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Economic Impacts of Behind the Meter Distributed Energy Resources on Transmission Operations

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SUMMARY

The increasing penetration of customer-owned Distribution Energy Resources (DERs) will have an impact on the economics that govern market operation. Visibility and control of local Independent System Operators (ISOs) over these resources are currently restricted or available in some form of aggregation. Additionally, non-curtailable resources pose a serious problem while balancing the market with eminent risks of over-generation and added congestion to the system. This study attempts to decouple the model at the Transmission-Distribution interface and demonstrate the following: 1) economic implications of such resources under two control strategies, 2) aspects of market dynamics affected by several DER penetration levels, 3) Potential benefits of increased ISO visibility beyond the Transmission-Distribution(T-D) interface.

KEYWORDS

Ancillary services, Behind the Meter DER, energy markets, production simulation, renewables.

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1. INTRODUCTION

Distributed Energy Resource (DER) penetration into the grid has been increasing in recent years. This could be related to advancements in technology that provide cheaper renewable energy and increases in opportunities as a result of recent policy updates (e.g., state-level Renewable Portfolio Standards [RPS] across the United States). In the state of California, all retail sellers and publicly owned utilities must procure 50% of their electricity from eligible renewable energy resources by 2030 [1]. These numbers generally do not account for residential DERs, which cannot be directly dispatched by Independent System Operator (ISO) price signals and are local to utility planning areas. There are several evolving market models taking into consideration schemes with control over these resources [2].

Several studies indicate that a larger penetration of renewable resources into the grid can potentially impact system reliability and market operations [3–14]. The key challenges associated with these resources relate directly to their operational characteristics. For example, with the variability and uncertainty associated with DER production, there is a likelihood of over-generation from non-dispatchable units. The existing and planned generation fleet will likely need to operate at lower minimum operating levels for longer times, which may directly impact the economics of the system.

This paper builds on [4], which indicates reduced frequency reserves due to increased displacement of conventional generation by DERs resulting from day-ahead scheduling. This paper attempts to demonstrate the benefits of local ISO visibility over residential DER using detailed production simulations and comparing the economic impacts of having curtailable (controlled) DER units in the market. The benefits of residential DER participation in the wholesale market is clearly visible, and availability of curtailable DER units reduces displacement of conventional resources and provides a mix of generation to provide superior ancillary services.

Generally, in an ISO, DERs are classified by three categories: 1) customer-owned Behind-the-Meter (BTM) DER-, 2) merchant DER, and 3) microgrid. Among these three DER categories, the customer owned DER and the merchant DER directly impact the grid. Merchant DERs are further categorized based on their participation in the ISO markets. Participating merchant DERs are connected to the supply-side, while non-participating merchant DERs are connected to the demand-side of the grid. Typically, the local ISOs have control over supply-side DERs. These DERs are larger in size and participate in the market. The customer owned DERs are traditionally connected behind the meter (demand-side), where the DER is treated as a load modifier. BTM and Net Energy Metering (NEM) mask the generation within the available load schedule. However, for accurate modeling, it is imperative to distinguish load from generation and establish differentiated models within production and power flow simulation.

To study the market participation of these units, two scenarios are considered. The “Non-Participating” scenario, herein referred to as Scenario 1, represents current market operations wherein distribution-connected renewables deliver active power. These units are non-curtailable and do not provide reactive power support or any form of frequency support. The “Participating” scenario, herein referred to as Scenario 2, considers a model that is in compliance with the updated California Rule 21 [15] and IEEE 1547 [16] standards. Further, Scenario 2 represents a future-market model, where the local ISO has complete control over individual distribution-connected resources as well, either in the form of generation resources or ancillary services. The benefits of Scenario 2 are evaluated within this work.

The DER penetration levels considered in this study are based on the published California Energy Commission (CEC) forecasts for self-generation in the year 2024 [17]. The study was conducted using detailed production simulation. Detailed models were built, and a DER forecast was implemented at distribution and sub-transmission networks. At each interface bus, an equivalent model was developed to represent the distribution network within the ABB GridView [18] production software tool. With the models that were built for the two scenarios, studies were conducted at 100% and 200% CEC forecast penetration levels.

2. MODELING DETAILS AND ASSUMPTIONS

The simulation cost model used in this study was developed using the Western Electricity Coordinating Council (WECC) Transmission Planning Policy Committee (TEPPC) 2024 economic model. The base model was modified to match the High Distributed Generation (DG) portfolio scenario. The California Public Utilities Commission (CPUC)-approved 1,325 MW of energy storage (as modeled in the TEPPC 2024) was used, and Diablo Canyon (2,400 MW) nuclear units were considered in-service. Publicly available CEC-forecasted loads for the year 2024 were used as the foundation to include PV and non-PV generation in the California region.

The additional DER self-generation was added at select buses throughout the state of California's major utilities (i.e., PG&E, Southern California Edison [SCE] and SDG&E) by reviewing the California resource maps for future renewable development and resource forecasts. Loads were also added at these locations to offset the generation for 100% CEC generation values.

Fig. 1 depicts the generic, developed model used to represent DER at each interface bus. The model includes BTM inverter units (CEC PV DG units) and their associated impedances for connection to the interface transmission bus. The rotating-machine-based DGs (CEC Non-PV DG units) and their associated impedances are also included in Fig. 1. Dispatchable inverter-based PV units correspond to merchant DER that exists in the base case and is represented as DG1. PV and non-PV generators were interconnected at appropriate voltage levels through equivalent impedances and the DG interconnection transformer.

The following assumption were made while modeling the case:

- The additional self-generation was modeled at several buses ranging from 4.7 kV to 230 kV, and the self-generation units modeled included PV (residential) and non-PV (commercial generation) units. Based on 100% CEC forecast penetration, the total generation added was 4,000 MW, which included 2,100 MW of PV and 1,900 MW of non-PV generation.
- In the 200% penetration scenario, the total generation added was 8,000 MW, which included 6,100 MW of PV and 1,900 MW of non-PV generation.

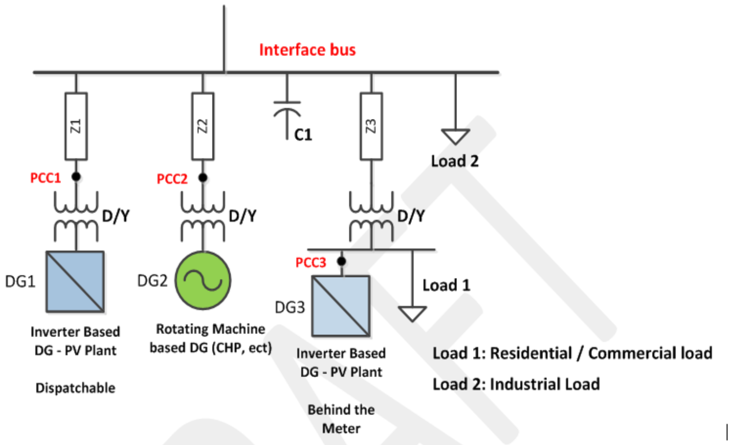

Fig. 1. Interface bus representation in the model.

- Under the assumption that load is directly offset by the increase of self-generation, a total of 4,015 MW of load was added at the same location. For accuracy, loads and generations were modeled separately. This load was carried into the 200% penetration scenarios without any changes.
- In Scenario 1, the newly-added CEC generation was made non-curtailable; in Scenario 2, the newly-added CEC generation was made curtailable with a curtailment price of $0.
- DER dispatch and load schedules were allotted using original base-case forecasts. Stochastic variability was added using random distribution.

- A zero-export constraint was imposed for regions where the local ISO is not allowed to export energy at any point in time.

3. PRODUCTION COST SIMULATION – 100% AND 200% CEC PENETRATION LEVELS

This study includes an analysis of energy and ancillary service market operations, impact of import/export constraints, and congestion analysis, while also considering comparisons between scenarios with non-curtailable and curtailable DER units.

3.1. Grid Operational Trends in Scenario 1

With the increase in DER penetration, there is a possibility of increase in late-afternoon ramp-up and mid-morning ramp-down operational requirements. Net load, commonly defined as the difference between load and renewable generation from only solar and wind resources, demonstrates this ramp requirement.

The generation variability was also analyzed to understand contribution from other generation sources during hours of peak and off-peak PV availability. The spring off-peak day is discussed in detail, as this case has the highest ramp-up and ramp-down requirements and could significantly impact market operations.

Fig. 2 and Fig. 3 depict the load and generation variability for the 100 and 200% CEC spring off-peak cases in Scenario 1. They demonstrate the maximum delta change in ramp-up requirements around 16 to 17 hours as about 5,500 MW for the 200% CEC penetration scenario and 4,200 MW for 100% CEC penetration scenario, at the steepness point of the well-known duck curve. For both penetration levels, the Combustion Cycle (CC) and Combustion Turbines (CT) were responding to the variability in generation.

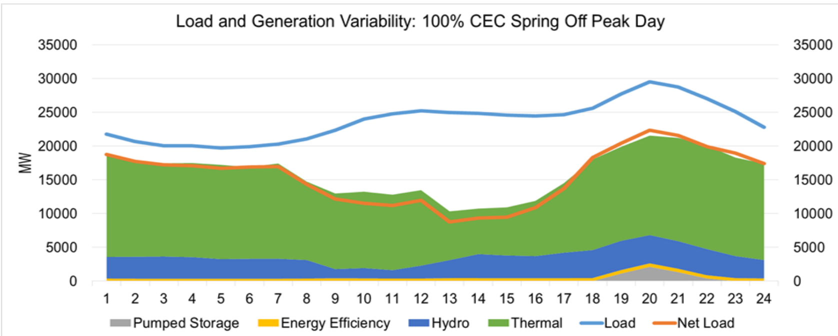

Fig. 2. Load and generation variability: 100% CEC penetration spring off-peak day.

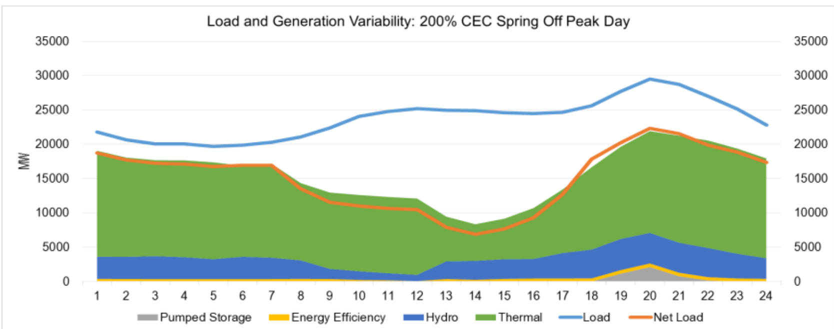

Fig. 3. Load and generation variability: 200% CEC penetration spring off-peak day.

Fig. 4 and Fig. 5 show the solar and wind merchant DER generation curtailments for 100 and 200% CEC cases in the spring off-peak case in Scenario 1. The graphs illustrate that the curtailments are more than double during peak generation hours. It was observed that higher curtailments resulted in lower average Locational Marginal Prices (LMPs) in the region. Fig. 6 shows the flows on zero-export constraint used in the study. The hours with constrained flows are directly correlated to solar and wind curtailments between hours 8 and 17. Over-generation within the region and export restrictions drive the curtailment and LMP prices. During summer- and winter-peak days, there were no curtailments observed, and the ramping requirements were less than those for the spring off-peak case.

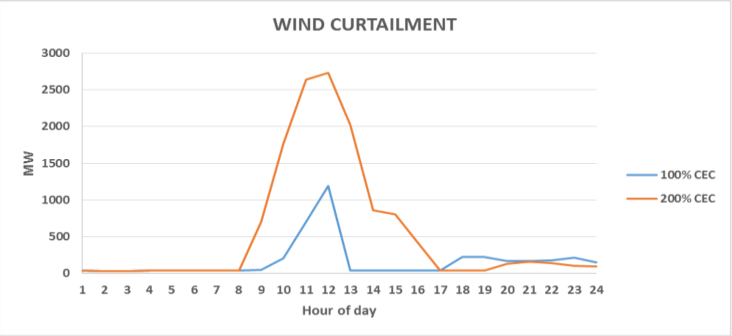

Fig. 4. Wind Curtailment for 100% and 200% CEC during spring off-peak day.

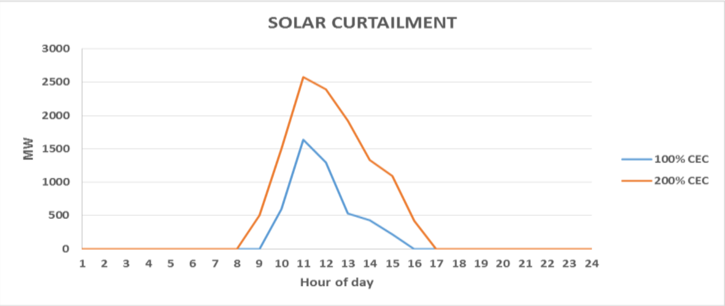

Fig. 5. Solar curtailment for 100% and 200% CEC during spring off-peak day.

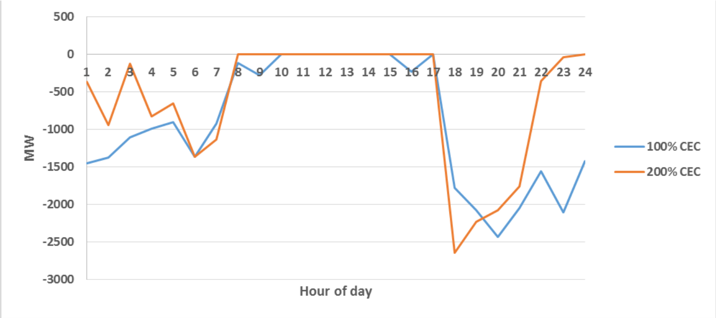

Fig. 6. Region zero export constraint flows.

3.2. LMP Variation and Congestion in Scenario 1

The LMPs within the region were evaluated using both penetration levels to identify the impact of non-curtailable generation on regional average LMPs weighted by generation and load.

Availability of cheaper generation in the form of renewables can impact LMP prices during peak hours and off-peak hours. Redispatch of resources locally within the region under study could lead to congestion. Hourly simulations for select days in spring, summer, and winter were used to simulate the change in system operational costs and network congestion. It has been observed that congestion on the zero-export constraint closely trails the regional LMP congestion component and hourly resource curtailment. During the spring off-peak days, the congestion on the zero-export constraint is responsible for the large difference in LMPs between the 100 and 200% scenarios. The shadow price is more prominent in the 200% CEC penetration case due to additional generation in the system. The LMPs in the region reflect a dip during the hours from 9 to 17. During the spring off-peak day, 200% CEC penetration cases show a larger decline in region LMPs due to additional non-curtailable resources and larger congestion on zero-export constraint.

Figs. 7 and 8 show the region load-weighted LMP and LMP-congestion component, respectively, for the spring off-peak day. Fig. 9 shows the shadow price of the zero-export constraint and how it directly relates to the constraint flows shown in Fig. 6, thereby justifying the reduced LMPs in the region.

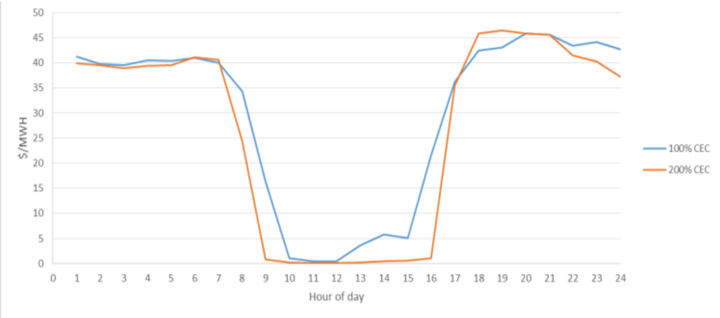

Fig. 7. ISO region load weighted LMP: spring off-peak day.

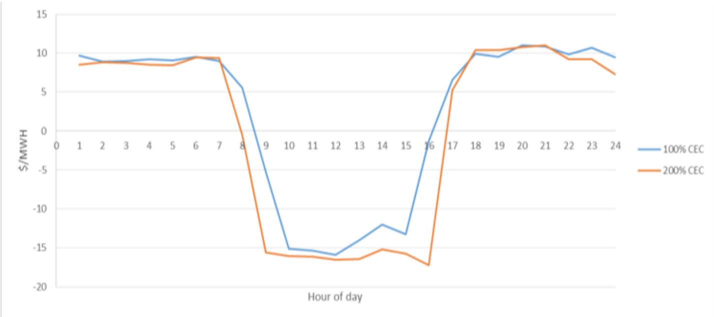

Fig. 8. ISO region LMP congestion component: spring off-peak day.

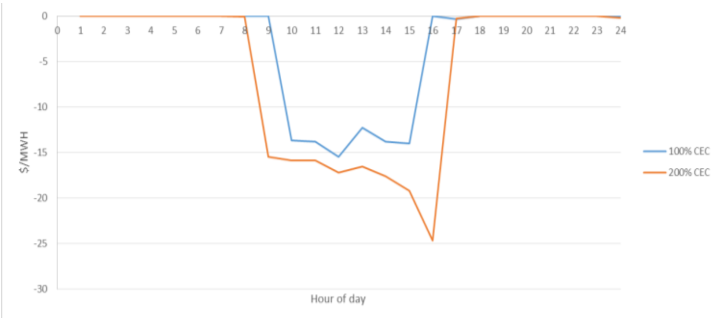

Fig. 9. Zero export constraint shadow price: spring off-peak day.

As expected, during the summer- and winter-peak days, the LMPs in the 200% CEC case show reductions as compared to the 100% CEC case. It is observed that during the summer-peak day, the region zero-export constraint is never binding and results in a closely comparable load-weighted LMP and LMP-congestion component. During the winter-peak day, the largest dip in LMP price is observed during hours 9 through 11 when the most congestion is observed on the interface.

3.3. Energy Markets and Reserves in Scenario 1

The increased penetration of DER resources contributes to cheaper resources of energy available to the system during peak hours of the day. There is some concern associated with the fulfillment of ancillary services, which includes the satisfaction of spinning reserve, non-spinning reserve, flexible down, flexible up, regulation up, and regulation down. The three considered days were studied in detail to draw conclusions on energy market and reserve performance within the region. An increase in the uplift costs moving from base to 100 and 200% was noted, and the energy prices in the 200% CEC case are lower as a result of lower LMPs.

Fig. 10 shows the net generator revenue (profit) for spring off-peak day, and a negative generation profit can be noted, which is indicative of uplift charges. It should be noted that the uplift charges are only during times of high DER penetration and having DER resources that are non-curtailable further add to the uplift charges.

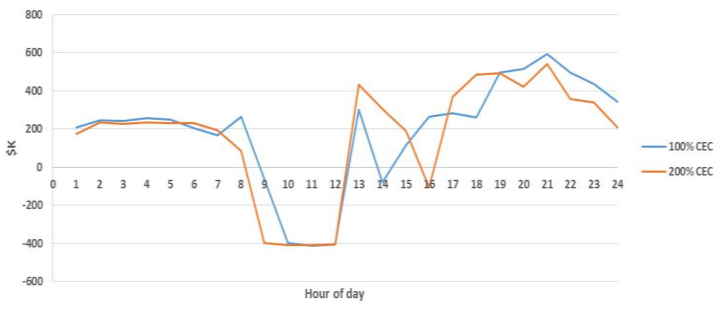

Fig. 10. Generation profit ($K) in the region: spring off-peak.

Table 1 lists the annual uplift charges as a result of a difference between production cost and LMP payment. Uplift was observed to increase in both the 100 and 200% CEC cases.

Table 1: Annual uplift charges in Scenario 1

Base	100%	200%
$0.2B	$0.88B	$1.04B

In the 100 and 200% CEC scenarios, capacity shortfalls were observed in flexible down and regulation down based on yearly runs. No shortfalls were observed from any of the other ancillary services. In order to participate in flexible down or regulation down, the generation must be operating at a level higher than P_{min}. The maximum flexible-down shortfall of 1,500 MW was observed during the spring off-peak day. From the revenue calculated from ancillary service and energy markets, it is observed that the increase in non-curtailable PV and non-PV additional self-generation in Scenario 1 reduces the energy market revenue as a whole due to the availability of cheaper renewable generation. This leads to reduced LMPs, but the increased revenue in the ancillary service market shows additional requirements of generation units with flexible-up/flexible down and regulation-up/ regulation-down capabilities.

3.4. Scenario 2 and its Comparison to Scenario 1

Scenario 2 represents a case where all CEC generation (DER) was made curtailable. The objective was to model a case where additional CEC units were allowed to respond to curtailment signals during hours of over-generation. In the real world, this would mean local ISO has jurisdiction to control BTM generation connected to the distribution network (similar to their control exercised towards merchant DER units).

Overall, the results between the Scenario 2 and Scenario 1 studies are comparable. Several distinct observations can be made on additional leverages granted to the local ISO under Scenario 2. The balance of LMPs throughout the system demonstrate higher social welfare. The value of this is reflected in the reduced uplift costs. The visibility of the ISO market operations extends beyond the local transmission nodes, thereby enabling efficient control. This is directly reflected, even in the reduced congestion costs in Scenario 2, for both 100 and 200% CEC penetrations.

In Scenario 2, larger curtailments were observed from the CEC generation resulting in reduced shadow price and reduced congestion on zero-export constraint. The annual curtailments were compared between Scenario 2 and Scenario 1. Scenario 1 recorded curtailments on the order of 410 GWh in the 200% case and 104 GWh in the 100% case. Scenario 2 recorded curtailments of 392 GWh in the 200% case and 81 GWh in 100% case. Over all curtailment is lower in Scenario 2 as a result of less curtailment in non-DER and larger-capacity resources.

The binding nature of the zero-export constraint imposed during times of high DER penetration on a spring off-peak day gives the local ISO greater flexibility in curtailments during hours of over-generation. This enables the ISO to provide better ancillary services and would improve the reliability and frequency response of the system while operating the market more efficiently.

In Scenario 2, due to the reduced non-DER curtailments, the revenue from ancillary service market and uplift payments are is lower. Also, reduced curtailments of non-DER resources greatly increases the system stability and the frequency response by having generators with more inertia and headroom in-service.

4. CONCLUSIONS

Two scenarios were created by considering PV and non-PV self-generating DERs. In the production simulations for Scenario 1, the self-generating DERs added to the base case were treated as BTM units that the local ISO has no control over (i.e., non-curtailable). In contrast, Scenario 2 represents a near-future grid condition wherein the ISO does have control over the distribution network and BTM DER units can be curtailed. Each scenario was studied under 100 and 200% CEC penetration-level conditions (two cases).

The studies show a large displacement in conventional(thermal) units to compensate for larger penetration. The displacement is higher in Scenario 1 than in Scenario 2. With the CEC 200% forecast, faster ramp up was required for late afternoons and faster ramp down for mid-morning. This resulted in an increase in uplift payments and an increased need for ancillary services. However, in Scenario 2, a reduction in uplift payments and ancillary service market revenue was observed. This could be related to higher DER curtailment in Scenario 2 but lower overall curtailment as a result of reduced non-DER hourly curtailment as compared to Scenario 1. Reduced total curtailment in Scenario 2 could be directly related to increased stability and reliability of the system by more flexible generation redispatch and governor response in case of a grid event.

Therefore, it could be concluded that the grid can operate with greater efficiency from an economic and reliability standpoint in the scenario where local ISO has control over the DER-BTM units (Scenario 2).

Future tasks include analyzing Scenario 2 with appropriate non-zero curtailment prices to better understand the extent of curtailment, impact on LMPs, and ramping requirements on the duck curve. Different sensitivity scenarios need to be studied for greater insight into the over- and under-commitment of resources, stranded assets, and the impact of PV-forecast variability on real-time market operations. Studies should be performed that include the Energy Imbalance Market (EIM) scenario in the market model.

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