An Evaluation of Electricity Net Load Profiles and the Baseload Generation Concept

Overview

Beginning in the 1980s, electricity resource planning focused on least cost planning and flattening system demand. Demand-side management began to be a driving concept for system planning, and demand profile analysis was important. This planning approach addressed the idea that a flatter consumer demand profile is preferred because it could be served efficiently by baseload generators such as pulverized coal and nuclear plants. In parallel, the construction of new generation was driven by peak demand growth, and thus flattening loads delayed new construction.

Today, primarily due to renewable portfolio standards (RPS) and subsidies for renewable power, the concept of flattening a system demand profile appears to have fallen in priority. This has led to concerns such as the infamous "duck curve" which creates a challenge for California utilities trying to solve the economic dispatch issues caused by the unequal match between demand and intermittent renewable resources.

This paper provides an analysis of net load profiles (NLP) for several power system regional transmission organizations (RTOs): California (CAISO), Midcontinent Independent System Operator (MISO), PJM Regional Transmission Organization, and the Electric Reliability Council of Texas (ERCOT). The objective of this study is to answer the question: Would targeting a level demand profile and high baseload generation result in more efficient power systems, better balancing the use of renewable energy resources (RERs) and effective baseload capacity (EBC)?

Methods

In answering the above question, two types of analyses were undertaken. One analysis involved obtaining historical load data for the PJM and CAISO RTOs, and evaluating the load shapes for changes that could be attributed to inducing electricity consumers to use electricity so a flatter load results. Two statistics, daily kurtosis and annual system load factor (SLF), were used to assess changes in the PJM loads over the 1993-2016 period, and CAISO over the 2000-2013 period. This provides a basis for assessing the progress in flattening the consumer's electric load profile.

Another analysis was done by simulating the economic dispatch of RTO power systems in 2030 as they are estimated to operate after RPS goals have been met by the states in each respective RTO. This future scenario is compared to another scenario in which it is assumed there are no RPS regulations, and therefore, there are no renewable resources. This simulation enables the aggregation of wind and solar supply profiles for multiple locations to be compiled to meet the RTO demand, and leaving what is known as the net load for the dispatchable generation to serve. The EBC was thus calculated based on model load profile simulation results for the consumer net load profile with and without renewable resources.

In addition to the load profile analyses and evaluating effective baseload capacity, the levelized cost of electricity (LCOE) was applied to all resources to calculate the difference in RTO system energy costs with and without renewable resources attributable to RPS goals. High efficiency generation consistent with R&D development goals was included in the analysis, factoring in improvements in all resources out to 2030. Fuel costs are from the EIA 2018 Annual Energy Outlook Reference case.

Results

The analysis of the PJM historic consumer demand profiles shows that, statistically, there is little change in the load shape from 1993 to 2016, even though there was considerable changes in system size and consumer demand. In contrast, the CAISO results suggest a transition to more peaked, or variable, daily load shapes as RERs were added to the power system. In addition, the load shape analysis for 2030 consumer demand profiles for each RTO shows that having a RPS in place will result from about 8 GW to about 18 GW less EBC in each RTO, depending on how well the RERs match customer load (see Table 1). Interestingly, the MISO results suggest it will have the greatest absolute change in EBC in 2030, due to the high penetration of RERs.

Table 1: 2030 No RPS vs RPS 2030, Effective Baseload Capacity

ISO/RTO	**2016 Effective Baseload Capacity (GW)**	**RPS 2030 NLP Effective Baseload Capacity (GW)**	**No RPS 2030 Effective Baseload Capacity (GW)**	**2030 Differences (GW)**
CAISO	28	**9**	**27**	18
ERCOT	38	**26**	**43**	17
MISO	79	**77**	**95**	18
PJM	88	**81**	**97**	16
Total	233	**193**	**262**	69

There is also an estimated net savings in power costs the higher the level of EBC, although these results do not include transmission costs. Table 2 shows the energy and total cost estimates including capital costs for the new high efficiency coal and natural gas combined cycle plants needed to meet reserve margins. Reserve margins in 2030 were met with new generation, and in the RPS cases taking into consideration the allowed capacity for RERs by each RTO.

Table 2: 2030 No RPS vs RPS 2030 Cost

ISO/RTO	**No RPS 2030 Total Energy Cost**	**RPS 2030 Total Energy Cost**	**No RPS 2030 Total Annual Cost, Capital Included**	**RPS 2030 Total Annual Cost, Capital Included**	**Total 2030 Benefit (Cost) for RPS Efficiency, Capital Included**
	$M	**$M**	**$M**	**$M**	**$M**
CAISO	$11,083	$13,256	**$14,804**	**$15,318**	**($514)**
ERCOT	$12,455	$14,481	**$17,832**	**$17,653**	**($179)**
MISO	$21,620	$26,035	**$36,297**	**$38,575**	**($2,278)**
PJM	$22,092	$26,672	**$26,167**	**$30,351**	**($4,184)**
Total	$67,251	$80,444	**86,073**	**$103,181**	**($6,797)**

Conclusions

Based on these analyses, there was little change in the PJM load shape characteristics from 1993-2016, suggesting a consistent demand management approach and the aggregation of loads with consistent consumer characteristics. In contrast, the CAISO system shows more diversity in the NLP from 2000 to 2016, likely due to a higher penetration of RERs.

With the penetration level of RERs in 2030 set by state RPSs, the CAISO system is estimated to have the highest percentage reduction in the EBC level, at about 17% lower than if no RERs were on the system. The CAISO and MISO systems are projected to have about 14% less EBC in 2030 with RPS in place, and PJM about 5% less EBC. In all four RTOs, the cost of energy is estimated to be higher in 2030 applying the costs of RERs without subsidies, excluding transmission costs. Theses extra costs are estimated from $7 billion to $13 billion annually for the RPS efficiency losses, depending on capital cost assumptions for conventional generation. Subsidies and partial capacity payments for RPS RERs are difficult to trace, but if RTOs required the inclusion of energy cost recovery amount in the economic dispatch energy cost bidding, it could provide a more visible cost of RERs that are assumed to have zero energy cost but recover most of the needed revenue to be financially whole through energy sales. Admittedly, more investigation of how such an economic dispatch system would work is needed to understand the implications.

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