Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application 15-04-012
Exhibit No.: SDG&E-03

PREPARED DIRECT TESTIMONY OF

ROBERT B. ANDERSON

~~CHAPTER 3~~

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 3

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

February 9~~December 1~~, 201~~5~~6

#301912

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PREPARED DIRECT TESTIMONY OF

ROBERT B. ANDERSON IN SUPPORT OF SECOND AMENDED APPLICATION

CHAPTER 3

I. PURPOSE AND OVERVIEW

The purpose of my testimony is to support a proposed change in the time-of-use ("TOU") periods of San Diego Gas & Electric Company ("SDG&E") as proposed by SDG&E witness Cynthia Fang. SDG&E's proposal reflects the need to respond to changes caused by the large increase in variable renewable generation, solar and wind, put in place over the last few years in the San Diego Greater Local Reliability area and in California. This change is expected to persist for the foreseeable future as California supports both a 50 percent Renewable Portfolio Standard as required by Senate Bill 350 and continued expansion of rooftop solar. The proposed changes to the TOU periods will help manage the integration of renewables by increasing demand in midday when solar is producing at its maximum and reducing demand later in the day when solar has reduced output or no output at all. As the California Independent System Operator ("CAISO") stated in a recent fact sheet:

> "The state policy has driven investment in several approaches to maximize use of the renewable resources and support greenhouse gas reduction goals. Among these mechanisms is price signals to consumers when there's surplus and constrained supplies, so they can make decisions on use based on cost…. Now, in this era of plentiful electricity from renewable sources, we need to alert customers not only to times when supply is constrained, but also when there is a surplus, to provide incentives to consumers to take advantage of low-cost electricity."[1]

[1] CAISO, "Matching Time-of-use Rate Periods with Grid Conditions Maximizes Use of Renewable Resources," June, 2015.

My testimony is organized as follows:

Section II. Net Load

"Net Load" reflects the electricity demand net of electricity supply from solar and wind resources. The change in the net load over the last several years, which is expected to continue, has created a need for dispatchable generation to ramp up on a daily basis from around 2 p.m.to the early evening hours as solar production drops off.[2] Current TOU periods do not reflect these changes in system conditions and system needs and instead create incentives for customers to reduce demand during periods with abundant solar resources and increase demand in the early evening hours, serving to unintentionally increase ramping needs.

The change in TOU periods SDG&E is proposing herein have been designed to better reflect the actual system conditions that exist today and which are anticipated to exist over the next five years (through 2021) in both San Diego and California in general. When implemented, the new TOU periods will create incentives for customers to shift demand from the early evening hours to mid-day. The analysis includes both historical and expected loads in the San Diego area net of expected solar and wind production in the San Diego Greater Reliability area.[3] In addition, net loads in California are changing as well. Historical data on loads and net loads in the CAISO area are also presented to show the net loads are changing for California as well as for SDG&E. More detailed analysis by the CAISO is presented in the Appendix to this testimony.

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[2] This ramping generation has been called "flexible capacity" in the resource adequacy proceeding. The need for load serving entities to acquire flexible capacity to maintain reliability during this ramping period has been ordered in D.14-06-050 and D.15-06-063.

[3] SDG&E has followed the CAISO analysis convention of only deducting variable renewable generation and did not remove other must-take or must-run resources.

The data in this section supports the change of the on-peak period to 4 p.m. to 9 p.m. on a daily basis to reduce ramping needs.

Section III. San Diego Local Area Prices

This section describes how the hourly price profile of energy prices in the San Diego area have changed over the last few years as renewable generation has been added. The highest price hours are now in the late afternoon and early evening on a daily basis year round. The data on hourly energy price profiles, as provided in this Section below, supports changing the SDG&E on-peak TOU period to 4 p.m. - 9 p.m. daily.

Section IV. Super Off-peak TOU Period

A super off-peak TOU period is proposed for all rate schedules as 12 a.m. to 6 a.m. weekdays, and 12 a.m. to 2 p.m. on weekends/holidays. During these time periods, the net load is expected to be low and prices are expected to be low, consistent with 2014 and 2015 data and forecasted net loads.

Section V. Relative Loss of Load Expectation

As new distributed solar generation lowers the demand in daylight hours and as new central station solar produces increased resource adequacy in daylight hours, the need for capacity in various hours throughout the day are expected to change. This section describes the modeling to forecast the 2016 hourly expectations of the needs for capacity.

Section VI. Statement of Qualifications: This section presents my qualifications.

II. NET LOAD

Because of California's drive to a low carbon economy and a preference for renewable technologies, the addition of solar and wind resources have had an impact on electricity net loads. These technologies produce electricity as nature provides. When these renewables produce energy, it is accepted by the grid regardless of need or price; hence, they are referred to as “must-take” resources.

The impact of solar in particular on the net load shape is noticeable in the historical data as shown below. The increase in net load as solar production declines requires significant ramping resources in the afternoon to meet peak net demand in the early evening. TOU periods to encourage reduction in customer demand in the evening hours and increase customer energy use midday can reduce the need for ramping resources.

Chart RBA-1 below shows that beginning 2014, current TOU periods, with incentives to shift load from summer afternoons (11 am to 6 pm or hours ending 12 to 18) to early evening hours (6 pm to 9 pm or hours ending 19 to 21), are no longer providing the right price signal and exacerbate the net load peak in the San Diego area. Adjustment of the TOU periods to encourage more customer electricity use in the midday hours when solar is producing at its maximum will occur by moving the weekday hours of 11 a.m. to 4 p.m. (hours ending 12 to 16) to off-peak. Shifting 6 p.m. to 9 p.m. (hours ending 19 to 21) to the on-peak TOU period will provide incentive to reduce use during the early evening peak, reducing the need for fossil resources to meet ramping needs.

SDG&E has also calculated the forecasted net peak for 2016 and 2021 based on currently signed renewable contracts.[4] Over 85% of the renewable energy in 2016 is from renewable projects that are producing power as of October 2015.[5]

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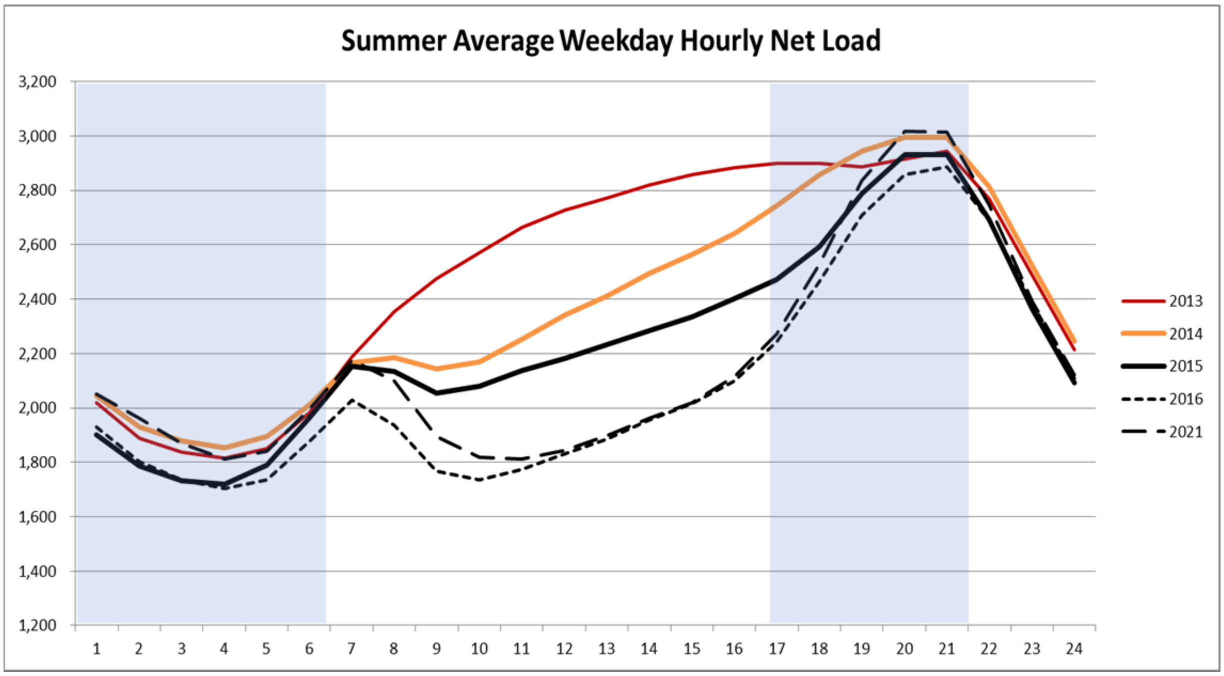
[4] Renewable energy data is recorded actual data for 2013, 2014, and 2015 through October. It is forecast data for November and December 2015 and for 2016 and 2021. SDG&E Load data is recorded actuals for 2013 and 2014 and forecasted loads for 2015, 2016, and 2021.

[5] Based on 1320 MW compared to the full amount of 1,544 in 2016. The 1320 MW figure does not include facilities producing “test energy” as of October 2015 (i.e., project built and producing energy prior to their online date).

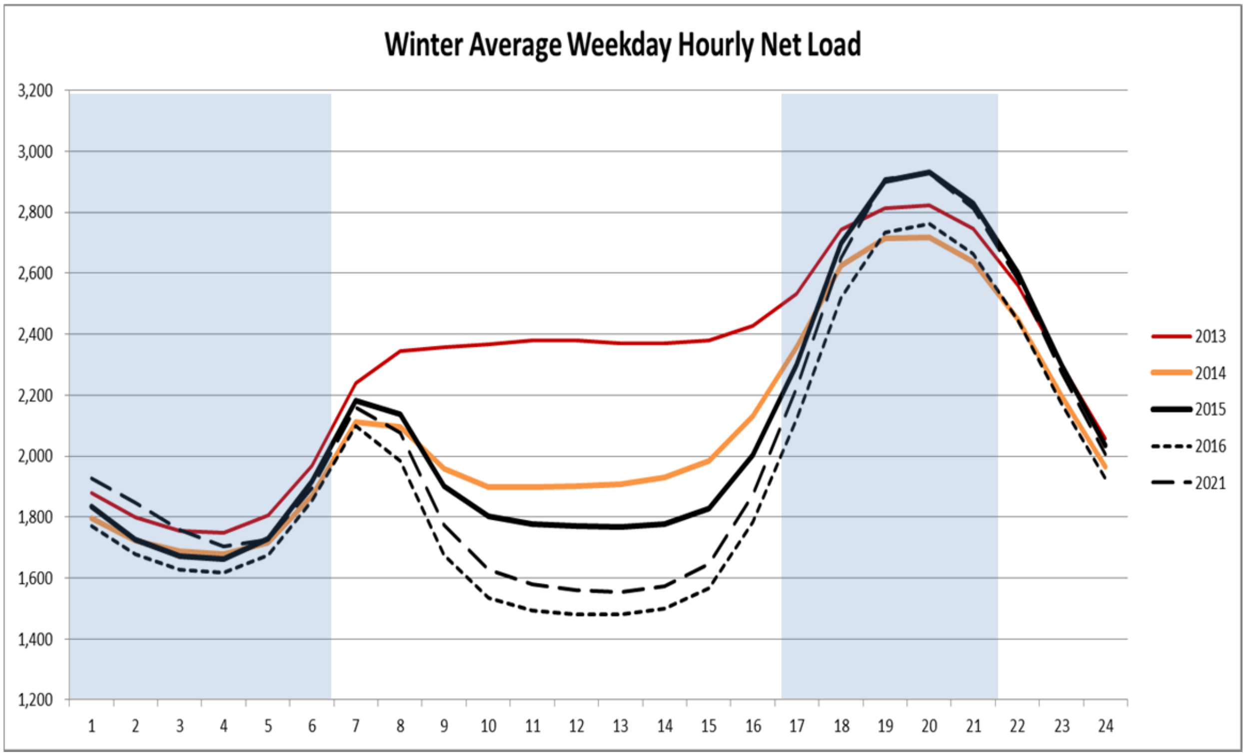
In 2016, it is forecast that on average net load will increase by more than 800 MWs from 2 p.m. to 9 p.m. (Hours ending 15 to 21) on summer weekdays and by more than 1,000 MWs on summer weekends.

Chart RBA-1. Summer Weekday Average Load for the SDG&E Local Area Net of Distributed Generation and Central Station Renewables



In winter months, the ramp up in net load is expected to be even more dramatic. In 2016, SDG&E forecasts that on average net load will increase by almost 1,300 MWs during the 6 hours from 2 p.m. to 8 p.m. (hours ending 15 to 20) on weekdays and by more than 1,400 MWs on weekends.

Chart RBA-2. Winter Weekday Average Load for the SDG&E Local Area Net of Distributed Generation and Central Station Renewables



Statewide, CAISO data shows a similar but less dramatic shift in the historical data. From 2012 to 2014, the amount of renewables have widened the gap between load and net load and have increased the amount of ramping needed as shown in charts RBA-3 and RBA-4.[6] As shown in CAISO forecasts for 2021 in the Appendix, the trend is expected to continue and will look more like the SDG&E net load charts by 2021.

[6] See, California Independent System Operator Corporation Explanation of Data, Assumptions and Analytical Methods, Assumptions, and Analytical Methods, https://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-R1512012.pdf; http://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-TOUPeriodBackup-R1512012.zip, submitted in~~The CAISO renewable data for 2014 is based on 1/1/2014 to 10/16/2014.data provided by the CAISO in the TOU Period OIR~~, R.15-12-012,~~ in~~ January, 22, 2016.

Chart RBA-3 CAISO Load and Net Loads for Summer Weekdays

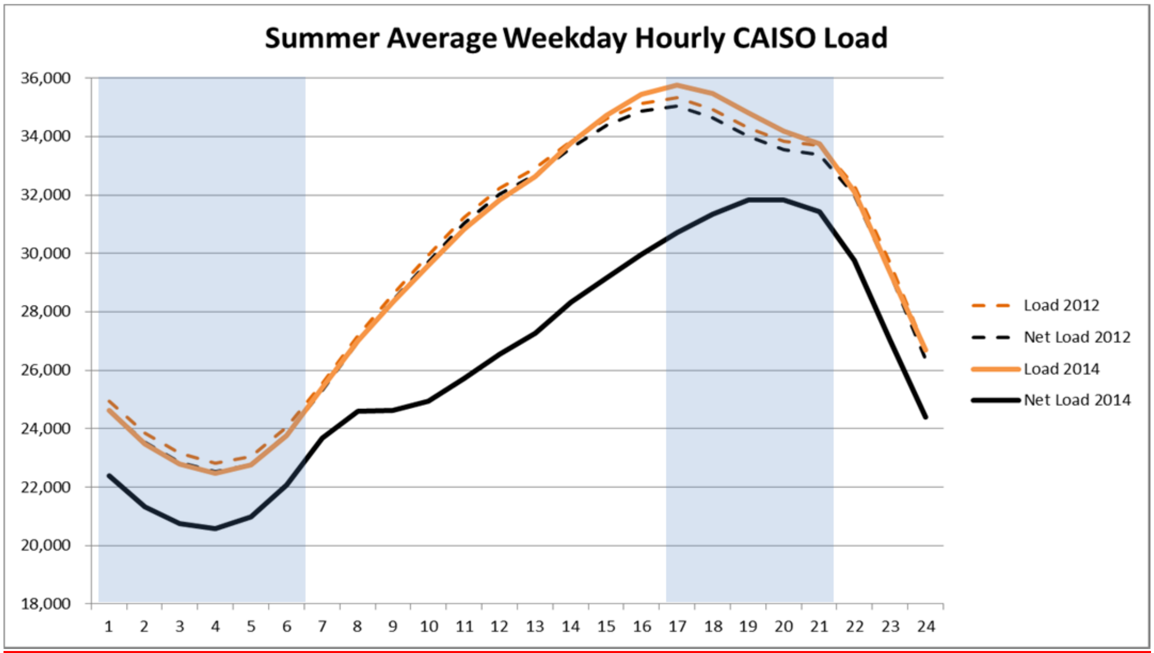
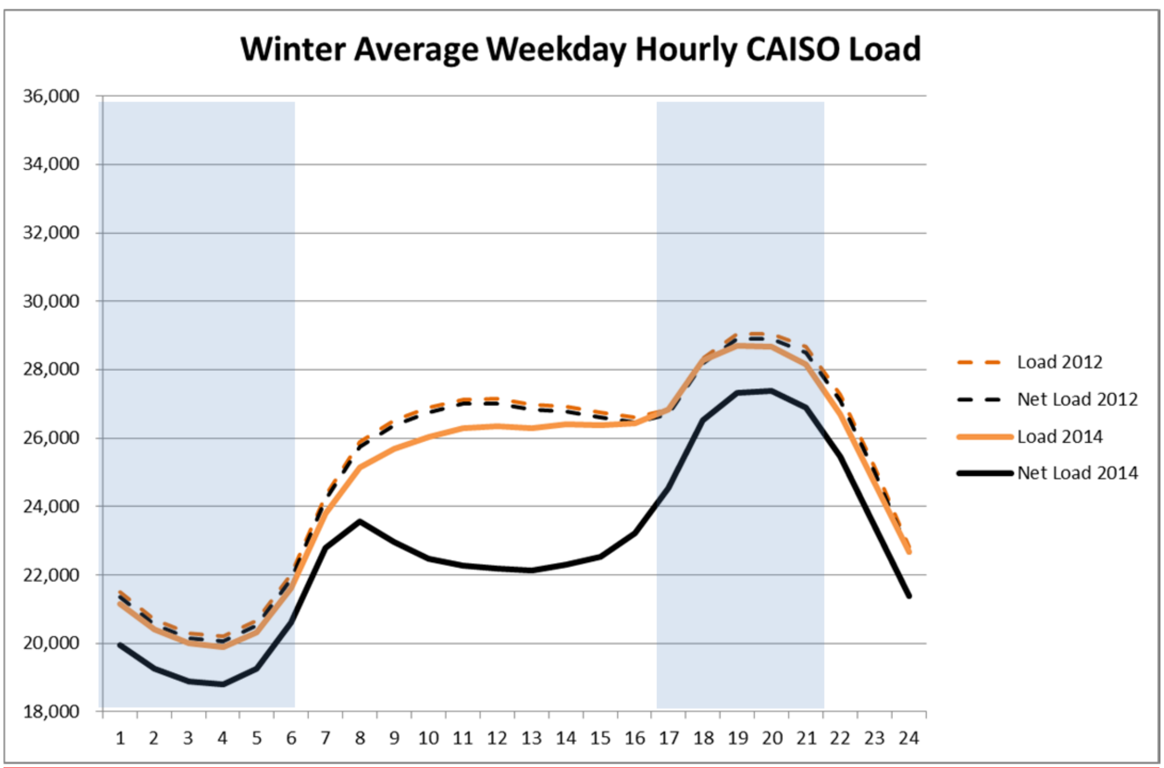


Chart RBA-4 CAISO Load and Net Loads for Winter Weekdays



The CAISO, the California Energy Commission and the CPUC have acknowledged this forecasted change in net loads[7] and the CPUC now requires an amount of "flexible capacity," capacity that can be ramped up or down to meet the net load changes that occur in the morning and evening related to changes in net loads.[8]

The CAISO performed its own analysis of net loads to determine when surplus and limited supplies might occur and to suggest appropriate TOU periods.[9] Using both historical data from 2014 and forecast data from 2021 for total system load and wind and solar energy projections, the CAISO recommended that the on-peak period be established as 4 p.m. to 9 p.m.(hours ending 17 to 21) daily, the same on-peak period as proposed by SDG&E.[10]

III. SAN DIEGO LOCAL AREA PRICES

One of the objectives in choosing TOU period definitions is to group together hours with similar energy costs. In competitive electricity markets, prices are determined by supply and demand conditions. Demand is based on customer electricity usage and offset in part by distributed energy resources including customer generation, primarily from rooftop solar. Supplies include must-take resources such as renewable generation, some hydroelectric power, and combined heat-and-power facilities (that operate primarily to provide heat for the facilities'

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[7] CAISO, "Building a Sustainable Future, 2014-2016 Strategic Plan," page 9; California Energy Commission, 2013 Integrated Energy Policy Report, CEC-100-2013-001-CMF; and CPUC Decision 14-06-050..

[8] See D.14-06-050 and D.15-06-063.

[9] CAISO, "TOU Period Analysis to Address 'High Renewable' Grid Needs," March 12, 2015; ~~and~~ CAISO, "Matching Time-of-use Rate Periods with Grid Conditions Maximizes Use of Renewable Resources," June, 2015; and California Independent System Operator Corporation Explanation of Data, Assumptions and Analytical Methods, Assumptions, and Analytical Methods, https://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-R1512012.pdf; http://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-TOUPeriodBackup-R1512012, submitted in R.15-12-012 on January 22, 2016. ~~CAISO, "CAISO Time-of-Use Periods Analysis," January 22, 2016. .~~

[10] The CAISO did make a distinction for July and August, labeling 4 pm to 9 pm in those months a "super-~~-~~on-peak" period.

thermal needs), and “must-run” generation, operating in order to provide grid stability. The rest of the supply is composed of dispatchable fossil resources which are bid into the CAISO’s markets to meet variable consumer demands for electricity in excess of the must-run and must-take supply resources.

With added distributed solar, net customer demand for electricity is reduced in the middle of the day when solar production is at a maximum. With added central station solar generation, supply increases at midday. This combination moderates electricity market prices in those hours, all other things being equal.

The proposed TOU periods would capture the hours with the highest electricity prices as shown by the shift that began occurring in 2014. The charts below show the SDG&E average Default Local Aggregation Point (“DLAP”) prices by year for 2010 through 2015 by season for weekdays. The chart RBA-5 below shows that the highest price period in the summer has shifted to 4 p.m. to 9 p.m. (hours ending 17 to 21) beginning in 2014. For winter, the prices shown in RBA-6 reflect a bi-modal peak with the larger peak occurring during 4 p.m. to 9 p.m. (hours ending 17 to 21).

Chart RBA-5[11] Highest Price Summer Hours are in the 4 p.m. to 9 p.m. time period (Hours Ending 17 to 21) beginning in 2014.

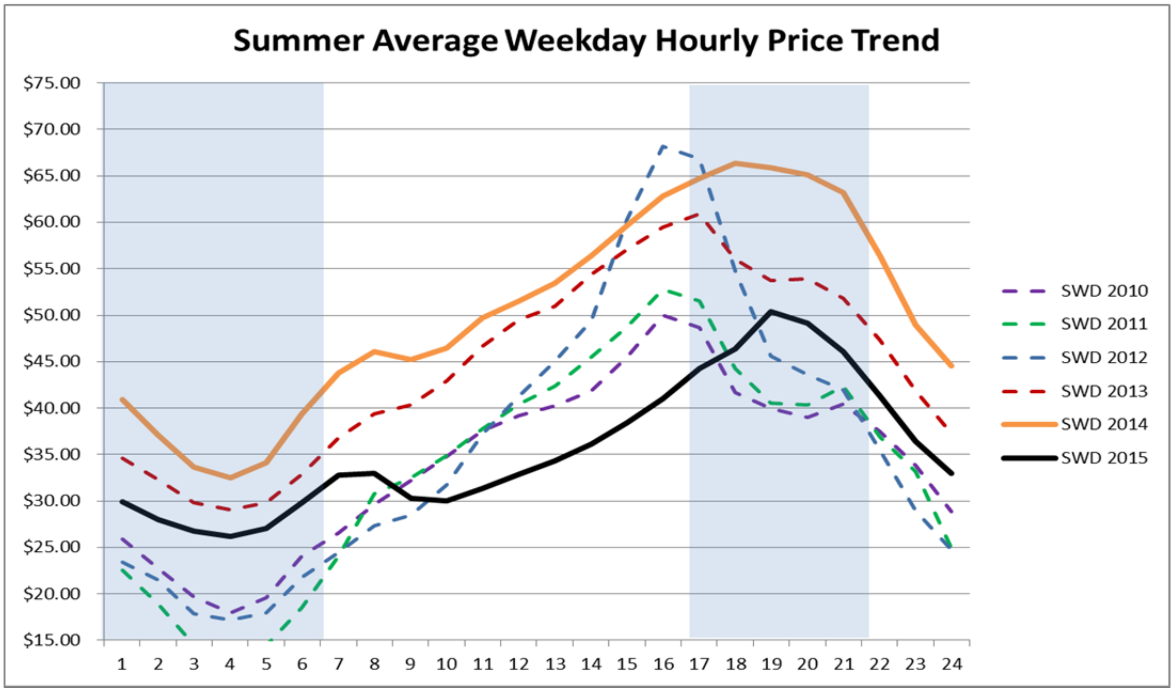

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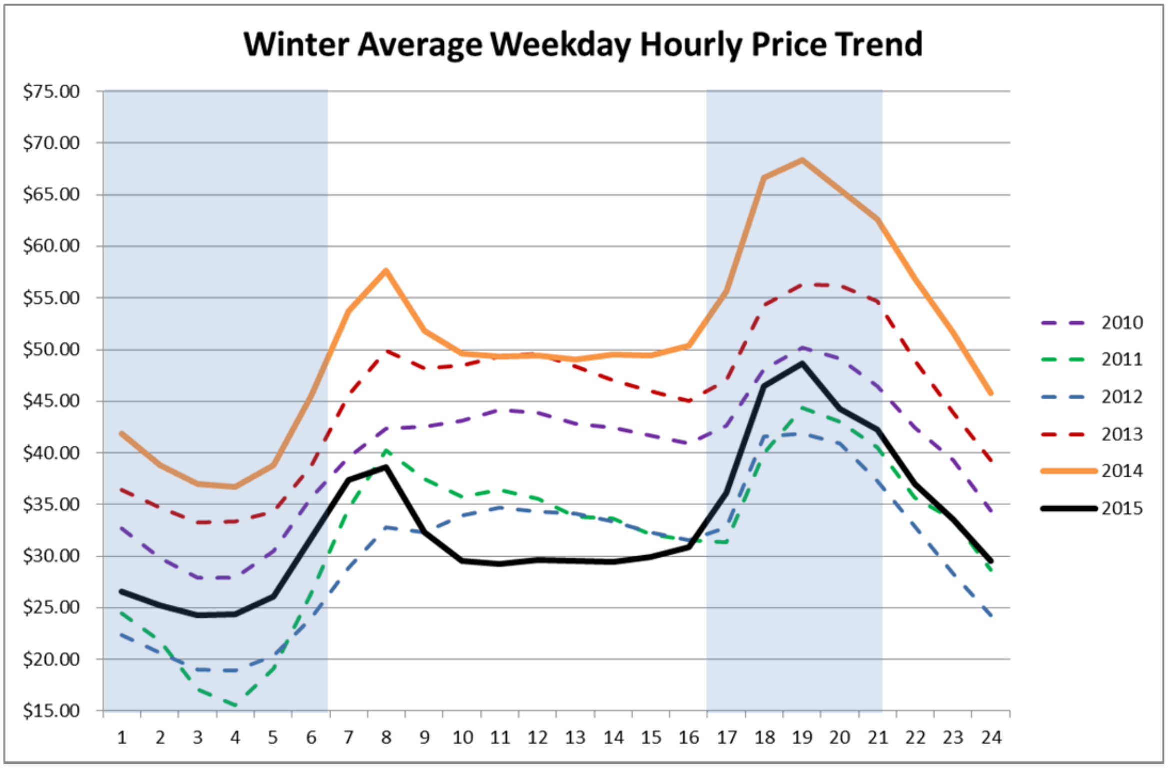
Chart RBA-6[11,12] Highest Price ~~Summer~~ Winter Hours are in the 5 p.m. to 9 p.m. time period (Hours Ending 18 to 21)



IV. SUPER OFF-PEAK TOU PERIOD

A super off-peak period of 12 a.m. – 6 a.m. weekdays and 12 a.m. – 2 p.m. weekends proposed by SDG&E is consistent with low net loads during this time period and low energy prices. As shown in the charts RBA-1 to RBA-4, net loads have been low in the 12 a.m. – 6 a.m. on weekdays historically, especially when looking at the CAISO area. Similarly, prices have been low in the middle of the night as shown in Charts RBA-5 and RBA-6.

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[11] Prices are actual electricity prices reported for the SDG&E DLAP. Differences in the levels across years reflect differing electric prices due to different natural gas prices and greenhouse gas allowance prices. ~~WWE,WWD,SWE, and SWD refer to winter weekend, winter weekday, summer weekend, and summer weekday, respectively.~~

[12] ~~2015 d~~Data has been updated to include all winter months in 2015.~~is only for the months of January – April.~~

As shown in the charts RBA-7 and RBA-8 below, net load in weekend hours are different than the weekdays. Net loads before 2 p.m. (hour ending 14) do not ramp up in the morning as on weekdays and are generally becoming lower as shown in the trend from 2013 to 2016 for both summer and winter.

Chart RBA-7. Summer Weekend Average Load for the SDG&E Local Area Net of Distributed Generation and Central Station Renewables

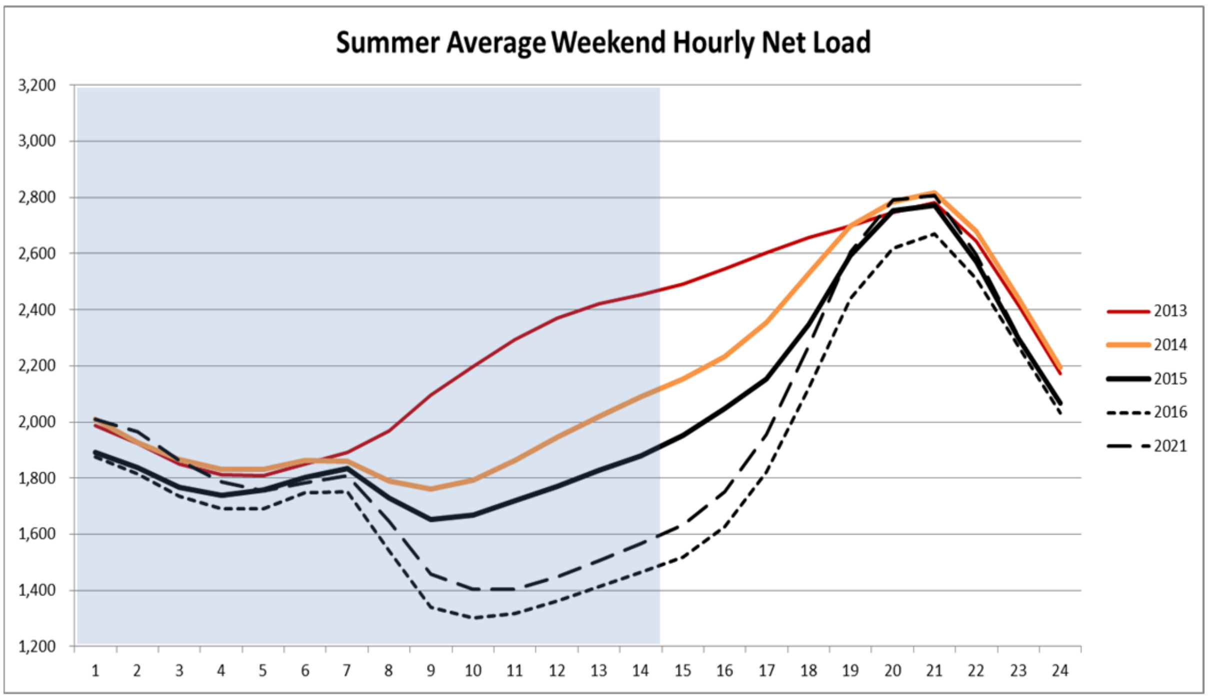

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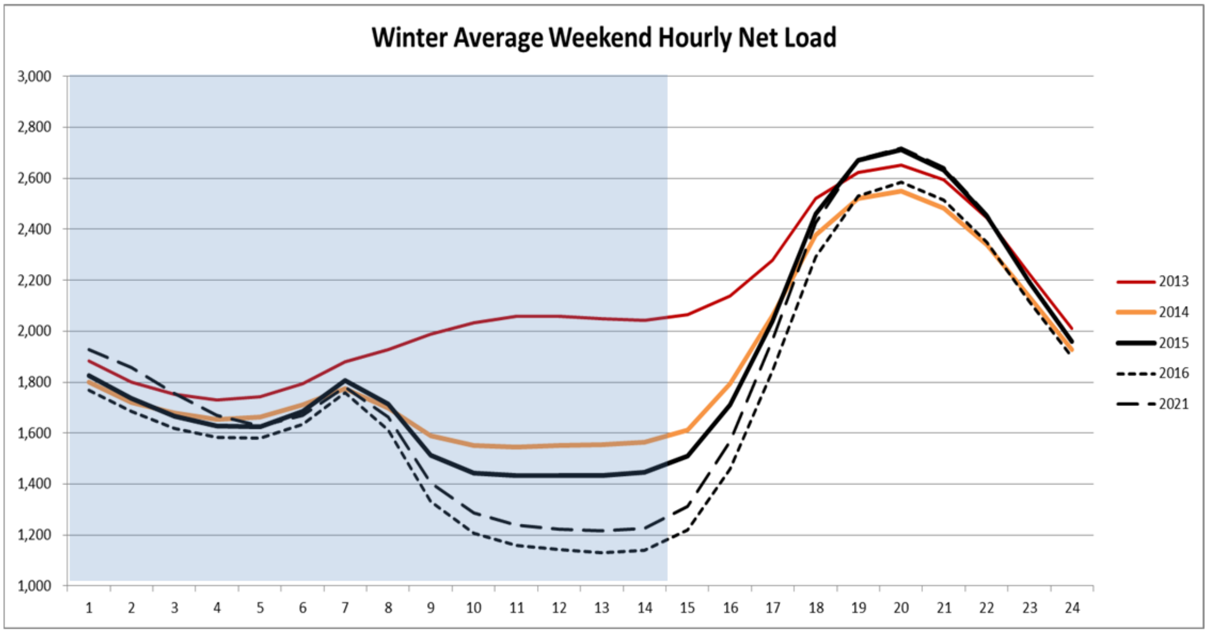
Chart RBA-8. Winter Weekend Average Load for the SDG&E Local Area Net of Distributed Generation and Central Station Renewables



The analysis by the CAISO also found significant differences between weekdays and weekends with the CAISO including many daylight hours in its super off-peak period.[13]

Similarly, in 2015 prices in the summer before 2 p.m. (hour ending 14) do not start increasing significantly until after 2 p.m. as shown in Chart RBA-9. In the winter, prices increase significantly on weekends after 2 p.m. as shown in RBA-10.

[13] CAISO, "TOU Period Analysis to Address 'High Renewable' Grid Needs," March 12, 2015;~~ and~~ CAISO, "Matching Time-of-use Rate Periods with Grid Conditions Maximizes Use of Renewable Resources," June, 2015; and California Independent System Operator Corporation Explanation of Data, Assumptions and Analytical Methods, Assumptions, and Analytical Methods, https://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-R1512012.pdf; http://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-TOUPeriodBackup-R1512012, submitted in R.15-12-012 on January 22, 2016 ~~"CAISO Time-of-Use Periods Analysis," January 22, 2016~~.

Chart RBA-9 Low Price Period Becoming Extended on Summer Weekends

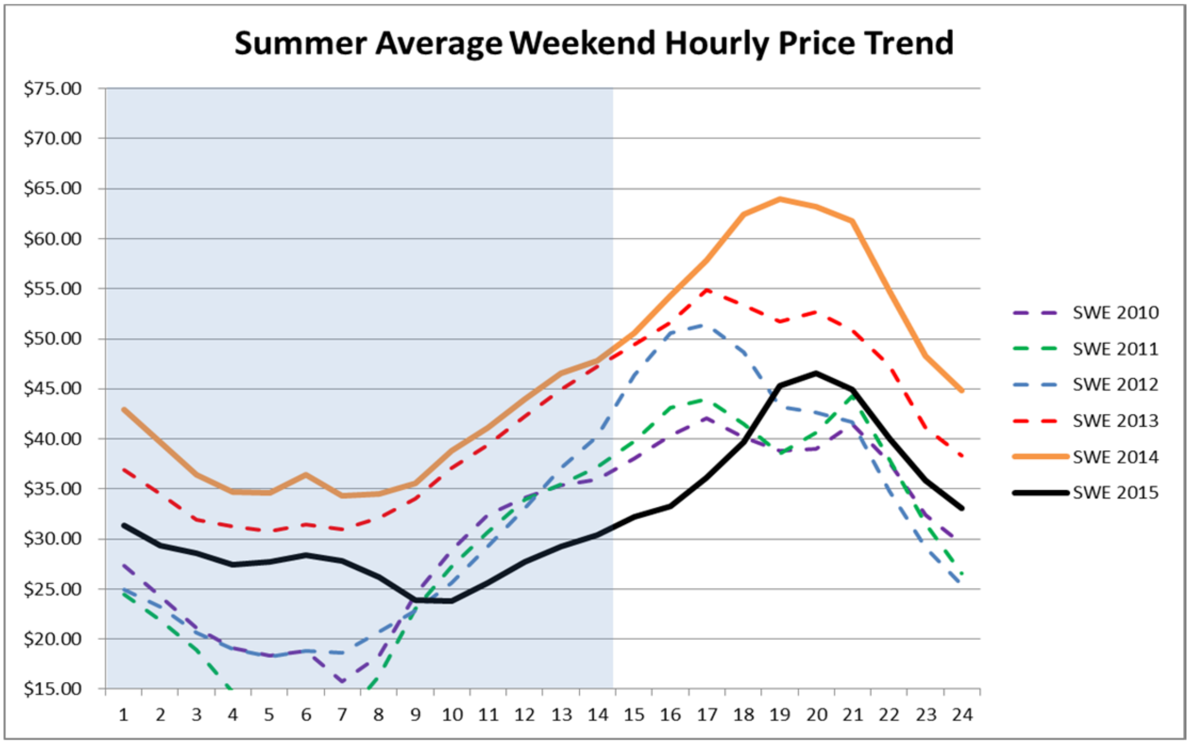
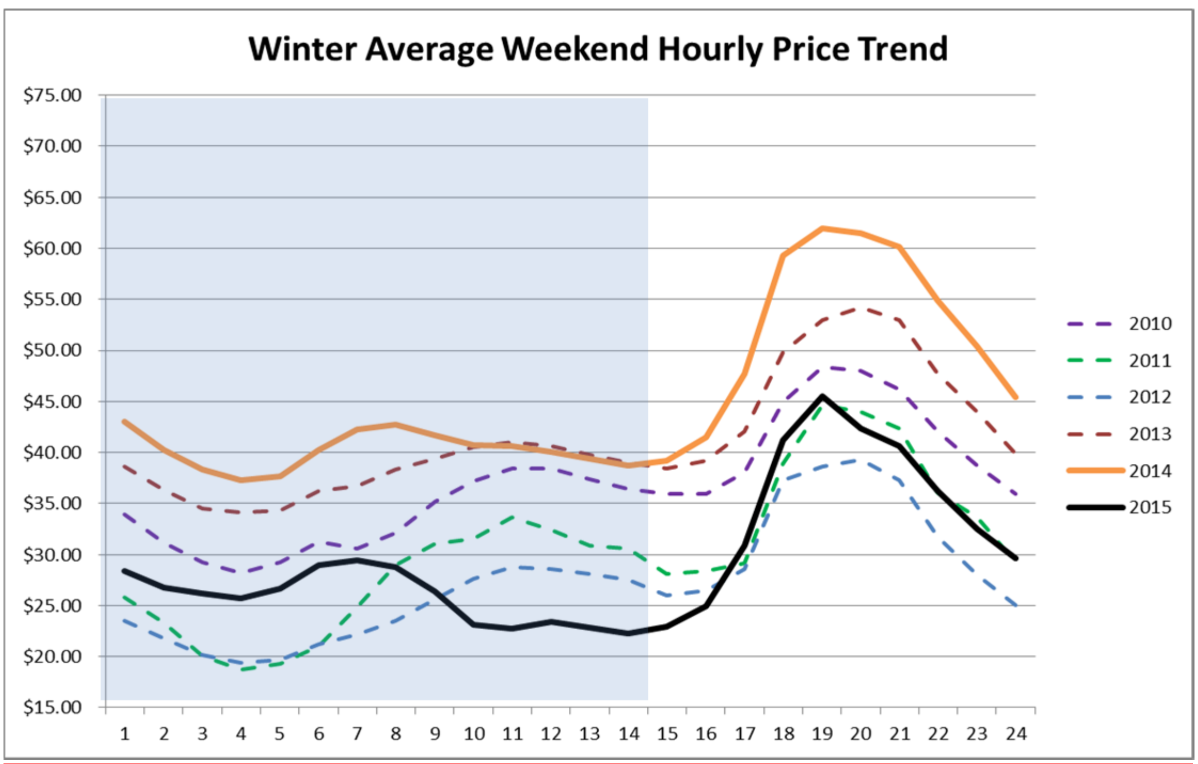


Chart RBA-10 Low Price Period Extended on Winter Weekends



Both net load and price data support the SDG&E proposal for a super off-peak period of 12 a.m. to 6 a.m. on weekdays and 12 a.m. to 2 p.m. on weekends.

V. RELATIVE LOSS OF LOAD EXPECTATION

To identify the periods when the likelihood of needing additional resources, SDG&E undertook several Loss of Load Expectation ("LOLE") analyses. This type of analysis provides the expectation of the hours with the highest need for new resources given the variable nature of customer demands due to weather and the variable nature of solar and wind energy production.

LOLE, loss of load expectation, is the probability of not meeting load in an hour when key system variables are analyzed stochastically. SDG&E determined the LOLE for the SDG&E system using the Ventyx Planning and Risk model, a system dispatch model tailored to the SDG&E system.[14] In order to model real world uncertainties, different load and variable renewable production levels are generated by a stochastic process based on historical data. The Planning and Risk model then performs an hourly economic dispatch of generation resources against loads for each hour of the year. By running the model multiple times, a probability distribution of hours with relative expected loss of load can be developed.

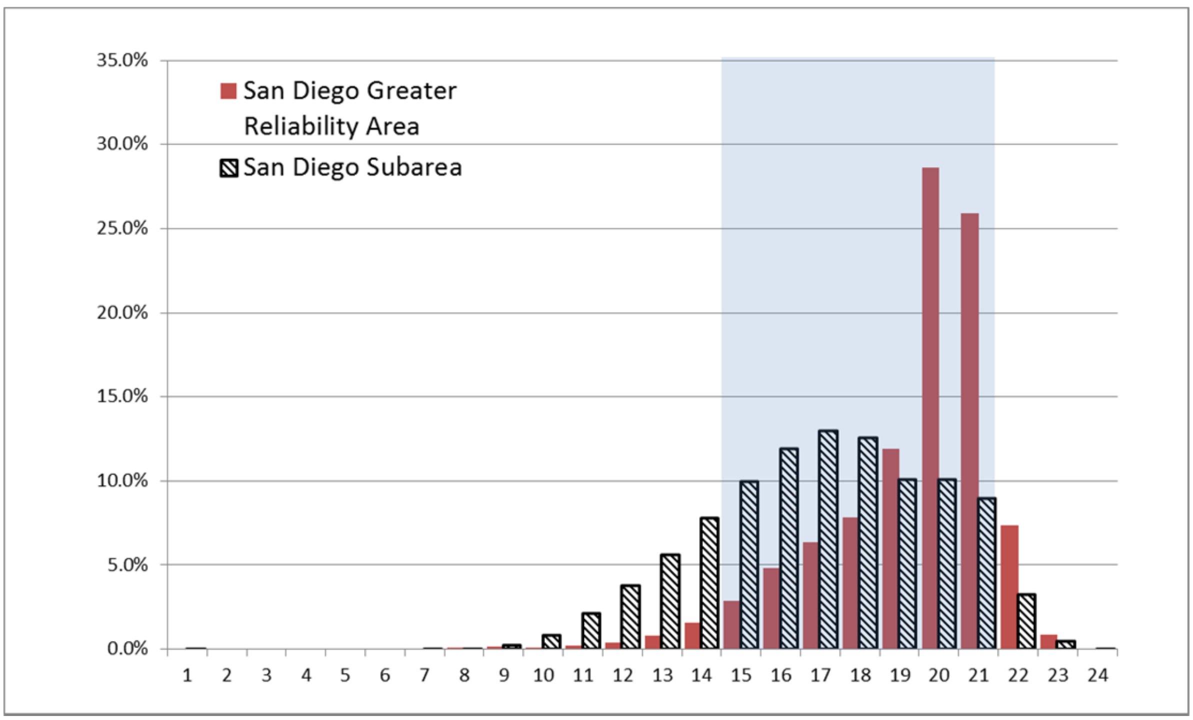
Available generation in the analysis includes the generation units, including both new renewable and conventional generation, that exist or are expected to be constructed by 2016 for in the San Diego Greater Reliability area (both SDG&E service area and Imperial Valley).

[14] It is the same production cost model as used by SDG&E to forecast procurement costs in the ERRA proceeding. The focus in this analysis is on local capacity and the needs for local capacity that can be reduced through the use of appropriate consumer price signals in TOU periods and demand response availability periods to provide incentives for load modification. The Planning and Risk model accommodates detailed hour-by-hour simulation of the operations of electric systems. It considers a complex set of generation operating constraints to simulate the least-cost operation of the system. The model's unit commitment and dispatch logic is designed to mimic "real world" power system hourly operation, minimizing system production cost, enforcing the constraints specified for the system, generation stations, associated transmission, fuel, and so on.

SDG&E is unique in that local capacity considers both the San Diego Greater Reliability area and separately the San Diego sub-area (excluding generation from Imperial Valley). SDG&E analyzed LOLE for both areas separately and combined. The resulting analysis is not a measure of need for new capacity; but, instead, if there were a need, what hours of the year would likely experience the highest likelihood of a loss of load.

In Chart RBA-11 below is a comparison of relative LOLE results for local capacity in the San Diego Greater Reliability area and for local capacity in the San Diego subarea. The results show a relative need for capacity between 2 p.m. and 9 p.m. (hours ending 15 to 21) when considering both the Greater Reliability area and the San Diego subarea.

Chart RBA-11 Relative Loss of Load Expectation for the San Diego Local Capacity Areas by Hour in the Summer



This concludes my prepared direct testimony.

VI. WITNESS QUALIFICATIONS

My name is Robert B. Anderson. My business address is 8330 Century Park Court, San Diego, California, 92123.

I am employed by San Diego Gas & Electric Company (SDG&E) as Director – Resource Planning. My responsibilities mainly include electric resource planning. I have been employed by SDG&E since 1980, and have held a variety of positions in resource planning, corporate planning, power plant management, and gas planning and operations. I have a BS in Mechanical Engineering and a MBA - Finance. I am a registered professional engineer in Mechanical Engineering in California.

I have previously testified before this Commission.

APPENDIX

The CAISO, the operator of a large percent of the State's electric grid, performed an analysis to determine when surplus and limited supplies might occur. The CAISO used data from the 2024 Trajectory Case in the CPUC's Long-term Procurement Plan proceeding. From this data, the CAISO created projections of future load curves and net load curves, calculated by subtracting solar and wind output from the overall demand. The CAISO observed patterns in the data that resulted in the on-peak period (or super on-peak) period of 4 p.m. to 9 p.m. on both weekdays and weekends through the year.[15] Further, the CAISO found weekends to be different than weekdays and placed many weekend daylight hours in their super off-peak period.

Attached is a set of CAISO Charts from the "CAISO's Proposed TOU Periods to Address Grid Needs with High Numbers of Renewables."[16] The charts depict representative summer and winter average loads and net loads. The loads are shown are the top line and shown in blue. Net loads have wind and solar renewable energy subtracted from load and so are represented by the lower lines, shown in red.

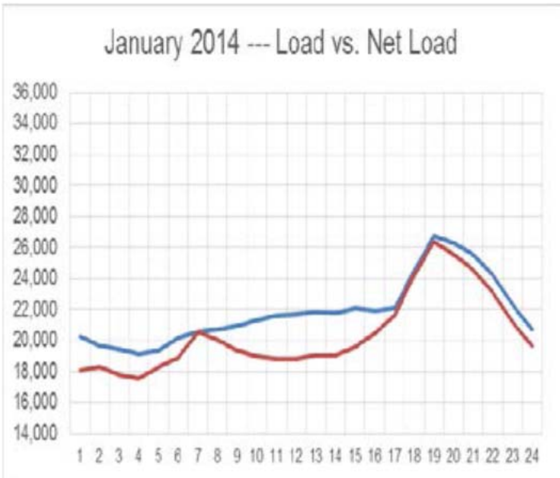
[15] CAISO, "Matching Time-of-use Rate Periods with Grid Conditions Maximizes Use of Renewable Resources," June, 2015; and ~~.~~ See, California Independent System Operator Corporation Explanation of Data, Assumptions and Analytical Methods, Assumptions, and Analytical Methods, https://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-R1512012.pdf; http://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-TOUPeriodBackup-R1512012, submitted in R.15-12-012 on January 22, 2016. ~~"CAISO Time-of-Use Periods Analysis," January 22, 2016.~~

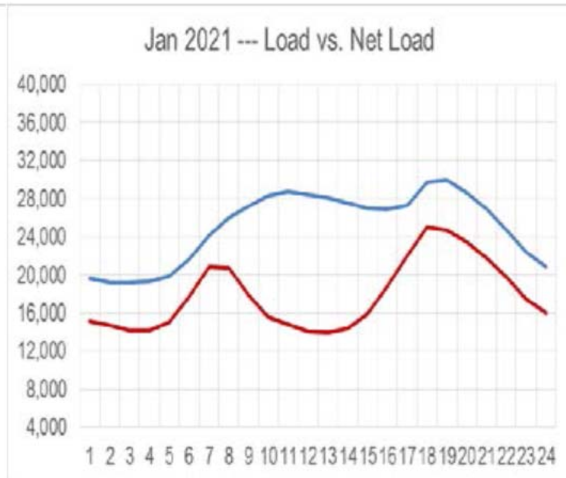
[16] Clyde Loutan, Sr. Advisor, Renewable Energy Integration, CAISO, "CAISO's Proposed TOU Periods to Address Grid Needs with High Numbers of Renewables," CPUC Residential Rate Reform proceeding (R.12-06-013), November 17, 2015, slides 5 – 8. The recently released document, "CAISO Time-of-Use Periods Analysis" has the same charts depicted.

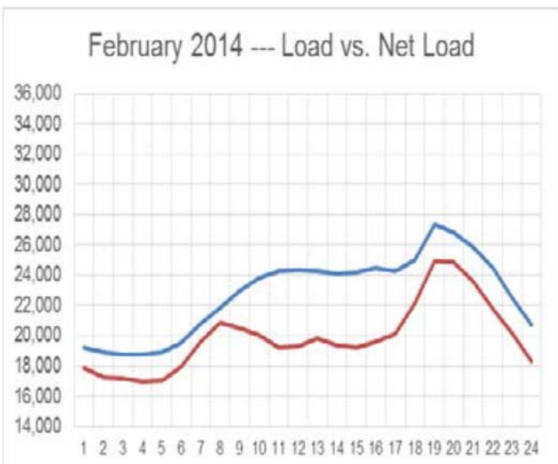
Monthly Weekday Load and Net Load Profiles

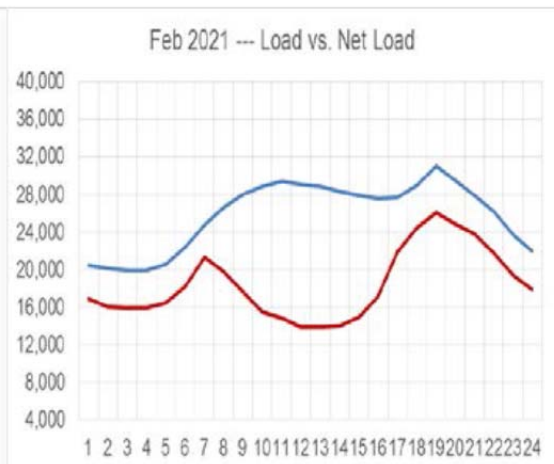
Loads are shown in blue and are the upper line, while net loads are shown in red and are the lower line since net load subtracts off wind and solar generation from load. The data in 2014 support both the on-peak proposal of SDG&E and the weekend super off-peak proposal.

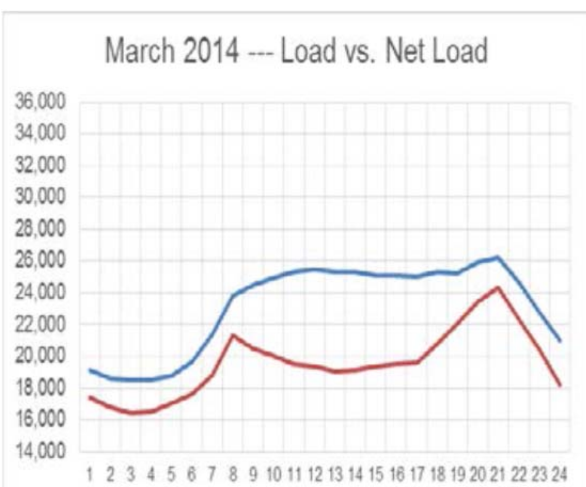
2014 Actual Winter Weekdays 2021Forecast Winter Weekdays

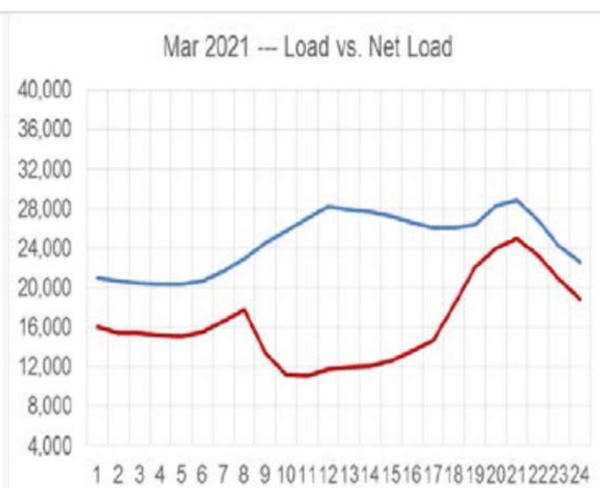


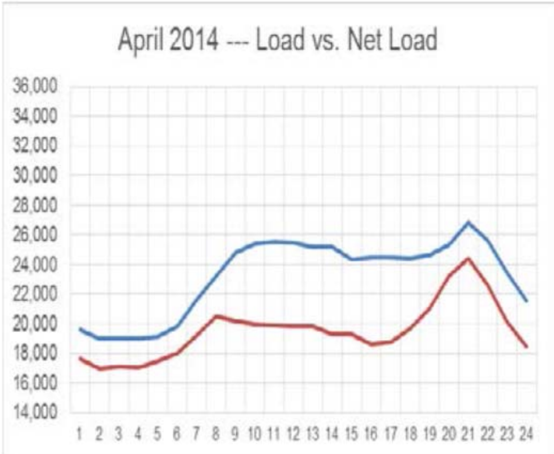


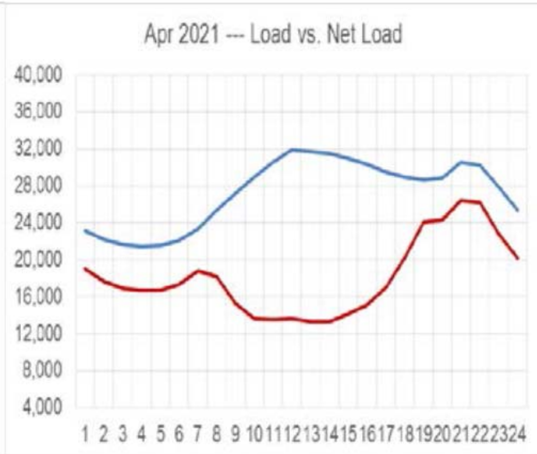


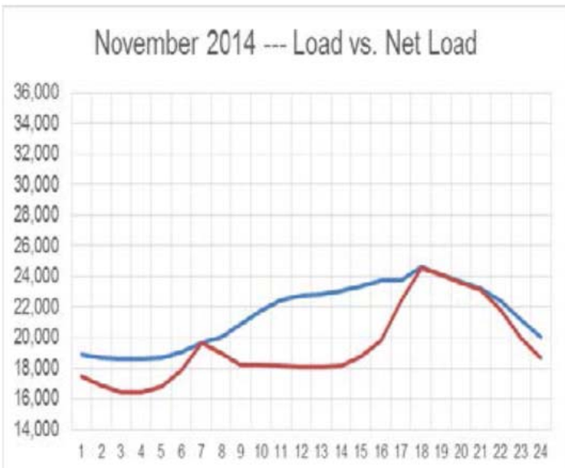


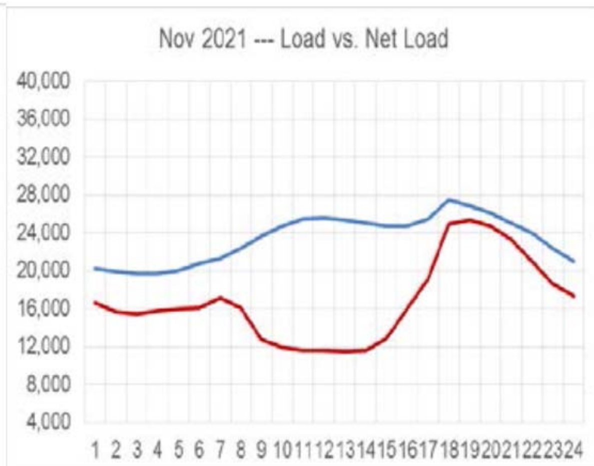


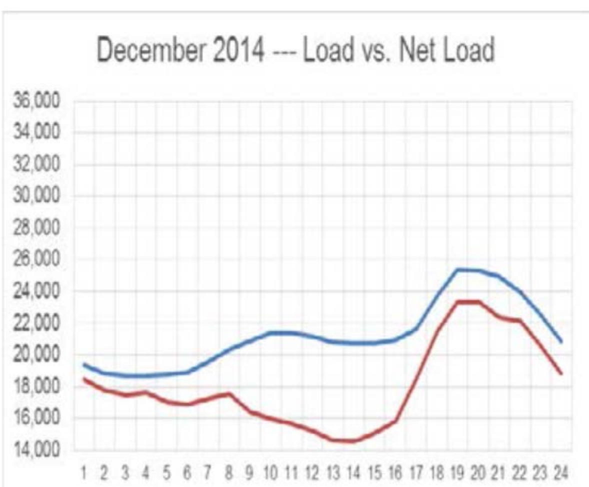


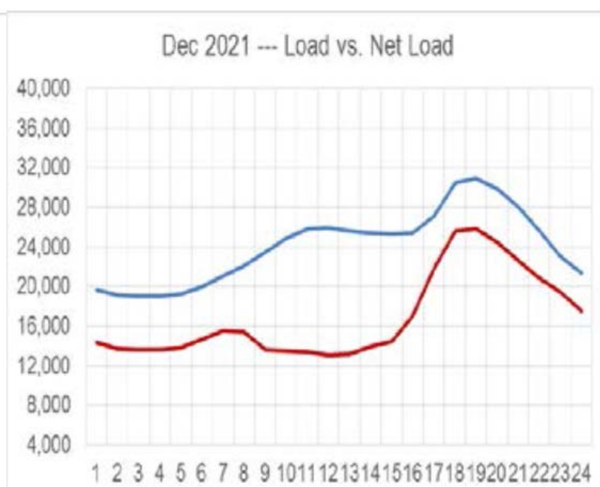

April 2014 --- Load vs. Net Load
36,000
34,000
32,000
30,000
28,000
26,000
24,000
22,000
20,000
18,000
16,000
14,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


Apr 2021 --- Load vs. Net Load
40,000
36,000
32,000
28,000
24,000
20,000
16,000
12,000
8,000
4,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

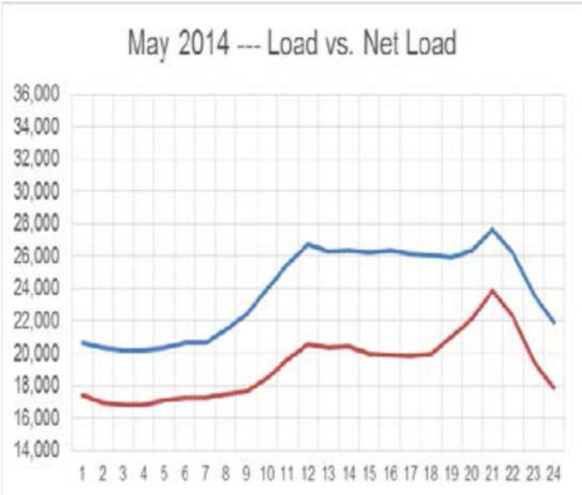

November 2014 --- Load vs. Net Load
36,000
34,000
32,000
30,000
28,000
26,000
24,000
22,000
20,000
18,000
16,000
14,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

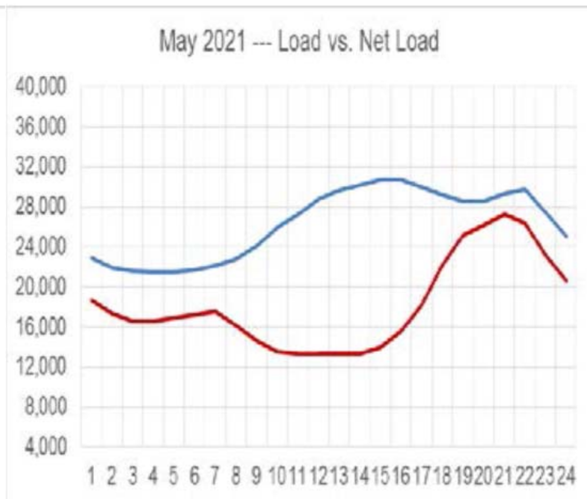

Nov 2021 --- Load vs. Net Load
40,000
36,000
32,000
28,000
24,000
20,000
16,000
12,000
8,000
4,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

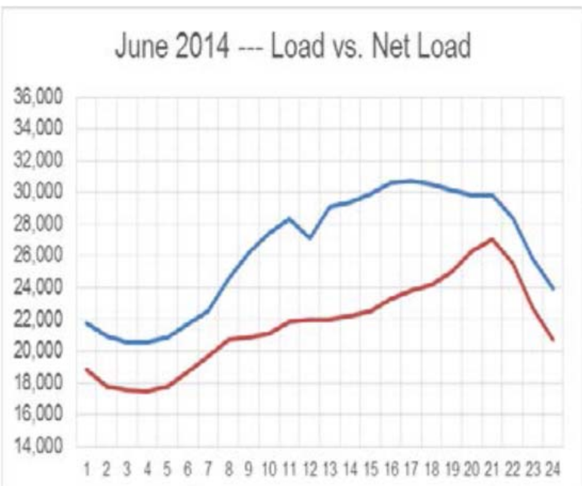

December 2014 --- Load vs. Net Load
36,000
34,000
32,000
30,000
28,000
26,000
24,000
22,000
20,000
18,000
16,000
14,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

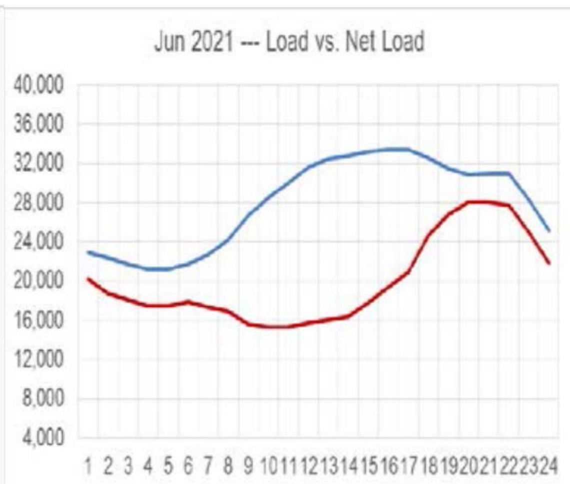

Dec 2021 --- Load vs. Net Load
40,000
36,000
32,000
28,000
24,000
20,000
16,000
12,000
8,000
4,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

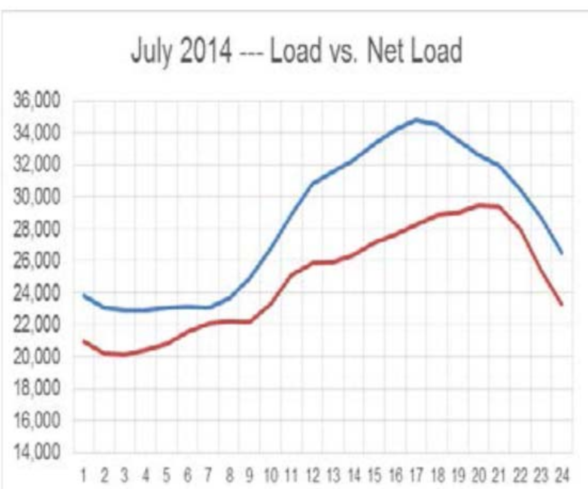
2014 Actual Summer Weekdays   2021 Forecast Summer Weekdays

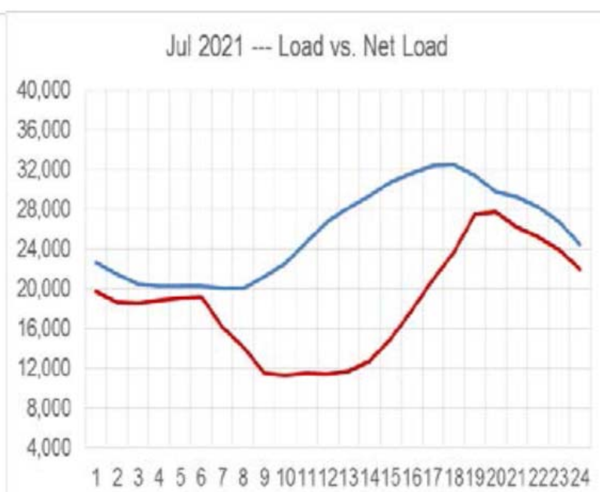


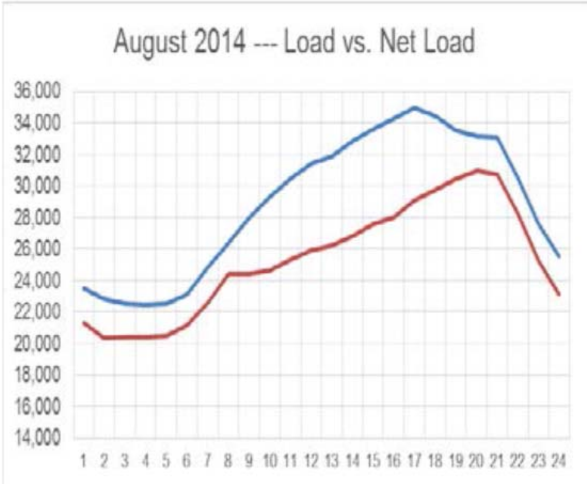


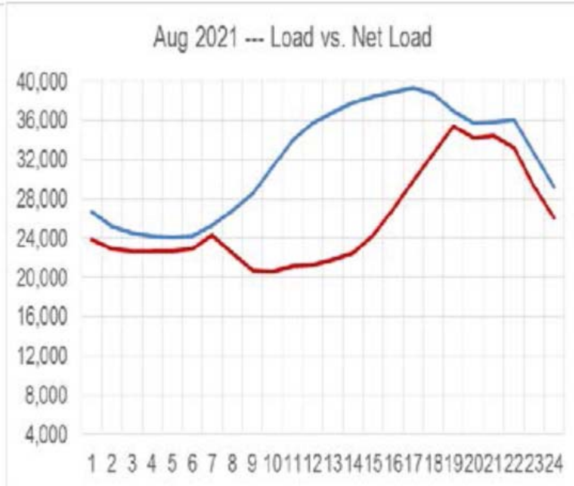


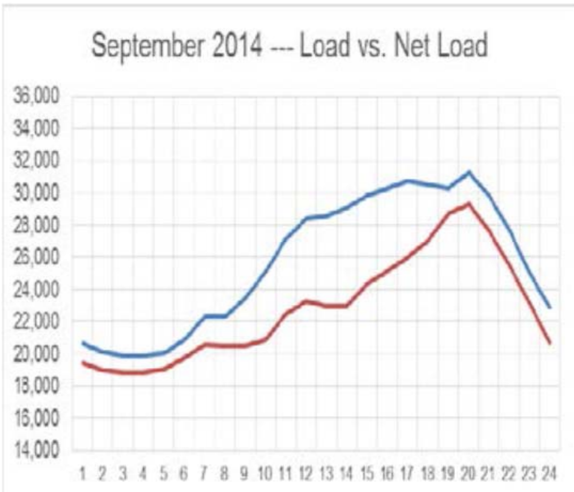


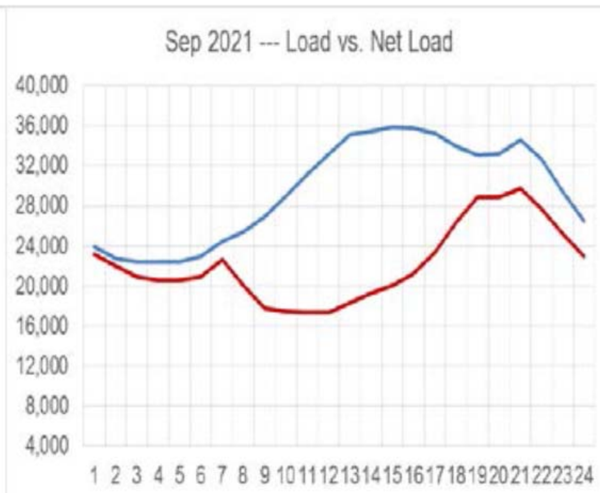


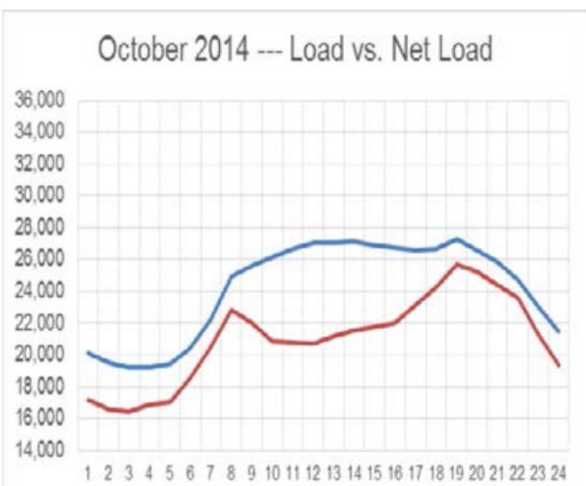


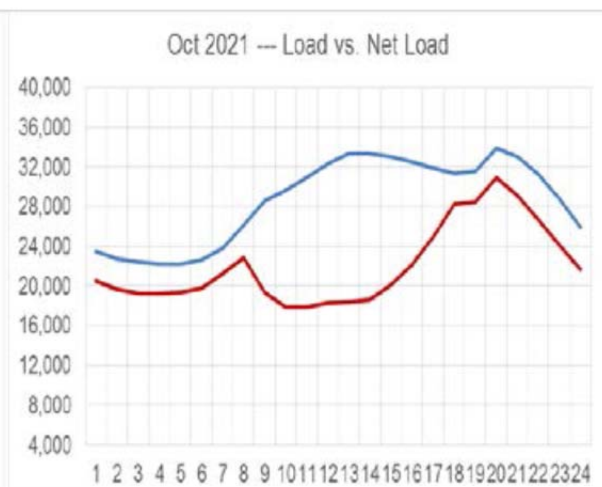

August 2014 --- Load vs. Net Load


Aug 2021 --- Load vs. Net Load


September 2014 --- Load vs. Net Load

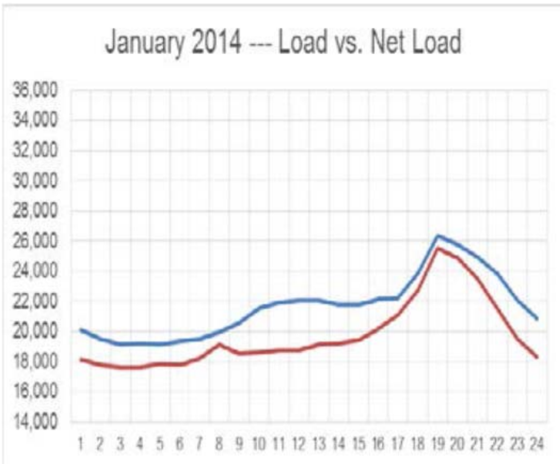

Sep 2021 --- Load vs. Net Load

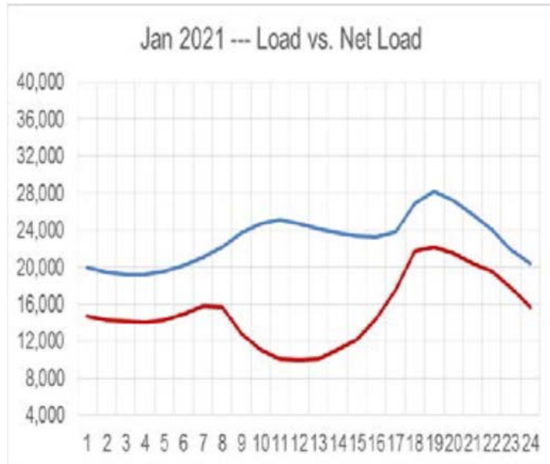

October 2014 --- Load vs. Net Load

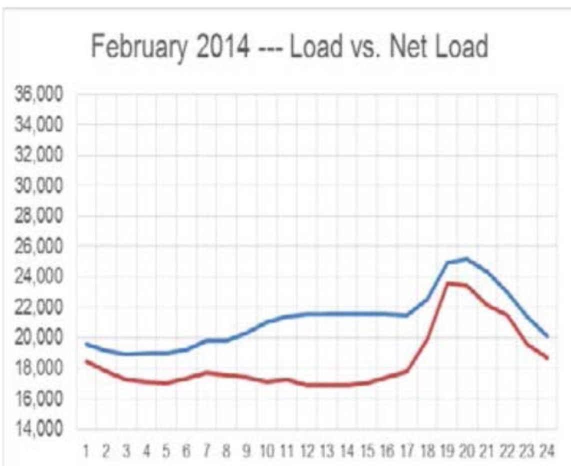

Oct 2021 --- Load vs. Net Load

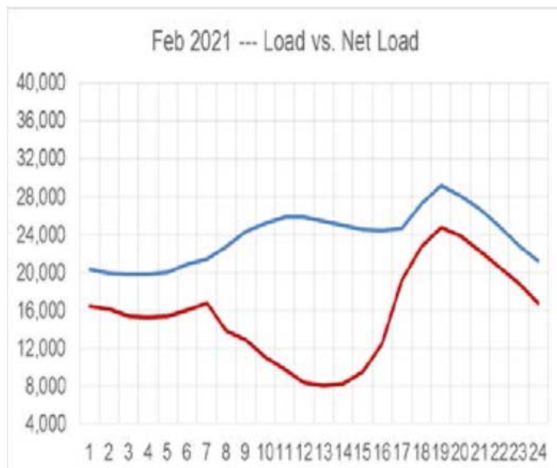
Actual 2014 Monthly Weekend Load vs. Net Load profiles

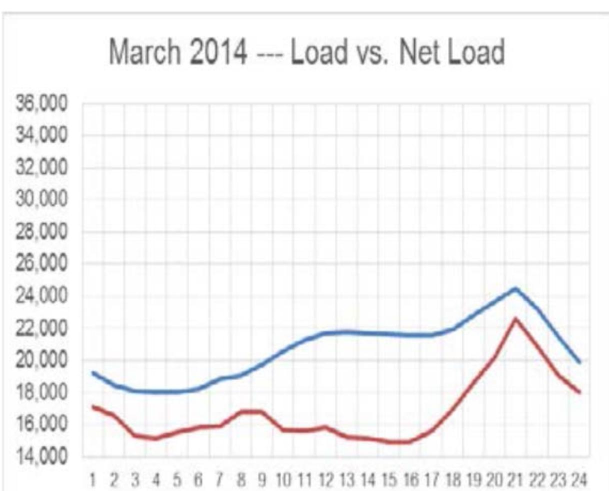
Actual 2014 Winter Weekends **Forecast 2021 Winter Weekends**

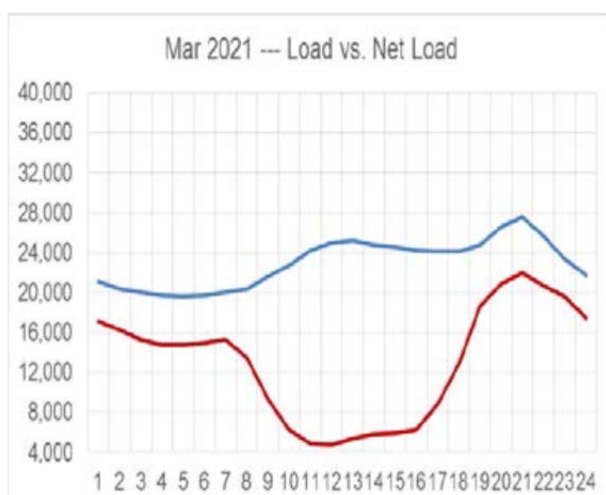


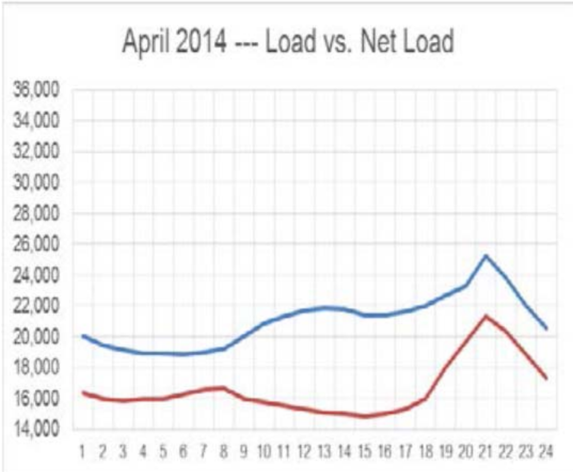











April 2014 --- Load vs. Net Load
36,000
34,000
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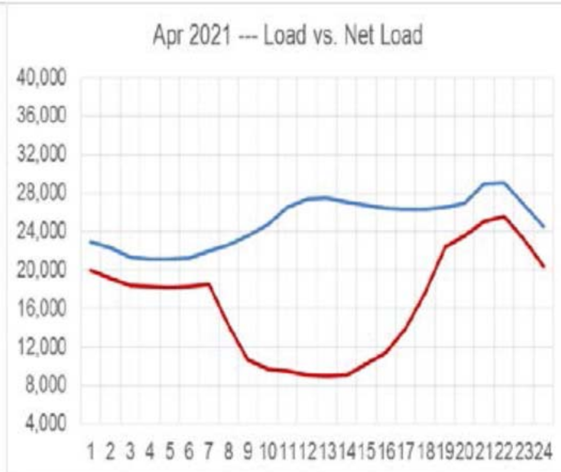
Apr 2021 --- Load vs. Net Load
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32,000
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4,000
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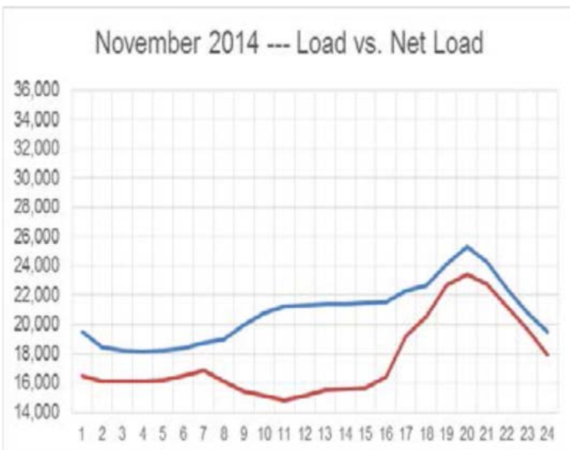
November 2014 --- Load vs. Net Load
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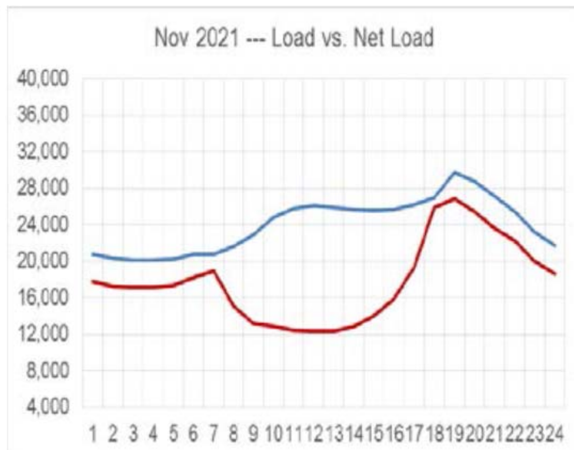
Nov 2021 --- Load vs. Net Load
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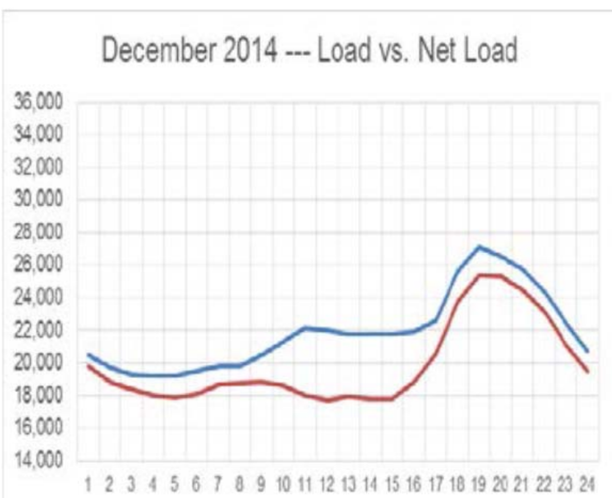
December 2014 --- Load vs. Net Load
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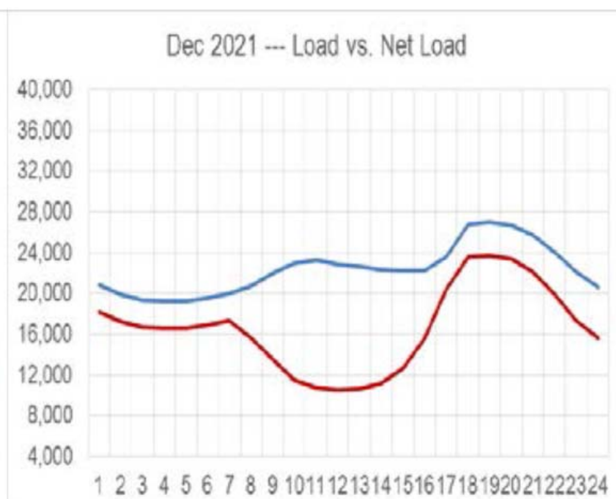
Dec 2021 --- Load vs. Net Load
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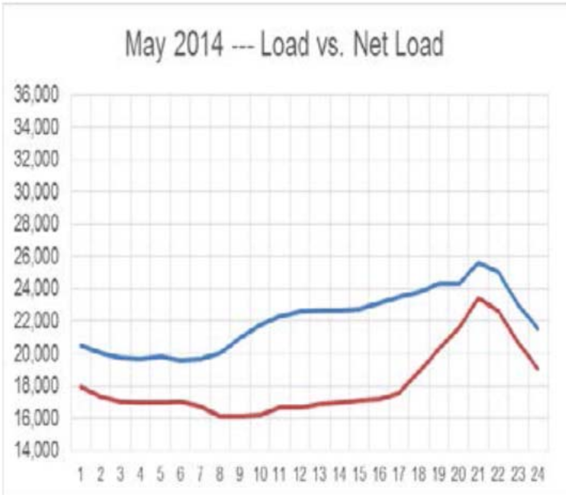
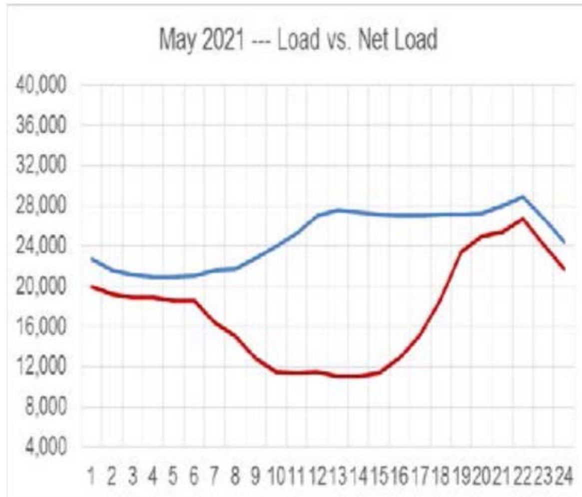
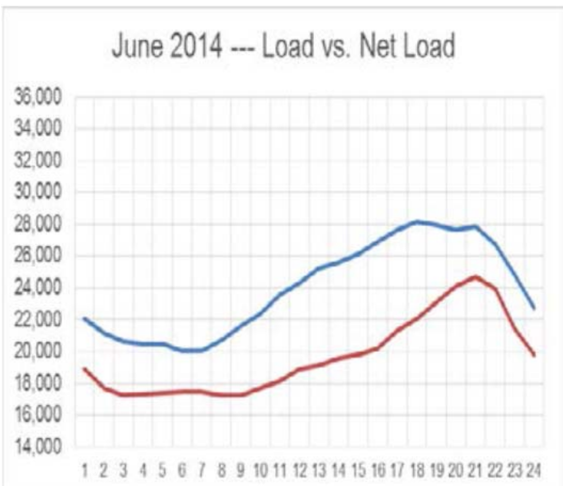
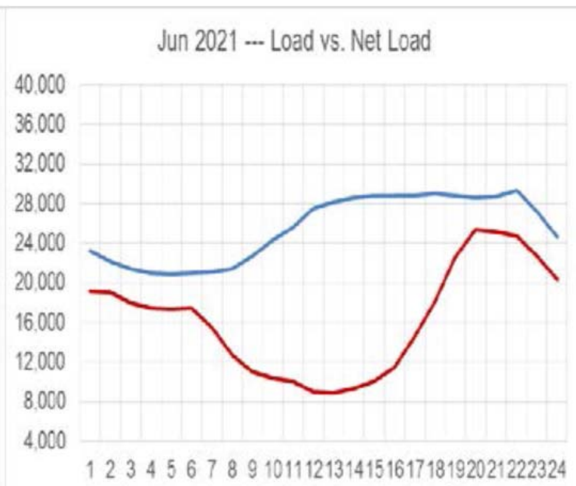
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

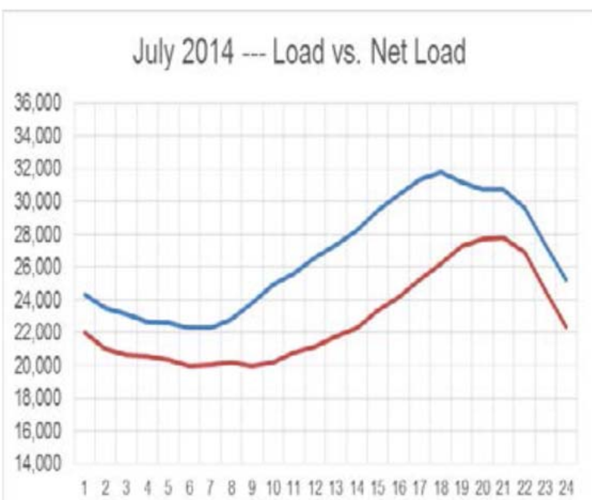
2014 Summer Weekends

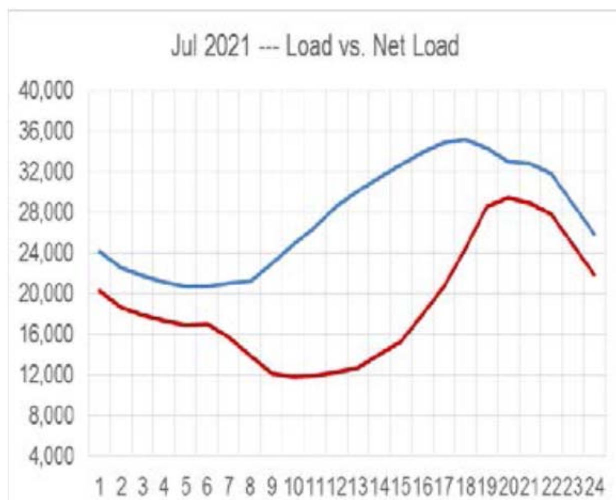


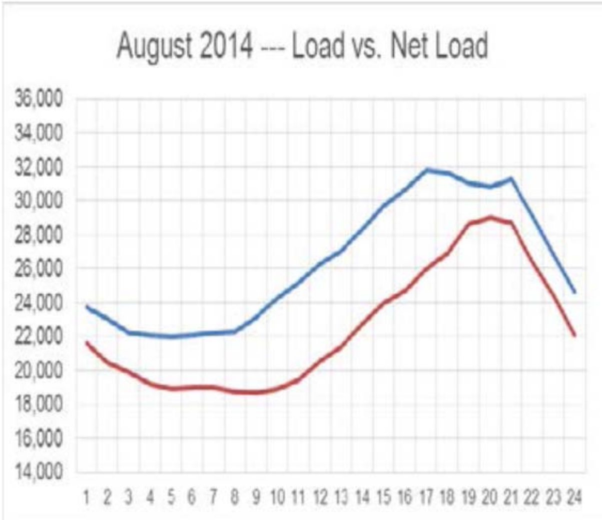








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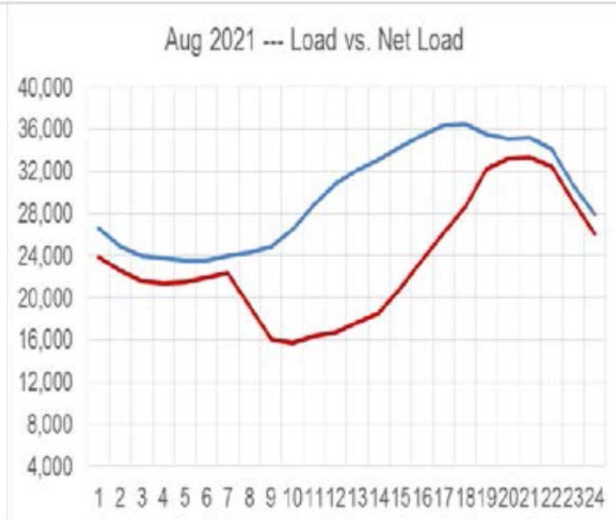
Aug 2021 --- Load vs. Net Load
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4,000
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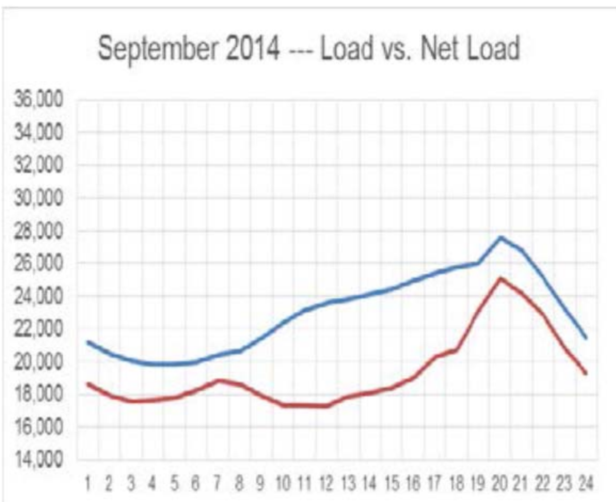
September 2014 --- Load vs. Net Load
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14,000
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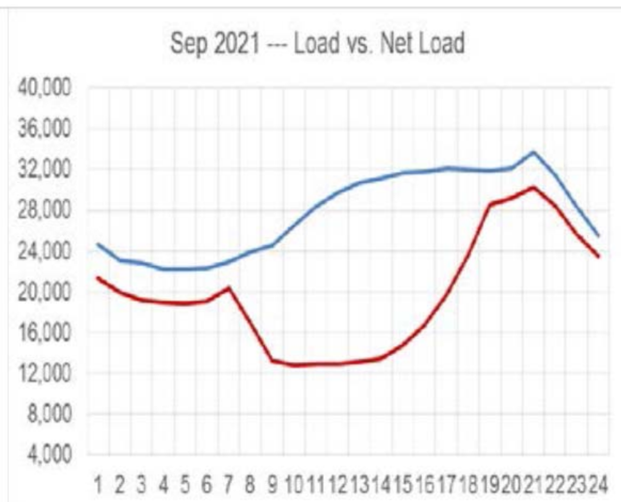
Sep 2021 --- Load vs. Net Load
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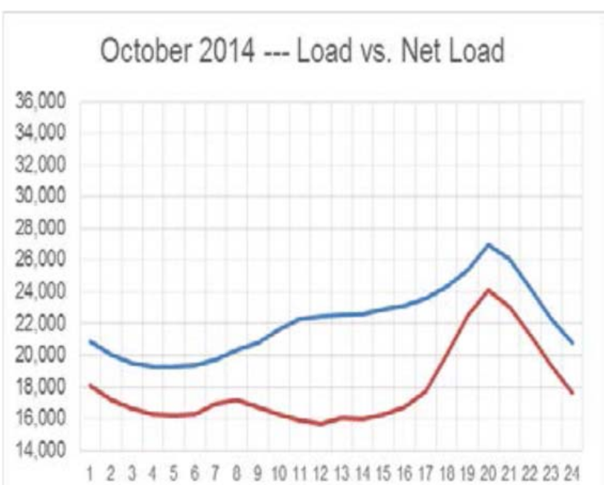
October 2014 --- Load vs. Net Load
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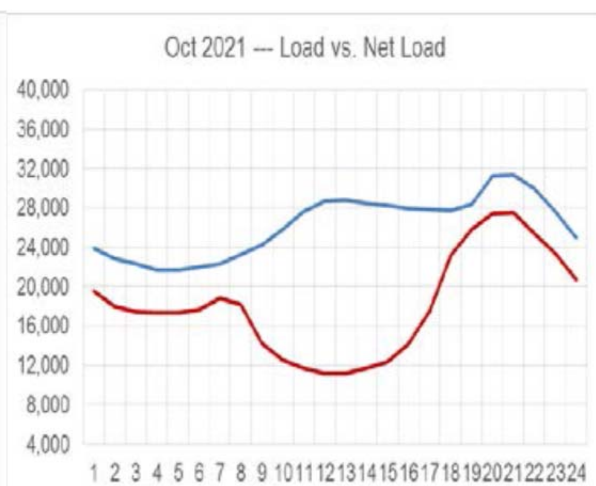
Oct 2021 --- Load vs. Net Load
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1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24