

Leveraging Energy Storage Resources to Improve Combined Cycle Gas Turbines Operational Efficiency

Fengyu Wang, Ryan Ebarb, Humberto Morales, Olga Lavrova

Klipsch School of Electrical and Computer Engineering,
New Mexico State University, Las Cruces, NM, USA, 880011
{fywang; rlebarb; hm154; olavrova} @nmsu.edu

Liang Sun

Department of Mechanical and Aerospace Engineering,
New Mexico State University, Las Cruces, NM, USA, 880011
lsun@nmsu.edu

Yazhou Jiang

Department of Electrical and Computer Engineering
Clarkson University, Potsdam, NY 13699
yjiang@clarkson.edu

Zhongyu Wu

Midcontinent Independent System Operator, Carmel IN, 46032
zwu@misoenergy.org

Abstract – Combined-cycle Gas Turbines (CCGT) are gaining traction in recent years due to lower natural gas prices, high flexibility, and high efficiency. Compared to single cycle gas turbines, the introduction of heat recover steam turbines significantly improves the CCGT efficiency, which also subjects CCGTs to non-convex and nonlinear cost curves. However, in widespread geographical power service territories with electricity markets, a Regional Transmission Organization (RTO) can only process piecewise linear cost curves of generating resources due to the computational complexity. Therefore, the nonconvex cost curves of CCGTs are approximated by piecewise linear cost curves, which deviate from the actual cost curves and subsequently leads to inefficient dispatch of the CCGTs. This issue can potentially be addressed by co-locating energy storage resources with CCGTs. The energy storage is dispatched to maintain CCGTs operated at the economic output range. To this end, this paper proposes a computational model to optimize the coordination of energy storage resources and CCGTs such that the operational efficiency of CCGTs is improved.

Index Terms – Battery storage resource, combined cycle gas turbines, electricity market, hybrid power plant, security constrained unit commitment.

NOMENCLATURE:

Sets:

K Set of dispatch segment; $k \in K$.
 T Time periods; $t \in T$.

Parameters (index t denotes period):

C_{seg_k} Slope (marginal cost) of piecewise linear cost curve
 η energy storage round trip efficiency
 E^+, E^- maximum charge and discharge rate
 SOC_0 Initial state of charge.
 $\underline{SOC}, \overline{SOC}$ minimum and maximum level of SOC

L Time interval duration, i.e., 10 mins
 P_t Unit output for scenario s at t in MW

Variables (index t denotes period):

soc_t The state of charge of the energy storage resource.
 e_t^+, e_t^- Charge and discharge output of the energy storage resource.
 p_t unit output for scenario s at time t in MW
 u_t Energy storage mode. Charge:0; Discharge: 1.
 $p_{seg_k,t}$ Dispatch segment k output for at time t
 $u_{seg_k,t}$ Commitment of dispatch segment k

I. INTRODUCTION

Combined cycle gas turbines (CCGTs) technologies have been gaining traction in the past decade across the United States [1]–[2] due to the need of flexible generating units. CCGTs integrate thermodynamic cycles of combustion turbines (CTs) and steam turbines (STs) to improve the thermal efficiency [3]. The CTs are very similar to jet engines and the fuel is mixed with compressed air to ignite. A CCGT recycles the waste heat from the CTs into the boiler and the steam from the boiler is used to drive the steam turbine. CCGTs have a higher power generation efficiency when compared with simple cycle thermal generators. This improved power generation efficiency comes from the use of a heat recovery steam generator (HRSG) between the combustion turbine (CT) and the steam turbine (ST). The HRSG uses the CT's exhaust gas to operate the ST unit and provides additional power with minimal additional fuel inputs.

Due to computational complexity of large-scale electricity markets, Regional Transmission Organizations (RTOs) require generation owners to submit stepwise non-decreasing incremental cost offers. The multi-unit structure of the CCGTs complicates the cost modeling. The difference between the CCGT's generation offer and the actual incremental cost curve may be significant. For example, the non-decreasing incremental cost

This work is sponsored by New Mexico Consortium, Subcontract No: 027953 and National Science Foundation # 1950121.

curve indicates the efficiency of the generating unit does not get better as the output increases. However, CCGTs may have its most economic operational range in the middle of its output range. Inaccurate generation offer may lead to inefficient generation dispatch solutions from RTOs. Configuration-based combined cycle model is proposed in [4-5] to allow CCGTs to offer different offer curves in different configurations. However, a configuration-based combined cycle model can incur significant computational burden of unit commitment problems because each configuration requires a binary variable to represent the CCGT operational status. In this modeling [6]-[7], each configuration was modeled as a conventional unit and had its own operating characteristics. However, the proposed modeling still needs convex approximation of the cost curve of CCGTs and it is computationally challenging to implement configuration-based CCGT models.

Recently, RTOs allow more than one set of resources, which locate on the same bus, to share a single point of interconnection (POI). Federal Energy Regulatory Council (FERC) defines such resources as hybrid resources [8]. Interest in co-located hybrid resources rises in recent years because hybridizing power plants can reduce project cost and increase project market value [9]. However, natural gas power plant paired with energy storage is often overlooked. Fig.1 shows a CCGT paired with energy storage sharing a single POI. The CCGT and energy storage is defined as hybrid resource, which is modeled and dispatched as a single integrated resource. This paper proposes a CCGT and energy storage co-optimization model to determine the optimal dispatch of CCGT and optimal charging scheduling of energy storage. The energy storage resource can help improve the operational efficiency of the CCGTs while meeting RTO's dispatch targets. Instead of having CCGT always respond to constantly changing RTO's dispatch target, energy storage resources may respond and help CCGT stay in its economic operational range. Additionally, less frequent cycling of CCGT can lower wear-and-tear cost such as maintenance cost.

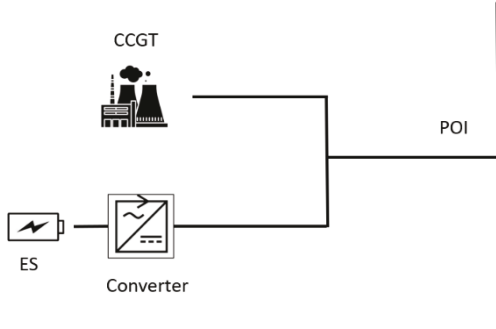


Fig.1 CCGT paired with energy storage at POI

It is critical to study the net economic benefits of hybridizing CCGTs using energy storage resources. The optimal sizing of the energy storage resources is a tradeoff between improved operational efficiency and investment cost on energy storage such that the marginal benefit equals to the marginal cost of energy storage. Utility-scale energy storage cost, such as battery energy storage system (BESS) cost, changes rapidly over the past decade. To study energy storage cost on net economic benefit, this paper examines the net economic benefits of energy storage

investment with three different projected battery cost from low cost to high cost.

Another factor that greatly impacts the net economic benefit of the proposed hybrid resources is the RTO's dispatch targets. If the RTO often cycles CCGT between its economic and uneconomic operational range, energy storage can play an important role in improving the overall operational efficiency of the CCGT unit, which indicates higher net economic benefit. With higher penetration of intermittent generating resources, such as wind and solar resources, CCGTs are often turned on to provide flexibility, which requires CCGTs to cycle more often. The proposed model is tested on a synthetic Texas 7k system with the consideration of load and renewable energy uncertainties to validate the effectiveness.

II. METHODOLOGY

The CCGT and BESS are treated as a single integrated resource. CCGT needs to approximate its non-convex incremental cost curve to a non-decreasing stepwise cost curve. Therefore, there is a gap between CCGT offered cost curve and its actual cost curve. The energy storage can help bridge the gap and improve the operational efficiency of CCGTs. A CCGT and energy storage co-optimization modeling is formulated as below.

Objective:

$$\min \sum_{t=1}^T \sum_{k=1}^K C_{segk} p_{segk,t} \quad (1)$$

subject to:

$$soc_t - e_t^- L + \eta e_t^+ L = SOC_0, \quad t = 1 \quad (2)$$

$$soc_t + e_t^- L - \eta e_t^+ L = soc_{t-1} \quad 2 \leq t \leq T \quad (3)$$

$$0 \leq e_t^+ \leq u_t E^+, \quad \forall t \quad (4)$$

$$0 \leq e_t^- \leq (1 - u_t) E^-, \quad \forall t \quad (5)$$

$$SOC \leq soc_t \leq \overline{SOC}, \quad \forall t \quad (6)$$

$$p_t + e_t^- - e_t^+ = P_t, \quad \forall t \quad (7)$$

$$p_t = p^{min} + \sum_{k=1}^K p_{segk,t}, \quad \forall t \quad (8)$$

$$0 \leq p_{segk,t} \leq u_{segk,t} P_{segk}^{max}, \quad \forall t \quad (9)$$

$$u_{segk,t} \leq \frac{p_{segk-1,t}}{P_{segk-1}^{max} - P_{segk-1}^{min}}, \quad \forall t \quad (10)$$

The proposed CCGT and BESS co-optimization minimizes the total fuel cost while still meeting RTOs dispatch target. Objective (1) minimizes the total fuel cost of the CCGT and the actual incremental cost for each segment k is C_{segk} . Note that the incremental cost curve C_{segk} may be nonconvex. Constraint (2) models the state of charge (SOC) with a consideration of the initial SOC, i.e., SOC_0 . Constraint (3) models the relationship between the charging output, discharging output, and its SOC. Constraint (4) presents the maximum charge rate of the energy storage resource and constraint (5) presents the maximum discharge rate of the energy storage resource. u_t is a binary variable to determine the mode of the energy storage resource with charge=1 and discharge=0. Introducing u_t aims to avoid having the energy storage charge and discharge at the same time. Constraint (6) limits the minimum and maximum SOC level for the energy storage resource. Constraint (7) enforces that the net output of CCGT and energy storage resource should be equal to the RTO's dispatch target. Constraint (8) models the cleared piecewise linear segments and the total output of the CCGT. Constraint (9) limits the output range of each piecewise linear

segment. Constraint (10) indicates the commitment of each segment and it guarantees that the commitment of segments are in sequence, i.e., from a lower order segment to a higher segment. Without the segment commitment variable, non-convex cost function will lead to a clear higher segment with lower cost first instead of lower segment with higher cost.

The CCGT and energy storage co-optimization model minimizes the total real-time operational cost by optimally scheduling the energy storage resource while meeting the RTO's dispatch target. The energy storage needs to manage the SOC across real-time intervals to have the CCGT operated at its economic range.

III. NUMERICAL RESULTS

The proposed CCGT and energy co-optimization model is tested on a synthetic Texas 7K bus system [10]-[11]. The network covers the geographic footprint of the electric reliability council of Texas (ERCOT). The test system has 6717 buses, 9,140 branches, 74GW peak load. The datasets are high-quality synthetic electric grid models, built from public information and a statistical analysis of actual power systems. The optimization models are built in AIMMS 4.79 with Solver CPLEX 20.1. All results in this section were performed on 3.40 GHz CPU Intel i7-10700K Windows 7 Operating System. The sensitivity cutoff, i.e., power transfer distribution factors (PTDFs), is 0.05%. If the absolute value of a sensitivity is below 0.05%, the associated sensitivity will be set as zero.

The simulation scenarios are generated based on the assumption that load uncertainty is 3-5%. Four different types of days are considered: summer peak day, summer off-peak day, winter peak day, winter off-peak day. In the simulation, BESS has a round-trip efficiency of 85%. The CCGT cost curve is presented in Fig. 2. The solid blue curve is the actual incremental cost curve of the CCGT unit, which is non-convex. This CCGT unit has two CTs and one ST. The minimum output of the CCGT unit is 64.35MW and the maximum output of the CCGT unit is 590MW. The CCGT unit turns on only CT units to produce power in the power output range from 63.35MW to 280MW. Once the unit reaches 280MW and above, the CCGT has enough exhaust to start up the ST unit, which does not consume fuel. At 2CT+1ST mode, we can observe that the CCGT has lower cost than 1CT or 2CT mode, which leads to a non-convex cost curve. With the CCGT unit output operating above

490MW, the ST reaches its maximum operating capacity, and any additional power will be supplied by CTs again. Therefore, the incremental cost curve rises to \$24/MWh of the operating range between 490MW and 590MW. The dotted curve is the submitted generation offer of the CCGT unit, which is a convex approximation of the actual incremental cost curve because RTOs can only solve real-time electricity market or day-ahead electricity market models with convex generation offer curves.

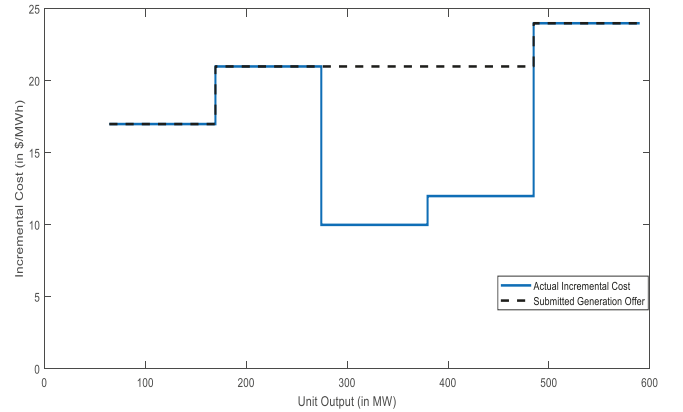


Fig. 2 CCGT Incremental Cost Curve

The proposed method is tested in a wholesale electricity market setting. Security constrained unit commitment (SCUC), which is the process of deciding the commitment status of generating units, is used in the day-ahead electricity market. SCUC meets all the power constraints, such as generator output constraints, power flow constraints, power balance constraints, spinning reserve requirements, ramp rate constraints, and minimum-up and minimum-down constraints [12]-[13]. The objective of SCUC is to minimize the total cost, which includes the variable operating costs, the no-load costs, and the start-up costs. The day-ahead market is simulated by running the SCUC and following the pricing run by fixing all the binary variables from SCUC. The real-time market is simulated with all the commitment decisions the same as day-ahead market while considering real-time load and renewable uncertainties [14]. Note that only one CCGT in the system is studied as hybrid resource and the rest of CCGTs are still conventional units.

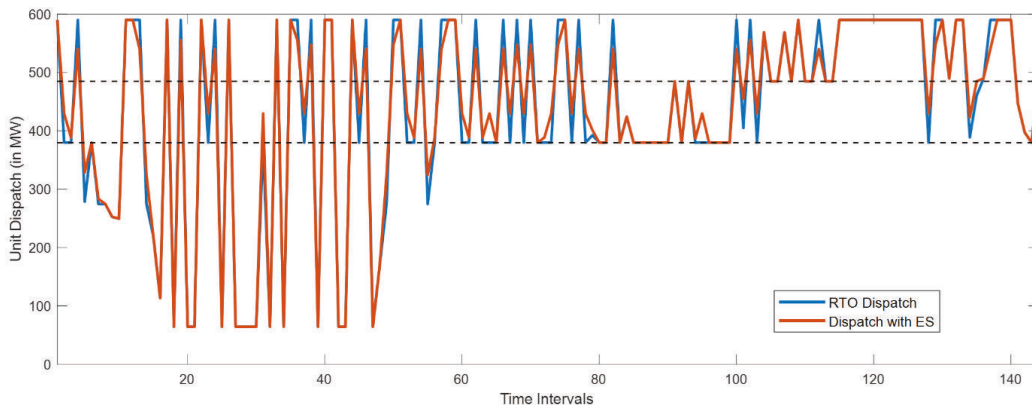


Fig. 3 Real time dispatch of CCGT with ES size 8.33MWh

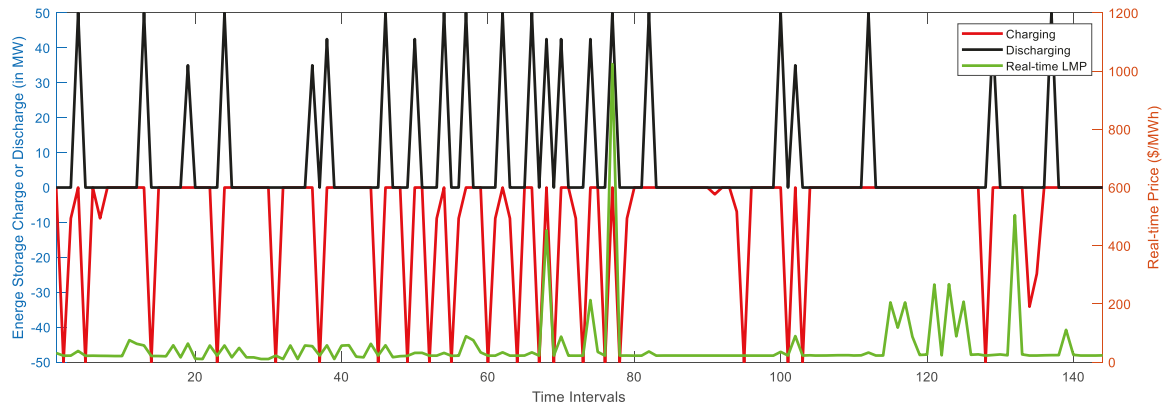


Fig. 4 Real-time dispatch of ES with ES size 8.33MWh

The co-located CCGT and energy storage resource are treated as one single resource and the combined output should meet the RTO's dispatch target. In this section, for the CCGT unit, the optimal energy storage resource scheduling is studied for two different BESS sizes, 8.33MWh and 30MWh, respectively. Fig. 3 presents the real-time dispatch of the CCGT. The blue curve in Fig. 3 is the RTO dispatch target for a summer peak day and each time interval is 10 minutes for each real-time electricity market interval. This study assumes that RTO solves the real-time market every 10 minutes. Therefore, there are total 144 time intervals for each study day. The orange curve in Fig. 3 is the CCGT's actual dispatch with co-located energy storage resources. Based on the CCGT incremental cost curve, the CCGT's economic operational range is from 280MW to 490MW.

It can be observed that the actual dispatch of CCGT with co-located ES tries to stay as close to the economic operational range as possible. In Fig. 4, the charging (red curve) and discharging (black curve) schedules of energy storage resource are presented. The green curve is the real-time LMP for the CCGT and it can be observed that instead of following the LMP to arbitrage the energy storage resource actually is trying to keep the

CCGT in its economic operational range. This strategy does not require LMP forecasting and can take the most average of the co-located energy storage resources to minimize the fuel cost while meeting RTO's dispatch target.

Figs. 5 and 6 present the result of CCGT dispatch and energy storage resource scheduling with the energy storage capacity 30MWh. It can be observed that with higher energy storage capacity, the CCGT unit can stay closer to the operational range comparing with the case of ES size 8.33MWh. More energy storage capacity indicates more ability to keep the units in its economic operational range, which is from 490MW to 590MW.

It is significant to study the net benefits of energy storage, which is the cost savings less the investment cost of energy storage. We studied the net benefit of energy storage with three projected cost scenarios, i.e., \$100/kWh, \$200/kWh, and \$300/kWh. The projected cost includes the investment cost and the average degradation cost. Note that this paper uses the average degradation cost instead of more accurate degradation cost modeling, which is a function of SOC. By perturbing the size of BESS from 5MWh to 20MWh, we can find that the optimal sizes of energy storage resources are 8.33MWh, 9.2MWh, and 9.8MWh for BESS projected cost \$100/kWh, \$200/kWh, and \$300/kWh, respectively.

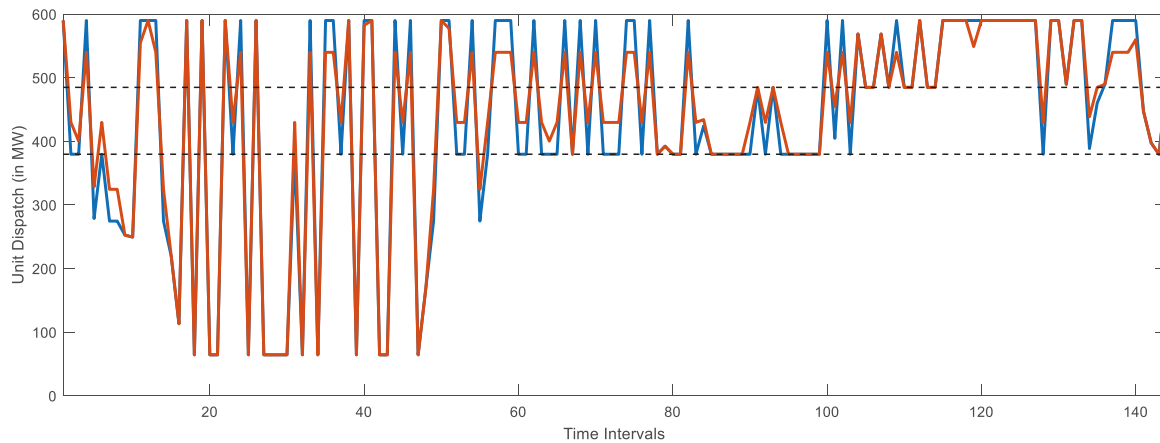


Fig. 5 Real time dispatch of CCGT with ES size 30MWh

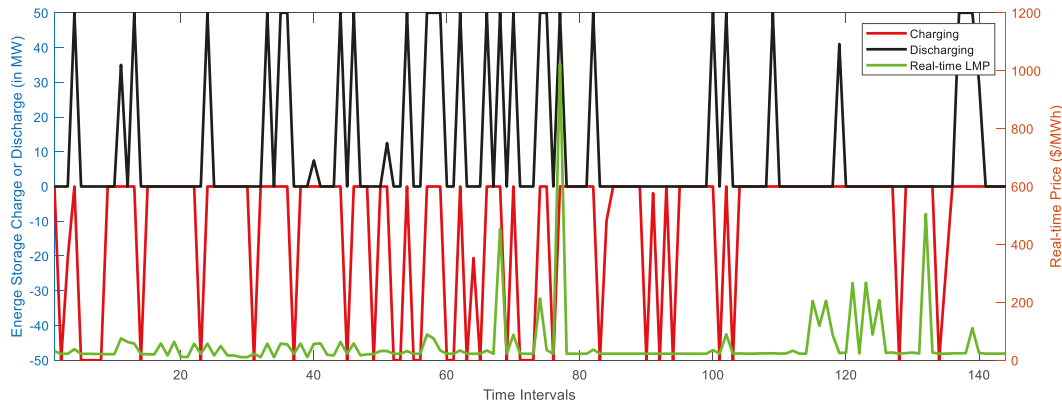


Fig. 6 Real-time dispatch of ES with ES size 30MWh

The net cost benefit is the total CCGT profit less the cost of battery. Four types of days are studied to calculate the average profit of the CCGT. The 10-year net cost benefit with BESS cost \$300/kWh is \$401,500. The 10-year net cost benefit with battery cost \$200/kWh is \$1,168,000. The 10-year net cost benefit with battery cost \$100/kWh is \$2,015,600. Therefore, the optimal BESS size and associated net cost benefits are highly subject to the BESS cost as well as the actual incremental cost curve, as shown in Fig. 2. Note that the energy storage gets more benefit with a higher ST capacity. Additionally, higher natural gas price can increase the net benefit of energy storage resources as well. Further, additional cost benefits may be realized if BESS is operated in a manner that can provide additional services (such as Fast Frequency response, etc) or can be monetized as part of other reserves (spinning reserve, etc). Such benefits stacking can further shorten ROI time for BESS, therefore making proposed scenarios more economically beneficial.

IV. CONCLUSIONS

Energy storage can improve the operational efficiency of generators with nonconvex incremental cost, such as combined cycle power plant. The energy storage can help CCGT operate close to its economic range. Unlike other energy storage resources, who arbitrage in the electricity market, the scheduling of co-located energy storages with CCGT does not need the inaccurate locational marginal price forecast. Instead, the strategy is to keep the combined cycle stay as close as possible in its economic operation range.

The BESS cost has great impact on the optimal sizing. The results are dependent on the system and generator parameters, but the model is general enough to expand to any generators with nonconvex cost curves. With proper scenarios modeled, the proposed optimal energy resource sizing model can determine the optimal sizing of the energy storage such that the net benefit is maximized. The scenarios in this report examines uncertainties from load and renewables. With higher penetration of renewable energy, the system expects more flexibility from fast units such as CCGT. This may require CCGTs to cycle more frequently and such frequent cycling may lead to more ramping cost and emission, and Operation and Maintenance (O&M) and wear-and-tear cost. Currently, four types of days are simulated. In the future, we plan to simulate more testing days to improve the credibility of the numerical results.

Future study will focus on 1) more detailed degradation cost modeling, which is a function of SOC 2) leveraging energy storage to reduce the greenhouse emission. 3) comparing the economic benefits of different types of energy storage resources.

REFERENCES

- [1] B. Lu and M. Shahidehpour, "Short-term scheduling of combined cycle units," *IEEE Trans. Power Syst.*, vol. 19, no. 3, pp. 1616–1625, Aug. 2004.
- [2] US DoE Energy Information Administration, Annual energy outlook 2017. [Online]. Available: <https://www.eia.gov/outlooks/aeo/>.
- [3] Y. Liu, L. Wu, J. Li, Y. Chen, and F. Wang, "Towards accurate modeling on configuration transitions and dynamic ramping of combined-cycle units in UC problems," *IEEE Trans. Power Syst.*, vol. 35, no. 3, pp. 2200–2211, May 2020.
- [4] Y. Chen and F. Wang, "MIP formulation improvement for large scale security constrained unit commitment with configuration based combined-cycle modeling," *Elect. Power Syst. Res.*, vol. 148, pp. 147–154, Jul. 2017.
- [5] C. X. Dai, Y. H. Chen, F. Y. Wang, J. Wan, and L. Wu, "Configuration-component based hybrid model for combined-cycle units in MISO day-ahead market," *IEEE Trans. Power Syst.*, vol. 34, no. 2, pp. 883–896, Mar. 2019.
- [6] C. Liu, M. Shahidehpour, Z. Li, and M. Fotuhi-Firuzabad, "Component and mode models for the short-term scheduling of combined-cycle units," *IEEE Trans. Power Syst.*, vol. 24, no. 2, pp. 976–990, May 2009.
- [7] G. Morales-Espana, C. M. Correa-Posada, and A. Ramos, "Tight and compact MIP formulation of configuration-based combined-cycle units," *IEEE Trans. Power Syst.*, vol. 31, no. 2, pp. 1350–1359, Mar. 2016.
- [8] FERC, "Hybrid Resource White Paper." [Online]. Available: <https://www.ferc.gov/sites/default/files/2021-05/white-paper-hybrid-resources.pdf>
- [9] W. Gorman, A. Millsa, M. Bolinger, R. Wisera, N. G. Singhal, E. Ela, E. O'Shaughnessy, "Motivations and options for deploying hybrid generator-plus-battery projects within the bulk power system," *Electr. J.*, vol. 33, no. 5, Jun. 2020, Art. no. 106739.
- [10] A. B. Birchfield, T. Xu, K. M. Gegner, K. S. Shetye, and T. J. Overbye, "Grid structural characteristics as validation criteria for synthetic networks," *IEEE Trans. Power Syst.*, vol. 32, no. 4, pp. 3258–3265, Jul. 2017.
- [11] Texas A&M University Electric Grid Test Case Repository, Computer Assignments; available online at <https://electricgrids.engr.tamu.edu/computer-assignments/>
- [12] Y. Chen, F. Wang, Y. Ma, and Y. Yao, "A distributed framework for solving and benchmarking security constrained unit commitment with warm start," *IEEE Trans. Power Syst.*, vol. 35, no. 1, pp. 711–720, Jan. 2020.
- [13] Y. Chen, A. Casto, F. Wang, Q. Wang, X. Wang, and J. Wan, "Improving large scale day-ahead security constrained unit commitment performance," *IEEE Trans. Power Syst.*, vol. 31, no. 6, pp. 4732–4743, Nov. 2016.
- [14] F. Wang and Y. Chen, "Market implications of short-term reserve deliverability enhancement," *IEEE Trans. on Power Syst.*, vol. 36, no. 2, pp. 1504–1514, Mar. 2021.