01 Jan 2023

Coordinated System Reliability Assessment And Production Cost Simulation In Transmission Planning Of Eastern Interconnection

Xiaokang Xu

Reza Yousefian

Jie Tang

Rui Bo
Missouri University of Science and Technology, rbo@mst.edu

et. al. For a complete list of authors, see https://scholarsmine.mst.edu/ele_comeng_facwork/5176

Recommended Citation

X. Xu et al., "Coordinated System Reliability Assessment And Production Cost Simulation In Transmission Planning Of Eastern Interconnection," *IEEE Power and Energy Society General Meeting*, Institute of Electrical and Electronics Engineers, Jan 2023.
The definitive version is available at https://doi.org/10.1109/PESGM52003.2023.10253151

Coordinated System Reliability Assessment and Production Cost Simulation in Transmission Planning of Eastern Interconnection

Xiaokang Xu, Reza Yousefian, and Jie Tang
S&C Electric Company
Chicago, IL, USA
xiaokang.xu@sandc.com

Rui Bo
Department of Electrical and Computer Engineering
Missouri University of Science & Technology
Rolla, MO, USA
rbo@mst.edu

John P. Buechler[1], Jordon Bakke[2] and Zheng Zhou[2]
[1] JohnPBuechler Consulting Inc.
Long Island, NY, USA
[2] Midcontinent Independent System Operator
Minneapolis, MN, USA

2023 IEEE Power & Energy Society General Meeting (PESGM) | 978-1-6654-6441-3/23/$31.00 ©2023 IEEE | DOI: 10.1109/PESGM52003.2023.10253151

***Abstract*—This paper presents a transmission need analysis for the Eastern Interconnection (EI) using a coordinated technical approach consisting of system reliability assessment (SRA) and production cost simulation (PCS). As North American Transmission Systems are being evolved with increasing levels of renewable energy resources such as wind, solar, storage, biomass, hydro, etc., maintaining grid reliability and managing transmission congestion cost are becoming increasingly challenging. It also poses complexity and challenges in technical and economic planning of the transmission grid. The coordinated SRA and PCS were conducted to assess transmission reliability and congestion for the interconnected grids of the EI in a 10-year planning horizon. The paper discusses new automation tools and models developed for such assessment including case studies showing the applicability of the coordinated methodology and developed models.**

***Index Terms*— Inverter-based resources (IBRs), distributed energy resources (DERs), transmission congestion, production cost simulation, renewable energy resources, system reliability assessment, transmission planning, transmission reliability.**

I. Introduction

North American Transmission Systems are being evolved with increasing levels of renewable energy resources such as wind, solar, storage, biomass, hydro, etc. Most of such resources are generally referred to as Inverter-Based Resources (IBRs) and Distributed Energy Resources (DERs). As more and more IBRs and DERs are being integrated with the transmission grid, maintaining grid reliability and managing transmission congestion cost are becoming increasingly challenging. It also poses complexity and challenges in technical and economic planning of the large-scale transmission grid, which routinely requires System Reliability Assessment (SRA) and Production Cost Simulation (PCS).

This paper presents a transmission need analysis for the Eastern Interconnection (EI) using a coordinated technical approach consisting of SRA and PCS. The coordinated SRA and PCS were conducted to assess transmission reliability and congestion for the interconnected grids of the EI in a 10-year planning horizon, which is the largest North American transmission system representing approximately two-thirds of the United States and Canada. The paper discusses new automation tools and models developed for such assessment including case studies showing the applicability of the coordinated methodology and models. To the best knowledge of the authors, there is no published literature on this coordinated approach/analysis and the developed model applied for such sizable transmission grid. The paper serves a useful industry reference for new tools, technical approach, and similar studies of the large-scale interconnected systems as well as provides a forward-looking grid development with a high level of renewable penetration.

II. Tools, Methodology, Models and Criteria

A. Development of Automation Tools

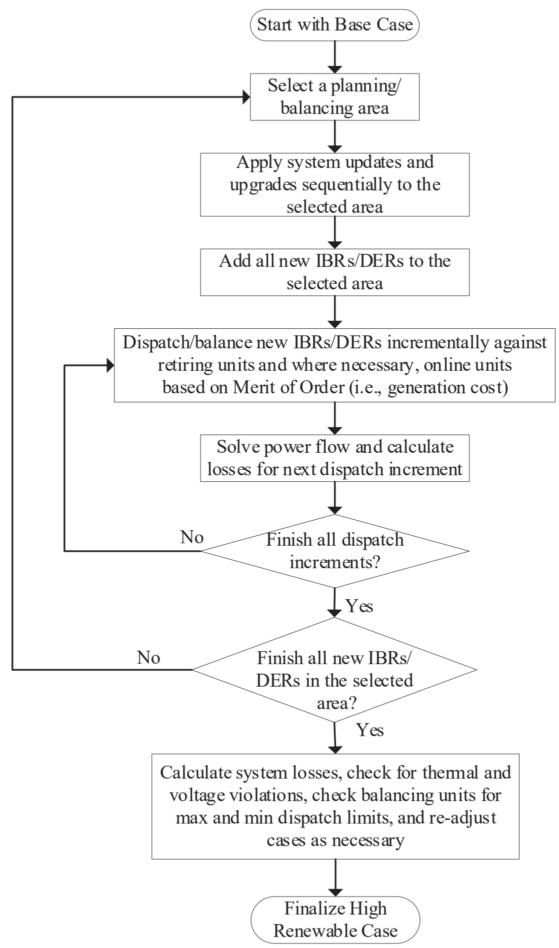

Fig. 1: Iterative Procedure of Developing High Renewable Summer Peak and Winter Peak Cases for the Eastern Interconnection

There was a vast amount of input data from reginal Planning Coordinators (PCs) for developing transmission reliability and production cost models for the EI for a 10-year planning horizon, such as new IBRs, DERs and conventional generation resources, retiring generators, new resource dispatch percentages, total generation and load projections as well as transmission updates and upgrades. To improve productivity and efficiency in model development, Python-based automation tools were developed to process a huge amount of input data and create system planning cases/models to represent future high renewable summer and winter peak scenarios for use in SRA and PCS. These tools were designed and structured such that the input files would be automatically pre-processed and applied to the base cases/models (representing the normal amount of renewable generation) to create high renewable cases/models in the transmission planning software PSS®E [1]. In addition, these tools were used for automatically processing and analyzing study results. Without such automation tools, it would require significant engineers' effort to develop system planning cases/models and process study results, which is time consuming.

Fig. 1 shows the iterative procedure and steps implemented in the automation tools for integrating and dispatching new IBRs/DERs to create high renewable cases/models, starting with base cases/models. For adding and dispatching new conventional and other resources or removing retiring generators, the same iterative process and steps are repeated, with the retiring generation proportionally balanced by the headroom of new conventional generation.

B. Development of High Renewable Planning Cases/Models

Using the iterative procedure in Fig. 1, 10-year out high renewable cases for the EI were created from the base cases of the same planning year. In the high renewable cases, the dispatch for IBRs/DERs was set at different levels depending on each PC's dispatch rules at the peak load hour, generation type and case season (summer or winter). On the average, renewable resources were dispatched at approximately 45% and 37% capacity factors for the summer and winter peak cases, respectively. As for other new generation resources, they were dispatched per PC area's balancing requirements.

Fig. 2 summarizes the dispatch mix in the 10-year out high renewable cases compared to the 10-year out base cases. The renewable dispatch (i.e., wind, solar, storage and hydro) in the summer peak load scenario is 9% and 19% in the base case and high renewable case respectively, indicating an approximate 10% increase in renewables. The renewable dispatch in the winter peak load scenario is 10% and 18% in the base case and high renewable case respectively, showing an approximate 8% increase in renewables. As expected, in the high renewable cases, the majority of renewables is solar generation (8% of total generation) in the summer peak load case. For the winter peak load case, the majority of renewables is wind generation (9% of total generation).

The 10-year out base cases/models and high renewable cases/models were used for SRA as well as an input to PCS, i.e., both SRA and PCS used the same power flow model.

C. Development of Base and High Renewable Production Cost Models/Cases

National Renewable Energy Laboratory (NREL) provided the raw dataset of the production cost model, which includes generator characteristics data, historical load profiles, 10-year out load targets and fuel price forecast, wind/solar profiles, and hydro capacity factor profiles. The full transmission model and generation/load model of the EI were included in the production cost models [2].

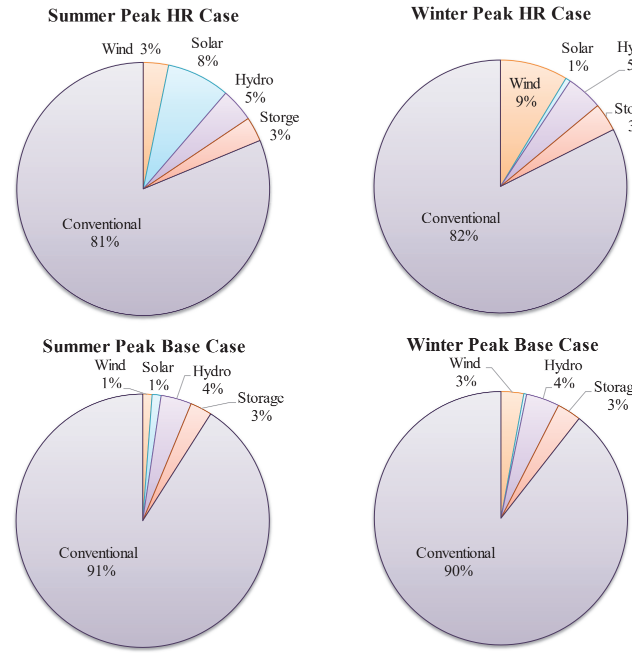

Fig. 2: Dispatch Mix for 10-Year Out Summer and Winter Peak Base Cases and High Renewable (HR) Cases (Note: DERs were modeled as loads.)

On generation side, the dataset includes generator characteristics such as Pmin, Pmax, heat rate, ramp, start-up cost, minimum up/down time, etc. Regulation reserve and contingency reserve requirement were calculated and modeled. External transactions were modeled to represent the power exchange between the EI and other areas. Historical wind/solar/external hourly transaction profiles were all shifted for weekday/weekend alignment to obtain and match the 10-year out hourly profiles. Economic and reliability must-run statuses were modeled.

On transmission side, the transmission topology, upgrades and parameters were taken from the 10-year out summer peak power flow case, and winter ratings were taken from 10-year out winter power flow case. MW control transformers were modeled as phase shifters. Non-blocked mode DC lines were modeled as DC lines. High voltage networks or transmission circuits as well as common interfaces were monitored for congestions under base case (system intact) and contingency conditions.

On load side, station service loads and non-scalable loads were identified and properly modeled. 10-year out load targets were used to scale historical load profiles to obtain 10-year out hourly load profiles for each area. The 10-year out hourly load profile for each area was then allocated to each load bus based on the bus-level scalable load in 10-year out summer peak power flow case. Multiple loads with different ownerships at the same bus were identified and properly modeled to accurately capture the load ownership.

A base case production cost model (PCM) was developed using the PLEXOS software [3] to model the 10-year out projection of the EI. Based on this model, a high renewable PCM of the same projection year was also developed with increased levels of renewable generation, generation

978-1-6654-6441-3/23/$31.00 ©2023 IEEE

retirements and transmission upgrades. An unconstrained PCM that removes all transmission constraints was also developed to represent the transmission constraint free condition of the system for the 10-year out base case and high renewable case, respectively.

D. System Reliability Assessment (SRA)

Using both the 10-year out planning base cases and high renewable cases, SRA was performed to evaluate the grid reliability performance of the EI for the 10 years into the future. The assessment focused on identifying thermal overloads in system normal and N-1 contingency conditions and comparing the performance of the grid in the base case and high renewable case in the next 10 years. The identified overloads were further investigated with possible mitigation solutions. The N-1 contingency analysis evaluated all single-element (lines and transformers) contingencies associated with the high voltage bulk electric systems (BES). Approximately 65,000 N-1 contingencies were evaluated for each case. The BES facilities were monitored for potential overloads.

E. Production Cost Simulation (PCS)

The 10-year out base case and high renewable PCMs were simulated for the EI for the full year, namely, 8784-hour chronological simulation of Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED). The simulation results include a host of information such as hourly generation and cost, transmission flow and congestion, locational marginal price (LMP), shadow prices, etc. In this simulation, the generation mix and generation cost by dispatch pool, transmission congestion measured in congestion cost by flowgates (consisting of one or more circuits), renewable energy curtailment by pool, monthly average LMP by pool, inter-area transfer are of particular interest.

The unconstrained PCMs were also simulated and compared with their respective constrained PCMs for the base case and high renewable scenarios for their respective years, and the results differences indicate the impact of transmission constraints/congestion on the future outlook of the grid. Identified overloads/congestion may be mitigated by transmission updates.

F. Coordination between Planning Models and Production Cost Models and Simulations

The development of the planning and production cost models was coordinated such that both sets of models have:

(1) Consistent transmission network and topological configuration
(2) Consistent network updates, upgrades, and circuit capacities
(3) Consistent generation categories, locations, fuel types and generation costs
(4) Consistent interchange levels or transactions between regions

Simulations and results from the planning and production cost models are cross-examined and compared. Details of the results are discussed in Section III.

G. Criteria

NERC Planning Standard TPL-001-5 [4] is the reliability criteria applied in SRA. Circuit normal and long-term emergency ratings were used for testing system intact (N-0) and contingency (N-1) conditions. In addition, reliability guidelines and operating procedures from regional PCs were used to mitigate reliability issues. These criteria, guidelines and operating procedures were also reflected in PCS.

III. Application of The Coordinated technical Approach and Developed Models

The coordinated technical approach and models developed in Section II were applied for SRA and PCS for the EI and the results are discussed below.

A. Description of the Grid

The EI consists of the interconnected grids of bulk electric systems stretching from New England to Florida and to the Rocky Mountains, as shown in Fig. 3, which operates to ensure the efficient and reliable delivery of electricity to over 240 million Americans and Canadians. In SRA and PCS, the interconnected grids included the transmission systems of ISO New England, New York ISO, PJM Interconnection, Midcontinent ISO, Southwest Power Pool (SPP), Southeastern Electric Reliability Council (SERC) and Florida Reliability Coordinating Council (FRCC). Canadian planning areas/systems were modeled as firm interchange transactions or equivalent generators in SRA and PCS.

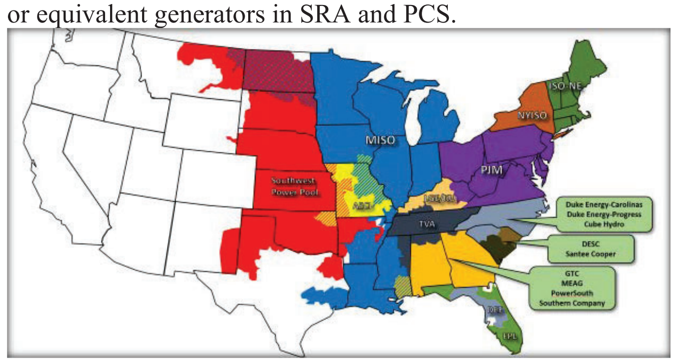

Fig. 3: Map of the Eastern Interconnection

B. Case Studies

(1) System Reliability Assessment Results

For SRA, the EI was divided into several power pools that consist of multiple individual utilities that coordinate their planning and reliability responsibilities through planning regions. The assessment results by pool for both the 10-year out base cases and high renewable cases in summer and winter peak conditions are summarized in Table I and Table II. As expected, more overloads (N-0 and/or N-1) are seen in the high renewable case than in the base case. In addition, more overloads are seen in the summer peak case than in the winter peak case.

An additional investigation indicates that most overloads observed are local or known issues, pre-existing or resulting from additions of new generation sources. The dispatch of the new generation resources has an impact on these overloads. In addition, with the interconnection of a large number of new IBRs/DERs and retirement of several generators, transmission

978-1-6654-6441-3/23/$31.00 ©2023 IEEE

circuit flows change significantly with re-dispatching existing units for balancing, thus resulting in certain overloads. A further investigation indicates that these overloads can be mitigated by operating procedures, generation redispatch, Special Protection Protections (SPS), etc.

Table I: Number of Overloads in 10-Year Out Base Cases

Power Pool	Overloads with System Intact		Overloads with N-1 Contingencies	
	Summer	Winter	Summer	Winter
Pool A	0	0	3	2
Pool B	0	0	11	1
Pool C	0	0	3	2
Pool D	0	0	9	8
Pool E	0	0	0	0
Pool F	0	0	0	0
Pool G	0	0	4	0

Table II: Number of Overloads in 10-Year Out High Renewable Cases

Power Pool	Overloads with System Intact		Overloads with N-1 Contingencies	
	Summer	Winter	Summer	Winter
Pool A	0	0	4	5
Pool B	0	0	23	5
Pool C	0	3	0	1
Pool D	0	0	11	0
Pool E	11	0	8	0
Pool F	0	0	4	0
Pool G	0	0	5	3

(2) Production Cost Simulation Results

In the 10-year out base case PCM, over 90% of the total generation comes from conventional steam coal, nuclear, natural gas fired combined cycle, wind, and conventional hydroelectric, and natural gas fired combustion turbine. From 10-year out base case PCM to high renewable PCM, generation of conventional steam coal and natural gas fired combined cycle dropped the most, and it was largely compensated by increased wind and solar generation. Table III compares the generation GWh and percentage of the top 5 generation categories between the 10-year out base case and high renewable case.

Table III: Generation GWh and Percentage Comparison of Top 5 Generation Categories in 10-Year Out Base Case and High Renewable Case

Base Case Scenario			High Renewable Scenario		
Gen Type	GWh	Percent	Gen Type	GWh	Percent
Conven-tional Steam Coal	1,253,398	42.10%	Conven-tional Steam Coal	1,000,513	33.48%
Nuclear	632,786	21.26%	Nuclear	614,208	20.55%
Natural Gas Fired Combined Cycle	447,343	15.03%	Wind	493,267	16.51%
Wind	227,809	7.65%	Natural Gas Fired Combined Cycle	375,145	12.55%
Conven-tional Hydroelectric	82,431	2.77%	Solar	159,023	5.32%

In the 10-year out simulations, about 475 flowgates showed congestion in one or more hours in the base case scenario, and approximately 585 flowgates showed congestion in one or more hours in the 10-year out high renewable scenario. The 10-year out annual congestion cost for all congested flowgates increased from $2 billion in the base case to $3.1 billion in the high renewable case. The percentage of congestion contributed by the top 20 flowgates reduced from approximately 79% in the base case to approximately 59% in the high renewable case, indicating that the congestion is more spread out over a larger number of flowgates. These numbers are shown in Table IV.

Table IV: Annual Congestion Cost Comparison

Flowgates	10-Year Out Annual Congestion Cost (k$)	
	Base Case	High Renewable Case
Top 20 flowgates	1,587,634	1,846,314
All flowgates	2,006,815	3,140,089
Percentage	79.11%	58.80%

The change in congestion cost is related to renewable energy additions. For illustration, Figure 3 is the scatter plot between the changes in Pool C wind and Pool C congestion cost. There are two clusters in the figure: one cluster on the left is around $-800k~$-1000k in congestion cost changes (namely, decreased congestion cost), and the other cluster on the right is around $0k~$250k in congestion cost changes (namely, increased congestion cost). The cluster on the left is due to the incremental wind generation from the 10-year out base case PCM to the 10-year out high renewable PCM mitigating the congestion on a major flowgate in Pool C. At the same time, congestion increased significantly on other flowgates as a result of the incremental wind generation, which is the cluster on the right. The zoom-in scatter plot of the cluster on the right (not included in this paper) shows a strong positive correlation between the incrementally added wind generation in Pool C and the increased congestion cost in Pool C. These results indicate that the major driver of change in congestion cost in Pool C is the incremental wind in this pool.

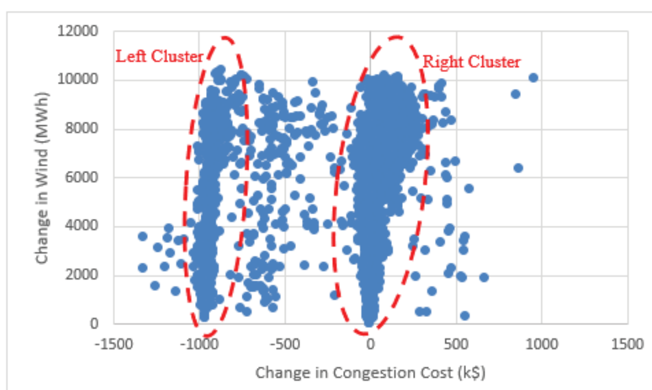

Fig. 3: Change in Wind vs. Change in Congestion Cost in Pool C for 10-Year Out Base Case to High Renewable Case

(3) Discussion

In general, SRA identifies overload violations in steady state, while PCS focuses on congestion, generation dispatch and production cost, Locational Marginal Price (LMP) and congestion cost. There are consistencies between the two analyses. PCS is a chronological simulation that simulates every hour of the study year for generation and load profiles and considers many transmission constraints. For example, both analyses are based on the models developed using consistent transmission network, generator categories and locations, etc., as described in Section II.F. There are also discrepancies between the two analyses. For example, PCS considers 8760-hour load profiles while SRA uses summer/winter peak loads which represent snapshots of system loading conditions in specific hours. This is likely one of the causes that the high renewable cases do not show a large number of overloads in SRA as compared to the base cases, since at these peak hours the renewables are not producing power at full capacity. PCS uses economic data and operational characteristics data for generator dispatch, while SRA uses a simplified merit-of-order dispatch. PCS manages congestion through re-dispatching generation, while SRA considers fixed generation dispatch in evaluating overloads. In addition, SRA uses AC power flow model with voltage and reactive control, while PCS adopts DC power flow model neglecting voltage and reactive power effects. Further, a power flow model generally reflects the non-coincident peak condition, and thereby can be viewed as a worst case. In contrast, PCS performs SCUC/SCED to determine generation dispatch and manages transmission congestions through redispatch. Therefore, overloads identified from SRA may not show up as violations in PCS but are reflected as congestions.

Nevertheless, the results from SRA and PCS are to some extent correlated. Table V shows the list of congested flowgates in PCS that also showed up as overload violations at the same facility or immediately adjacent facility in SRA. Despite consistent findings between PCS and SRA in some flowgates as seen in the table, other flowgates do not show the consistency between PCS and SRA results. Flowgates having overload violations in SRA may not show up as congestions in PCS due to redispatch. Likewise, flowgates showing congestions in PCS may not have overloads in SRA due to different dispatch. There are many other factors contributing to this situation. For example, SRA does not model interfaces while PCS monitors transactions in the interfaces. In addition, congestions in PCS may occur at non-summer/winter peak hours.

Table V: PCS Showing Congested Flowgates That Are Also Overloaded in SRA

Case	Flowgate	Constraint	Congestion Cost (k$)
Base Case	Line 1	Overloaded	7,199
Base Case	Line 2	Overloaded	7
Base Case	Line 3	Overloaded	22
High Renewable Case	Line 4	Overloaded	1,040
High Renewable Case	Line 5	Overloaded	908
High Renewable Case	Line 6	Overloaded	44
High Renewable Case	Line 7	Overloaded	1,445
High Renewable Case	Line 8	Overloaded	4,469
High Renewable Case	Line 9	Overloaded	9
High Renewable Case	Line 10	Overloaded	1,562
High Renewable Case	Line 11	Overloaded	24

(4) Future Work

Given the different methodology and strengths of SRA and PCS, the two analyses can be better coordinated with one another to improve the analysis results through an iterative process. For instance, PCS can identify stressed system conditions/dispatch at critical hours which are not necessarily occurring in the summer peak or winter peak times and provide these conditions to SRA for contingency analysis. In turn, the identified overloading transmission facilities from SRA can be selected and passed back to PCS to include as constraints in the analysis. The following more detailed analyses between SRA and PCS are considered for the future work:

(i) Perform initial PCS to identify critical general dispatch/hours using load and generation profiles, interchange levels and renewable penetration levels.
(ii) Pass the critical dispatch/hours to SRA for solving AC power flow and performing contingency analysis to identify thermal and voltage constraints.
(iii) Model the constraints identified by SRA and pass over to PCS to determine dispatch, congestion cost, LMPs, etc.
(iv) Repeat steps (i)-(iii) until no new constraints are identified from SRA.

The above steps may be implemented in a co-simulation procedure in PSS®E and PLEXOS software platforms, which would provide a highly effective coordination of two analyses in one integrated study.

IV. Conclusions

This paper has presented a coordinated methodology for SRA and PCS applied in technical and economic planning studies of the EI. The paper has also presented development of the 10-year out planning and production cost models of the EI for assessing/simulating system base cases and high renewable scenarios. The results from SRA and PCS are to some extent correlated, which shows the applicability of the coordinated methodology and the models developed. More detailed analyses are recommended for the future work in Section III (4). The paper contributes to the area of technical and economic planning for large-scale interconnected systems with high levels of renewable penetration.

V. Acknowledgments

The authors gratefully acknowledge regional Planning Coordinators for their participation in and support to the work presented in this paper. The authors also thank NREL for providing input and discussions on production cost modeling.

VI. References

[1] PSS®E Revision 35.1.0 Documentation and Manuals, Siemens PTI, Schenectady, NY, May 2020.
[2] Rui Bo, Charles Wu, Yifan Li, Ling Luo, Zheng Zhou, "Market Simulation Tool Benchmarking Analysis for Transmission Planning at MISO", Proceedings of the 2016 IEEE PES General Meeting, Boston, MA.
[3] Exemplar, Energy, PLEXOS® Simulation Software, last accessed in October 2022.
[4] NERC Planning Standard TPL-001-5—Transmission System Planning Performance Requirements, January 23, 2020.