Impact of Detailed Parameter Modeling of Open-Cycle Gas Turbines on Production Cost Simulation

Preprint

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Impact of Detailed Parameter Modeling of Open-Cycle Gas Turbines on Production Cost Simulation

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***Abstract*—Flexible resources are increasingly important as variable renewable energy deployment in the power system increases. Although many systems are transitioning away from fossil fuels, open-cycle gas turbines are likely to play an important balancing role for some time, thus requiring accurate modeling of their operational parameters. This paper explores the impact of detailed representation of three operational parameters—start-up costs, run-up rates, and forced outage rates—in the production cost model of a system as it adopts higher levels of wind and solar. Using PLEXOS simulations of the NREL-118 bus test system, the study examines how more detailed parameter modeling affects outcomes such as the number of start-ups and shutdowns, ramping and total generation costs for open-cycle gas turbines, as renewable energy levels increase. The results suggest the value of detailed parameter modeling and continued research on combustion turbines' ability to provide flexibility.**

***Index Terms*—Economic dispatch, energy markets, open-cycle gas turbine, production cost simulation, unit commitment**

I. Introduction

In 2022, solar photovoltaics (PV) accounted for about 18% of California's total net electricity generation [1]. For the United States, the combined wind and solar share of total generation increased from 12% to 14% from 2021 to 2022 [2], reflecting a trend toward greater integration of variable renewable energy (VRE) in the country. The combined share of renewable energy generation under "business as usual" is expected to be 44% by 2050 [3], with potentially much higher levels if the U.S. pursues more aggressive decarbonization. Though these changes have numerous advantages, the variability and uncertainty associated with renewable energy resources pose new operational and economic challenges to the grid. A manifestation of one of these challenges is represented by California Independent System Operator's (CAISO's) well-known net-load or "duck" curve [4], which reflects the increasing need for ramping of other resources to manage large changes in solar output in early morning and late evening. Fig. 1 shows the changing shape of CAISO's net-load curve, having a deeper "belly" in April 2023 than in May 2018, with the net load dropping below zero during the day, when solar PV generation is dominant. The trend seen in Fig. 1 is evolving into a "canyon" curve [5], necessitating fast-response and flexible units that can manage the steep ramping requirements

Figure 1. CAISO's duck curve comparison for a spring day of 2018 and 2023. Reproduced from [5].

Gas turbines are one option that could provide many of the characteristics required to respond rapidly to changes in the net-load balance. These include effective cycling requirements, such as continuous upward or downward ramping capability, quick run-up and ramp rates, and features required to quickly start up or shut down. In the United States, there are over 1,500 gas-fired power plants, which accounted for about 39% of generation in 2022 [2]. Gas turbine technologies include combined-cycle gas turbines (CCGT) and open-cycle gas turbines (OCGT). In 2021, OCGTs accounted for 28% of gas-based generation [2]. OCGTs have a much lower average capacity factor than CCGTs due to higher operational costs, and they have historically been used as peaking units to manage quick-ramping requirements. The lower overnight build-cost of OCGTs as well as their ease of installation has historically advantaged them over CCGTs as peaking units. As the use of OCGTs for balancing VRE grows, it will be important to incorporate more short-term operational constraints into their production cost models for more realistic unit commitment (UC) results.

Assessments of associated impacts of operational constraints are needed to perform production cost simulation (PCS) studies, which come under the field of power system operation and planning. Some of the key operational parameters for modeling OCGTs, such as start-up profiles (hot and cold

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starts), run-up rates, and equivalent forced outage rates (EFORs) are not included in some publicly available PCS databases such as the NREL-118 bus database [6]. This paper describes incorporating these three operational parameters and presents the obtained PCS results in different VRE generation scenarios. The results of this current work are analyzed to evaluate the impact of these parameters on the overall system costs, generation costs of OCGTs, and the operational requirements, such as the number of start-ups/shutdowns for OCGTs and their ramping profiles.

This paper is organized as follows. Section II describes the short-term operational constraints and parameters for OCGTs for performing PCS studies in PLEXOS, including the additional operational parameters introduced in this study. Section III describes the test system, NREL-118 bus, VRE scenarios, and OGCT parameter study cases for which PCS studies were performed. Section IV provides details of the simulation parameters in PLEXOS and presents the results. Section V summarizes the study conclusions.

II. MODEL FORMULATION

Unit commitment (UC) and economic dispatch models based on direct current optimal power flow are widely used for PCS studies to ensure the economic and reliable operation of the power system. They are used to determine the least-cost operational day-ahead (DA) schedule for each period over a selected horizon. UC is a mixed-integer linear programming problem that is difficult to solve, especially with the incorporation of detailed short-term operational constraints and time series data for the VRE resources.

For this study, we use the power system optimization tool PLEXOS to perform PCS analysis. The tool has been widely adopted by industries and researchers to carry out ambitious grid integration studies [7]. For this paper, PLEXOS's production costing feature (or short-term schedule) is used to solve for a full year of DA scheduled UC and economic dispatch at an hourly resolution, by co-optimizing over distinct operational constraints of varying generation technologies and time series VRE (solar and wind) and load data. The generation units are dispatched based on their short-run marginal cost (SRMC), which is the unit's variable cost for producing one more megawatt of generation. The SRMC is a function of the fuel cost in a particular period in addition to the variable operation and maintenance (VO&M) charge. In PLEXOS, production cost formulation for each generator and their types can be customized according to the data and selected parameters or options [8]. Here a generic UC formulation based on the dispatching of units as per their SRMC is given below [9][10]:

$$\text{Minimize } \sum_t \sum_g \mathrm{MC_g} \,.\, \mathrm{P_{g,t}} + \mathrm{C_{g,su}} \,.\, \mathrm{u_{g,t}} \quad (1)$$

$$\text{Subject to } 0 <= \mathrm{u_{g,t}} <= 1 \quad (2)$$

$$\sum_g \mathrm{u_{g,t}} \,.\, \mathrm{P_{g,t}} = \mathrm{D_t} \quad (3)$$

$$\mathrm{u_{g,t}} \,.\, \mathrm{P_{g,min}} <= \mathrm{P_{g,t}} <= \mathrm{u_{g,t}} . \mathrm{P_{g,max}} \quad (4)$$

$$\mathrm{P_{g,t+1}} - \mathrm{P_{g,t}} <= \mathrm{R_{g+}} \quad (5)$$

$$\mathrm{P_{g,t-1}} - \mathrm{P_{g,t}} <= \mathrm{R_{g-}} \quad (6)$$

The SRMC of a generator g, is given by $\mathrm{MC_g}$. The objective is to minimize total system cost for all time periods, t. The total system cost in Eq. (1) is the SRMC of the unit times its generation in that period $\mathrm{P_{g,t}}$, in addition to the start-up cost of the unit $\mathrm{C_{g,su}}$, considering it is committed or $\mathrm{u_{g,t}}$ = 1. The first constraint, Eq. (2) just enforces the UC variable to be binary. Eq. (3) ensures the system-wide demand, $\mathrm{D_t}$, is balanced in all periods. The third constraint (4) ensures the unit's output is between its min stable level, $\mathrm{P_{g,min}}$ and its max capacity, $\mathrm{P_{g,max}}$, once it is operating. Eqns. (5) and (6) depict the generic ramp rate constraints, with limitations due to the max ramp-up parameter, $\mathrm{R_{g+}}$ and max ramp-down parameter, $\mathrm{R_{g-}}$.

The base parameters modeled for OCGTs for PCS include min stable level, max ramp rates, min uptimes and downtimes, and fixed start costs. Heat rate modeling is included to optimally determine the fuel costs for a period. For the OCGTs part of the NREL-118 bus system, the heat rate modeling is done by specifying a base heat rate along with multiple pairs of heat rate increments and load points. The fuel cost is computed by multiplying the heat rate increment (BTU/kWh) corresponding to the load point segment with fuel price ($/MMBTU). VO&M charge ($/MWh) is also modeled for all the OCGTs. This charge is used to recover maintenance costs such as wear-and-tear costs and other regular equipment replacement and servicing costs.

A. *Start-up profiles*

Next, we present the additional operational constraints included in our study that are relevant to OCGTs. Two starting modes are modeled for each OCGT unit: hot start and cold start. The categorization is based on the time required since the last shutdown for the unit to start up again, and each start mode incurs a specified fixed start cost. The start-up profile in PLEXOS has a multiband feature with start cost times linked to their respective fixed start costs. The hot start time is assumed to be 1 hour for each OCGT, and the cold start time is assumed to be 2 hours since the last shutdown. These start times are more reflective of existing, grid-connected OCGTs since newer OCGTs can have much shorter hot and cold start times [11].

These parameters offer the best assumption of start times for OCGTs because PCS is performed on an hourly resolution. For this reason, warm starts, which fall in the middle of the start-up profile between hot starts and cold starts, are not modeled. Their inclusion would further delay the cold start time by at least an hour, making it unrealistic for flexible units such as OCGTs. The fixed start cost for a hot start is assumed to be the same value as provided in the base case for OCGTs part of the NREL-118 bus [6]. Because the cost is higher for restarting a unit at or after a cold start time, its linked fixed start cost is assumed to be 1.3× the fixed hot start cost. This assumption is based on the projected 2030 lower bound start cost data for different generation technologies in the Intertek-Western Electricity Coordinating Council study [14].

B. *Run-up rates*

In the NREL-118 PLEXOS base case, the maximum ramp-up and ramp-down rates (MW/min) for OCGTs are modeled. This operational constraint is enforced only when the unit is committed; the ramp-up and ramp-down limitations are shown in constraints Eqns. (5) and (6) above. The modeling of this constraint by itself represents what is shown by the "block loading of unit" feature in Fig. 2 [8]. This feature assumes that the unit instantaneously reaches its $P_{g,min}$, following which it can ramp up at maximum of 3 MW/min (shown by the black line) or 180 MW/hr. However, this is a relaxed assumption, as units such as OCGTs have run-up rates associated with their start profiles (hot start, cold start). As shown by the gray line in Fig. 2 [8], this example has a run-up rate of 2 MW/min, which it adheres to until reaching its $P_{g,min}$, after which the max ramp-up rate constraint becomes active, as shown by the black line.

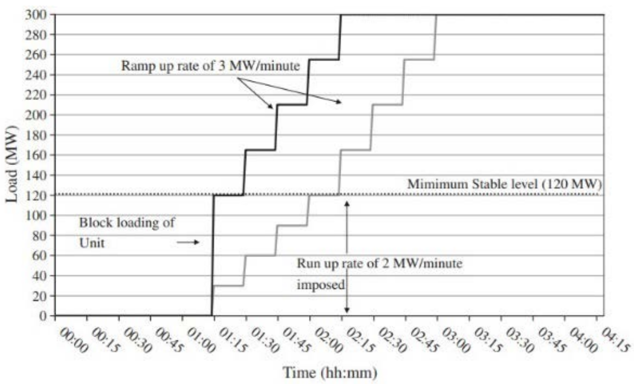

Figure 2. Example of a run-up rate. Reproduced from [8].

For this paper, model run-up rates for OCGTs in their start-up profiles, associated with hot and cold starts. The run-up rate for a hot and cold start is estimated to be a fraction of the max ramp-up rate for each OCGT. This assumption is made by analyzing input data of CCGTs part of the system [6], with their run-up rates modeled. The run-up rate for a cold start is lower than that for a warm or hot start, as the unit is slower to start after being turned off for a longer time. The modeling of run-up rates is expected to directly influence the start cost of the unit, as it now includes the fuel offtake cost while the unit is starting up, in addition to their fixed start cost.

C. Equivalent forced outage rates (EFORs)

The EFORs are modeled for each OCGT. FOR is provided in percentage (%), and it sets an expected level of unplanned outages, which could result in partial or complete loss of generating capacity for a certain period. PLEXOS uses a triangular probability distribution function [15] to model this. The associated parameters with the FO (%) are min time to repair, max time to repair, and mean time to repair. In this setup, the unit is modeled as out of service for a duration on average of EFOR×periods of the year, and the duration of outage events vary from min time to repair to the max to repair, having a maximum frequency at mean time to repair. The FORs are obtained from [16], which provides upper bound data for expected FORs for varying capacities of OCGTs.

Table I provides some of the sample parameters discussed above used to model a 200-MW OCGT in PLEXOS.

TABLE I. SAMPLE INPUT PARAMETERS FOR AN OCGT IN PLEXOS

Parameter	Value	Parameter	Value
Max capacity	200 MW	Max ramp up/down	5.33 MW
Min stable level	90 MW	Forced outage rate	6.65%
Hot start cost time	1 hour	Min time to repair	3 hours
Cold start cost time	1 hour	Max time to repair	100 hours
Hot start cost	$19,654	Mean time to repair	36 hours
Cold start cost	$25,550	Min up/down time	2 hours
Run up rate (hot start)	3.73 MW/min	VO&M charge	0.6 $/MWh
Run up rate (cold start)	2.67 MW/min	Fuel charge	5.4 $/MMBTU

As can be seen in Table 1, the EFOR has a value of 6.65%. This implies the unit is expected to be out for approximately 583 hours in the year (considering hourly resolution), with repair times ranging from 3 hours to 100 hours and having a mode at 36 hours. It may also be noted that the max ramp-up and ramp-down rates and run-up rates are low for an OCGT compared to modern-day General Electric OCGTs, which are capable of ramp rates of tens of MW/min [11]. The same is the case with minimum up and down times. However, the main goal of this paper is to assess the impact of three operational parameters (start-up costs, run-up rates, and forced outage rates) of OCGTs by benchmarking it against the PCS results of the open-source NREL-118 bus in different VRE scenarios. Hence, some of these crucial parameters are not modified for this paper.

III. TEST SYSTEM AND SCENARIOS

In this section, we describe the test system, NREL-118 bus, which was used to perform PCS studies for this paper. We also describe the different VRE scenarios and test cases for which the PCS was performed in PLEXOS. The details of this test system can be found in [6], and here we address its key features relevant to our scope.

A. NREL-118 bus system

The NREL-118 bus system is an extended version of the IEEE-118 bus system [13] and is available as an open-source economic dispatch and UC PLEXOS model. The system comprises three regions (R1, R2 and R3) in California and 10 power generation technologies obtained from the Western Electricity Coordinating Council's 2024 Common Case Database [6][12]. In summary, the system consists of 118 buses, 186 transmission lines, and 327 generators distributed across the three regions. Time-synchronous actual and forecasted data for solar, wind and regional electricity load (hourly resolution) for 1 year are also included. The constraints of the generation technologies have been modeled in detail in the production cost model. There is also an allotment of reserves, regulation up/down, and spinning reserves for each region, with a total of 234 thermal generators. The system consists of 66 OCGTs of varying generation capacity across the three regions, and the maximum capacity ranges from 1.3 MW to 200 MW. The total installed capacity for all three regions is 24.5 GW. Fig. 3(a) shows the distribution of the installed capacity by generation type.

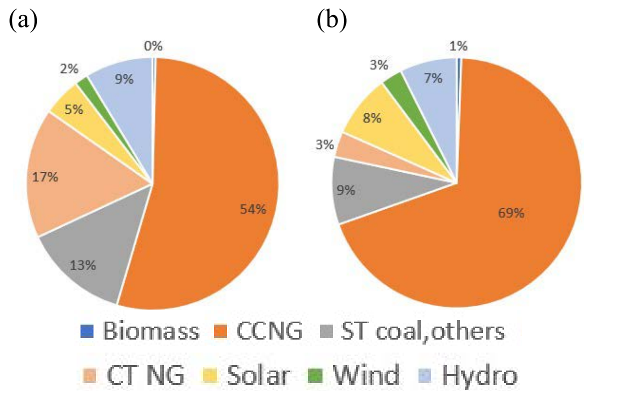

Figure 3. Distribution of the total installed capacity of 24.5 GW (a) and share of system-wide dispatch for 2024 by generation type (b).

OCGTs comprise about 4.17 GW of the combined installed capacity of 24.5 GW in the test system. Of this, R1 accounts for 1.58 GW, R2 for 0.54 GW, and R3 for about 2.05 GW. The higher share of installed capacity of OCGTs in R3 coincides with the fact that 27% of the installed capacity in R3 in the base case comes from variable forms of energy sources (18% solar and 9% wind), compared to 14% in R1 and just 8% in R2. Fig. 3(b) shows the whole year's (2024) system-wide dispatch according to the generation type. It is evident that the share of OCGTs in system-wide dispatch is quite low (3%) compared to their share in the installed capacity. The reason for this is the high operational cost, primarily fuel costs associated with OCGTs.

B. Scenarios and test cases

For this paper, PCS is performed for three VRE scenarios: low, medium, and high VRE. The Low VRE scenario reflects the NREL-118 bus base case, which has an installed solar and wind capacity as shown in Fig. 3a. We assume three times the installed capacity (3×) of wind and solar of the low VRE scenario (i.e., the base case) for each region for the medium VRE scenario, and six times (6×) the installed wind and solar capacity for the high VRE scenario. Table II summarizes the installed VRE capacity in each region.

TABLE II. INSTALLED WIND AND SOLAR CAPACITY (GW) BY SCENARIO

Region	Technology	VRE scenario		
		Low	*Medium*	*High*
1	Solar	1.16	3.47	6.93
	Wind	0.32	0.95	1.89
2	Solar	0.43	1.30	2.59
	Wind	--	0.0	0.0
3	Solar	1.80	5.40	10.80
	Wind	0.77	2.31	4.62

To study the impact of OCGT parameter assumptions, we compare results from two study cases:

- Case 1: Base case of the NREL 118 bus system with given OCGT parameters for PCS analysis;
- Case 2: Base case of the NREL 118 bus system with the additional OCGT parameters described in Section II, including start-up profiles, run-up rates, and FOR modeling for each of the 66 OCGTs.

Case 3 incorporates additional parameter modeling of Case 2 and introduces three 100-MW OCGTs at Node 18 in R1, having ramping flexibility as modern-day OCGTs [11]. These OGCTs replace 250 MW of ST Coal and CCGTs and are co-located with 981 MW of solar PV in the high VRE scenario.

All three VRE scenarios given are run for Case 1 and Case 2. Case 3 is introduced to examine the localized impact of grid integration of modern-day OCGTs with detailed parameter modeling in the high VRE scenario at a node with high installed solar PV capacity. It was observed that conventional technologies at Node 18 operate with negligible capacity factors in the high VRE scenario, so they were replaced with the OCGTs. The impact of the replacement on system-wide costs is compared using the high VRE scenario of Case 2 as the benchmark because Case 3 is a minor adjustment to Case 2.

To focus on the impact of OCGT parameter assumptions at different VRE deployment levels, we assume identical load across each of the six scenarios. As the large deployment of VRE would likely require transmission expansion, which is beyond the modeling scope of this study, we assume a copperplate transmission system with no transmission line limits imposed on any of the three regions.

IV. RESULTS

The PCS was done on a Windows workstation with Intel Xeon Gold 2.5 GHz processors. The average simulation time for each scenario for a year's worth of DA-UC was 7 hours. In total, seven scenarios were simulated: three each for Case 1 and Case 2 and the high VRE scenario for Case 3. Also, a look-ahead period of 8 hours was provided in the short-term schedule simulation settings. PLEXOS solves for this look-ahead period window in addition to the optimization period (1 day in our case) for more-accurate decision making. Gurobi 9.5 was selected as the solver with a relative optimality gap set at 0.5%.

Fig. 4 shows the system-wide net-load curve or the duck curve for the three VRE scenarios on the forecasted peak load day (07/05/2024). On the y-axis is the difference between the load and VRE (wind and solar) dispatch across the periods/hours of the day (x-axis).

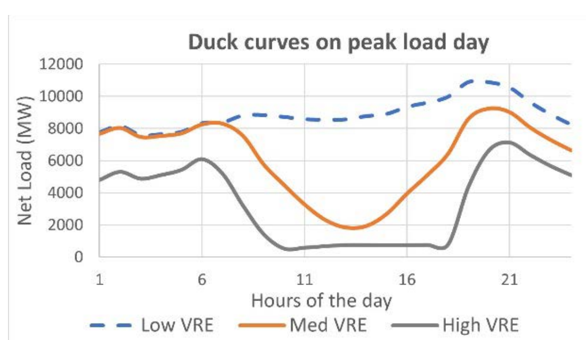

Figure 4. Generated duck curves on peak load day for different VRE scenarios.

A. Operational impacts on OCGTs

In this subsection, we analyze the operational impact, which includes the total number of start-ups, the total number of shutdowns, and the ramping requirements of OCGTs that are part of the NREL-118 bus. Table III shows the total numbers of start-ups and shutdowns annually for Case 1 and Case 2 in each VRE scenario.

TABLE III. ANNUAL START-UPS AND SHUTDOWNS FOR OCGTS

Case	Metric	VRE scenario		
		Low	*Medium*	*High*
1	Start-ups	14506	18252	21860
	Shutdowns	14507	18256	21841
2	Start-ups	12342	15624	18692
	Shutdowns	12345	15632	18680

Two findings are clearly observed in Table III. First, the numbers of start-ups and shutdowns increase as the VRE share increases. This is expected, as due to increase in variability caused by increased VRE, the flexible OCGTs, particularly the ones with higher capacity factors are required to start-up and shutdown to effectively manage load-generation balance. It is also observed that for each scenario, the total annual numbers of start-ups shutdowns decrease in Case 2 compared to Case 1. The intuitive reasoning behind this is that the additional parameter modeling of OCGTs for PCS studies results in accounting for more realistic assumptions such as the inclusion of the start-up profiles and forced outage rates in the DA-UC model.

To meet the prime objective of minimizing total system cost, the model compensates by reducing the number of starts and shutdowns while adhering to the additional short-term operational constraints. The highest number of annual start-ups and shutdowns for an OCGT is 663 each in the high VRE scenario in the base case (Case 1). Also, in the high VRE scenario, the average number of start-ups for an OCGT is 331 for Case 1 and 283 for Case 2. Fig. 5 shows the comparison of the combined annual number of start-ups (y-axis) in the high VRE scenario for a few OCGTs with the highest capacity factors found in region, R3. The largest difference is for OCGT 21 and 26 (569 versus 644 and 552 versus 628, respectively), with the decrease in the number of annual start-ups in Case 2 being about 11.7%.

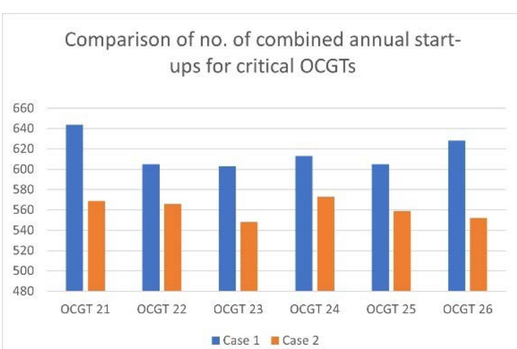

Figure 5. Combined annual start-ups for OCGTs with highest capacity factors in R3, Case 1 versus Case 2.

Next, we look at the combined results for the annual ramping requirements (ramp-up/ramp-down) of OCGTs part of the grid in the low, medium, and high VRE scenarios.

TABLE IV. ANNUAL RAMPING REQUIREMENTS (GW) FOR OCGTS

Case	Metric	VRE scenario		
		Low	*Medium*	*High*
1	Ramp up	407.7	481.7	579.9
	Ramp down	407.7	481.4	579.8
2	Ramp up	354.0	454.7	500.5
	Ramp down	353.9	454.7	500.3

As the VRE level increases, up and down ramping increases across both cases to respond to the variability in generation. Also, the ramping requirements reduce with increased parameter modeling in Case 2 for both scenarios, with up to a 13.7% decrease in high VRE scenario in Case 2 versus Case 1, for both ramp-up and ramp-down.

B. Generation and system-wide costs

In this subsection, the differences in the test system's annual costs are examined to assess the impact of additional parameter modeling for the two cases and scenarios. The total generation costs for all the OCGTs comprise the fuel cost, VO&M cost and start/shutdown (SUSD) costs. Fig. 6 shows the combined annual generation costs breakdown for the 66 OCGTs part of the system.

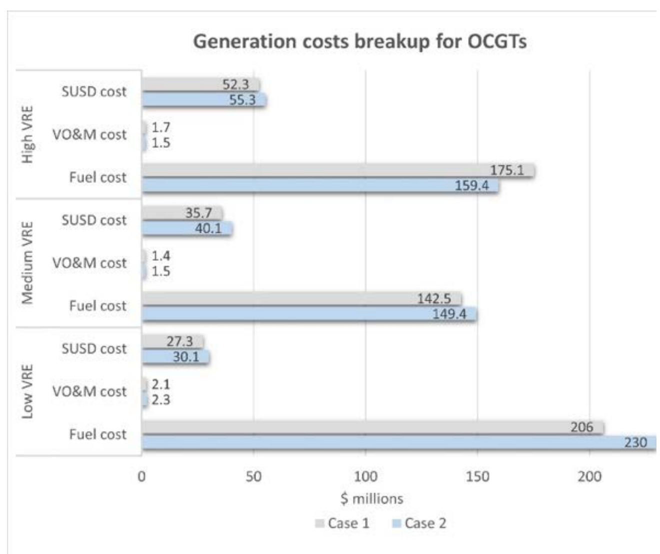

Figure 6. Combined annual generation costs breakdown ($ million)

The combined annual OCGT generation costs for all scenarios consist primarily of the fuel cost. The VO&M costs are a minor component of the overall costs. It can be seen from Fig. 6 that the total fuel costs decrease in the medium and high VRE scenarios versus the low VRE scenario. Also, and as expected, SUSD costs increase as the VRE share increases due to higher number of start-ups and shutdowns. As an example, in the medium VRE, the combined fuel cost decreases by up to 35%, and the SUSD cost increases by about 33% versus the low VRE scenario. In the high VRE scenario, the SUSD cost increases by about 84% in Case 2 versus in the low VRE scenario for the same case. It is also observed that for both the low and medium VRE scenarios, all generation cost components are higher for Case 2 than for Case 1. The modeling of start-up profiles in Case 2 results in (1) additional SUSD costs due to the fuel offtake from including different run-up rates and (2) higher fixed start costs for cold starts.

In Case 1, the total fuel cost in high VRE setting is greater by 23% versus medium VRE, whereas the corresponding increase is only about 6% in Case 2. This shows that the role of OCGTs in dispatch becomes prominent as the share of VRE is drastically higher (6× low VRE). However, in medium versus high VRE scenario, the increase in fuel cost in Case 2 is not as significant as in Case 1; this is because the stricter start-up profiling in Case 2 limits the operation of OCGTs. The increased flexible requirements in high VRE cannot be met at the level as the base case, with the additional restrictions imposed on OCGT operations. This also results in a lower total generation cost in Case 2 than in Case 1 for high VRE.

Next, we look at the comparison of annual system-wide costs for the two cases in the three VRE scenarios. In our assumed model, the system-wide costs include the annual cost of operation of all the generation technologies across the three regions. The absolute change is an increase of up to $20 million in low and medium VRE scenarios.

TABLE V. ANNUAL SYSTEM-WIDE COSTS COMPARISON

Case	**Units**	**VRE scenario**		
		Low	***Medium***	***High***
1	$billion	4.40	3.39	2.48
2	$billion	4.42	3.41	2.50
Difference	$million	20	20	17

C. *Case 3: Grid integration of modern-day OCGT*

This case extended Case 2 to examine the effect of grid integration of modern-day OCGTs [11] with quick ramping and run-up rates. The integration of 3 × 100-MW OCGTs was done at a node in region, R1, which has a relatively high solar PV deployment (about 1 GW in the high VRE scenario). As mentioned in Section III, this case was only simulated for the high VRE scenario, in which OCGT technology becomes critical as peaking units. Case 2 resulted in an annual cost of $2.5 billion and Case 3 $2.49 billion, indicating an annual savings of $10 million.

V. CONCLUSION

This paper studies the annual impact of detailed parameter modeling of OCGTs on operational and economic variables from production cost simulation results. The impact was examined using PLEXOS simulations on the NREL-118 bus system with varying levels of VRE. The addition of three operational constraints in production cost models for grid-connected OCGTs (Case 2) resulted in an increase of $20 million in total annual system costs.

The benefit of small-scale grid integration/replacement with modern OCGT technology was also examined at a node with high solar levels, resulting in a reduction of total annual system cost by $10 million in the high VRE scenario. As the role of OCGTs will become increasingly vital in future years, for future work, it would be interesting to model the modified test system at subhourly resolution considering the fast operation of modern OCGT technology. Doing so would help in incorporating more details in the start-up profiles, such as warm starts, of the flexible units' part of the grid and would thus result in more-accurate projections.

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