Rhode Island

2019 Electric Peak (MW) Forecast

Long-Term: 2019 to 2033

[Narragansett Electric Company]

December 2018

Rev. 2, 12/15//2018

Advanced Data & Analytics
Business Processes

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Rev. 2	12/15/2018	- add additional load curves
Rev. 1	12/04/2018	- correct Appendix B PV table
Rev. 0	11/01/2018	- ORIGINAL

General Notes:

- Input data through **August 2018**; Projections from 2019 forward;
- Economic data is from Moody's vintage **August 2018**.
- Energy Efficiency data is vintage **August 2018.**
- Distributed Generation data is vintage **August 2018.**
- Electric Vehicle data is vintage **August 2018**. **[NEW FOR 2018]**
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (1/2003 to 6/2018); internal unreconciled **preliminary** data (Jul. 2018 & Aug. 2018).
- Peak day & times in this report refer to those for the Company and not for ISO-NE peak.
- "Independent" refers to the zone's peak day/time.
- References to "zone" refers to the Company's service territory within the ISO-NE zonal designations; all data is National Grid's service territory within the zones.
- The term "Weather-Normal" and "Extreme" 90/10 ("1 in 10") and 95/5 ("1 in 20") weather are based on 20 year average.
- DR impacts are "added-back" to loads
- PV impacts are based on BEHIND THE METER installations
- 24 hour peak & typical day curves are new for 2018.

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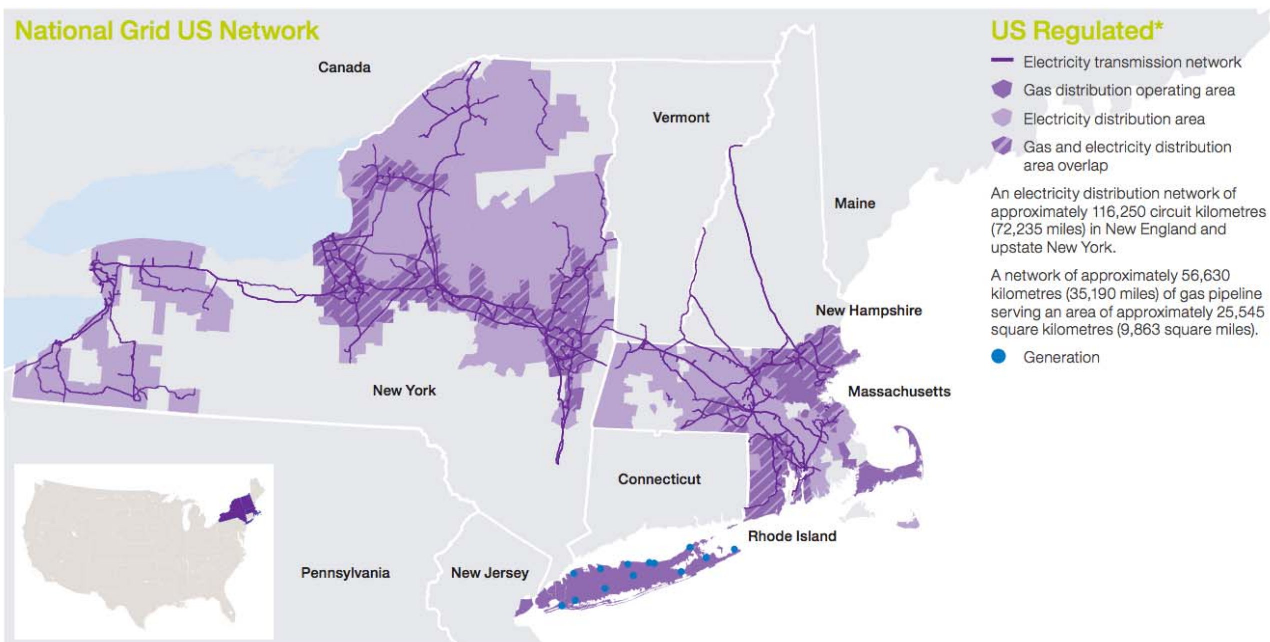
Summary

National Grid's US electric system is comprised of four companies serving 3.4 million customers in Rhode Island, Massachusetts and Upstate New York. The four electric distribution companies are Narragansett Electric Company, serving 0.5 million customers in Rhode Island, Massachusetts Electric Company and Nantucket Electric Company, serving 1.3 million customers in Massachusetts and Niagara Mohawk Power Company, serving 1.6 million customers in upstate New York. Figure 1[1] shows the Company's service territory in the U.S..

Figure 1



*Access to electricity and gas transmission and distribution assets on property owned by others is controlled through various agreements.

Source: National Grid

Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electric infrastructure, enables timely procurement and installation of required facilities, and it provides system planning with information to prioritize and focus their efforts. In addition to these internal reliability and capital planning internal uses, the peak forecast is also used to support regulatory requirements with the state, federal, and other agencies.

Narragansett electric Company's (NECO) peak demand in Rhode Island in 2018 was 1,845[2], on Wednesday, August 29th at hour-ending 17. The 2018 peak was 7% below the NECO all-time high of 1,985 MW reached on Wednesday, August 2, 2006.

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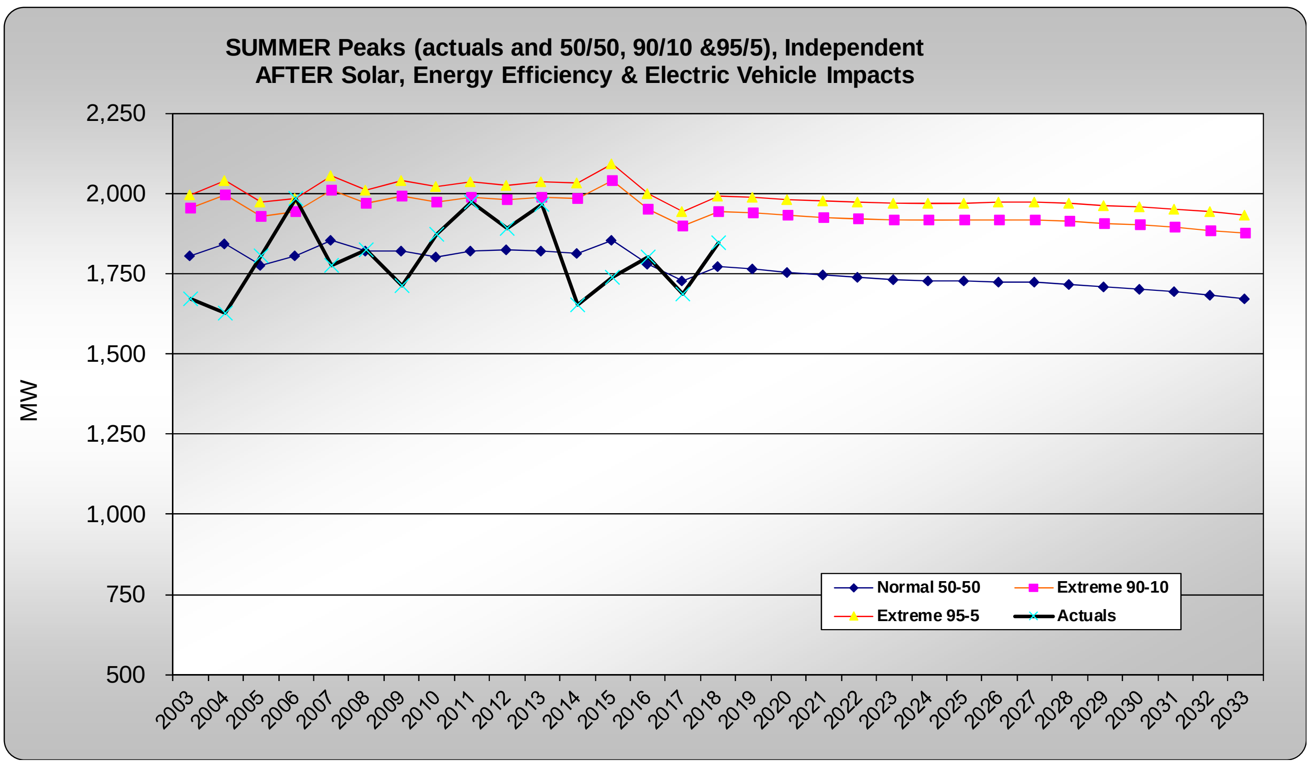
[1] National Grid also serves gas customers in these same states which are also shown on this map.
[2] Meter Data Service's system level PRELIMINARY peak and subject to change

This summer's peak weather was considered *warmer* than normal (50/50 or average). It could be considered about an 70/30 summer, or more than average, but less than the most extreme[3]. This year's peak is estimated to be 71 MW above the peak the company would have experienced under normal weather conditions. Thus, on a weather adjusted "normal" basis this year's peak was estimated to be 1,774 MW, an increase of 2.7% vs. last year's weather-adjusted 'normal' peak.

The forecast indicates that the overall service territory will experience negative growth of -0.4% annually over the next fifteen years, primarily due to the impacts of energy efficiency and solar PV offsetting any underlying economic growth. Electric vehicle impacts are not expected to overcome decreases due to the EE and PV.

Figure 2 shows this forecast graphically.

Figure 2



Forecast Methodology

National Grid in Rhode Island forecasts its peak MW demands for its service territory in the state.

[3] For planning purposes, network strategy uses a 90/10 for transmission planning and a 95/5 for distribution planning for weather extremes.

The overall approach to the peak forecast is to relate (or regress) peak MWs to energy growth and state economic factors (if appropriate). This method allows the peak MW forecasts to grow along with energy growth rates, however it also allows the peak to adjust to other economic influences in each area.

The model is developed based on a “reconstructed” model of past load. That is, claimed energy efficiency, known solar PV and EV are first added back to the historical data set before the model is run. Future projections are made based on the “reconstructed” data set, then future cumulative estimates of savings for the distributed energy resources (DERs) for energy efficiency, solar-PV and EV are taken out to arrive at the final forecast.

Post-model reductions were made to the initial forecast model for energy efficiency (EE), solar (DG), electric vehicles (EV) and increased for historical demand response (DR) impacts.

The results of this forecast are used as input into various system planning studies. The forecast is presented for all three weather scenarios. The transmission planning group uses the extreme-90/10 weather scenario for its planning purposes. For distribution planning, the degree of diversity is reduced and the variability of load is greater, so a 95/5 forecast is used.

Distributed Energy Resources (DERs)

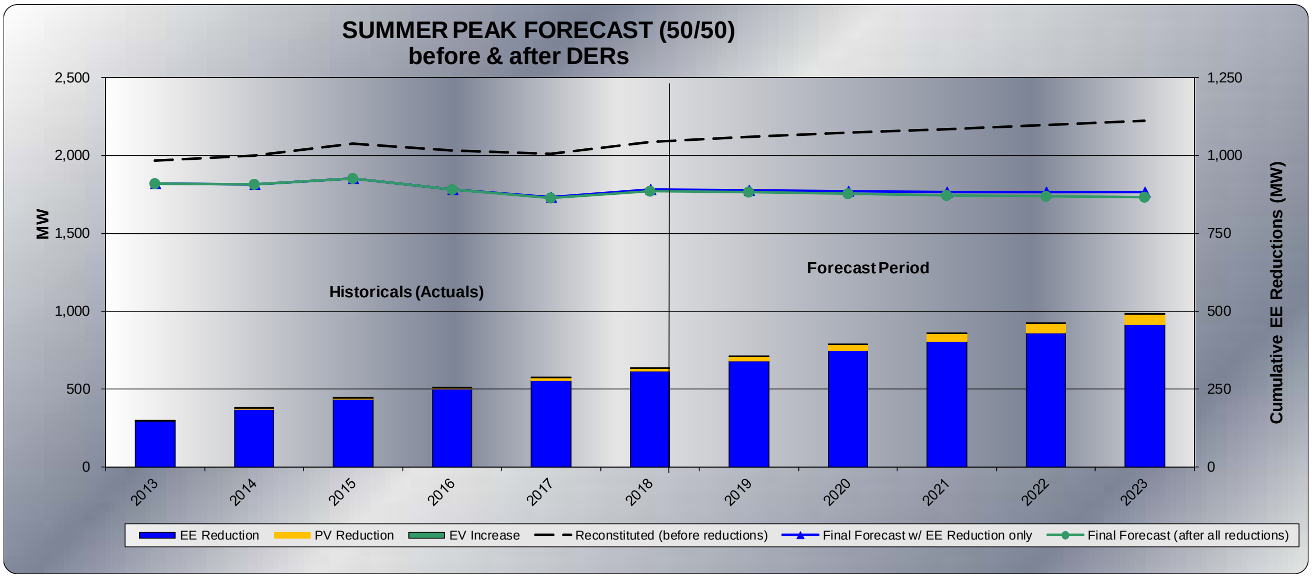
In New England there are a number of policies, programs and technologies that are impacting customer loads. These include, but are not limited to energy efficiency, distributed generation (specifically solar distributed generation), electric vehicles and demand response. These collectively are termed distributed energy resources because they impact the loads at the customer level, as opposed to traditional, centralized power supplies.

Energy Efficiency (EE)

National Grid has been running energy efficiency programs in its Rhode Island jurisdiction for a number of years and will continue to do so for the foreseeable future. In the short-term (one to three years) energy efficiency targets are based on approved company programs. Over the longer term the Company uses the ISO-NE projections for the state. The ISO-NE EE projections account for state policies, company programs and other market factors.

Figure 3 shows the expected loads and energy efficiency program reductions to NECO peaks by year. As of 2018, it is estimated that these EE programs have reduced loads by 308 MW than if there were no programs run. By 2033, it is expected that this reduction will grow to 646 MW or 27.0% of what load would have been had these programs not been implemented. Over the fifteen year planning horizon these reductions lower annual growth from 0.9% to -0.1% per year.

Figure 3



Distributed Generation (Solar – Behind-the-meter[4] PV)

There has been a rapid increase in the adoption of solar[5] throughout the state. The Company tracks historical PV and that becomes the basis of the historical values shown. The projection for the future is based on the Company's pro-rata share by load of PV in each zone that the ISO-NE shows in its annual load & capacity report[6]. The ISO-NE considers current PV and policy goals for the future. Since the Company does not have its own territory wide PV programs as it does with energy efficiency this approach ensures consistency with the statewide and area specific projections of the ISO. In the short-term (one to two years) the company reviews the quantity of applications already in the 'queue' to make sure the projections based on the share of ISO estimates are reasonable.

Figure 3 above shows the expected NECO loads and solar reductions to peaks by year. As of 2018, it is estimated that this technology may have already reduced system peak loads by 8 MW. By 2033 it is expected that these reductions may grow to 78 MW[7], or 3.3% of what load would have been had this technology not been installed. Over the fifteen year planning horizon these reductions lower annual growth from 0.9% to 0.7% per year.

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[4] This discussion is limited to "Behind-the-(customer) meter PV which is that expected to reduce loads, and would not include those PV installations considered as 'supply' by the ISO-NE.

[5] The Company limits this discussion to the impacts of solar distributed generation because it is the single largest contributor and the fastest growing of all distributed generation technologies at this time.

[6] 2018 Capacity, Energy, Load & Transmission Report, a report by the New England Independent System Operator, Inc., "CELT", dated May 2018.

[7] These are Company system summer peak impacts; these are approximately 21% of connected PV MWs.

The prevalence of the EE and PV and their continued expansion clearly show how loads have been significantly lowered due to their success.

Electric Vehicles

Over the longer-term, the forecast results are further adjusted for the penetration of plug-in electric vehicles (PEVs). Electric vehicles of interest are those that "plug-in" to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in 'battery-only' electric vehicles" (BEVs). These two types are those that could have potential impacts on the electric network.

National Grid has developed estimates for several scenarios covering a mix of different levels of future adoption of PEVs. These scenarios generally range low to higher levels of adoption. These scenarios include:

- Annual Energy Outlook (AEO) Low: This scenario uses information from the Department of Energy's 2018 AEO8 report to determine a scenario for PEVs in National Grid's share of the state's in which its service territory spans, mainly Massachusetts, Rhode Island and New York. The "low" scenario is selected as AEO "Reference" case.

- Annual Energy Outlook (AEO) High: This scenario similarly uses information from 2018 AEO report. For the "high" scenario, the AEO "High Oil (price)" case was used. While this case is not a high PEV case per se, it does have the highest penetration of PEVs versus the other AEO cases.

- Percent of New Registrations: This scenario uses the historical adoption rate of "non plug-in hybrid electric vehicles" (NPHEVs) as a proxy for how the plug-in electric vehicle adoption might behave. This scenario is determined as a function of new PEV registrations each year as a percent of all new vehicle registrations[9]. NPHEVs have been in the market for over ten years and have a record of adoption over that time frame. This scenario assumes that PEVs, which have not until recently begun to be widely adopted in the marketplace, may behave similarly to that of NPHEVs. This scenario is considered the **Base Case**.

- Zero Emissions Vehicles (ZEVs) target: This scenario assumes that PEV adoption meets the ZEV targets of about 45,000[10] in Rhode Island by the year 2025. National

[8] 2018 Annual Energy Outlook (AEO) report, U.S. Energy Information Administration (EIA), Department of Energy (DOE).

[9] National Grid has a contract with R.L. POLK and Company (IHS Automotive), a Company which is a leader in compiling electric vehicle registration information. It also contracts with Moody's Analytics, a leader in compiling economic and demographic information including motor vehicle registrations and future projections.

[10] Based on share of population for RI vs. total multi-state ZEV targets of 3.3 million by 2025.

Grid is assumed to garner a share of those goals as a function of its current share of PEVs in its service territory as a percent PEVs in the entire state. Current levels of PEVs are ramped up between now and the year 2025 to achieve those shares.

In Rhode Island, basecase PEV adoption may result in increased sales of about 3 MW, or 0.1% by 2033. PEV volumes grow to over 9,500 over the fifteen year planning horizon, or by 2033, for the Base Case. **Figure 3** above includes the EV projections.

Explicit impacts to system peaks have been made for these energy efficiency, solar PV and electric vehicle projections.

Demand Response

Demand Response (or "DR") are programs that actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These are in contrast to the more passive energy efficiency savings discussed above that provide savings throughout the year. The DR programs enable utilities and operating areas, such as the New England Independent System Operator (ISO-NE) to take action in response to a system reliability concern or economic (pricing) signal. During these events customers can actively participate by either cutting their load or by turning on a generator to displace load from behind the customer's meter.

The ISO-NE has been implementing these type programs for a number of years now and for the purposes of this report are referred to as "wholesale DR". These programs have been activated several times over the last decade (they have not been activated since 2016). The Company's policy has been to add-back reductions from these call-outs to its reported system peak numbers. This is because the Company is not in control of the call-out days nor times and thus there is no guarantee that these ISO –NE call-outs would be at the times of Company peaks. Therefore, the Company recognizes their existence, but must plan in the event that they are not called.

Table 1 shows the estimated reductions* for the historical call-outs on the peak days.

Table 1

DATE	HOUR	NEMA	SEMA	WCMA	RI
11-Aug-2016	16	4.9	5.4	16.7	10.4
11-Aug-2016	17	4.9	4.9	17.1	10.0
11-Aug-2016	18	4.5	3.7	15.9	8.8
11-Aug-2016	19	3.7	3.5	15.5	8.5
19-Jul-2013	14	4.6	6.0	13.5	9.8
19-Jul-2013	15	5.2	6.0	14.0	11.7
19-Jul-2013	16	4.4	5.1	13.5	8.8
19-Jul-2013	17	4.4	4.2	12.3	9.8
19-Jul-2013	18	4.2	3.2	12.3	7.8
19-Jul-2013	19	4.0	3.7	10.1	5.9
19-Jul-2013	20	3.8	3.7	8.4	5.9
22-Jul-2011	13	9.3	12.9	16.3	24.8
22-Jul-2011	14	13.3	18.3	23.2	35.2
22-Jul-2011	15	15.1	20.7	26.3	39.9
22-Jul-2011	16	14.8	20.4	25.8	39.2
22-Jul-2011	17	14.2	19.6	24.8	37.7
22-Jul-2011	18	13.1	18.0	22.8	34.7
02-Aug-2006	13	1.0	7.0	13.5	36.1
02-Aug-2006	14	1.0	7.0	13.5	36.1
02-Aug-2006	15	1.0	7.0	13.5	36.1
02-Aug-2006	16	1.0	7.0	13.5	36.1
02-Aug-2006	17	1.0	7.0	13.5	36.1
02-Aug-2006	18	1.0	7.0	13.5	36.1
01-Aug-2006	16	0.2	1.1	2.2	5.8
01-Aug-2006	17	0.2	1.1	2.2	5.8
01-Aug-2006	18	0.2	1.1	2.2	5.8
01-Aug-2006	19	0.2	1.1	2.2	5.8
01-Aug-2006	20	0.2	1.1	2.2	5.8

*It should be noted that the absolute MW do not always translate into one-to-one reductions to the peak depending on the timing of DR call-outs and pre-DR metered loads.

The Company recently began a DR program at the 'retail', or customer level. In contrast to the wholesale level DR programs implemented by the ISO-NE, these programs would be activated by the Company. Committed amounts for the 2018 program in RI were about 10 MWs. The program was called on a number of days this summer (July 3rd and 5th, August 6th, 7th 28th and 29th and September 5th). The evaluated results from these call-outs will be analyzed and a decision on how to handle these retail DRs during the next planning cycle will be made. An important consideration will be the achieved vs. committed reductions, the timing of call-out days vs. actual peak days and long-term commitments to these programs. Since planning decisions for reliability purposes are based on achievable, longer term reductions, these are important considerations for network strategy & planning.

Weather Assumptions

Weather data is collected from the relevant weather stations located within the Company's New England service territory and used to weather-adjust peak demands. The relevant weather station for Rhode Island is Providence.

The weather variables used in the model include heating degree days for the colder winter months and temperature – humidity indexes (THIs)[11] for the warmer summer months. These weather variables are correlated to the actual days that each peak occurs in each season over the historical period. Summer THI uses a weighted three day index (WTHI)[12] to capture the effects of prolonged heat waves that drive summer peaks.

Weather adjusted peaks are derived for "normal (50/50)" average weather, "90/10 (1 in 10)" extreme weather and "95/5 (1 in 20)" extreme weather. Extreme weather scenarios are determined using a "probabilistic" approach that employs "Z-values" and standard deviations (i.e. the more variable the weather has been on peak days over the historical period, the higher the 90/10 and 95/5 levels will be versus the average).

- Normal "50/50" weather is the average weather on the past 20 seasonal peak days.
- Extreme "90/10" weather is such that it is expected that 90% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a ten year period.
- Extreme "95/5" weather is such that it is expected that 95% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a twenty year period.

These "normals" and "extremes" are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Peak Day 24 Hourly Curves (before and after DERs)

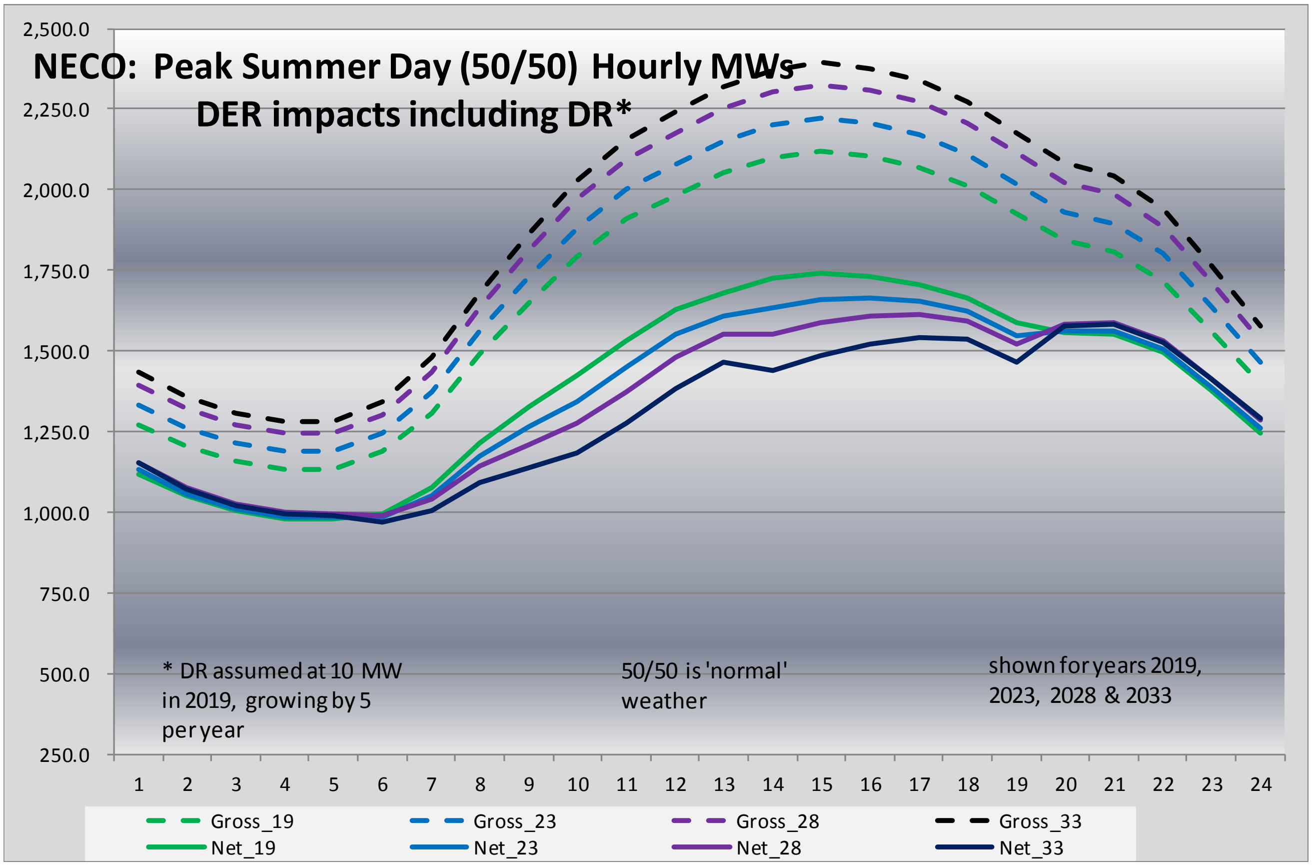
There are several initiatives proposed under the state's Power Sector Transformation (PST) proceeding that may impact customer loads, DERs and network planning. The company is aware of these and will monitor the progress of this proceeding and make appropriate changes to this forecast as appropriate. One of the initial changes to this annual planning report is the inclusion of estimated impacts due to DERs on an hourly basis on the peak day. This will allow the Company to look beyond the traditional approach of predicting the 'single' highest summer system peak each year. The process now looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as

[11] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.
[12] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior

more DERs are added. For example, as more and more solar PV is placed on the system, the concept is that the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off.

Figure 4 shows the impact of the “24 hour” PEAK day perspective for selected peak summer days over the planning horizon.

Figure 4

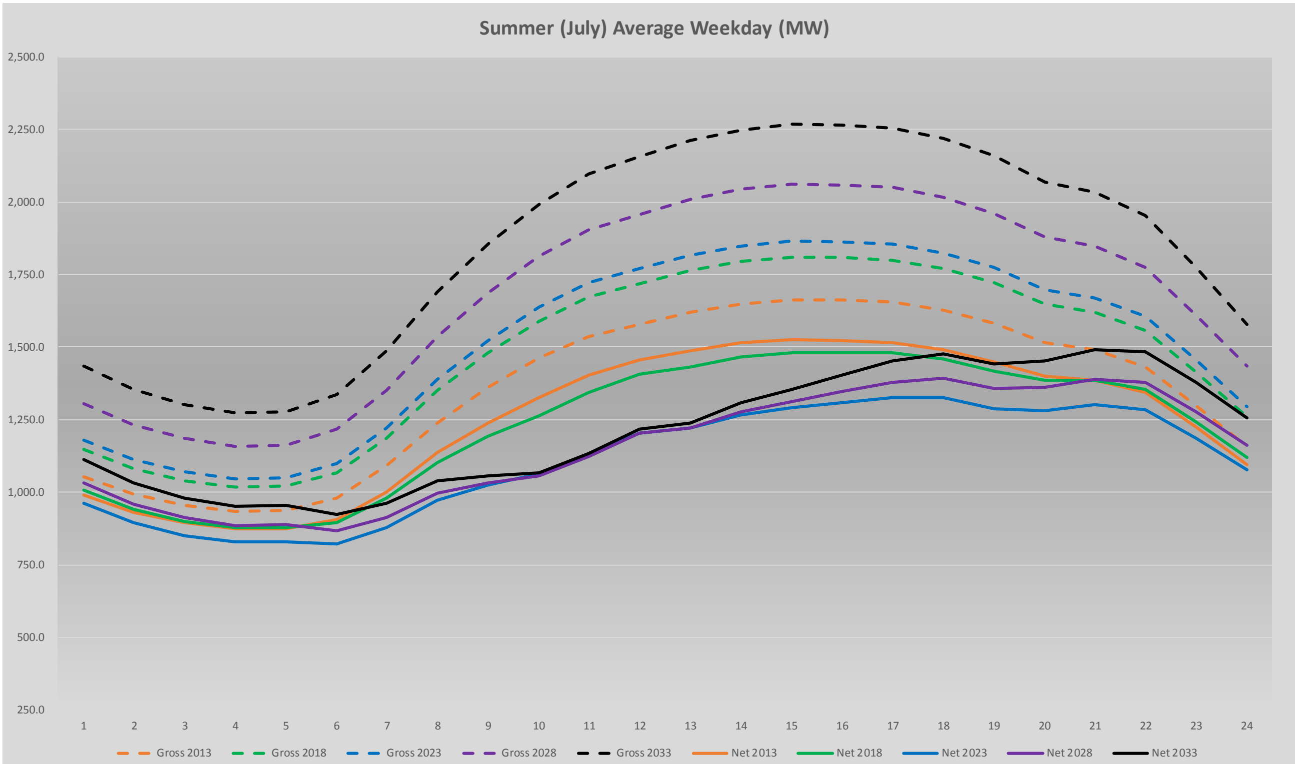


In this figure, it clearly shows how the expected DERs not only lower the loads, but also shift the hour of the peaks. In this figure, the hour of the peak begins at hour-ending 17 in year 2019 but shifts to hour-ending 21 by the year 2033. This shows how PV and DR can shift the peak away from the typical afternoon hours to late evening. EV charging can further add to evening and possibly even later peaks.

“Gross” refers to before any DER impacts and “Net’ refers to load after DER. The numbers refer to years 2019, 2023, 2028 and 2033, respectively.

Figure 5 shows the impact of the “24 hour” AVERAGE summer weekday perspective for selected peak summer days over the planning horizon.

Figure 5



In this figure, it shows similar hourly patterns to the peak days, however at lesser MW levels because this displays an average summer day vs. the less frequent peak weather producing days. Also, on an average day, it is not expected that DR would be implemented.

Appendix D contains additional load shapes for other days types including winter and shoulder month average weekdays and summer, winter and shoulder month weekend days. These show the varying seasonal patterns as well as the lower load shoulder months which for the most part show baseloaded energy use with minimal impacts of cooling or heating. Weekend loads patterns also provide a view on lower loads due to the lesser impacts of weekday business use.

[These values and graphs are shown for ***informational purposes only*** at this time and have **not** been explicitly included in the peak forecasts in the rest of this document].

Appendix A: Forecast Details

NARRAGANSETT ELECTRIC COMPANY (NECO)

NECO
SUMMER (Independent) Peaks — **AFTER Solar, Energy Efficiency & Electric Vehicle Impacts**

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2003	1,670		1,806		1,954		1,996		80.1
2004	1,628	-2.5%	1,842	2.0%	1,997	2.2%	2,041	2.3%	78.5
2005	1,805	10.8%	1,775	-3.6%	1,930	-3.4%	1,973	-3.3%	83.1
2006	1,985	10.0%	1,806	1.8%	1,945	0.8%	1,983	0.5%	85.9
2007	1,777	-10.5%	1,855	2.7%	2,011	3.4%	2,055	3.6%	80.9
2008	1,824	2.6%	1,820	-1.9%	1,969	-2.1%	2,011	-2.1%	82.9
2009	1,713	-6.1%	1,820	0.0%	1,993	1.2%	2,041	1.5%	80.3
2010	1,872	9.3%	1,802	-1.0%	1,973	-1.0%	2,021	-1.0%	84.5
2011	1,974	5.5%	1,821	1.1%	1,990	0.9%	2,038	0.8%	84.8
2012	1,892	-4.2%	1,826	0.3%	1,981	-0.4%	2,026	-0.6%	83.5
2013	1,965	3.9%	1,821	-0.2%	1,990	0.4%	2,038	0.6%	84.7
2014	1,653	-15.9%	1,814	-0.4%	1,985	-0.2%	2,034	-0.2%	80.4
2015	1,738	5.1%	1,854	2.2%	2,040	2.8%	2,093	2.9%	80.4
2016	1,803	3.8%	1,782	-3.9%	1,951	-4.4%	2,000	-4.5%	82.6
2017	1,688	-6.4%	1,727	-3.1%	1,897	-2.8%	1,946	-2.7%	81.7
2018	1,845	9.3%	1,774	2.7%	1,945	2.5%	1,994	2.5%	83.4
2019	-	-	1,764	-0.5%	1,939	-0.3%	1,989	-0.3%	-
2020	-	-	1,755	-0.5%	1,932	-0.3%	1,983	-0.3%	-
2021	-	-	1,745	-0.6%	1,925	-0.4%	1,976	-0.3%	-
2022	-	-	1,738	-0.4%	1,921	-0.2%	1,973	-0.1%	-
2023	-	-	1,732	-0.3%	1,918	-0.2%	1,970	-0.1%	-
2024	-	-	1,729	-0.2%	1,917	-0.1%	1,970	0.0%	-
2025	-	-	1,727	-0.1%	1,917	0.0%	1,971	0.1%	-
2026	-	-	1,726	-0.1%	1,918	0.1%	1,973	0.1%	-
2027	-	-	1,722	-0.2%	1,917	-0.1%	1,972	-0.1%	-
2028	-	-	1,717	-0.3%	1,913	-0.2%	1,969	-0.2%	-
2029	-	-	1,710	-0.4%	1,908	-0.3%	1,964	-0.2%	-
2030	-	-	1,703	-0.4%	1,902	-0.3%	1,959	-0.3%	-
2031	-	-	1,694	-0.5%	1,894	-0.4%	1,952	-0.4%	-
2032	-	-	1,684	-0.6%	1,886	-0.5%	1,943	-0.4%	-
2033	-	-	1,673	-0.7%	1,876	-0.5%	1,934	-0.5%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Compound Avg. 15 yr ('03 to '18)	-0.1%	0.0%	0.0%
Compound Avg. 10 yr ('08 to '18)	-0.3%	-0.1%	-0.1%
Compound Avg. 5 yr ('13 to '18)	-0.5%	-0.5%	-0.4%
Compound Avg. 5 yr ('18 to '23)	-0.5%	-0.3%	-0.2%
Compound Avg. 10 yr ('18 to '28)	-0.3%	-0.2%	-0.1%
Compound Avg. 15 yr ('18 to '33)	-0.4%	-0.2%	-0.2%

WTHI

NORMAL	82.3
EXTREME 90/ 10	85.1
EXTREME 95/ 5	85.8

NECO	**SUMMER Independent 50/50 Peaks (MW) (before & after DERs)**										
	------------- SYSTEM PEAK (50/50) -------------					------------ DER IMPACTS ----------			EE % of	PV % of	EV % of
Calendar Year	Reconstituted (before reductions)	Final Forecast w/ EE Reduction only	Final Forecast w/ PV Reduction only	Final Forecast w/ EV Reduction only	Final Forecast (after all reductions)	EE Reduction Forecast	PV Reduction Forecast	EV Increase Forecast	'Reconstituted' Deliveries	'Reconstituted' Deliveries	'Reconstituted' Deliveries
2003	1,816	1,806	1,816	1,816	**1,806**	9	0	0.0	0.5%	0.0%	0.00%
2004	1,863	1,842	1,863	1,863	**1,842**	21	0	0.0	1.1%	0.0%	0.00%
2005	1,806	1,775	1,806	1,806	**1,775**	30	0	0.0	1.7%	0.0%	0.00%
2006	1,847	1,806	1,847	1,847	**1,806**	41	0	0.0	2.2%	0.0%	0.00%
2007	1,906	1,855	1,906	1,906	**1,855**	51	0	0.0	2.7%	0.0%	0.00%
2008	1,881	1,820	1,881	1,881	**1,820**	61	0	0.0	3.3%	0.0%	0.00%
2009	1,897	1,820	1,897	1,897	**1,820**	77	0	0.0	4.0%	0.0%	0.00%
2010	1,891	1,802	1,891	1,891	**1,802**	89	0	0.0	4.7%	0.0%	0.00%
2011	1,923	1,821	1,923	1,923	**1,821**	102	0	0.0	5.3%	0.0%	0.00%
2012	1,947	1,826	1,947	1,947	**1,826**	121	0	0.0	6.2%	0.0%	0.00%
2013	1,970	1,822	1,969	1,970	**1,821**	148	1	0.0	7.5%	0.0%	0.00%
2014	2,002	1,815	2,001	2,002	**1,814**	187	1	0.0	9.3%	0.0%	0.00%
2015	2,076	1,856	2,074	2,076	**1,854**	220	1	0.1	10.6%	0.1%	0.01%
2016	2,035	1,785	2,032	2,036	**1,782**	250	4	0.1	12.3%	0.2%	0.01%
2017	2,013	1,733	2,007	2,013	**1,727**	280	7	0.2	13.9%	0.3%	0.01%
2018	2,089	1,782	2,081	2,089	**1,774**	308	8	0.3	14.7%	0.4%	0.02%
2019	2,119	1,778	2,106	2,120	**1,764**	342	14	0.5	16.1%	0.6%	0.02%
2020	2,147	1,773	2,128	2,148	**1,755**	374	19	0.7	17.4%	0.9%	0.03%
2021	2,171	1,768	2,148	2,172	**1,745**	404	24	1.0	18.6%	1.1%	0.04%
2022	2,197	1,766	2,169	2,199	**1,738**	432	29	1.2	19.6%	1.3%	0.05%
2023	2,222	1,764	2,189	2,223	**1,732**	458	33	1.4	20.6%	1.5%	0.06%
2024	2,246	1,765	2,208	2,248	**1,729**	481	38	1.6	21.4%	1.7%	0.07%
2025	2,269	1,768	2,227	2,271	**1,727**	502	43	1.8	22.1%	1.9%	0.08%
2026	2,291	1,771	2,243	2,293	**1,726**	520	47	2.0	22.7%	2.1%	0.09%
2027	2,309	1,772	2,258	2,312	**1,722**	538	52	2.2	23.3%	2.2%	0.10%
2028	2,326	1,771	2,270	2,329	**1,717**	556	56	2.4	23.9%	2.4%	0.10%
2029	2,342	1,768	2,281	2,344	**1,710**	574	60	2.5	24.5%	2.6%	0.11%
2030	2,357	1,765	2,292	2,359	**1,703**	592	65	2.5	25.1%	2.8%	0.11%
2031	2,370	1,761	2,301	2,373	**1,694**	610	69	2.5	25.7%	2.9%	0.11%
2032	2,383	1,755	2,309	2,385	**1,684**	628	74	2.6	26.3%	3.1%	0.11%
2033	2,394	1,748	2,316	2,396	**1,673**	646	78	2.6	27.0%	3.3%	0.11%

Compound Avg. 15 yr ('03	0.9%	-0.1%	0.9%	0.9%	**-0.1%**
Compound Avg. 10 yr ('08	1.1%	-0.2%	1.0%	1.1%	**-0.3%**
Compound Avg. 5 yr ('13	1.2%	-0.4%	1.1%	1.2%	**-0.5%**
Compound Avg. 5 yr ('18	1.2%	-0.2%	1.0%	1.3%	**-0.5%**
Compound Avg. 10 yr ('18	1.1%	-0.1%	0.9%	1.1%	**-0.3%**
Compound Avg. 15 yr ('18	0.9%	-0.1%	0.7%	0.9%	**-0.4%**

NECO

WINTER (Independent) Peaks

AFTER Energy Efficiency & Electric Vehicle Impacts

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2003	1,389		1,316		1,375		1,391		55.7
2004	1,394	0.4%	1,426	8.3%	1,477	7.5%	1,492	7.2%	36.7
2005	1,329	-4.6%	1,322	-7.3%	1,369	-7.3%	1,383	-7.3%	45.0
2006	1,329	0.0%	1,315	-0.5%	1,363	-0.5%	1,376	-0.5%	45.5
2007	1,352	1.7%	1,325	0.8%	1,372	0.7%	1,385	0.6%	44.8
2008	1,305	-3.5%	1,314	-0.8%	1,365	-0.5%	1,379	-0.4%	40.0
2009	1,294	-0.8%	1,326	0.9%	1,379	1.0%	1,394	1.1%	35.0
2010	1,315	1.6%	1,263	-4.8%	1,320	-4.3%	1,336	-4.2%	53.1
2011	1,243	-5.5%	1,248	-1.1%	1,302	-1.4%	1,317	-1.4%	41.6
2012	1,320	6.2%	1,287	3.1%	1,341	3.0%	1,356	3.0%	51.9
2013	1,328	0.7%	1,321	2.6%	1,375	2.6%	1,391	2.6%	43.9
2014	1,275	-4.0%	1,227	-7.1%	1,284	-6.6%	1,301	-6.5%	52.2
2015	1,223	-4.1%	1,198	-2.3%	1,248	-2.8%	1,263	-2.9%	55.0
2016	1,239	1.3%	1,275	6.4%	1,336	7.0%	1,353	7.2%	35.9
2017	1,277		1,202	-5.7%	1,279	-4.3%	1,300	-3.9%	53.8
2018	-		1,186	-1.4%	1,256	-1.7%	1,276	-1.8%	-
2019	-		1,169	-1.4%	1,243	-1.1%	1,264	-1.0%	-
2020	-		1,147	-1.9%	1,222	-1.6%	1,244	-1.6%	-
2021	-		1,129	-1.6%	1,206	-1.3%	1,228	-1.2%	-
2022	-		1,125	-0.4%	1,206	0.0%	1,229	0.1%	-
2023	-		1,117	-0.7%	1,201	-0.4%	1,225	-0.3%	-
2024	-		1,114	-0.3%	1,202	0.0%	1,227	0.1%	-
2025	-		1,112	-0.1%	1,203	0.1%	1,229	0.2%	-
2026	-		1,112	0.0%	1,206	0.2%	1,232	0.3%	-
2027	-		1,117	0.5%	1,215	0.8%	1,243	0.9%	-
2028	-		1,128	1.0%	1,231	1.3%	1,260	1.3%	-
2029	-		1,133	0.5%	1,240	0.7%	1,270	0.8%	-
2030	-		1,140	0.6%	1,251	0.9%	1,282	0.9%	-
2031	-		1,147	0.6%	1,261	0.8%	1,293	0.9%	-
2032	-		1,154	0.6%	1,272	0.9%	1,306	1.0%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Compound Avg. 15 yr ('02 to '17)	#VALUE!	#VALUE!	#VALUE!
Compound Avg. 10 yr ('07 to '17)	-1.0%	-0.7%	-0.6%
Compound Avg. 5 yr ('12 to '17)	-1.4%	-0.9%	-0.8%
Compound Avg. 5 yr ('17 to '22)	-1.3%	-1.2%	-1.1%
Compound Avg. 10 yr ('17 to '27)	-0.7%	-0.5%	-0.4%
Compound Avg. 15 yr ('17 to '32)	-0.3%	0.0%	0.0%

HDD_wtd

NORMAL	43.3
EXTREME 90/10	54.0
EXTREME 95/5	57.0

Appendix B: POWER SUPPLY AREAS (PSAs)

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer)								after EE, PV and EV impacts					
			2018 Weather-Adjustments (2)				Annual Growth Rates (percents) (3)				5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2019	2020	2021	2022	2023	'19 to '23	'24 to '28	'29 to '33
RI	Blackstone Valley	RI	96.1%	105.4%	108.0%	(0.8)	(0.8)	(0.7)	(0.5)	(0.5)	(0.6)	(0.2)	(0.5)
RI	Newport	RI	96.1%	105.4%	108.0%	(0.4)	(0.4)	(0.5)	(0.3)	(0.3)	(0.4)	(0.1)	(0.4)
RI	Providence	RI	96.1%	105.4%	108.0%	(0.7)	(0.7)	(0.7)	(0.5)	(0.5)	(0.6)	(0.3)	(0.5)
RI	Western Narraganset	RI	96.1%	105.4%	108.0%	0.3	0.2	0.1	0.2	0.2	0.2	0.2	(0.2)

Year One Weather-Adjustment & Multi-Year Annual Growth (Summer)								after EE & EV impacts, but before PV reductions					
			2018 Weather-Adjustments (2)				Annual Growth Rates (percents) (3)				5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 90/10	for 95/5	2019	2020	2021	2022	2023	'19 to '23	'24 to '28	'29 to '33
RI	Blackstone Valley	RI	96.1%	105.4%	108.0%	(0.5)	(0.5)	(0.5)	(0.3)	(0.2)	(0.4)	(0.0)	(0.2)
RI	Newport	RI	96.1%	105.4%	108.0%	(0.1)	(0.2)	(0.2)	(0.0)	(0.0)	(0.1)	0.1	(0.2)
RI	Providence	RI	96.1%	105.4%	108.0%	(0.5)	(0.5)	(0.5)	(0.3)	(0.2)	(0.4)	(0.0)	(0.3)
RI	Western Narraganset	RI	96.1%	105.4%	108.0%	0.5	0.5	0.3	0.5	0.5	0.5	0.5	0.0

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (WINTER)								after EE and EV impacts					
			2017/18 Weather-Adjustments (2)				Annual Growth Rates (percents) (3)				5-yr avg	5-yr avg	5-yr avg
State	PSA	Zone (1)	for 50/50	for 10/90	for 05/95	2018	2019	2020	2021	2022	'18 to '22	'23 to '27	'28 to '32
RI	Blackstone Valley	RI	94.2%	100.1%	101.8%	(2.3)	(1.5)	(2.0)	(1.6)	(0.3)	(3.6)	(0.2)	0.8
RI	Newport	RI	94.2%	100.1%	101.8%	(1.9)	(1.1)	(1.7)	(1.4)	(0.0)	(1.8)	(0.0)	0.9
RI	Providence	RI	94.2%	100.1%	101.8%	(2.3)	(1.5)	(2.0)	(1.6)	(0.3)	(2.0)	(0.2)	0.8
RI	Western Narraganset	RI	94.2%	100.1%	101.8%	(1.3)	(0.5)	(1.1)	(0.8)	0.5	(1.2)	0.4	1.2

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current winter peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents can be applied to the current winter peaks to determine what the growth for each area is.

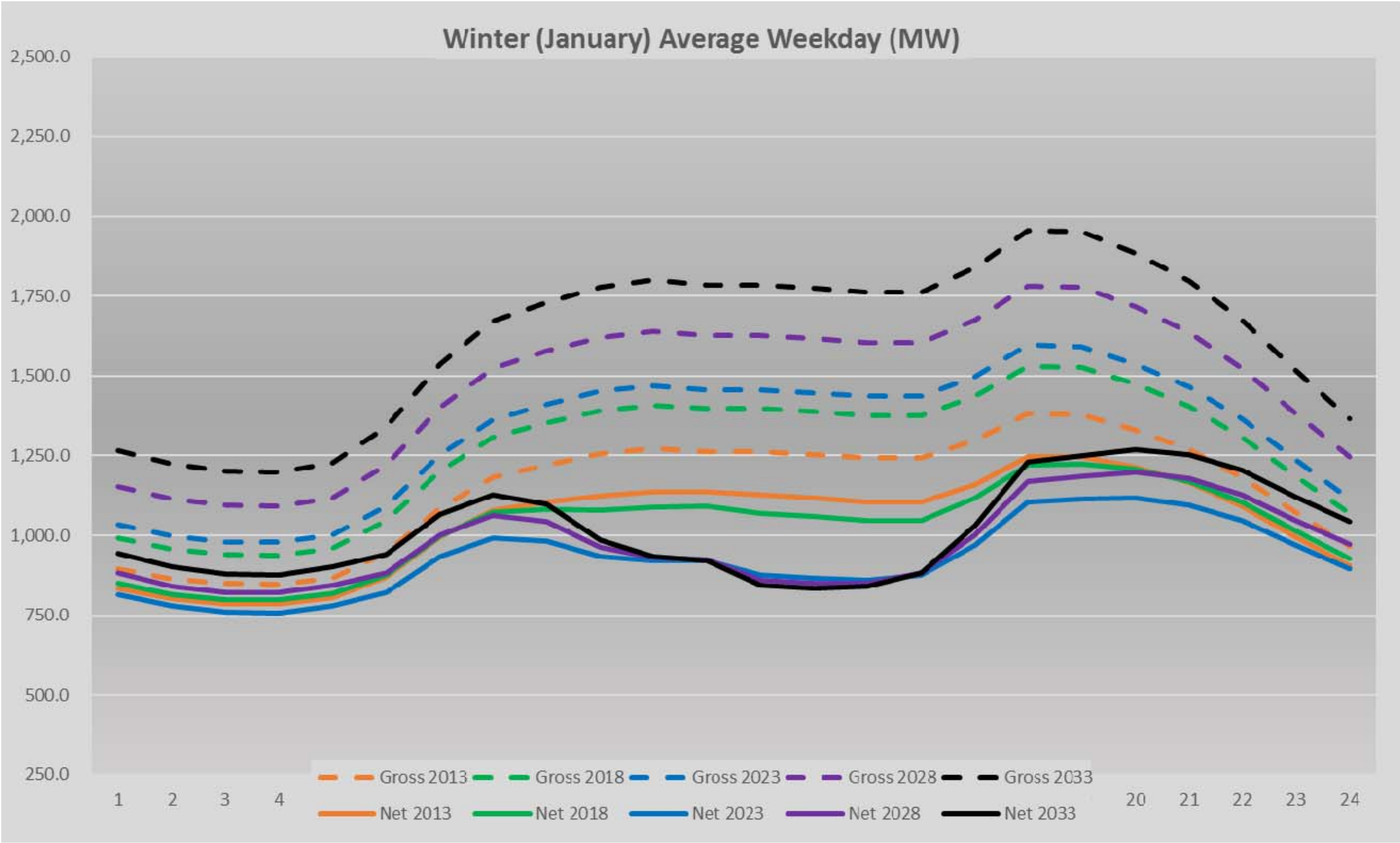
Appendix C: Historical Summer Peak Days and Hours

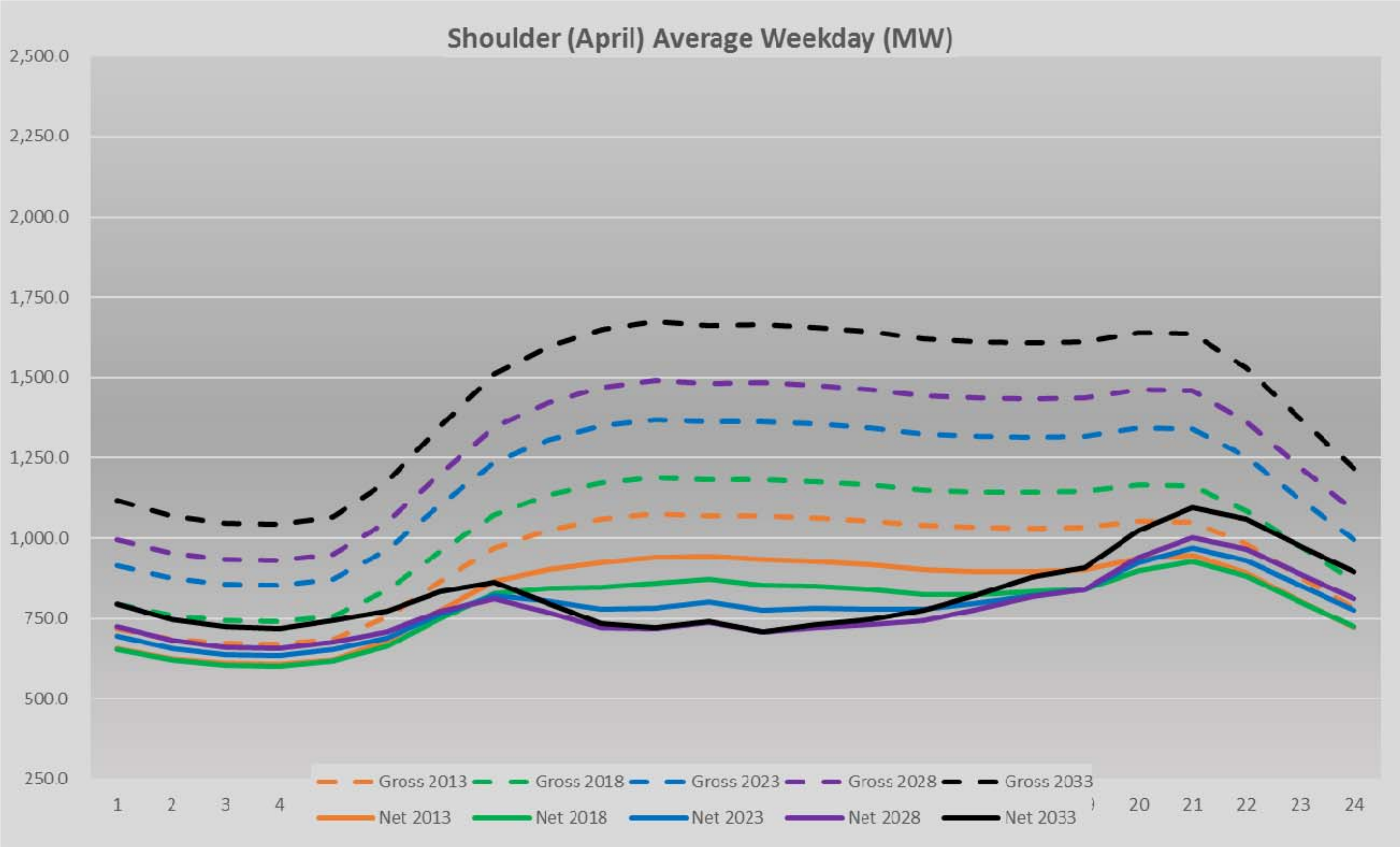
year	ri	dt_ri	hr_ri
2003	1,670.3	8/22/2003	15
2004	1,628.0	8/30/2004	15
2005	1,804.5	8/5/2005	15
2006	1,985.2	8/2/2006	15
2007	1,777.3	8/3/2007	15
2008	1,823.6	6/10/2008	15
2009	1,713.2	8/18/2009	15
2010	1,872.0	7/6/2010	15
2011	1,974.1	7/22/2011	16
2012	1,892.2	7/18/2012	15
2013	1,965.4	7/19/2013	15
2014	1,652.9	9/2/2014	16
2015	1,737.6	7/20/2015	15
2016	1,802.9	8/12/2016	16
2017	1,688.2	7/20/2017	16
2018	1,845.4	8/29/2018	17

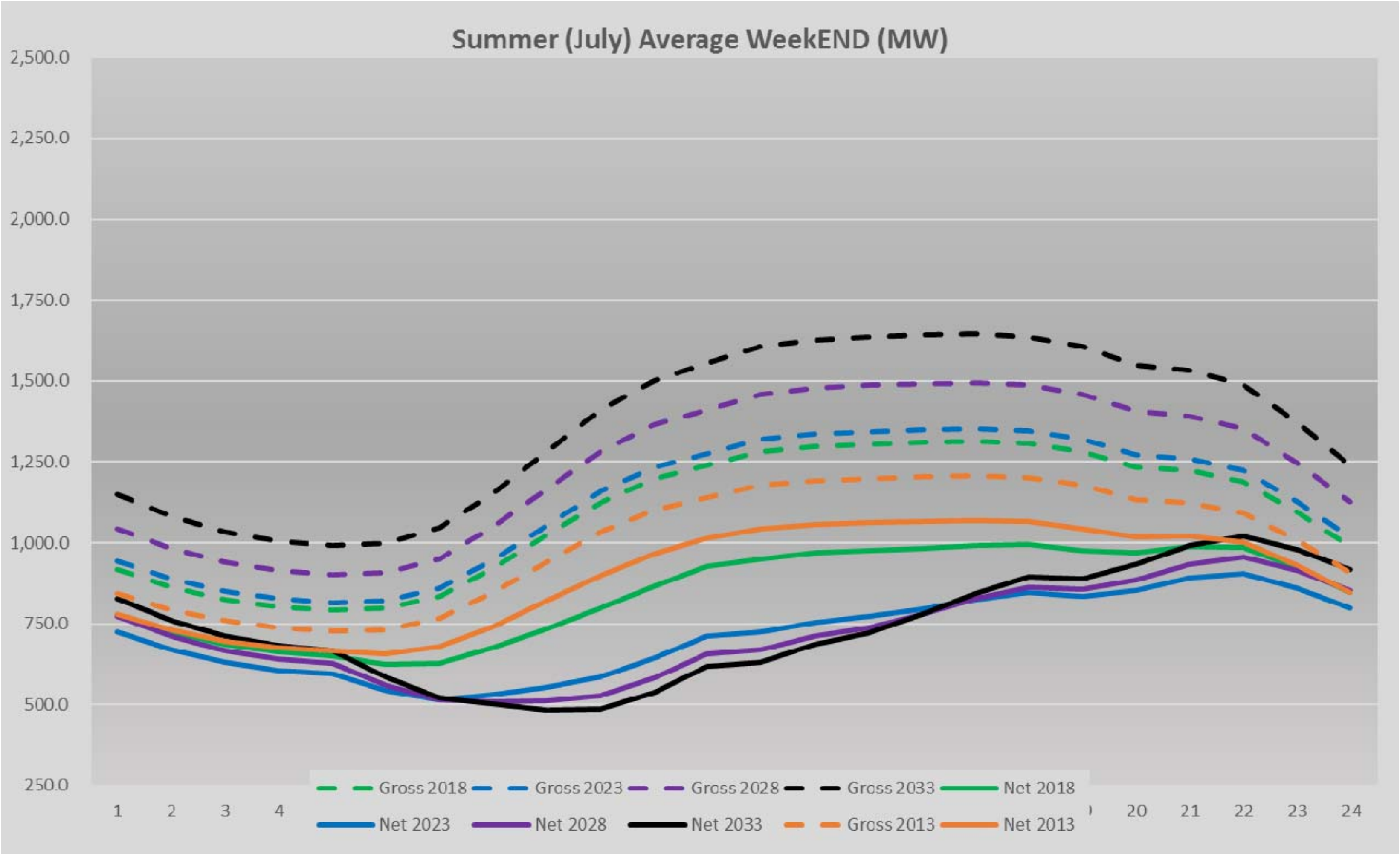
Appendix D

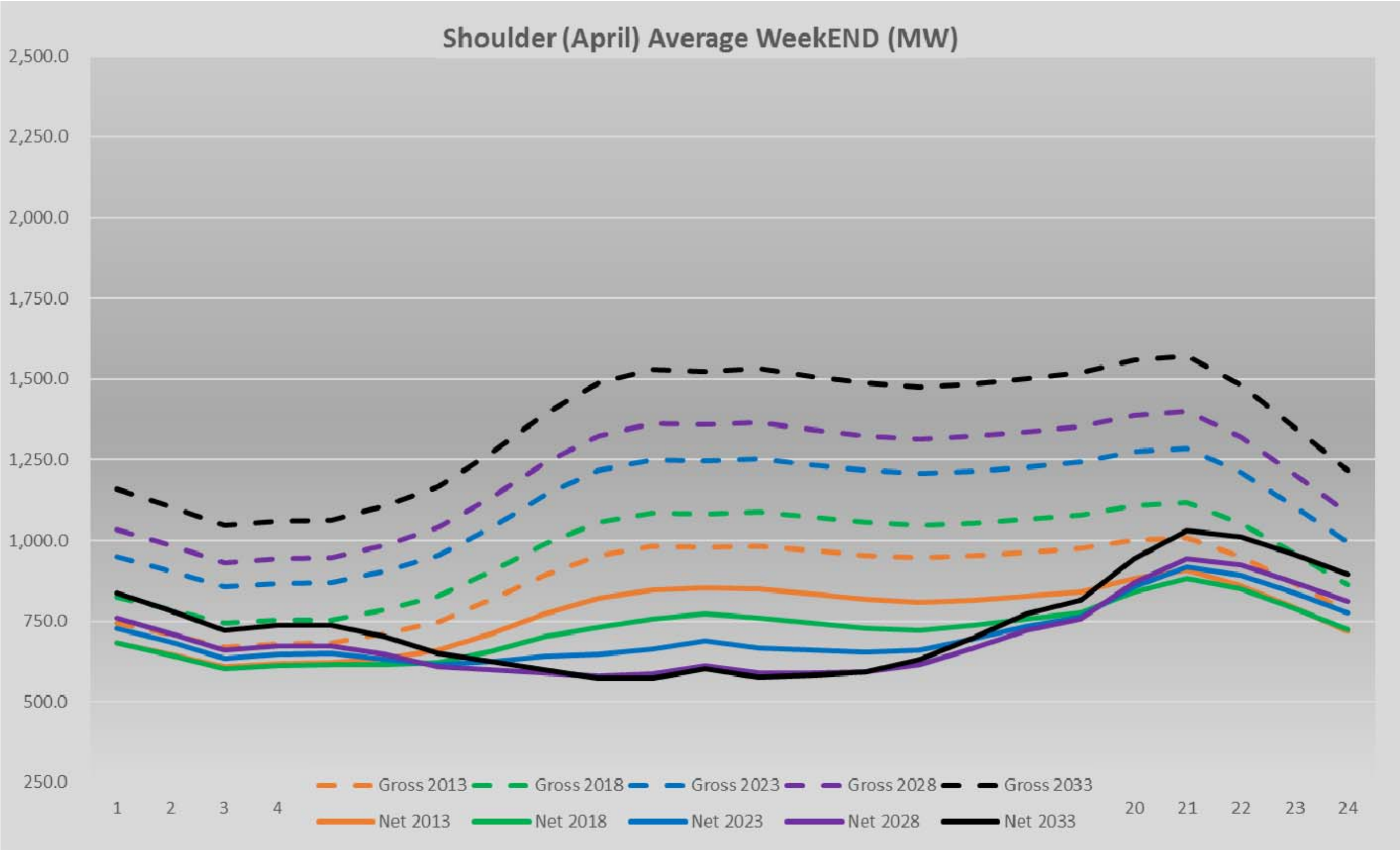
Load Shapes for Typical Day Types *

- Load shapes for peak and average summer days contained in body of report.


Winter (January) Average Weekday (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1 2 3 4 20 21 22 23 24
Gross 2013
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2013
Net 2018
Net 2023
Net 2028
Net 2033


Shoulder (April) Average Weekday (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1 2 3 4 20 21 22 23 24
Gross 2013
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2013
Net 2018
Net 2023
Net 2028
Net 2033


Summer (July) Average WeekEND (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1
2
3
4
20
21
22
23
24
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2018
Net 2023
Net 2028
Net 2033
Gross 2013
Net 2013


Shoulder (April) Average WeekEND (MW)
2,500.0
2,250.0
2,000.0
1,750.0
1,500.0
1,250.0
1,000.0
750.0
500.0
250.0
1
2
3
4
20
21
22
23
24
Gross 2013
Gross 2018
Gross 2023
Gross 2028
Gross 2033
Net 2013
Net 2018
Net 2023
Net 2028
Net 2033