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Exploring the Benefits of Demand Response in the PJM Wholesale Energy Market: A Cost-Benefit Perspective

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SUMMARY

Over the past decade, the participation of demand response (DR) in the PJM wholesale electricity markets has experienced significant progress. DR has emerged as an effective solution for addressing the challenge of load demand stochasticity by bridging the gap between the demand and supply sides while rapidly responding to market operator signals. It offers enhanced reliability, affordability, efficiency and cost-effectiveness to the system. Under the new Economic DR program in PJM, any member has the opportunity to offer DR services in various markets, including capacity, energy and ancillary services such as regulation, synchronized reserve and secondary reserve.

This paper seeks to quantify the net benefits of DR in the PJM Real-Time Market (RTM). It explores the underlying foundations of DR models in PJM and their practical implementations. Additionally, it investigates the impact of DR on the various revenue streams for generators, prices and uplift payments. To achieve this objective, a simulation-based approach was employed that involves simulating the PJM RTM under various DR scenarios to replicate the market dynamics with the presence of DR. The study examines three different scenarios with DR levels of 1%, 2% and 5% of the base system load. The results demonstrate that the potential net benefits range from \$1.48 billion for 1% DR implementation to \$6.6 billion for 5% DR implementation. Furthermore, the findings reveal that the implementation of DR can result in significant load savings and a reduction in the dispatch of more inefficient and pollution-intensive resources.

KEYWORDS

Cost-Benefit Analysis, Demand Response, Electricity Markets

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1. INTRODUCTION

PJM, as the largest regional transmission organization (RTO) in the United States, plays a significant role in ensuring the security and reliability of the power grid. PJM coordinates wholesale electricity as a part of the Eastern Interconnection, serving more than 65 million people. The PJM wholesale energy market employs a two-market settlement system to procure enough energy to meet total customer demand for any given day. These two markets include the day-ahead and the real-time markets [1].

In the Day-Ahead Market (DAM), the initial commitment and dispatch of the system take place the day before the operating day. The results of this market are then utilized in the Real-Time Market (RTM). The RTM acts as a balancing mechanism, effectively managing fluctuations within each 5-minute interval. By considering different system constraints, this two-settlement market seeks to determine the optimal unit commitment and dispatch and ensure sufficient energy procurement to meet the overall customer demand on any given day.

Electricity demand is quite unpredictable and stochastic and it is always a challenge for Independent System Operators (ISOs), RTOs and utility companies to predict the required demand every minute. The traditional solution to this problem is to generate surplus capacity to ensure that demand is met. However, this method is economically inefficient and environmentally harmful due to the potential for increased carbon emissions. Demand response (DR) is an effective tool to solve the problem of load demand stochasticity by bridging the gap between the demand and supply sides, and responding swiftly to market operator signals. It shifts the focus from the supply side to the demand side as a cost-efficient and eco-friendly solution.

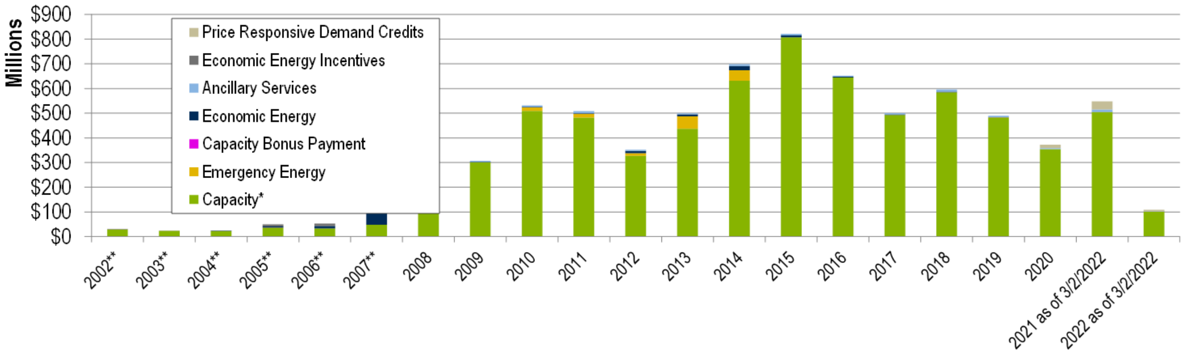
In recent years, PJM’s generation mix has continued to evolve by integrating more renewables, energy storage resources and DR capability. This transformation has significantly impacted the structure and operations of its wholesale electricity market. One such change has been the development of a program that allows end-use customers to voluntarily participate in its energy markets by reducing their electricity use when requested by PJM during periods of high power prices or when the reliability of the grid is threatened. PJM operates the day-ahead and real-time energy and ancillary services markets on a least-cost basis. If a DR resource proves competitive, it will clear the market the same way as a generator.

PJM end-use customers have the opportunity to participate in its energy and ancillary services markets as part of its Economic DR program. The Economic DR program is facilitated by Curtailment Service Providers (CSPs). These providers enable customers to contribute their load-reduction capability to the PJM DAM or RTM. In the energy markets, participants receive compensation solely for load reductions that go beyond their regular electricity usage patterns or baselines. For the ancillary service markets, participation encompasses market products such as regulation, synchronized reserves and secondary reserves.

This paper aims to quantify the net benefits of DR in the PJM RTM. It explores the foundations behind the DR models in PJM and their practical implementations. It also explores the impact of DR on the various revenue streams for generators, prices and uplift payments. The remainder of this paper is organized as follows. Section II presents an overview of the existing DR products and capabilities in PJM, Section III details the methodology and assumptions employed in the cost-benefit analysis, Section IV showcases the simulation results used for the study, Section V provides a comprehensive discussion and analysis of the results and, finally, Section VI presents some overall conclusions and highlights potential avenues for future work.

2. PJM CURRENT DEMAND RESPONSE PRODUCTS

Over the past decade, the participation of DR in the PJM wholesale electricity markets has experienced significant progress. DR has transitioned from a traditional utility program to becoming a valuable resource managed by CSPs. The CSP model allows an aggregator (that is not required to be the load-serving entity, electric distribution company or end-use customer but is required to be a PJM member) to be responsible for DR activity in the wholesale markets. Under this model, any PJM member has the opportunity to offer DR services in various markets, including capacity, energy and ancillary services such as regulation, synchronized reserve and secondary reserve. Figure 1 shows the DR revenue in PJM by wholesale service from 2002 to March 2022. The revenues generated by CSPs in the wholesale market for DR have witnessed a significant increase since the implementation of the PJM Reliability Pricing Model (RPM) capacity market in 2007, particularly in terms of capacity payments.



* Capacity net revenue inclusive of capacity credits and charges

**PJM assumes capacity value at $50 MW Day (PJM does not know the value of capacity credits in the forward market prior to RPM; only a portion of capacity was purchased through the daily capacity market at the time)

Figure 1: PJM demand response (DR) revenue by wholesale service, 2002 – March 2022 [2].

Under the Capacity Performance (CP) framework, DR resources are required to showcase their load reduction capabilities throughout the year, extending beyond the traditional summer-only participation. This shift not only brings DR resources closer into alignment with conventional generation resources but also impacts their historical participation patterns. The CP requirements incentivize DR resources to aggregate the individual capabilities of customers into comprehensive portfolios. They also allow them to meet the availability criteria.

Within the PJM wholesale markets, DR participation can take place via three pathways:

1. DR can engage in load management during emergency or pre-emergency conditions by committing to limit consumption to a specified level. These load management commitments also receive energy revenue when PJM requests load reductions.
2. DR can participate as an economic DR resource by offering load reductions in the energy and ancillary service markets, driven by economic considerations.
3. Customers can simultaneously participate in both load management and as an economic DR resource. Load management resources can also offer load reductions in the energy market for purely economic reasons, without waiting for a PJM emergency or pre-emergency request.

Current DR participation encompasses a diverse range of customers who implement various measures to reduce their load. For example, Figure 2 shows the confirmed load management DR registration business segments for the 2022/2023 delivery year [2]. In that year, the manufacturing sector accounted for 60 percent of the DR load management capability, while schools contributed 8 percent and the residential sector contributed just 0.3 percent.

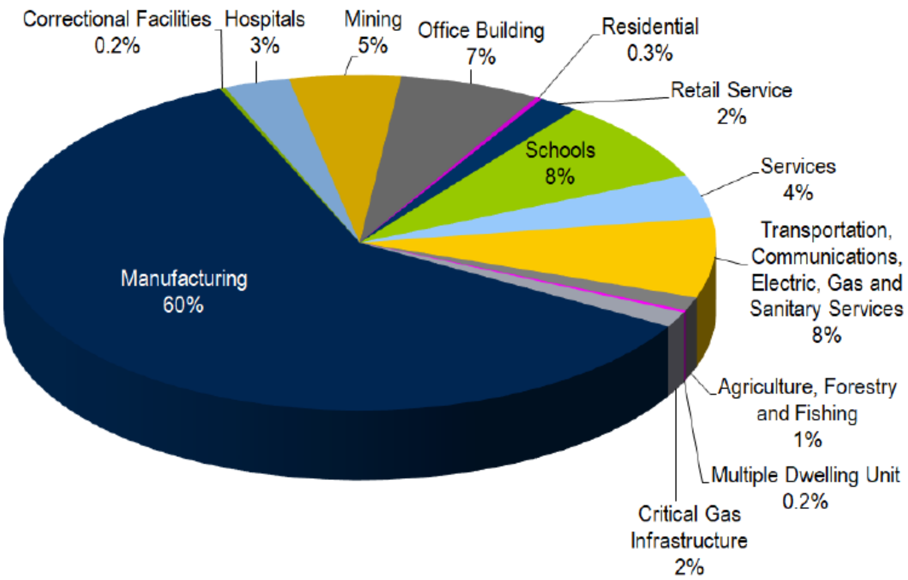


Figure 2: Confirmed load management demand response (DR) registrations business segments for the 2022/2023 delivery year [2].

3. METHODOLOGY AND ASSUMPTIONS

This study investigates the impact and net benefits of DR on the PJM RTM. To achieve this objective, a simulation-based approach was used that involves simulating the PJM RTM under various DR scenarios to replicate the market dynamics with the presence of DR. For conducting the simulations, PowerGEM's Portfolio Ownership and Bid Evaluation (PROBE) simulation tool was used [3]. Specifically, the PROBE Perfect Dispatch (PROBE PD) version of the PROBE simulation tool was employed. This version is designed to replicate the PJM RTM clearing process, assuming all system conditions are known in advance (i.e., no forecast uncertainty or unexpected generator outages) [4]. By using a simulation-based methodology and employing PROBE PD, one can gain valuable insights into the impacts of DR on the PJM RTM.

3.1. SCENARIO DESIGN

Three different DR scenarios were simulated in addition to a base case. In the DR scenarios, DR is deployed only during PJM peak load hours, which are defined as the hours from hour ending 8 to hour ending 23. The amount of DR deployed in each scenario is based on a proportion of the base system load in each 15-minute interval. The three DR scenarios simulated included DR equivalent to 1%, 2% and 5% of the base system load, respectively. Historical data from the year 2022 was simulated, excluding 13 days that exhibited anomalous results due to missing input data, software convergence errors, and other issues. With the exception of the amount of DR deployed in each DR scenario, all other parameters were held constant between the different cases. Figure 3 shows the average amount of DR deployed during each time interval across all the simulated days in 2022 for each DR scenario.

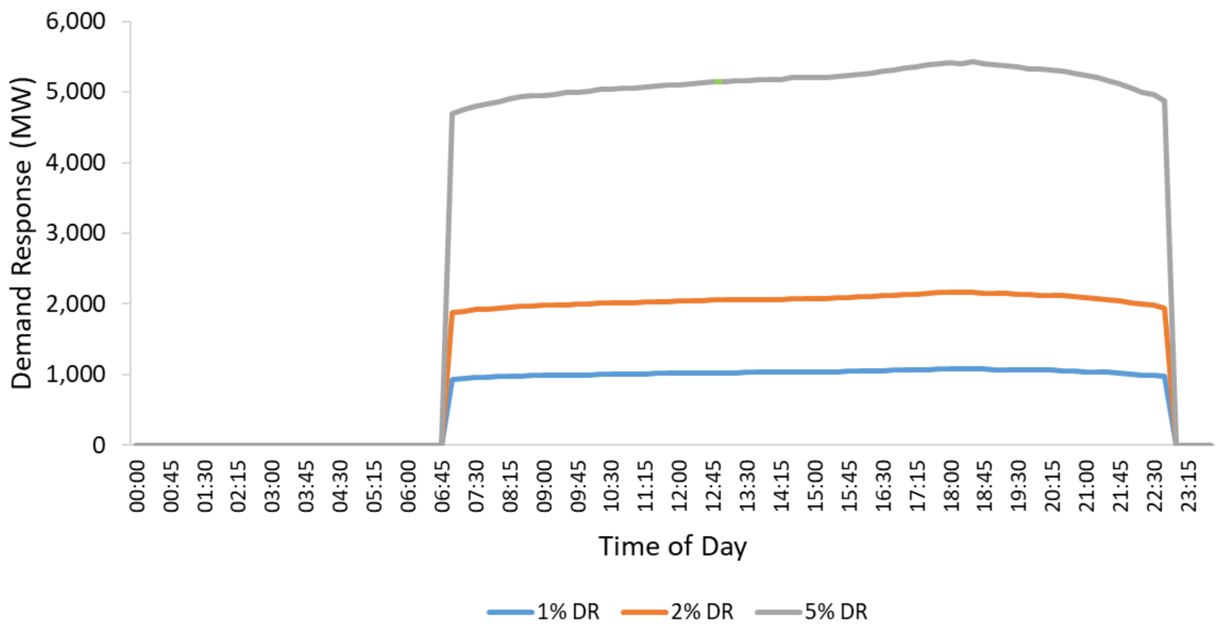


Figure 3: Average demand response (DR) MW deployed during each time interval across all days in 2022 for each DR scenario.

Figure 3 shows that the amount of DR deployed in each scenario varies during the day based on the overall load amount during each interval and is highest during the peak load hour, which typically occurs around 18:00. Table I shows the total amount of DR implemented in each scenario by month.

Table I: Amount of Demand Response in each Scenario (TWh)

Month	Base	DR = %1	DR = %2	DR = %5
January	0	0.58	1.16	2.93
February	0	0.46	0.93	2.32
March	0	0.45	0.91	2.28
April	0	0.39	0.79	1.97
May	0	0.41	0.82	2.06
June	0	0.49	0.98	2.44
July	0	0.58	1.16	2.90
August	0	0.58	1.16	2.90
September	0	0.43	0.87	2.18
October	0	0.42	0.84	2.11
November	0	0.44	0.88	2.21
December	0	0.53	1.06	2.65

As shown in Table I, July and August during the summer months and December and January during the winter months demonstrate the highest amounts of DR deployment. These months typically have the peak electricity demand during a year.

3.2. METHODOLOGY

To perform the cost-benefit analysis, PROBE PD was used to simulate the RTM and identify the system commitment and dispatch that minimizes total system bid production cost, as described in Section 3.1. The PROBE PD tool requires several input data, including unit cost curve and ramp rate information, real-time unit statuses, generator operating characteristics, and load data.

To simulate the impact of DR on the system, the simulations use actual 15-minute load data from the year 2022 adjusted to account for the various amounts of DR implemented in each scenario during the peak load hours. The DR values used in each scenario were calculated as a percentage of the base case system load, as discussed in Section 3.1.

In order to quantify the cost and benefits derived from implementing DR in each scenario, both the cost associated with DR and the savings achieved through its implementation were calculated. The cost of implementing DR is calculated as shown in equation (1).

$$C_{DR} = \sum_{n=1}^{365} \sum_{i=1}^{24} \left(LMP_{i,n} \times E_{DR_{i,n}} \right) + \left(C_{UPLIFT_{DR}} - C_{UPLIFT_{BASE}} \right) \tag{1}$$

Where the $LMP_{i,n}$ is the average system locational marginal price (LMP) in PJM at time *i* on day *n*, $E_{DR_{i,n}}$ is the amount of DR deployed in MWh, $C_{UPLIFT_{DR}}$ is the total system uplift in the DR case, and $C_{UPLIFT_{BASE}}$ is the total system uplift in the base case. Total system uplift is calculated as the summation of the differences between each unit's costs and revenues over a single day and is a crude approximation of PJM's settlement calculation that is much more granular.

The savings obtained from implementing DR are calculated as shown in equation (2).

$$S_{DR} = \left(REV_{ENERGY_{BASE}} - REV_{ENERGY_{DR}} \right) + \left(REV_{SR_{BASE}} - REV_{SR_{DR}} \right) + \left(REV_{PR_{BASE}} - REV_{PR_{D}} \right) \tag{2}$$

Where $REV_{ENERGY_{BASE}}$ and $REV_{ENERGY_{DR}}$ represent the generator energy revenue in the base case and the DR case respectively, $REV_{SR_{BASE}}$ and $REV_{SR_{DR}}$ represent the synchronized reserve revenue in the base case and the DR case respectively, and $REV_{PR_{BASE}}$ and $REV_{PR_{DR}}$ represent the primary reserve revenue in the base case and the DR case respectively.

The net benefits of implementing DR are calculated as shown in equation (3).

$$B_{DR} = S_{DR} - C_{DR} \tag{3}$$

Where B_{DR} is the net benefit of the DR implementation over a given year.

4. RESULTS

Table II shows the total generator energy revenue for the base case and all three DR scenarios by month in 2022.

Table II: Generator Energy Revenue for the Base and Demand Response Scenarios in 2022 by Month ($B)

Month	Base Case	DR = %1	DR = %2	DR = %5
January	4.04	3.88	3.72	3.39
February	2.76	2.69	2.62	2.46
March	2.54	2.46	2.40	2.24
April	3.17	3.06	2.96	2.74
May	4.13	4.01	3.90	3.60
June	5.60	5.40	5.21	4.72
July	7.04	6.72	6.43	5.74
August	7.69	7.34	7.01	6.22
September	4.39	4.28	4.15	3.84
October	2.98	2.89	2.79	2.53
November	3.04	2.99	2.87	2.64
December	6.04	5.81	5.52	4.92
Year 2022	53.42	51.53	49.58	45.03

From the results in Table II, it is clear that the implementation of DR leads to reduced generator energy revenue, which results in savings to load. The revenue reductions range from $1.9 billion when applying 1% DR to $8.4 billion when incorporating 5% DR. Table III shows the total amount of load savings obtained in each DR scenario.

Table III: Load Savings for each Demand Response Scenario in 2022 by Month ($M)

Month	DR = %1	DR = %2	DR = %5
January	162.0	320.1	648.2
February	72.3	143.0	300.3
March	75.0	136.9	296.5
April	113.3	213.7	438.0
May	117.6	229.7	528.7
June	200.0	384.5	878.2
July	326.5	616.7	1,304.8
August	353.3	686.0	1,478.0
September	109.5	239.0	551.0
October	91.0	189.5	458.1
November	47.4	165.9	394.0
December	224.2	512.7	1,113.5
Year 2022	1,892.0	3,837.5	8,389.1

As shown in Table III, the highest load savings occur during the summer and winter months when the highest system load occurs. DR effectively reduces system load and replaces the need for expensive peaking generation on the system. Specifically, August shows the highest amount of load savings across all months, with the 5% DR scenario potentially reaching nearly $1.5 billion in load savings.

Along with reducing generator revenues and load payments, the implementation of DR also reduces LMPs on the system. By reducing system load, less cost-effective generators can be kept off the system during the peak hours, and more efficient lower marginal cost resources can set prices during a greater period of time. Figure 4 shows the monthly breakdown of the system average generation-weighted LMPs for each scenario in 2022.

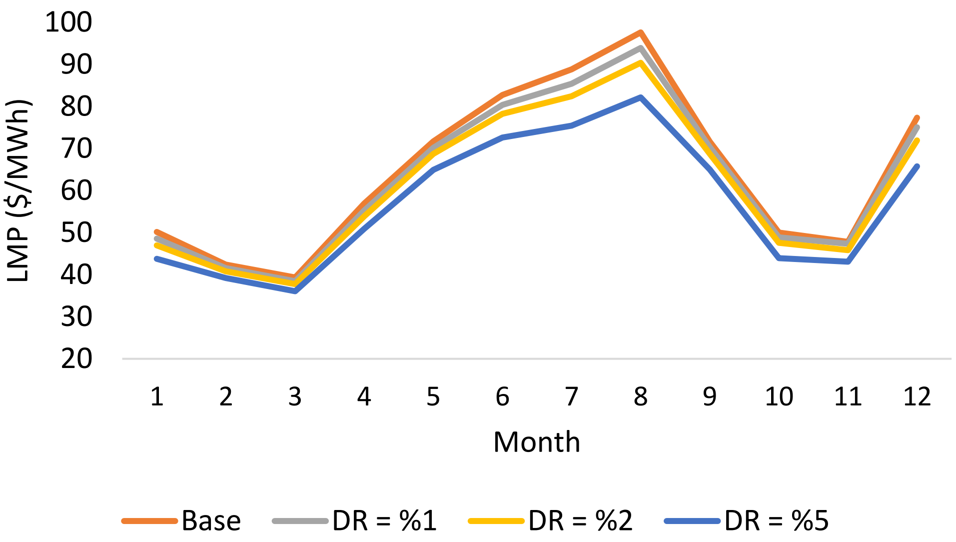


Figure 4: System average generation-weighted locational marginal prices (LMPs) in 2022 by month for each scenario.

Figure 4 illustrates that implementing DR leads to a reduction in the system's average generation-weighted LMP. The decrease is more significant during the summer and winter months when DR plays a bigger role on the system.

Moreover, the use of DR decreases the need to operate inefficient peaking generators on the system. Table IV shows the change in system dispatch for each unit type in 2022.

Table IV: Change in System Dispatch for each Unit Type in 2022 (MWh)

Unit Type	**DR = %1**		**DR = %2**		**DR = %5**	
	MWh Change	***Percentage***	***MWh Change***	***Percentage***	***MWh Change***	***Percentage***
CT	- 1,051,150	- 5.74%	- 2,055,408	- 11.22%	- 4,441,599	- 24.25%
Diesel	- 17,261	- 6.60%	- 38,824	- 14.85%	- 91,823	- 35.12%
Fuel Cell	0	0	0	0	0	0
Hydro	- 106	- 0.01%	- 156	- 0.01%	- 4,419	- 0.03%
Landfill	- 906	- 0.09%	- 1,853	- 0.19%	- 3,421	- 0.35%
Nuclear	51	0.00%	- 39	- 0.00%	- 468	- 0.00%
Solar	0	0	0	0	0	0
Steam	- 4,700,750	- 1.02%	- 9,461,909	- 2.06%	- 24,412,057	- 5.30%
Wind	0	0	0	0	0	0

Table IV shows that DR has a noticeable impact on the dispatch of the more inefficient units on the system. The steam, combustion turbine (CT) and diesel units have the most significant decrease in dispatch in MWh. On the other hand, there is no change or very little change in the dispatch of renewable resources and nuclear units.

As indicated in equation (3), the total net benefit of DR implementation can be calculated from the difference between the total load savings obtained from DR and the total DR costs. Table V quantifies the DR net benefit for each month as well as the overall net benefit for the year 2022.

Table V: Net Benefit of Demand Response in 2022 by Month ($M)

Month	DR = %1	DR = %2	DR = %5
January	132.4	263.7	524.4
February	52.5	104.7	212.3
March	56.4	101.0	214.7
April	89.8	168.3	335.3
May	85.0	165.9	381.2
June	153.7	295.2	675.5
July	268.4	505.5	1,056.3
August	290.4	565.4	1,211.1
September	74.2	170.5	391.6
October	68.2	145.6	360.5
November	23.9	121.4	293.8
December	181.3	432.2	943.6
Year 2022	1,476.1	3,039.4	6,600.2

Table V highlights the potential system net benefit from DR, ranging from $1.48 billion with 1% DR implementation to $6.6 billion with 5% DR implementation. The results shown in Table V are also plotted in Figure 5.

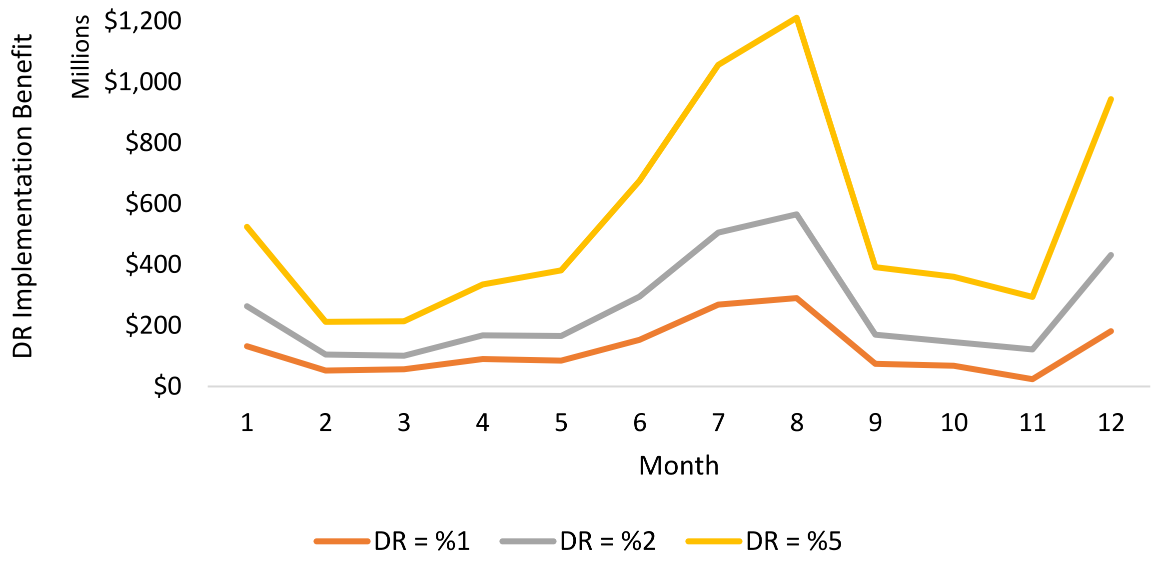


Figure 5: Net benefit of demand response in 2022 by Month.

While there may be days when the net benefits decrease after incorporating DR, or the load savings are not as significant, the overall net benefit of adding DR to the system remains consistently positive. Even during the shoulder months such as October and November, implementing DR has the potential to add significant value to the system.

5. DISCUSSION

This study aims to quantify the impact of DR on PJM's wholesale energy markets by simulating three DR scenarios with DR levels of 1%, 2% and 5% of the base system load. These values represent realistic ranges of DR of 1,000 MW to 5,000 MW during peak load hours on the PJM system. The simulation results showed the potential net benefits range from $1.48 billion for 1% DR implementation to $6.6 billion for 5% DR implementation.

The results also revealed a substantial added value to the system with the incorporation of DR. As indicated in Table II, DR played a crucial role in alleviating system pressure during high-demand months in the summer and winter. During these times, when electricity demand is at its highest, DR allows the power system to curtail or shift non-critical loads. Additionally, it ensures a more stable and reliable power supply by enabling utilities to effectively manage sudden spikes in demand.

Moreover, the findings illustrate that the dispatch of inefficient and typically more pollution-intensive units was reduced. The most significant observed impacts were on diesel, CT and steam units, where dispatch levels decreased by 35%, 24% and 5%, respectively, when there was 5% DR implementation. The introduction of DR also showed a reduction in generator energy revenue, resulting in significant load savings, especially in the summer and winter months.

6. CONCLUSION AND FUTURE WORKS

The implementation of DR has become an increasingly important resource in power system operations. It offers enhanced reliability, affordability, efficiency and cost-effectiveness to the system. The benefits of DR are particularly pronounced during the peak load months in the summer and winter, where it effectively reduces the net load and improves the system's reliability and security.

While this study sheds light on some advantages of DR implementation in the PJM system, further exploration is warranted in future works. The impact of DR implementation can vary across different zones due to different load requirements, weather characteristics, usage patterns and other factors. Hence, future works could dive deeper into the benefits of DR at a zonal level, providing more localized insights. Additionally, investigating optimal DR deployment for various locations and times of the day and year could be another interesting topic to investigate.

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