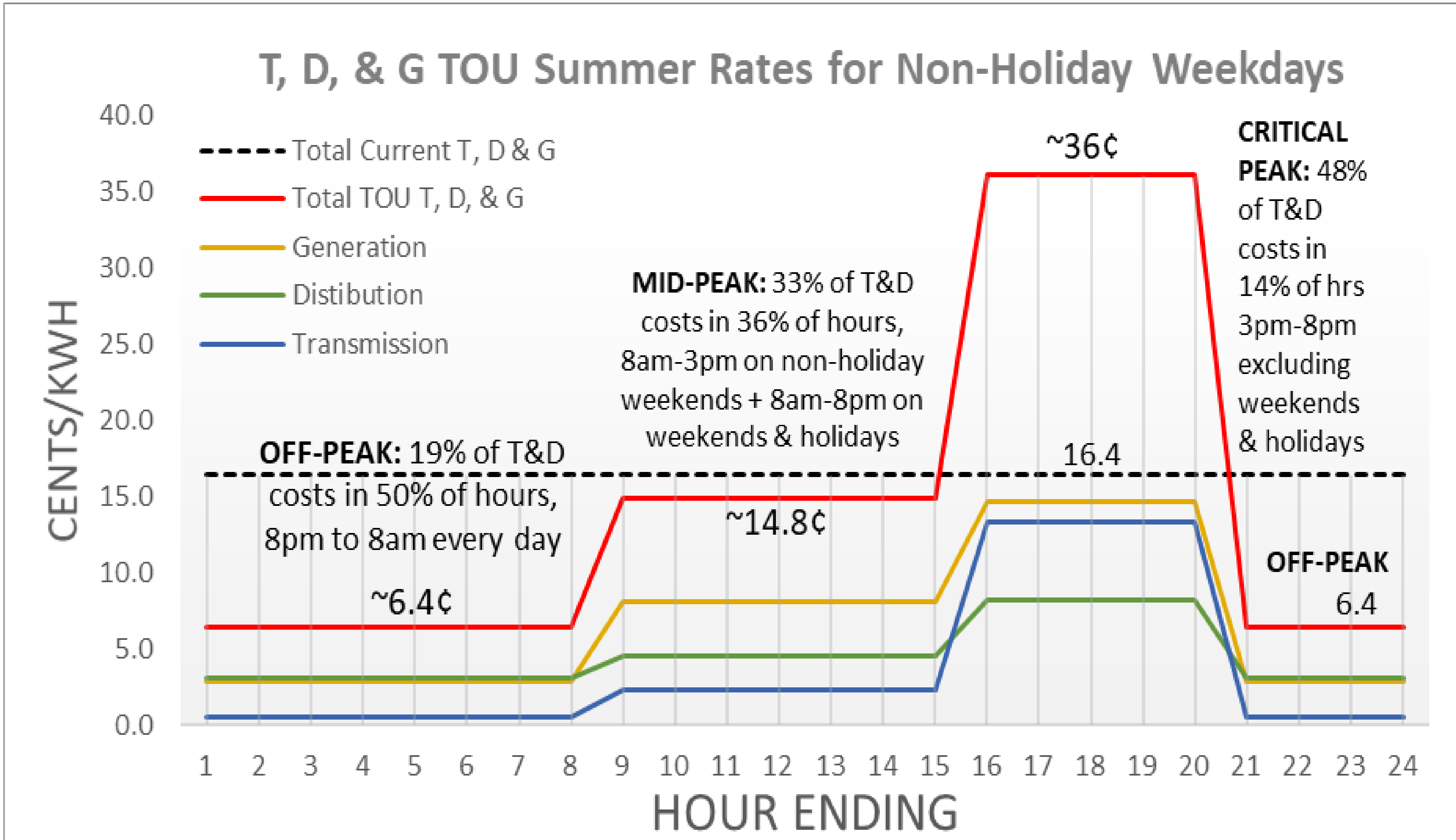


Consensus Results from Data Used for 2018

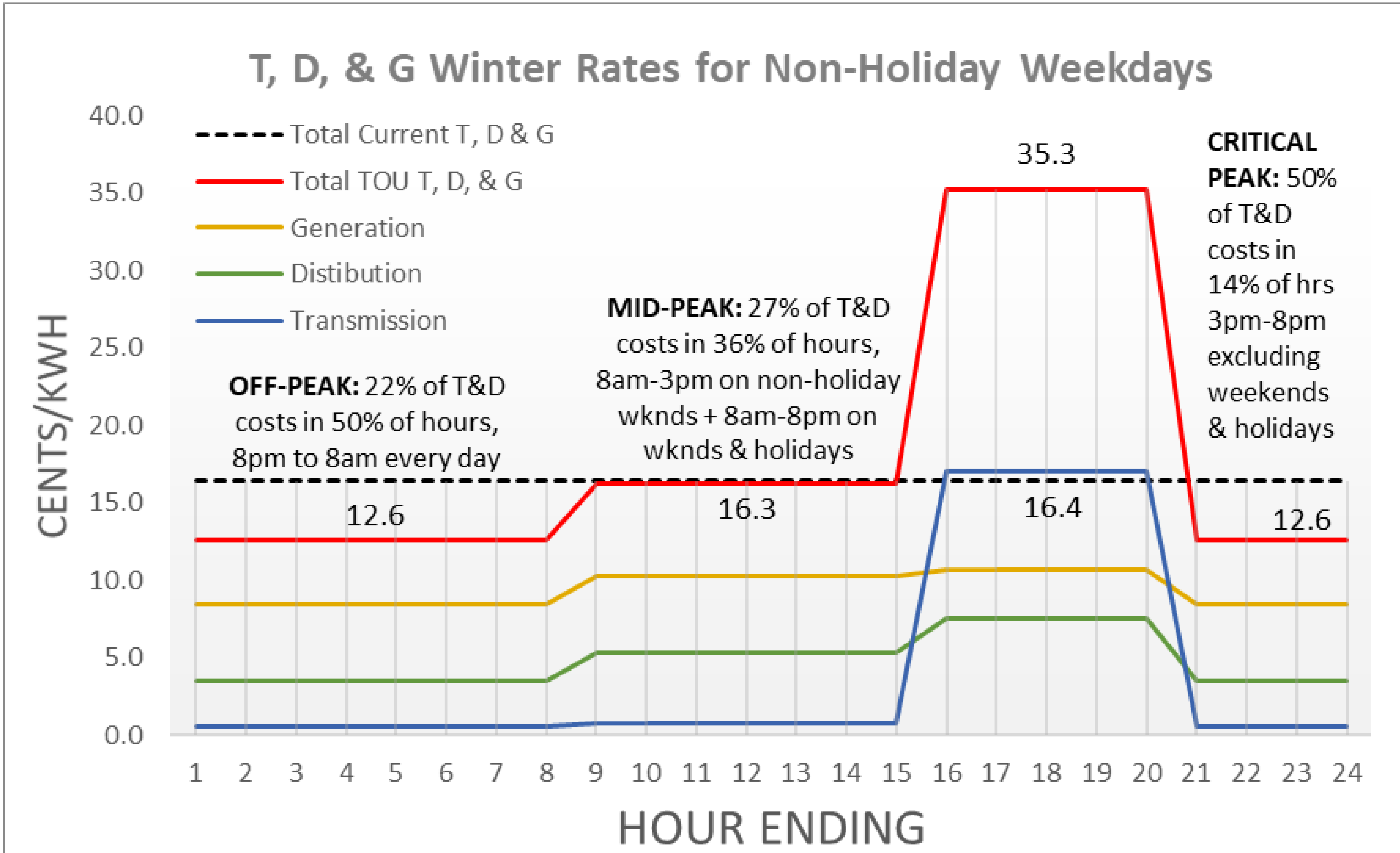
Rates are cents per kWh	Critical-Peak	Mid-peak	Off-peak	Current
Summer Energy (G) Rate =	14.6	8.1	2.9	8.3
Summer Distribution (D) Rate =	8.1	4.5	3.1	4.7*
Summer Transmission (T) Rate =	13.3	2.3	0.5	3.5
SBC and other minor charges/credits =	0.4	0.4	0.4	0.4
TOTAL SUMMER Variable Rate =	**36.4**	**15.3**	**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

Model designed to update with each refresh of Default Rates, T&D Rates, CP history (T & Capacity), & Annual Hourly Load and Energy Costs Data

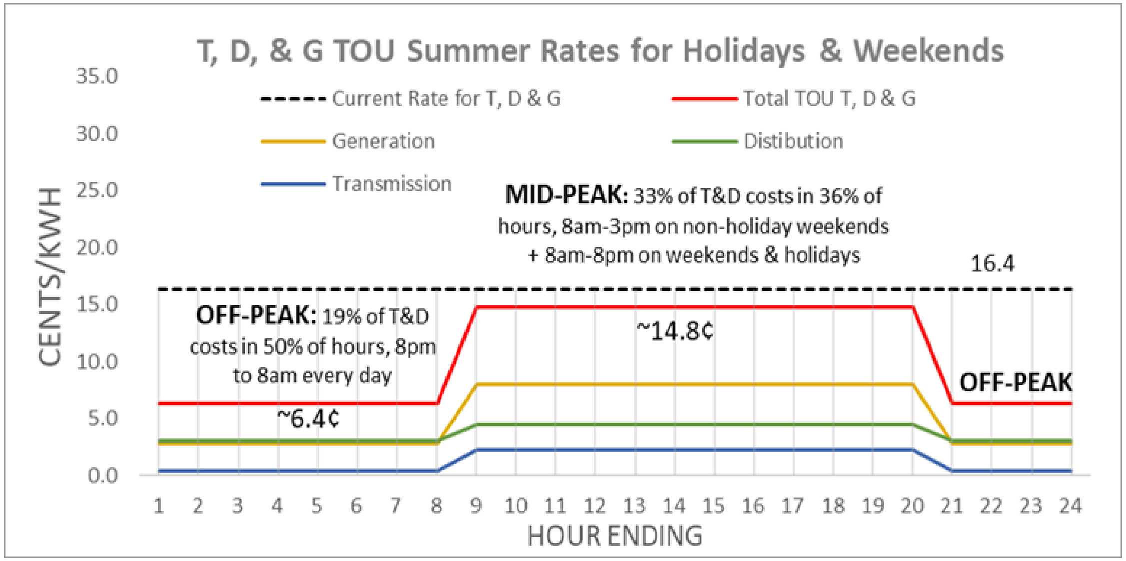
Resulting Summer TOU Rates After considering many permutations

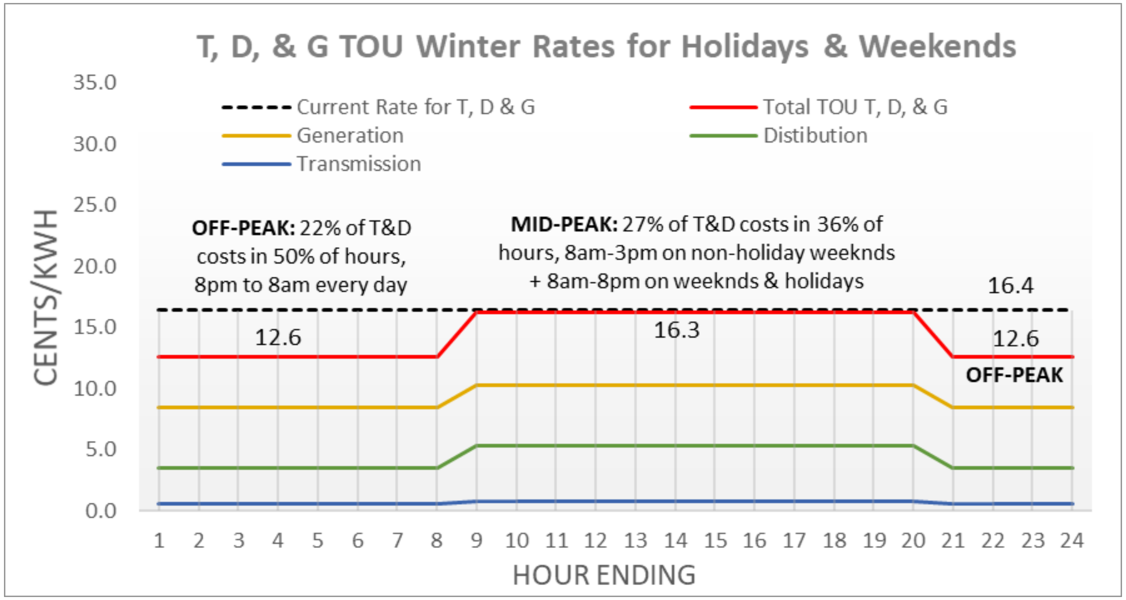


L.U. Winter TOU



L.U. TOU for Weekends & Holidays





	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.						

	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														

Liberty's Current TOU Rates

Rates Effective August 1, 2020 through October 31, 2020

Customer Charge $ 14.74

	Monday through Friday				Saturday through Sunday and Holidays	
	Critical Peak	On Peak	Off Peak		On Peak	Off Peak
Distribution	**$ 0.09675**	**$ 0.05339**	**$ 0.03628**	**Distribution**	**$ 0.05339**	**$ 0.03628**
REP/VMP	$ 0.00008	$ 0.00008	$ 0.00008	REP/VMP	$ 0.00008	$ 0.00008
Total Distribution	$ 0.09683	$ 0.05347	$ 0.03636	Total Distribution	$ 0.05347	$ 0.03636
Transmission	**$ 0.11010**	**$ 0.01670**	**$ 0.00115**	**Transmission**	**$ 0.01670**	**$ 0.00115**
Energy Service	**$ 0.09143**	**$ 0.06356**	**$ 0.04188**	**Energy Service**	**$ 0.06356**	**$ 0.04188**
SBC	$ 0.00678	$ 0.00678	$ 0.00678	SBC	$ 0.00678	$ 0.00678
Consumption Tax	$ -	$ -	$ -	Consumption Tax	$ -	$ -
Stranded Costs	$ (0.00072)	$ (0.00072)	$ (0.00072)	Stranded Costs	$ (0.00072)	$ (0.00072)
Total	**$ 0.30442**	**$ 0.13979**	**$ 0.08545**	**Total**	**$ 0.13979**	**$ 0.08545**

Rates Effective November 1, 2020 through April 30, 2021

Customer Charge $ 14.74

	Monday through Friday				Saturday through Sunday and Holidays	
	Critical Peak	On Peak	Off Peak		On Peak	Off Peak
Distribution	**$ 0.08955**	**$ 0.06289**	**$ 0.04196**	**Distribution**	**$ 0.06289**	**$ 0.04196**
REP/VMP	$ 0.00008	$ 0.00008	$ 0.00008	REP/VMP	$ 0.00008	$ 0.00008
Total Distribution	$ 0.08963	$ 0.06297	$ 0.04204	Total Distribution	$ 0.06297	$ 0.04204
Transmission	**$ 0.13615**	**$ 0.00337**	**$ 0.00212**	**Transmission**	**$ 0.00337**	**$ 0.00212**
Energy Service	**$ 0.09208**	**$ 0.08871**	**$ 0.07411**	**Energy Service**	**$ 0.08871**	**$ 0.07411**
SBC	$ 0.00678	$ 0.00678	$ 0.00678	SBC	$ 0.00678	$ 0.00678
Consumption Tax	$ -	$ -	$ -	Consumption Tax	$ -	$ -
Stranded Costs	$ (0.00072)	$ (0.00072)	$ (0.00072)	Stranded Costs	$ (0.00072)	$ (0.00072)
Total	**$ 0.32392**	**$ 0.16111**	**$ 0.12433**	**Total**	**$ 0.16111**	**$ 0.12433**