It also helps the public understand the Department's information collection requirements and provide the requested data in the desired format. The Department is soliciting comments on the proposed information collection request (ICR) that is described below. The Department is especially interested in public comment addressing the following issues: (1) is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: Nondiscrimination on the Basis of Sex in Education Programs or Activities Receiving Federal Financial Assistance.

OMB Control Number: 1870–0505.

Type of Review: A revision of a currently approved ICR.

Respondents/Affected Public: Private Sector; State, Local, and Tribal Governments.

Total Estimated Number of Annual Responses: 24,785.

Total Estimated Number of Annual Burden Hours: 598,982.

Abstract: The U.S. Department of Education (the Department) published a Notice of Proposed Rulemaking for the Nondiscrimination on the Basis of Sex in Education Programs or Activities Receiving Federal Financial Assistance (title IX NPRM) to propose amendments to the Department's implementing regulations for title IX of the Education Amendments of 1972. The Department's proposed regulations would require a recipient to maintain various documents regarding its title IX activities for a period of at least seven years. These requirements are specified in proposed 34 CFR 106.8(f). Recipients impacted by the proposed regulations include local educational agencies, institutes of higher education and other entities that receive Federal grant funds from the Department. The information collected would allow recipients and the Department to assess on a longitudinal basis whether a recipient is complying with the Department's title IX regulations when it is has information about sex discrimination, the prevalence of sex discrimination affecting access to a recipient's education program or activity, and whether additional or different training is necessary for the recipient to fulfill its obligations under title IX.

Dated: June 15, 2023.

Stephanie Valentine,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2023–13181 Filed 6–20–23; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Northern New Mexico

AGENCY: Office of Environmental Management, Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces an in-person/virtual hybrid open meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Northern New Mexico. The Federal Advisory Committee Act requires that public notice of this meeting be announced in the **Federal Register**.

DATES: Wednesday, July 19, 2023; 1 to 5 p.m. MDT.

ADDRESSES: This hybrid meeting will be open to the public in person and via WebEx. To attend virtually, please contact the Northern New Mexico Citizens Advisory Board (NNMCAB) Executive Director (below) no later than 5 p.m. MDT on Friday, July 14, 2023.

Cities of Gold Hotel, Tribal Room, 10 Cities of Gold Road, Santa Fe, NM 87506.

FOR FURTHER INFORMATION CONTACT: Menice B. Santistevan, NNMCAB Executive Director, by Phone: (505) 699–0631 or Email: *menice.santistevan@em.doe.gov.*

SUPPLEMENTARY INFORMATION:

Purpose of the Board: The purpose of the Board is to provide advice and recommendations concerning the following EM site-specific issues: clean-up activities and environmental restoration; waste and nuclear materials management and disposition; excess facilities; future land use and long-term stewardship. The Board may also be asked to provide advice and recommendations on any EM program components.

Tentative Agenda:

- Surface Water and Storm Water Monitoring Presentation
- Agency Updates

Public Participation: The in-person/online virtual hybrid meeting is open to the public in person or virtually, via WebEx. Written statements may be filed with the Board no later than 5 p.m. MDT on Friday, July 14, 2023, or within seven days after the meeting by sending them to the NNMCAB Executive Director at the aforementioned email address. Written public comments received prior to the meeting will be read into the record. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Individuals wishing to submit public comments should follow as directed above.

Minutes: Minutes will be available by emailing or calling Menice Santistevan, NNMCAB Executive Director, at *menice.santistevan@em.doe.gov* or at (505) 699–0631.

Signed in Washington, DC, on June 14, 2023.

LaTanya Butler,

Deputy Committee Management Officer.

[FR Doc. 2023–13111 Filed 6–20–23; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD10–12–014]

Increasing Market and Planning Efficiency through Improved Software; Second Supplemental Notice of Technical Conference on Increasing Real-Time and Day-Ahead Market and Planning Efficiency Through Improved Software

As first announced in the Notice of Technical Conference issued in this proceeding on February 7, 2023, Commission staff will convene a technical conference on June 27, 28, and 29, 2023 to discuss opportunities for increasing real-time and day-ahead market and planning efficiency of the bulk power system through improved software. Attached to this Second Supplemental Notice is the agenda for the technical conference and speakers' summaries of their presentations.

While the intent of the technical conference is not to focus on any specific matters before the Commission, some conference discussions might include topics at issue in proceedings that are currently pending before the Commission, including topics related to capacity valuation methodologies for renewable, hybrid, or storage resources. These proceedings include, but are not limited to:

PJM Interconnection, L.L.C., Docket No. EL21–83–000
California Independent System Operator Corp., Docket No. ER21–2455–004
New York Independent System Operator, Inc., Docket No. ER21–2460–003
ISO New England, Inc., Docket No. ER22–983–002
PJM Interconnection, L.L.C., Docket No. ER22–962–003
Southwest Power Pool, Inc., Docket No. ER22–1697–001
Midcontinent Independent System Operator, Inc., Docket No. ER22–1640–000
ISO New England, Inc., Docket No. EL22–42–000
Southwest Power Pool, Inc., Docket No. ER22–379–000
PJM Interconnection, L.L.C., Docket No. ER22–1200–000
California Independent System Operator Corp., Docket No. ER23–1485–000
California Independent System Operator Corp., Docket No. ER23–1533–000
California Independent System Operator Corp., Docket No. ER23–1534–000
Midcontinent Independent System Operator, Inc., Docket No. EL23–28
Midcontinent Independent System Operator, Inc., Docket No. ER23–1195
Midcontinent Independent System Operator, Inc., Docket No. EL23–46

The conference will take place in a hybrid format, with presenters and attendees allowed to participate either in-person or virtually. Further details on both in-person and virtual participation will be available on the conference web page.[1] Foreign nationals attending in-person must register through the Commission's website on or before June 2, 2023. We also encourage all other in-person attendees to also register through the Commission's website on or before June 2, 2023, to help ensure Commission staff can provide sufficient physical and virtual facilities and to communicate with attendees in the case of unanticipated emergencies or other changes to the conference schedule or location. Access to the conference (virtual or in-person) may not be available to those who do not register.

The Commission will accept comments following the conference, with a deadline of July 28, 2023.

There is an ''eSubscription'' link on the Commission's website that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

FERC conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations please send an email to *accessibility@ferc.gov* or call toll free (866) 208–3372 (voice) or (202) 502–8659 (TTY), or send a fax to (202) 208–2106 with the required accommodations.

For further information about these conferences, please contact:

Sarah McKinley (Logistical Information), Office of External Affairs, (202) 502–8004, *Sarah.McKinley@ferc.gov*
Alexander Smith (Technical Information), Office of Energy Policy and Innovation, (202) 502–6601, *Alexander.Smith@ferc.gov*

Dated: June 14, 2023.

Debbie-Anne A. Reese,

Deputy Secretary.

Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software

Agenda

AD10–12–014

June 27–29, 2023

Tuesday, June 27, 2023

9:15 a.m. Introduction

Elizabeth Topping, Federal Energy Regulatory Commission (*Washington, DC*)

9:30 a.m. Session T1 (*Commission Meeting Room*)

Probabilistic Energy Adequacy Assessment under Extreme Weather Events
Jinye Zhao, ISO New England (*Holyoke, MA*)
Stephen George, ISO New England (*Holyoke, MA*)
Ke Ma, ISO New England (*Holyoke, MA*)
Steven Judd, ISO New England (*Holyoke, MA*)
Eamonn Lannoye, EPRI (*Dublin, Ireland*)
Juan Carlos Martin, EPRI (*Madrid, Spain*)

Transmission Outage Probability Estimation Based on Real-Time Weather Forecast
Mingguo Hong, ISO New England (*Holyoke, MA*)
Xiaochuan Luo, ISO New England (*Holyoke, MA*)
Slava Maslennikov, ISO New England (*Holyoke, MA*)
Tongxin Zheng, ISO New England (*Holyoke, MA*)

Overview of MISO and PJM Hybrid Multiple Configuration Resource Model Implementation Within PROBE Software
Qun Gu, PowerGEM (Clifton Park, NY)
Boris Gisin, PowerGEM (Clifton Park, NY)
Anthony Giacomoni, PJM Interconnection (Audubon, PA)
Chuck Hansen, Midcontinent ISO (Carmel, IN)

Optimizing Combined Cycle Units in PJM's Wholesale Energy Markets using a Hybrid Multiple Configuration Resource Model
Anthony Giacomoni, PJM Interconnection (Audubon, PA)
Danial Nazemi, PJM Interconnection (Audubon, PA)
Qun Gu, PowerGEM (Clifton Park, NY)
Boris Gisin, PowerGEM (Clifton Park, NY)

11:30 a.m. Lunch

12:30 p.m. Session T2 (*Commission Meeting Room*)

Enhancements to Ramp Rate Dependent Spinning Reserve Modeling
Shubo Zhang, New York ISO (*Rensselaer, NY*)
John L. Meyer, New York ISO (*Rensselaer, NY*)
Iiro Harjunkoski, Hitachi Energy (*Mannheim, Germany*)

Determining Dynamic Operating Reserve Requirements for Reliability and Efficient Market Outcomes: Tradeoffs and Price Formation Challenges
Matthew Musto, New York ISO (*Rensselaer, NY*)
Kanchan Upadhyay, New York ISO (*Rensselaer, NY*)
Edward O Lo, Hitachi Energy (*San Jose, CA*)

Operational Experience with Nodal Procurement of Flexible Ramping Product
Guillermo Bautista-Alderete, California ISO (Folsom, CA)
George Angelidis, California ISO (Folsom, CA)
Yu Wan, California ISO (Folsom, CA)

[1] *https://www.ferc.gov/news-events/events/increasing-real-time-and-day-ahead-market-and-planning-efficiency-through.*

Kun Zhao, California ISO (Folsom, CA)

Impact of DERs on Load Distribution Factors in Forecasting

Khaled Abdul-Rahman, California ISO (*Folsom, CA*)

Hani Alarian, California ISO (*Folsom, CA*)

Trevor Ludlow, California ISO (*Folsom, CA*)

Chiranjeevi Madvesh, California ISO (*Folsom, CA*)

Increased Congestion in SPP and Optimization in the Day Ahead Market with Gurobi

Seth Mayfield, Southwest Power Pool (*Little Rock, AR*)

Yasser Bahbaz, Southwest Power Pool (*Little Rock, AR*)

3:00 p.m. Break

3:30 p.m. Session T3 (*Commission Meeting Room*)

MISO Operations Risk Assessment and Uncertainty Management

Congcong Wang, Midcontinent ISO (*Carmel, IN*)

Long Zhao, Midcontinent ISO (*Carmel, IN*)

Jason Howard, Midcontinent ISO (*Carmel, IN*)

Market Simulation Tools and Uncertainty Quantification Methods to Support Operational Uncertainty Management

Nazif Faqiry, Midcontinent ISO (*Carmel, IN*)

Arezou Ghesmati, Midcontinent ISO (*Carmel, IN*)

Bing Huang, Midcontinent ISO (*Carmel, IN*)

Yonghong Chen, Midcontinent ISO (*Carmel, IN*)

Bernard Knueven, National Renewable Energy Laboratory (*Golden, CO*)

Pumped Storage Optimization in Real-time Markets under Uncertainty

Bing Huang, Midcontinent ISO (*Carmel, IN*)

Arezou Ghesmati, Midcontinent ISO (*Carmel, IN*)

Yonghong Chen, Midcontinent ISO (*Carmel, IN*)

Ross Baldick, University of Texas at Austin (*Austin, TX*)

Forecasting Aggregate Electricity Demand on a 5-minute Basis using Machine Learning

Yinghua Wu, PJM Interconnection (*Audubon, PA*)

Laura Walter, PJM Interconnection (*Audubon, PA*)

Anthony Giacomoni, PJM Interconnection (*Audubon, PA*)

Long-Term Outlook for the ERCOT Grid

Pengwei Du, Electric Reliability Corporation of Texas (*Austin, TX*)

6:00 p.m. Adjourn

Wednesday, June 28, 2023

9:00 a.m. Session W–A1 (*Commission Meeting Room*)

Uncertainty-Informed Renewable Energy Scheduling: A Scalable Bilevel Framework

Dongwei Zhao, Massachusetts Institute of Technology (*Cambridge, MA*)

Vladimir Dvorkin, Massachusetts Institute of Technology (*Cambridge, MA*)

Stefanos Delikaraoglou, Axpo Solutions AG (*Zurich, Switzerland*)

Alberto J. Lamadrid L., Lehigh University (*Bethlehem, PA*)

Audun Botterud, Massachusetts Institute of Technology (*Cambridge, MA*)

Enhancing Power System Resilience and Efficiency through Proactive Security Assessments and the Use of powerSAS.m: A Robust, Efficient, and Scalable Security Analysis Tool for Large-Scale Systems

Yang Liu, Argonne National Laboratory (*Lemont, IL*)

Feng Qiu, Argonne National Laboratory (*Lemont, IL*)

Jianzhe Liu, Argonne National Laboratory (*Lemont, IL*)

Stochastic Unit Commitment and Market Clearing in Julia with UnitCommitment.jl

Alinson Santos Xavier, Argonne National Laboratory (*Lemont, IL*)

Ogün Yurdakul, Technische Universität Berlin (*Berlin, Germany*)

Aleksandr M. Kazachkov, University of Florida (*Gainesville, FL*)

Jun He, Purdue University (*West Lafayette, IN*)

Feng Qiu, Argonne National Laboratory (*Lemont, IL*)

Reduced-order Decomposition and Coordination Approach for Markov-based Stochastic UC with High Penetration Level of Wind and BESS

Niranjan Raghunathan, University of Connecticut (*Storrs, CT*)

Peter B. Luh, University of Connecticut and National Taiwan University (*Alexandria, VA*)

Zongjie Wang, University of Connecticut (*Storrs, CT*)

Mikhail A. Bragin, University of California, Riverside (*Riverside, CA*)

Bing Yan, Rochester Institute of Technology (*Rochester, NY*)

Meng Yue, Brookhaven National Laboratories (*Upton, NY*)

Tianqiao Zhao, Brookhaven National Laboratories, (*Upton, NY*)

Learn to Branch and Dive for Large-scale Unit Commitment Problem

Jingtao Qin, University of California, Riverside (*Riverside, CA*)

Nanpeng Yu, University of California, Riverside (*Riverside, CA*)

Mikhail Bragin, University of Connecticut (*Storrs, CT*)

9:00 a.m. Session W–B1 (*Hearing Room One*)

Stochastic Nodal Adequacy Pricing Platform (SNAP)

Richard D. Tabors, Tabors Caramanis Rudkevich (*Newton, MA*)

Aleksandr Rudkevich, Newton Energy Group (*Newton, MA*)

Russel Philbrick, Polaris Systems Optimization (*Seattle, WA*)

Selin Yanikara, Newton Energy Group (*Newton, MA*)

Assessing Nodal Adequacy of Large Power Systems

F. Selin Yanikara, Newton Energy Group (*Newton, MA*)

Russ Philbrick, Polaris Systems Optimization (*Seattle, WA*)

Aleksandr M. Rudkevich, Newton Energy Group (*Newton, MA*)

Sophie Edelman, The Brattle Group (*New York, NY*)

Comparison of Flexibility Reserve and ORDC for Increasing System Flexibility

Phillip de Mello, Electric Power Research Institute (Niskayuna, NY)

Erik Ela, Electric Power Research Institute (Boulder, CO)

Nikita Singhal, Electric Power Research Institute (Palo Alto, CA)

Alexandre Moreira da Silva, Lawrence Berkeley National Laboratory (Berkeley, CA)

Miguel Heleno, Lawrence Berkeley National Laboratory (Berkeley, CA)

ABSCORES, A Novel Application of Banking Scoring and Rating for Electricity Systems

Alberto J. Lamadrid L., Lehigh University (*Bethlehem, PA*)

Audun Botterud, Massachusetts Institute of Technology (*Cambridge, MA*)

Jhi-Young Joo, Lawrence Livermore National Laboratory (*Livermore, CA*)

Shijia Zhao, Argonne National Laboratory (*Lemont, IL*)

Recent Developments in the Day-ahead and Real-time Electricity Market Design and Software Caused by the Higher Energy Costs and Emerging Technologies—European Experience

Petr Svoboda, Unicorn Systems A.S. (*Prague, Czech Republic*)

11:30 a.m. Lunch

12:30 p.m. Session W–A2 (*Commission Meeting Room*)

System Resilience through Electricity System Restoration and Related Services
Douglas Wilson, General Electric (*Edinburgh, United Kingdom*)
James Yu, ScottishPower Energy Networks (*Glasgow, United Kingdom*)
Ian Macpherson, ScottishPower Energy Networks (*Glasgow, United Kingdom*)
Marta Laterza, General Electric (*Glasgow, United Kingdom*)
Marcos Santos, General Electric (*Glasgow, United Kingdom*)
Richard Davey, General Electric (*Glasgow, United Kingdom*)
Coordinated Cross-Border Capacity Calculation Through The FARAO Open-Source Toolbox
Violette Berge, Artelys Canada (*Montréal, Canada*)
Nicolas Omont, Artelys (*Paris, France*)
Advanced Scenario Selection Methods for Probabilistic Transmission Planning Assessments
Eknath Vittal, Electric Power Research Institute (*Palo Alto, CA*)
Anish Gaikwad, Electric Power Research Institute (*Palo Alto, CA*)
Parag Mitra, Electric Power Research Institute (*Palo Alto, CA*)
Incorporating Climate Projections into Grid Models: Bridging the Data Gap to Capture Weather Dependent Representative and Extreme Events and Corresponding Uncertainties
Zhi Zhou, Argonne National Laboratory (*Lemont, IL*)
Neal Mann, Argonne National Laboratory (*Lemont, IL*)
Yanwen Xu, University of Illinois at Chicago, Urbana-Champaign (*Champaign, IL*)
Zuguang Gao, University of Chicago (*Chicago, IL*)
Akintomide Akinsanola, University of Illinois at Chicago (*Chicago, IL*)
Todd Levin, Argonne National Laboratory (*Lemont, IL*)
Jonghwan Kwon, Argonne National Laboratory (*Lemont, IL*)
Audun Botterud, Senior Energy Systems Engineer, Argonne National Laboratory (*Lemont, IL*)

12:30 p.m. Session W–B2 (*Hearing Room One*)

Enhancing Decision Support for Electricity Markets with Machine Learning
Yury Dvorkin, Johns Hopkins University (*Baltimore, MD*)
Robert Ferrando, University of Arizona (*Tucson, AZ*)
Laurent Pagnier, University of Arizona (*Tucson, AZ*)
Zhirui Liang, Johns Hopkins University (*Baltimore, MD*)
Daniel Bienstock, Columbia University (*New York, NY*)
Michael Chertkov, University of Arizona (*Tucson, AZ*)
Boosting Power System Operation Economics via Closed-loop Predict-and-Optimize
Lei Wu, Stevens Institute of Technology (*Hoboken, NJ*)
Xianbang Chen, Stevens Institute of Technology (*Hoboken, NJ*)
Synergistic Integration of Machine Learning and Mathematical Optimization for Sub-hourly Unit Commitment
Jianghua Wu, University of Connecticut (*Storrs, CT*)
Zongjie Wang, University of Connecticut (*Storrs, CT*)
Yonghong Chen, MIDCONTINENT ISO (*Carmel, IN*)
Bing Yan, Rochester Institute of Technology (*Rochester, NY*)
Mikhail Bragin, University of California, Riverside (*Riverside, CA*)
Privacy-Preserving Synthetic Dataset Generation for Power Systems Research
Vladimir Dvorkin, Massachusetts Institute of Technology (*Cambridge, MA*)
Audun Botterud, Massachusetts Institute of Technology (*Cambridge, MA*)

2:30 p.m. Break

3:00 p.m. Session W–A3 (*Commission Meeting Room*)

Parallel Interior-Point Solver for Security Constrained ACOPF problems on SIMD/GPU Architectures
Mihai Anitescu, Argonne National Laboratory (*Lemont, IL*)
François Pacaud, Ecole des Mines (*Paris, France*)
Michel Schanen, Argonne National Laboratory (*Lemont, IL*)
Sungho Shin, Argonne National Laboratory (*Lemont, IL*)
Daniel Adrian Maldonado, Argonne National Laboratory (*Lemont, IL*)
The Need for More Rigorous Calculation of Shadow Prices and LMPs
Xiaoming Feng, Hitachi Energy (*Raleigh, NC*)
Real-Time Market Enhancements for Reliability and Efficiency
Mort Webster, Pennsylvania State University (*University Park, PA*)
Anthony Giacomoni, PJM Interconnection (*Audubon, PA*)
Aravind Retna Kumar, Pennsylvania State University (*University Park, PA*)
Sushant Varghese, Pennsylvania State University (*University Park, PA*)
Shailesh Wasti, Pennsylvania State University (*University Park, PA*)
Economics of Grid-Supported Electric Power Markets: A Fundamental Reconsideration
Leigh Tesfatsion, Iowa State University (*Ames, IA*)

3:00 p.m. Session W–B3 (*Hearing Room One*)

Simulation of Wholesale Electricity Markets with Capacity Expansion and Production Cost Models to Understand Feedback between Short-Term Market Procedures and Long-Term Investment Incentives
Jesse Holzer, Pacific Northwest National Laboratory (*Richland, WA*)
Abhishek Somani, Pacific Northwest National Laboratory (*Richland, WA*)
Brent Eldridge, Pacific Northwest National Laboratory (*Bel Air, MD*)
Diane Baldwin, Pacific Northwest National Laboratory (*Richland, WA*)
Making the Right Resource Choice Requires Making the Right Model Choice
Rodney Kizito, Ascend Analytics (*Wheaton, MD*)
Gary W. Dorris, Ascend Analytics, CEO (*Boulder, CO*)
David Millar, Ascend Analytics (*Boulder, CO*)
Transmission Shortage Pricing By MW-Mile Based Demand Curve
Sina Gharebaghi, Pennsylvania State University (*University Park, PA*)
Xiaoming Feng, Hitachi Energy (*Raleigh, NC*)
Grid OS—A Modern Software Portfolio for Grid Orchestration
Renan Giovanini, General Electric (*Edinburgh, UK*)
Joseph Franz, General Electric (*Melbourne, FL*)

5:00 p.m. Adjourn

Thursday, June 29, 2023

9:30 a.m. Session H1 (*Commission Meeting Room*)

Integration of DER Aggregations in ISO-Scale SCUC Models
Brent Eldridge, Pacific Northwest National Laboratory (*Bel Air, MD*)
Jesse Holzer, Pacific Northwest National Laboratory (*Richland, WA*)
Abhishek Somani, Pacific Northwest National Laboratory (*Richland, WA*)
Eran Schweitzer, Pacific Northwest National Laboratory (*Richland, WA*)
Rabayet Sadnan, Pacific Northwest National Laboratory (*Richland, WA*)
Nawaf Nazir, Pacific Northwest National Laboratory (*Richland, WA*)

Soumya Kundu, Pacific Northwest National Laboratory (*Richland, WA*)

Current-Voltage AC Optimal Power Flow for Unbalanced Distribution Network

Mojdeh Khorsand Hedman, Arizona State University (*Tempe, AZ*)

Zahra Soltani, Arizona State University (*Tempe, AZ*)

Shanshan Ma, Arizona State University (*Las Vegas, NV*)

Empowering Electricity Markets through Distributed Energy Resources and Smart Building Setpoint Optimization: A Graph Neural Network-Based Deep Reinforcement Learning Approach

You Lin, Massachusetts Institute of Technology (Cambridge, MA)

Audun Botterud, Massachusetts Institute of Technology (*Cambridge, MA*)

Daisy Green, Massachusetts Institute of Technology (*Cambridge, MA*)

Leslie Norford, Massachusetts Institute of Technology (*Cambridge, MA*)

Jeremy Gregory, Massachusetts Institute of Technology (*Cambridge, MA*)

Multi-timescale Operations of Nuclear-Renewable Hybrid Energy Systems for Reserve and Thermal Products Provision

Jie Zhang, University of Texas at Dallas (*Richardson, TX*)

Jubeyer Rahman, University of Texas at Dallas (*Richardson, TX*)

11:30 a.m. Lunch

12:30 p.m. Session H2 (*Commission Meeting Room*)

Optimizing Stand-Alone Battery Storage Operations Scheduling Under Uncertainties in German Residential Electricity Market Using Stochastic Dual Dynamic Programming

Pattanun Chanpiwat, University of Maryland & Aalto University (*College Park, MD; Espoo, Finland*)

Fabricio Oliveira, Aalto University (*Espoo, Finland*)

Steven A. Gabriel, University of Maryland (*College Park, MD*)

Integration of Hybrid Storage Resources into Wholesale Electricity Markets

Nikita Singhal, Electric Power Research Institute (*Palo Alto, CA*)

Rajni Kant Bansal, Johns Hopkins University (*Baltimore, MD*)

Erik Ela, Electric Power Research Institute (*Palo Alto, CA*)

Julie Mulvaney Kemp, Lawrence Berkeley National Laboratory (*Berkeley, CA*)

Miguel Heleno, Lawrence Berkeley National Laboratory (*Berkeley, CA*)

Predicting Strategic Energy Storage Behaviors

Yuexin Bian, University of California (*San Diego, CA*)

Ningkun Zheng, Columbia University (*New York City, NY*)

Yang Zheng, University of California—San Diego (*San Diego, CA*)

Bolun Xu, Columbia University (*New York, NY*)

Yuanyuan Shi, University of California—San Diego (*San Diego, CA*)

Energy Storage Participation Algorithm Competition (ESPA-Comp)

Brent Eldridge, Pacific Northwest National Laboratory (*Bel Air, MD*)

Jesse Holzer, Pacific Northwest National Laboratory (*r*)

Abhishek Somani, Pacific Northwest National Laboratory (*Richland, WA*)

Kostas Oikonomou, Pacific Northwest National Laboratory (*Richland, WA*)

Brittany Tarufelli, Pacific Northwest National Laboratory (*Laramie, WY*)

Li He, Pacific Northwest National Laboratory (*Richland, WA*)

2:30 p.m. Break

3:00 p.m. Session H3 (*Commission Meeting Room*)

Congestion Mitigation with Transmission Reconfigurations in the Evergy Footprint

Pablo A. Ruiz, NewGrid (*Somerville, MA*)

Derek Brown, Evergy (*Topeka, KS*)

Jeremy Harris, Evergy (*Topeka, KS*)

German Lorenzon, NewGrid (*Somerville, MA*)

Grant Wilkerson, Evergy (*Kansas City, MO*)

Optimal Transmission Expansion Planning with Grid Enhancing Technologies

Swaroop Srinivasrao Guggilam, Electric Power Research Institute (*Knoxville, TN*)

Alberto Del Rosso, Electric Power Research Institute (*Knoxville, TN*)

The Key Role of Extended ACOPF-based Decision Making for Supporting Clean, Cost-Effective and Reliable/Resilient Electricity Services

Maria Ilic, Carnegie Mellon University (*Pittsburgh, PA*)

Rupamathi Jaddivada, SmartGridz (*Boston, MA*)

Jeffrey Lang, Massachusetts Institute of Technology (*Cambridge, MA*)

Eric Allen, SmartGridz (*Boston, MA*)

Data & API Standards for Clean Energy Solutions and Digital Innovation

Priya Barua, Clean Energy Buyers Institute (*Washington, DC*)

Ben Gerber, M–RETS (*Minneapolis, MN*)

Mine Production Scheduling under Time-of-Use Power Rates with Renewable Energy Sources

Daniel Bienstock, Columbia University (*New York, NY*)

Amy Mcbrayer, South Dakota School of Mines (*Rapid City, SD*)

Andrea Brickey, South Dakota School of Mines (*Rapid City, SD*)

Alexandra Newman, Colorado School of Mines (*Golden, CO*)

5:30 p.m. Adjourn

Conference Abstracts

Day 1—Tuesday, June 27

Session T1 (Tuesday, June 27, 9:30 a.m.) Commission Meeting Room

Probabilistic Energy Adequacy Assessment Under Extreme Weather Events

Dr. Jinye Zhao, Technical Manager, ISO New England (Holyoke, MA)

Stephen George, Director, ISO New England (Holyoke, MA)

Dr. Ke Ma, Senior Analyst, ISO New England (Holyoke, MA)

Steven Judd, Manager, ISO New England (Holyoke, MA)

Dr. Eamonn Lannoye, Program Manager, Electric Power Research Institute (Dublin, Ireland)

Juan Carlos Martin, Senior Engineer, Electric Power Research Institute (Madrid, Spain)

As intermittent and limited energy resources become a larger portion of the region's generation resource mix, and as the region's demand becomes increasingly electrified, it has become increasingly important to understand the operational risks associated with future weather extremes. To better inform the region's understanding of these risks, ISO New England in collaboration with EPRI, has developed a probabilistic energy adequacy assessment framework. This approach of stress testing the system's energy adequacy focuses on generating comprehensive extreme weather scenarios for the New England region and performing risk analyses across these scenarios. The framework offers a tailored approach to identify unique energy adequacy risks faced by the New England power system and enables us to analyze related stressors under extreme events.

Transmission Outage Probability Estimation Based on Real-Time Weather Forecast

Dr. Mingguo Hong, Principal Analyst, ISO New England (Holyoke, MA)

Dr. Xiaochuan Luo, Manager, ISO New England (Holyoke, MA)

Dr. Slava Maslennikov, Technical Manager, ISO New England (Holyoke, MA)
Dr. Tongxin Zheng, Director, ISO New England (Holyoke, MA)

Extreme weather patterns including both winter and summer storms have been posing increasing threats to power transmission security in the New England area. Being able to accurately predict their impacts will benefit both power system operation and planning. In recent years, the ISO New England has been developing machine-learning algorithms for estimating the probability of transmission line outage in real-time, given weather forecast variables such as wind, temperature, snow, and rain precipitation, etc. This presentation will share our study findings and on-going software implementation experience.

Overview of MISO and PJM Hybrid Multiple Configuration Resource Model Implementation Within PROBE Software

Dr. Anthony Giacomoni, Manager, Advanced Analytics, PJM Interconnection (Audubon, PA)
Dr. Danial Nazemi, Operations Research Engineer II, PJM Interconnection (Audubon, PA)
Dr. Qun Gu, Principal Consultant, PowerGEM (Clifton Park, NY)
Dr. Boris Gisin, President, PowerGEM (Clifton Park, NY)

For the past three years, PJM, MISO and PowerGEM have been working jointly on developing an advanced SCUC algorithm to prepare for the full-scale implementation of a Multiple Configuration Resource (MCR) model in their energy markets. PJM currently uses aggregate models for MCRs that do not accurately capture their true operating characteristics. Often MCRs may need to overestimate costs to ensure cost recovery, underestimate costs to ensure selection or offer reduced operating ranges to be able to accurately reflect their operating capabilities. This presentation will focus on the impacts to PJM's energy markets from optimizing the multiple configurations and components of their combined cycle units. The optimization of multiple configurations and components is very challenging due to the additional integer variables and constraints that impact the solution time and may lead to performance challenges. A prototype full-scale MCR model has been implemented in the PROBE Day-Ahead software, which is currently a critical component of PJM's Day-Ahead Market (DAM) clearing process. The prototype MCR model has the ability to perform energy and ancillary service co-optimization for combined cycle units with multiple configurations and components. The developed model has no practical limits on the number of configurations that each unit can have and the model allows for simultaneously enforcing configuration and component level constraints. Benefits of the new model include enhanced modeling flexibility and accuracy, which allows combined cycle participants to submit bids that align with their units' physical operating constraints, better alignment with the real-time model and market outcomes with increased social benefits. To quantify the impacts of the MCR model on PJM's energy markets, PJM gathered configuration and component data from a large number of combined cycle units in its footprint. Simulations using one year of historical DAM data were then performed to measure the impacts of the MCR model on the clearing engine's computational performance and market outcomes. Results clearly demonstrate significant potential bid production cost savings of over $100 million per year with a very modest increase in solution time. The MCR model is currently being implemented in PJM's DAM for the optimization of synchronous condensers. It is planned that after successful implementation of the MCR model for synchronous condensers the same model will be implemented for combined cycle units and possibly for hybrid resources as well.

Session T2 (Tuesday, June 27, 12:30 p.m.) (Commission Meeting Room)

Enhancements to Ramp Rate Dependent Spinning Reserve Modeling

Dr. Shubo Zhang, Energy Market Engineer, New York ISO (Rensselaer, NY)
John L. Meyer, Senior Energy Market Engineer, New York ISO (Rensselaer, NY)
Iiro Harjunkoski, Researcher, Hitachi Energy (Mannheim, Germany)

In a joint effort between the NYISO and Hitachi Energy, a Ramp Rate Dependent (RRD) formulation of spinning reserve scheduling that utilizes Multiple Response Rates (MRR) across a Combined Cycle Gas Turbine (CCGT) generator or other dispatchable resource's range of output has been developed. To provide more flexibility to Market Participants, a ''Limited Participation'' conceptual strategy is also included that would allow a CCGT or other dispatchable resource to selectively provide spinning reserves or regulation for a certain range of output. This presentation will discuss the market basis and design of Limited Participation in spinning reserves and regulation, in the context of Ramp Rate Dependent Spinning Reserve Modeling.

Determining Dynamic Operating Reserve Requirements for Reliability and Efficient Market Outcomes: Tradeoffs and Price Formation Challenges

Matthew Musto, Technical Specialist—Market Solutions Engineering, NYISO (Rensselaer, NY)
Kanchan Upadhyay, Senior Energy Market Engineer—Market Solutions Engineering, NYISO (Rensselaer, NY)
Edward O Lo, Consultant, Hitachi Energy (San Jose, CA)

With increasing intermittent resources in the generation mix, the need for more economic responsiveness and operational flexibility while maintaining system reliability is growing. The NYISO and Hitachi Energy have been working on advanced design and techniques for calculating operating reserve requirements dynamically for each reserve region while simultaneously optimizing the dispatch solution in the market clearing engine. A key benefit of the dynamic reserves formulation is the functionality to determine the least-cost generation and reserve mix to meet load. This dynamic determination of reserve requirements in New York Control Area (NYCA) and all reserve regions within the NYCA creates new tradeoffs between energy schedules and reserve requirements. This presentation will discuss these tradeoffs and highlight the associated price formation challenge.

Operational Experience with Nodal Procurement of Flexible Ramping Product

Dr. Guillermo Bautista-Alderete, Director, Market Analysis & Forecasting, California ISO (Folsom, CA)
George Angelidis, Executive Principal—Power Systems and Market Technology, California ISO (Folsom, CA)
Yu Wan, Power Systems Engineer, California ISO (Folsom, CA)
Kun Zhao, Market Engineering Specialist Lead, California ISO (Folsom, CA)

The CAISO's market procures flexible ramping capacity to manage weather-based uncertainty realized in real time. The CAISO introduced this product in 2016 using a procurement requirement at the system level. Using a system-level procurement requirement, the market frequently procured flexible ramping capacity from locations impacted by congestion, thereby stranding the flexible ramping capacity. The CAISO has enhanced the design of the flexible ramping product using a formulation that observes transmission constraints. This approach considers congestion management as part of the procurement of flexible ramping capacity helping to ensure the CAISO can deploy this capacity when uncertainty arises. This new design poses additional complexity because the market clearing process now considers transmission constraints for energy and for flexible ramping capacity. The CAISO will provide an update on the performance of its flexible ramping product under this new design.

Impact of DERs on Load Distribution Factors in Forecasting

Dr. Khaled Abdul-Rahman, Vice President, Power System and Market Technology, California ISO (Folsom, CA)
Hani Alarian, Executive Director of Power Systems Technology Operations, California ISO (Folsom, CA)
Trevor Ludlow, Specialist Lead of Power Systems Technology Operations, California ISO (Folsom, CA)
Chiranjeevi Madvesh, Lead Engineer of Power Systems Technology Operations, California ISO (Folsom, CA)

The calculation of load distributing factors (LDFs) is traditionally performed based on a collection of historical state estimator calculated values and stored in libraries for use when simulating power system operations in look-ahead market and reliability applications. The inherit assumption is that bus loads are accurately estimated from the aggregate system load forecast using LDFs, and generation quantities are deterministically known. Accordingly, it is assumed that there is a strong correlation between the system load and individual bus loads. However, the proliferation of behind-the-meter distributed energy resources, solar rooftops, batteries, hybrid resources, as well as the use of behind the-meter demand response utility programs, and electric vehicles introduces a non-conforming load component at locations that were previously conforming loads.

This issue requires a more accurate forecast of non-conforming loads by taking into consideration the probabilistic nature of bus loads and variable/intermittent generation. The CAISO's enhanced LDF forecast algorithm takes into account not just the average hour of the day and the day of the week but includes machine learning ability to distinguish between flows that scales up with load in both a non-linear and linear fashion. It also includes a new fusion-forecasting model that improves forecasting accuracy. Additionally, the CAISO's algorithm uses data engineering and preprocessing options to increase the accuracy of the proposed model. The CAISO analyzes load data to verify that the proposed methodology provides higher forecasting accuracy with lower error indices.

Increased Congestion in SPP and Optimization in the Day Ahead Market With Gurobi

Seth Mayfield, Manager of Market Support & Analysis, Southwest Power Pool (Little Rock, AR)
Yasser Bahbaz, Director of Markets Development, Southwest Power Pool (Little Rock, AR)

SPP has seen substantial increased congestion in recent years. These trends have numerous reliability and economic impact. In the Day-Ahead Market, SPP has noticed high transmission activation leading to longer optimization runtimes. High activations results in large increases in the mathematical growth, which then results in slower Mixed Integer Program (MIP) runtimes. Other factors include increasing market rules complexity (such as uncertainty product) and additional market resource registrations. SPP performed a study where we evaluate swapping our existing optimization engine (IBM's CPlex) with Gurobi's optimization engine. The study reran every approved DAMKT SCUC operating day for 2021 (365 cases). Gurobi solved the cases 41% faster than CPlex using Gurobi without tuning. A very light discussion with Gurobi resulted in a few tuning suggestions which pushed the runtime reduction to 43%. SPP is in the process of acquiring Gurobi licenses and will work with our software vendor to incorporate the engine into our market. Phase 1 will include simultaneously running both CPlex and Gurobi as we believe this will give us the best/fastest results for each day. It is expected that there will be a transition to using more Gurobi instances than CPlex as time goes on.

Session T3 (Tuesday, June 27, 3:30 p.m.) (Commission Meeting Room)

MISO Operations Risk Assessment and Uncertainty Management

Dr. Congcong Wang, Lead, Operations Risk Assessment, Midcontinent ISO (Carmel, IN)
Dr Long Zhao, Senior Advisor of Operations Risk Assessment, Midcontinent ISO (Carmel, IN)
Jason Howard, Director of Operations Risk Management, Midcontinent ISO (Carmel, IN)

Fleet transition is driving a new risk profile at MISO. Uncertainty and Variability are increasing in their intensity, diversity, and volatility. While probabilistic forecasting has made progress for wind and solar, its integration into operations and markets is uneven. Furthermore, uncertainty comes in more sources than just renewable energy such as generation and transmission outages, fuel scarcity especially during extreme weather events, resulting in challenges for the RTO to manage the aggregated or net uncertainty. This presentation will outline MISO's operations risk assessment and uncertainty management initiatives including: (1) Characterize Risks—transform traditional deterministic renewable, load and ''net'' load forecasts to probabilistic forecasts in production systems; and assess generation and fuel risks to better capture the unknowns; (2) Integrate risks into Operations Situational Awareness and Operations Planning—provide control room a dynamic and geographically granular visualization of operating reserve margin; and visibility of weather driven operations risks; (3) Automate risk management through market products with dynamic reserve requirements—assess net uncertainty across different timeframes; and predict risks to establish a daily target for procuring market-based reserves using analytical and meteorological techniques. This work is done in collaboration with R&D through the joint Uncertainty Roadmap.

Market Simulation Tools and Uncertainty Quantification Methods To Support Operational Uncertainty Management

Dr. Nazif Faqiry, R&D Engineer, Midcontinent ISO (Carmel, IN)
Dr. Arezou Ghesmati, R&D Engineer, Midcontinent ISO (Carmel, IN)
Dr. Bing Huang, R&D Engineer, Midcontinent ISO (Carmel, IN)
Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (Carmel, IN)
Dr. Bernard Knueven, Research Scientist, National Renewable Energy Laboratory (Golden, CO)

Portfolio evolution and more frequent extreme weather events are introducing more challenges to MISO Market Operations with new risk profiles. To improve market efficiency and generate efficient price signals for operational and investment decisions, it is increasingly important to align market design with reliability and risk management needs. This work presents the Electrical Grid Research & Engineering (EGRET) market simulation tool adapted and enhanced at MISO to evaluate existing and future system, and a novel netload ramp uncertainty prediction and scenario generation method to support stochastic simulation and reserve requirement settings. First, it presents a multi-periods market simulation tool and its capabilities, including rolling real-time unit commitment and economic dispatch (UCED), followed by the results of 8 GW solar penetration study. Then, it presents a novel method that is developed to predict and generate scenarios for uncertainties across different lead times. The scenarios can be used as inputs to the market simulation tool for stochastic simulation. The two parts together may lead to multi-scenario stochastic unit commitment in the future. In the near term, the stochastic market simulation can help to validate market design and operational procedures. The uncertainty predication and scenario generation may help operational situational awareness and better define reserve requirements and operational margins.

Pumped Storage Optimization in Real-Time Markets Under Uncertainty

Bing Huang, Research Engineer, Midcontinent ISO (Carmel, IN)
Arezou Ghesmati, R&D Scientist, Midcontinent ISO (Carmel, IN)
Yonghong Chen, Consulting Advisor, Midcontinent ISO (Carmel, IN)
Ross Baldick, Emeritus Professor, University of Texas at Austin (Austin, TX)

Pumped storage hydro units (PSHU) can provide flexibility to power systems and may especially be valuable with increasing shares of intermittent renewable resources. However, the scheduling of PSHUs, particularly in the real-time market, has not been thoroughly studied. To enhance the use of PSH resources and leverage their flexibility, it is important to incorporate the uncertainties to properly address the risks in the real-time market operation. In this work, first a deterministic PSHU model that incorporates the state of charge in the Day-ahead market optimization is introduced. Second, two pumped storage hydro (PSH) models that use probabilistic price forecasts are proposed for Look-ahead commitment (LAC) in the real-time market operation. A risk neutral stochastic PSH model and a risk averse robust optimization PSH model are developed using the probabilistic price forecasts to capture the real-time market uncertainties. Numerical studies in Mid-continent Independent System Operator (MISO) system demonstrate that the proposed models improve market efficiency and reduce PSH real time risk compared to the current approach. Probabilistic forecast for Real Time Locational Marginal Price (RT–LMP) is created and embedded into the proposed stochastic and robust optimization models, a statistically robust approach is used to generate scenarios for reflecting the temporal inter-dependence of the LMP forecast uncertainties.

Forecasting Aggregate Electricity Demand on a 5-Minute Basis Using Machine Learning

Dr. Yinghua Wu, Senior Lead Data Scientist, PJM Interconnection (Audubon, PA)
Laura Walter, Senior Lead Data Scientist, PJM Interconnection (Audubon, PA)
Dr. Anthony Giacomoni, Manager—Advanced Analytics, PJM Interconnection (Audubon, PA)

PJM currently has two load forecasts used in dispatch and real-time operations. These forecasts are comprised of the short-term forecast, which is the forecasted hourly average load for the next seven days, and the very short-term load forecast, which is the forecasted 5-minute load averages for the next six hours. The very short-term load forecast is constantly fed into the real-time dispatch software for optimal power flow calculations and real-time market pricing. It is of crucial importance that these forecasts closely match the actual load in the near future to maintain system frequency and voltage. If not, dispatchers must take action to quickly intervene and adjust the load up or down. The load profiles generally follow temporal patterns, but are also driven by weather and other usage patterns. Given the recent rapid growth of machine learning technologies, this presentation will survey a collection of some of the most representative and innovative methods that are suitable to time series predictions such as load forecasting, *e.g.,* gradient boosting, recurrent neural network, causal convolution, etc. We will also revisit some traditional methods such as generalized linear models and automatic regressive moving average (ARMA) methods to explore whether they can capture the load shape in short horizons. We will survey and analyze these new technologies for their power of prediction to see if these methods provide the potential to improve on current forecasting practices.

Long-Term Outlook for the ERCOT Grid

Pengwei Du, Supervisor—Economic Analysis & Long Term Planning Studies, The Electric Reliability Council of Texas (Austin, Texas)

The bulk transmission network within ERCOT consists of the 60-kilovolt (kV) and higher transmission lines and associated equipment. ERCOT conducts a forward-looking study to understand long-term reliability and economics need to ensure continued system reliability and efficiency. This talk will present the key challenges and findings from the most recent long-term system assessment planning study, which accounts for the inherent uncertainty of planning the system in the 10- to 15-year planning horizon.

Day 2—Wednesday, June 28

Session W–A1 (Wednesday, June 28, 9:00 a.m.) (Commission Meeting Room)

Uncertainty-Informed Renewable Energy Scheduling: A Scalable Bilevel Framework

Dr. Dongwei Zhao, Postdoctoral Associate, Massachusetts Institute of Technology (Cambridge, MA)
Dr. Vladimir Dvorkin, Postdoctoral Fellow, Massachusetts Institute of Technology (Cambridge, MA)
Dr. Stefanos Delikaraoglou, Data Scientist, Axpo Solutions AG (Zurich, Switzerland)
Dr. Alberto J. Lamadrid L., Associate Professor, Lehigh University (Bethlehem, PA)
Dr. Audun Botterud, Principal Research Scientist, Massachusetts Institute of Technology (Cambridge, MA)

The fast-growing variable renewable energy sources (VRES) in electricity markets are creating challenges to uncertainty management. This work addresses these challenges by adopting an uncertainty-informed adjustment toward VRES bidding quantities in the day-ahead market and minimizing expected system costs under the sequential market-clearing structure. However, implementing this mechanism requires solving a bilevel optimization problem, which is computationally difficult for practical large-scale systems. To overcome this challenge, we propose a novel technique based on strong duality and McCormick envelopes. This approach relaxes the original problem to a linear program, enabling efficient computation for large-scale systems. We conduct case studies on the 1576-bus NYISO systems and compare our bilevel VRES-adjustment model with the myopic strategy where VRES producers bid the forecast value in the day-ahead market. The results demonstrate that under a future high VRES penetration level (*e.g.,* 40%), our bilevel framework can significantly reduce the expected system cost and the volatility of the market prices, participants' revenues, and real-time re-dispatch adjustments, by efficiently optimizing VRES quantities in the day-ahead market. Furthermore, we found that increasing transmission ability may incur a much higher system cost under the myopic strategy while a lower cost under the bilevel model) because of the lack of flexible generators or reserves in real time to deal with uncertainty.

Enhancing Power System Resilience and Efficiency Through Proactive Security Assessments and the Use of powerSAS.m: A Robust, Efficient, and Scalable Security Analysis Tool for Large-Scale Systems

Dr. Yang Liu, Postdoctoral Appointee, Argonne National Laboratory (Lemont, IL)
Dr. Feng Qiu, Principal Computational Scientist, Argonne National Laboratory (Lemont, IL)
Dr. Jianzhe Liu, Energy Systems Scientist, Argonne National Laboratory (Lemont, IL)

Power system security assessment is directly related to increasing real-time and day-ahead market and planning efficiency because it helps ensure the reliable and secure operation of the power system, which is essential for efficient market and planning activities. Without proper security assessments, the power system is vulnerable to a variety of threats, including cyber attacks, natural disasters, and equipment failures, which can disrupt the operation of the system and lead to market inefficiencies and planning uncertainties. By performing security assessments and identifying potential vulnerabilities, system operators can take proactive measures to mitigate risks and improve the reliability and efficiency of the power system, which, in turn, supports the goals of real-time and day-ahead market and planning efficiency. Additionally, advanced software tools and models can be used to support security assessments, enabling operators to better anticipate and respond to potential security threats and further improve the efficiency and reliability of the power system. Existing tools (commercial or open-source) work fine for routine security analysis under normal operating conditions. However, in resilience analysis, which studies the system security and reliability under stressed scenarios, existing tools often experience various numerical issues, significantly impacting operators' assessment of system resilience. A recent example is the non-convergence issues with PSS/E, one of the best commercial power system analysis tools used in the DOE Puerto Rico resilience project led by Argonne. The numerical issues forced the team to give up more advanced analysis. A robust and efficient security analysis tool is imperative for resilience study in large-scale systems. In this talk, we will introduce a recently released open-source power system security analysis tool called powerSAS.m. The powerSAS.m is a robust, efficient, and scalable power grid analysis framework based on semi-analytical solutions (SAS) technology. The talk will cover the following two critical aspects and discuss how they are directly related to increasing real-time and day-ahead market and planning efficiency. First, we will introduce the fundamentals of the SAS technology and the major functionalities of the powerSAS.m, including (1) Steady-state analysis, including power flow, continuation power flow, and contingency analysis. (2) Dynamic security analysis, including voltage stability analysis, transient stability analysis, and flexible user-defined simulation. (3) Hybrid extended-term simulation provides adaptive quasi-steady-state-dynamic hybrid simulation in extended term with high accuracy and efficiency. We will also introduce some ongoing functionalities, including the SAS-based electromagnetic transient (EMT) simulation and multi-scale simulations. Second, we will present some use cases to demonstrate the key features and performance of the SAS technology and powerSAS.m tool, including: (1) High numerical robustness. Backed by the SAS approach, the PowerSAS tool provides much better convergence than the tools using traditional Newton-type algebraic equation solvers when solving algebraic equations/ordinary differential equations/differential-algebraic equations. (2) Enhanced computational efficiency and scalability. Due to the analytical nature, PowerSAS provides model-adaptive high-accuracy approximation, which brings significantly extended effective range and much larger steps for steady-state/dynamic analysis. PowerSAS has been used to solve large-scale system cases with 200,000+ buses.

Stochastic Unit Commitment and Market Clearing in Julia With UnitCommitment.jl

Dr. Alinson Santos Xavier, Computational Scientist, Argonne National Laboratory (Lemont, IL)
Ogün Yurdakul, Ph.D. Candidate, Technische Universität Berlin (Berlin, Germany)
Dr. Aleksandr M. Kazachkov, Assistant Professor, University of Florida (Gainesville, FL)
Jun He, Professor, Purdue University (West Lafayette, IN)
Dr. Feng Qiu, Principal Computational Scientist, Argonne National Laboratory (Lemont, IL)

UnitCommitment.jl (UC.jl) is a comprehensive open-source optimization package for the Security-Constrained Unit Commitment Problem (SCUC), providing an extensible and fully-documented data format for the problem, Julia/JuMP implementations of state-of-the-art mathematical formulations and solution methods, as well as a diverse collection of realistic and large-scale benchmark instances. This talk focuses on two major features recently introduced to the package. Firstly, the package now supports modeling and optimizing two-stage stochastic versions of the problem, in addition to the deterministic SCUC. Compared to existing implementations, UC.jl allows a broader set of network parameters to be treated as uncertain, including not only demands and generation limits, but also production costs, network topology, transmission limits, among others. Benchmark scripts are provided to accurately evaluate the performance of different stochastic solution methods. Secondly, the package now includes various functionalities for market clearing, such as the computation of generator payments and locational marginal prices (LMPs) using different methods proposed in the literature. In this talk, we will discuss the usage of these new features, technical challenges associated with them, and the potential simulations or studies that they enable.

Reduced-Order Decomposition and Coordination Approach for Markov-Based Stochastic UC With High Penetration Level of Wind and BESS

Niranjan Raghunathan, Ph.D. Student, University of Connecticut (Storrs, CT)
Dr. Peter B. Luh, Professor, University of Connecticut and National Taiwan University (Alexandria, VA)
Dr. Zongjie Wang, Professor, University of Connecticut (Storrs, CT)
Dr. Mikhail A. Bragin, Professor, University of California, Riverside (Riverside, CA)
Dr. Bing Yan, Professor, Rochester Institute of Technology (Rochester, NY)
Dr. Meng Yue, Research Staff Electrical Engineer, Brookhaven National Laboratories (Upton, NY)

Dr. Tianqiao Zhao, Renewable Energy Group, Brookhaven National Laboratories (Upton, NY)

With the growing need to achieve carbon neutrality, integrating renewable energy (*e.g.,* wind and solar) and battery energy storage systems (BESSs) into the grid is an urgent and challenging enterprise. At the day-ahead stage, unit commitment (UC) decisions need to account for uncertainties of geographically distributed renewable generation. BESS integration can help mitigate intermittence and reduce curtailment by storing energy during high renewable generation periods and releasing energy when needed, thus improving the cost efficiency of grid operation. Therefore, ensuring economic and reliable grid operations with the significant rise in renewable energy penetration necessitates the consideration of spatially distributed uncertainties and BESS in UC. To achieve this, a risk-neutral approach (*i.e.,* scenario-based stochastic UC and Markov-based stochastic UC) is preferred over risk-averse approaches (*e.g.,* robust optimization and interval optimization), as the latter yields overly conservative solutions. Between the risk-neutral approaches, Markov-based approaches have two advantages over scenario-based approaches: (1) Due to the Markov property, where stochastic information at the next time step depends only on the information at the current time step, the uncertainty can be compactly modeled by wind generation states at each time step and state transitions between subsequent time steps. Consequently, the overall number of possible states and transitions in the Markov model increases linearly with the number of intervals in the optimization horizon, whereas the number of possible scenarios increases exponentially. (2) Reduced Markov models preserve the volatility of wind generation, the underlying spatio-temporal correlation structure, and low-probability, high-impact events more effectively in uncertainty sets compared to scenarios. Therefore, the problem is formulated as Markov-based stochastic UC. With distributed wind, however, the number of possible wind states grows exponentially with the number of wind farms in different locations considered, posing major computational difficulties. To reduce complexity, an innovative decomposition and coordination framework is developed, where approximate area subproblems are formulated by utilizing area-perspective, reduced-order Markov models. In these models, the variability of local (in-area) windfarms is emphasized while that of nonlocal (out-of-area) windfarms is approximated by using Principal Component Analysis (PCA) to reduce dimensionality while preserving the maximum amount of variation. This is a reasonable approximation because variations at the local level have more impact on the behavior of local units and power flow through local transmission lines compared to variations at distant locations. The objective of an approximate area subproblem is to optimize in-area resources based on its area-perspective Markov model. The approximate area subproblems are solved iteratively while their solutions are coordinated using Surrogate Absolute-Value Lagrangian Relaxation (SAVLR), a state-of-the-art dual method with faster convergence than traditional Lagrangian Relaxation (LR)-based methods. To improve performance, an online filtering method for removing redundant transmission capacity constraints at each iteration is implemented in parallel by utilizing multiple cores. The solutions are validated using Monte Carlo simulations. Testing results based on the 118-bus system with 5 distributed wind farms show the effectiveness of the method in finding low-cost and robust UC solutions in a timely manner for multiple cases with different volatilities of wind generation and simulated extreme weather events. Analysis of the operation of BESSs shows that they absorb excess energy during high wind periods and release the energy during low wind periods, thus reducing wind curtailment and overall costs.

Learn To Branch and Dive for Large-Scale Unit Commitment Problem

Jingtao Qin, Research Assistant, University of California, Riverside (Riverside, CA)
Nanpeng Yu, Associate Professor, University of California, Riverside (Riverside, CA)
Mikhail Bragin, Assistant Research Professor, University of Connecticut (Storrs, CT)

Unit commitment (UC) problems are typically formulated as mixed-integer program (MIP) and solved by the branch-and-bound (B\&B) paradigm. The recent advances in graph neural network (GNN) motivate the application of GNN in learning to dive and branch for B\&B algorithm in modern MIP solvers. Existing GNN models are mostly constructed from B\&B trees, which are computationally expensive when dealing with large-scale UC problems. In this paper, we propose a physical network information-based hierarchical graph convolution model for neural diving that leverages the underlying features of various components of power systems to find high-quality variable assignments. Furthermore, we adopt the B\&B tree-based graph convolution model for neural branching to select the optimal variables for branching at each node of the B\&B tree. Finally, we integrate neural diving and neural branching into a modern MIP solver to establish a novel neural MIP solver that is specially designed for large-scale UC problems. Numeral studies show that our proposed model has better performance and scalability than the baseline B\&B tree-based model on neural diving. Moreover, the neural MIP solver yields the lowest MIPGap for all testing days after combining it with our proposed neural diving model and baseline neural branching model.

Session W–B1 (Wednesday, June 28, 9:00 a.m.) (Hearing Room One)

Stochastic Nodal Adequacy Pricing Platform (SNAP)

Dr Richard D. Tabors, Partner and President, Tabors Caramanis Rudkevich (Newton, MA)
Dr. Aleksandr Rudkevich, President, Newton Energy Group (Newton, MA)
Russel Philbrick, President, Polaris Systems Optimization (Seattle, WA)
Dr. Selin Yanikara, Analyst, Newton Energy Group (Newton, MA)

The Stochastic Nodal Adequacy Pricing Platform (SNAP) software system provides an implemented methodology to calculate the probability and value of RESOURCE INADEQUACY of electricity supply on an hourly basis for a period of one to five days ahead of real time. The stochasticity of SNAP is driven by the stochastic weather forecasts available and provided by IBM The Weather Company on a i5 day forward basis for a 4x4km grid worldwide (SNAP uses at most 5). Forecasts are developed from 76 different numerical weather prediction models (and their ensemble members) as inputs to their forecast system. Bayesian model averaging is used to correct for systematic errors (bias). Results are rearranged to create 100 synthetic weather system scenarios through the use of Ensemble Copula Quantile-Coupling technique. The result is a probabilistic forecast within which each of the scenarios is equally likely. As the electric supply system moves toward greater dependence on renewable sources both in front of and behind the meter and as weather conditions are evolving, the stochastics of weather have become a, if not the driving force in forecasting power system adequacy. SNAP is developed as an information/assist tool for operational planning at the utility system level. SNAP has been developed with funding from the Department of Energy's ARPA–E PERFORM program. SNAP uses the individual components of the weather forecast scenarios to create 100 probabilistic scenarios of the output of individual wind and solar locations as well forecasting of demand incorporating behind the meter generation. Based on the probability of renewable supply, demand, and the probability of outage of traditional supply sources and transmission, SNAP runs 100,000 Monte Carlo SCED/SCUC runs of the commercially available cloud-based ENELYTIX software system to identify the existence of resource inadequacy, the nodal location of that inadequacy, its cause and potential solutions. The objective is to present the structure of the computational and analytic processes that allow for running and evaluation of 100,000 scenarios for each individual forecast hour. The presentation will discuss the cloud-based structure the allows the analysis to be completed in under 50 minutes using 500 virtual machines at a costs of $120 at spot rates.

Assessing Nodal Adequacy of Large Power Systems

Dr. F. Selin Yanikara, Energy Analyst, Newton Energy Group (Newton, MA)
Russ Philbrick, President, Polaris Systems Optimization (Seattle, WA)
Aleksandr M. Rudkevich, President, Newton Energy Group (Newton, MA)
Sophie Edelman, Electricity Research Analyst, The Brattle Group (New York, New York)

Extreme weather events, increasing electrification, and integration of wind and solar power pose significant challenges for reliable operation of the power grid. Quantitative evaluation of these impacts is critical for making efficient policy and investment decisions and in designing markets and engineering controls. This presentation will summarize the theoretical foundation for nodal probabilistic assessment of resource adequacy and its applications to modern electrical systems with a significant penetration of weather dependent variable energy resources and storage technologies. In addition, this presentation will address the need for, and will present, new adequacy metrics that reflect an economically justified contribution of each system asset—generation, transmission, or demand resource to system adequacy. The analysis relies on the Monte Carlo based methodology using new computationally efficient and statistically accurate methods. We illustrate the numerical results and computational performance of our approach using the ENELYTIX® powered by PSO SaaS and our standard dataset for the ERCOT market.

Comparison of Flexibility Reserve and ORDC for Increasing System Flexibility

Phillip de Mello, Senior Technical Leader, Electric Power Research Institute (Palo Alto, CA)
Erik Ela, Program Manager, Electric Power Research Institute (Boulder, CO)
Nikita Singhal, Technical Leader, Electric Power Research Institute (Palo Alto, CA)
Alexandre Moreira da Silva, Research Scientist, Lawrence Berkeley National Laboratory (Berkeley, CA)
Miguel Heleno, Research Scientist/Engineer, Lawrence Berkeley National Laboratory (Berkeley, CA)

Power system composition changes are making flexible resources more important to balance the increasing variability and uncertainty. System operators often look to increase the amount of flexibility available to give real time operations greater control. Two common methods for increasing flexibility are to create new reserve products that are targeted towards flexibility and ramping capability or using an extended operating reserve demand curve (ORDC) to procure more of an existing reserve when the additional value exceeds costs. Detailed operation simulations to mimic day ahead and real time markets were conducted to compare flexibility reserves and ORDCs. Benefits to reliability were measured by a reduction in shortages of reserves and energy experienced across the system. The extra reserves generally increased the costs of running the system, but it was lower than the penalty prices of the shortages relieved. Some periods showed a reduction of system costs with added reserves, suggesting that more efficient designs of reserves could not only increase system reliability but also reduce costs. Both methods increase the flexibility on the system, but function differently in typical deployments in current ISO/RTO practice. The different parameters defining each technique was explored to understand how their differences manifest in improving reliability. Most differences reflect the tradeoff between flexibility in designing a new product versus ease of implementation of procuring more of an existing product. The key difference of the techniques results due to the sharing of generator ramp rates between different reserve products. Most existing implementations require dedicated capacity for each reserve product but often do not require dedicated ramp capability. Using a new flexibility reserve that can share ramp rates will typically be able to schedule more reserve for a certain available generator capacity than applying an ORDC to an existing product. This impacts the cost and effectiveness of those reserves particularly in periods of system stress. Toggling the ramp sharing constraint can be used to make either implementation perform similarly as the other.

ABSCORES, A Novel Application of Banking Scoring and Rating for Electricity Systems

Alberto J. Lamadrid L., Associate Professor, Lehigh University (Bethlehem, PA)
Audun Botterud, Principal Research Scientist, Massachusetts Institute of Technology (Cambridge, MA)
Jhi-Young Joo, Research Scientist, Lawrence Livermore National Laboratory (Livermore, CA)
Shijia Zhao, Energy Systems Scientist, Argonne National Laboratory (Lemont, IL)

This presentation discusses the basis for the establishment of an Electric Assets Risk Bureau. We are developing different scores customized according to the application required. We study the use of financial models to determine the risk associated to individual assets in the system. We present a model focused on managing operational risk, and outline the methodology for risk metrics applied to high impact, low probability (HILP) events. We distinguish between, first, public risk, related to the physical provision of supporting services required for the stability of the electricity system (*i.e.,* ancillary services); and second, financial risk, derived from positions taken by participants with pecuniary repercussions. A key paradigm of our framework is a focus on implementability of the approach (under existing regulatory structures) and a method for dispute resolution given potential decisions taken with the metrics proposed.

Recent Developments in the Day-Ahead and Real-Time Electricity Market Design and Software Caused by the Higher Energy Costs and Emerging Technologies—European Experience

Petr Svoboda, Engineer, Unicorn Systems a.s. (Prague, Czech Republic)

Europe has been dealing with the imbalance of production and consumption for years. This has led to the development of the single de-regulated electricity market to solve the barriers between the individual states and provide the most cost-effective way to ensure secure, sustainable, and affordable energy supply to the customers. Recent changes in the market caused by the increase of the energy costs and emergence of the new technologies have caused the fundamental shifts in the market design and software enabling its operations. In our presentation we would like to discuss the latest developments in the areas of: 1. New algorithms of transmission capacity calculation that have proven to increase the efficiency of capacity usage and relevant economic welfare. 2. Development of the HVDC interconnectors and their impact on the market efficiency and transmission costs. 3. 15-minute day-ahead markets. 4. Emergence of the integrated real-time markets, new reserve products and multi-interval market clearing. 5. Introduction of the flexibility instruments to the energy markets. 6. Successful implementation of the hourly renewable certificates as the next step towards clean energy transition.

Session W–A2 (Wednesday, June 28, 12:30 p.m.) (Commission Meeting Room)

System Resilience Through Electricity System Restoration and Related Services

Douglas Wilson, Principal Analytics Engineer, GE (Edinburgh, United Kingdom)
James Yu, Head of Future Networks, ScottishPower Energy Networks (Glasgow, United Kingdom)
Ian Macpherson, Senior Innovation Manager, ScottishPower Energy Networks (Glasgow, United Kingdom)
Marta Laterza, Power Systems Engineer, General Electric (Glasgow, United Kingdom)
Marcos Santos, Senior Power Systems Engineer, General Electric (Glasgow, United Kingdom)
Richard Davey, Senior Project Manager, General Electric (Glasgow, United Kingdom)

Electricity system restoration following a partial or system-wide outage is an essential service in the power system. There is a need to apply new resources based on renewable resources to replace the services that up to now have depended on fossil fuel generation. This presentation describes a project led by SP Energy Networks in collaboration with GE to demonstrate a co-ordinated restoration approach in the distribution grid using a novel control approach applied to a controlled zone with multiple resources. Live trials of the approach in the SP Energy Networks power system are presented, as well as results of testing the approach extensively in a hardware-in-the-loop environment. The emerging weaknesses of the traditional methodology were recognised in UK electricity regulation, which was recently changed to include a requirement for 60% of customer load to be restored within 24 hours on a regional basis, with all supplies restored within 5 days (Electricity System Restoration Standard, 2021). Previous restoration requirements were less onerous on the timeframes and did not define geographic requirements. Since some regions now lack large transmission-connected blackstart-capable plant for the traditional top-down restoration approach, there is a need to harness the capabilities that renewable and distributed generation and storage can offer to address the deficit of system restoration capability. The new service being developed and trialled involves starting distributed generation and growing an island with customer load within the distribution network. This island can be sustained by automated control through managed load pickup as well unplanned disturbances with existing distributed energy resources, battery storage and demand response providing the control capability to keep the island in balance. The blackstart zone may then be reconnected to the transmission network if this is energised and can then contribute to managing the power balance as the restoration of the wider system continues. If appropriate, neighbouring islands can be connected together, and the resulting larger island is capable of greater block load pickup of active and reactive loads. One of the distinctive benefits of the approach taken is that it uses diverse resources of existing generation, storage and demand response capability that is present and operational in the network for other day-to-day purposes. These resources can be harnessed to provide the new electricity system restoration services with few additional power assets. Inherently, some devices can provide faster response than others, and large instantaneous power, and some may be able to sustain an energy supply while others have limited energy resource. Voltage support and short circuit current are also considerations. A diversity of renewable resources is useful to mitigate against individual resources being unavailable *e.g.* low wind or low solar conditions. A key requirement for the co-ordination of an electricity system restoration zone is a wide area monitoring and control system that manages the power balancing and switching of the network to automate the process of growing and sustaining the power island. The approach being trialled includes a SCADA/distribution management system with the topology information for network switching, together with a synchrophasor based wide area control system that manages the balancing, frequency control and resynchronization alignment of the network. Since the island is small in comparison to the normal interconnection, a rapid response to disturbances is required to maintain a stable frequency. Once a distribution zone is instrumented with the measurement, communication and control equipment to deliver the service, it is possible to use the same infrastructure to offer further services to manage grid stability in the more common circumstance of disturbances during grid-connected operation.

Coordinated Cross-Border Capacity Calculation Through The FARAO Open-Source Toolbox

Violette Berge, Vice President, Artelys Canada (Montréal, Canada)
Dr. Nicolas Omont, Vice President of Operations, Artelys (Paris, France)

Cross-borders exchanges have taken a major role in European strategy to achieve climate goals. The European Commission set a target of 15% interconnections in 2030, meaning that each country should have the physical capability to export at least 15% of their production. Increasing exchanges makes short term planning more complex. In this context, the French TSO (RTE) released an open-source toolbox FARAO to perform Coordinated Capacity Calculation (CCC) and ensure the security of supply. Artelys is a consultancy expert in power systems optimization and carries out various projects around TSO operational coordination in Europe. FARAO performs the optimization of both preventive and curative remedial actions, including HVDC lines, phase-shifter transformers and counter-trading but also topological actions. It is operationally used for the exchanges between Italy and its northern neighbors as well as between France, Spain and Portugal. Artelys will present the algorithms of the FARAO toolbox and how they are actually used to enable greater operational coordination amongst the countries.

Advanced Scenario Selection Methods for Probabilistic Transmission Planning Assessments

Dr. Eknath Vittal, Principal Technical Leader, EPRI (Palo Alto, CA)
Anish Gaikwad, Senior Program Manager, Electric Power Research Institute (Palo Alto, CA)
Parag Mitra, Senior Technical Leader, Electric Power Research Institute (Palo Alto, CA)

Given the temporal and spatial characteristics of extreme weather events, developing transmission planning scenarios, *i.e.,* snapshots of instantaneous operational conditions, is a challenging problem. It requires a multi-model assessment that links long-term planning models that capture the operational performance of the system (resource adequacy and production cost modeling) to the future meteorological projections that will inform the impacts of weather and extreme events. Scenario generation and analysis is computationally and labor intensive. Identifying snapshot conditions for future system states can be challenge. This presentation will highlight and detail an EPRI application that helps transmission planners identify critical power flow conditions from operational simulations such as production cost simulations. The EPRI High-Level Screening (HiLS) for Data Analytics tool allows planners to apply statistical analysis to large dataset that capture the operational performance of the system. The tool allows for the data to be organized into clusters of similar operating conditions reducing the dimensionality of the state space. As an example, an operational simulation of 8760 hours can be reduced to 10 operating hours that capture 95% of the variability seen over the course of the year. As uncertainty and variability increase on both the generation and load, developing methods and processes to understand the conditions that present the most challenging reliability and stability conditions will be critical. The HiLS tools, provides transmission planners a platform that can help them organize and visualize data representing future operational conditions of the system that considers both load variability and generator availability.

Incorporating Climate Projections Into Grid Models: Bridging the Data Gap To Capture Weather Dependent Representative and Extreme Events and Corresponding Uncertainties

Dr. Zhi Zhou, Principal Computational Scientist, Argonne National Laboratory (Lemont, IL)
Dr. Neal Mann, Energy Systems Engineer, Argonne National Laboratory (Lemont, IL)
Yanwen Xu, Graduate Student, University of Illinois at Chicago, Urbana-Champaign (Champaign, IL)
Zuguang Gao, Graduate Student, University of Chicago (Chicago, IL)
Dr. Akintomide Akinsanola, Assistant Professor, University of Illinois at Chicago (Chicago, IL)
Dr. Todd Levin, Team Lead, Argonne National Laboratory (Lemont, IL)
Dr. Jonghwan Kwon, Energy Systems Engineer, Argonne National Laboratory (Lemont, IL)
Dr. Audun Botterud, Senior Energy Systems Engineer, Argonne National Laboratory (Lemont, IL)

It is crucial to consider high-fidelity weather data and climate projections in grid models in order to capture future weather trends, extremes, and uncertainties. However, traditional power system studies often overlook many of these considerations and rely solely on historical weather data. To address this challenge, we develop a computationally manageable framework to process high-quality representations of climate data for use with power system models. The framework includes a three-stage architecture to select representative regions and periods, and also identify periods of extreme weather conditions after translating climate data (temperature, wind-speed, etc.) into grid inputs (load, power generation profiles and outage probabilities). The framework also models and represents uncertainty of future weather events based on ensembles of climate model simulations. The outcome of the framework is a set of processed grid inputs in time series format that capture the impact of climate features on the system. This includes grid inputs directly converted from weather variables at the cell level, as well as those from representative regions and time periods, those representing the impact from extreme weather events, and their associated uncertainties. We apply this computational framework to translate downscaled climate projections generated by three different global climate models, encompassing over 60 different weather variables at 12-km geographic and 3-hour temporal resolution for all North America. We then demonstrate how consideration of high-quality climate-driven grid inputs in electricity system models impacts optimal long-term planning decisions. Capturing future weather conditions and associated uncertainties is becoming important as power systems, and their associated markets, are being impacted by both efforts to decarbonize the effects of a changing climate. These are also important considerations when updating market designs to maintain reliability and economic efficiency as the underlying power system evolves. In addition, capturing weather uncertainty is critical for risk-aware decision making. Therefore, this work provides a valuable resource for power system modelers by bridging the gap between climate models and grid models to help ensure that long-term system planning decisions are informed by the impacts of future climate conditions.

Session W–B2 (Wednesday, June 28, 12:30 p.m.) (Hearing Room One)

Enhancing Decision Support for Electricity Markets With Machine Learning

Yury Dvorkin, Faculty, Johns Hopkins University (Baltimore, MD)
Robert Ferrando, Graduate Assistant, University of Arizona (Tucson, AZ)
Laurent Pagnier, Assistant Professor, University of Arizona (Tucson, AZ)
Zhirui Liang, Ph.D. Student, Johns Hopkins University (Baltimore, MD)
Daniel Bienstock, Professor, Columbia University (New York, NY)
Michael Chertkov, Professor, University of Arizona (Tucson, AZ)

This presentation describes how machine learning can be leveraged to enhance computational speed of day-ahead and real-time unit commitment and optimal power flow routines, which are at the core of market-clearing procedures in US ISOs. Our machine learning architecture embeds both power flow physics and market design properties (*e.g.,* cost recovery and revenue adequacy) into the training stage, which increases accuracy of computations and preserves a relationship between primal (dispatch) and dual (prices) variables. The accuracy and scalability of the proposed method is tested on a realistic 1814-bus NYISO system with current and future renewable energy penetration levels. We also demonstrate ~100x gain in computations relative to traditional optimization approaches.

Synergistic Integration of Machine Learning and Mathematical Optimization for Sub-Hourly Unit Commitment

Jianghua Wu, Ph.D. Candidate, University of Connecticut (Vernon, CT)
Dr. Zongjie Wang, Assistant Professor, University of Connecticut (Storrs, CT)
Dr. Yonghong Chen, Consulting Advisor, Midcontinent ISO (Carmel, IN)

Dr. Bing Yan, Assistant Professor, Rochester Institute of Technology (Rochester, NY)
Dr. Mikhail Bragin, Assistant Project Scientist, University of California, Riverside (Riverside, CA)

The integration of intermittent renewables into power systems presents significant challenges for operators due to increased uncertainties and greater intra-hour net load variability. Sub-hourly Unit Commitment (UC) has been suggested as a solution to quickly respond to changes in electricity supply and demand, which is more complicated than hourly UC because of a higher number of time periods, and higher dependencies among coupled periods. Traditional optimization methods could be time-consuming while machine learning (ML) may have additional feasibility concerns. To address these challenges, a hybrid approach based on synergistic integration of ML and optimization is developed. This novel approach adopts our recent decomposition and coordination Surrogate Absolute-Value Lagrangian Relaxation (SAVLR) method with efficient coordination and accelerated convergence. ML is then used to quickly predict SAVLR subproblem solutions. Compared to those of the original overall problem, subproblem solutions are much easier to learn. Nevertheless, predicting ''good'' subproblem solutions is still challenging because of the ''jumps'' of binary decisions and many types of unit-level constraints. To overcome these issues, a generic ML model, embedding recurrent neural networks (RNNs) and the Attention mechanism in the encoder-and-decoder structure, is developed. Because of the features of RNNs and Attention, this generic model can learn different subproblem solutions to reduce the training effort, and can provide time-based predictions to capture dependencies. In addition, to resolve the limitation of ML in handling constraints, a rule-based feasibility layer is incorporated in the predicting process, ensuring feasibility with respect to unit-level constraints. Testing on the IEEE 118-bus system demonstrates the effectiveness of our approach, providing feasible and accurate subproblem solutions quickly, and obtaining near-optimal overall solutions efficiently.

Boosting Power System Operation Economics Via Closed-Loop Predict-and-Optimize

Dr. Lei Wu, Anson Wood Burchard Chair Professor, Stevens Institute of Technology (Hoboken, NJ)
Xianbang Chen, Ph.D. Candidate, Stevens Institute of Technology (Hoboken, NJ)

By and large, power system operations are implemented by Independent System Operators (ISO) in an open-loop predict-then-optimize (O–PO) process. First, the uncertainty realizations (*e.g.,* renewable energy availability) are predicted as accurately as possible. Taking the predictions as inputs, day-ahead unit commitment and real-time economic dispatch problems are then optimally resolved for determining the operation plan (*i.e.,* optimization). The operation goal is to achieve the minimum system operation cost, *i.e.,* the optimal operation economics. However, the operation economics could suffer from the open-loop process because its predictions may be myopic to the optimizations, *i.e.,* the predictions seek to improve the immediate statistical prediction errors (*i.e.,* accuracy-oriented) instead of the ultimate operation economics. To this end, we propose to improve operation economics by closing the open loop between the prediction and the optimization, *i.e.,* a closed-loop predict-and-optimize (C–PO) idea. Specifically, two C–PO frameworks are designed, including a feature-driven C–PO framework and a bilevel mixed-integer program (MIP) C–PO framework. Their core is to feed the induced operation cost back for training the predictor and measuring the prediction quality with the operation cost (*i.e.,* cost-oriented). As a result, the prediction and the optimization can be implemented jointly in a single framework. Based on real-world data, the feature-driven C–PO is compared to the traditional O–PO, showing noticeable improvement in operation economics, although with slightly compromised prediction accuracy for certain cases. The experiments on a large-size system show that the C–PO has potential in a real-world application. The bilevel MIP C–PO is more versatile than the feature-driven C–PO. Based on an IEEE 118-bus system, the bilevel MIP C–PO is compared to the state-of-the-art methods of handling uncertainties, *i.e.,* stochastic programming and robust optimization. The case studies show that the bilevel MIP C–PO is economically competitive with the state-of-the-art methods but is more compatible with the current operational practice.

Privacy-Preserving Synthetic Dataset Generation for Power Systems Research

Dr. Vladimir Dvorkin, Postdoctoral Fellow, Massachusetts Institute of Technology (Cambridge, MA)
Dr. Audun Botterud, Principal Research Scientist, Massachusetts Institute of Technology (Cambridge, MA)

Power systems research heavily relies on the availability of real-world power system datasets (network parameters, time series, etc.). However, data owners, such as system operators, are often hesitant to share their data due to valid security and privacy concerns. To overcome these challenges, we have developed state-of-the-art algorithms that enable the synthetic generation of optimization and machine learning datasets for the power systems industry. Our algorithms take real-world datasets as input and output their synthetic, perturbed versions that maintain the accuracy of the original data on specific problem classes, such as power system dispatch and wind power forecasting. Importantly, the original data remains undisclosed, effectively controlling the privacy risk in data releases. To ensure privacy preservation, we employ rigorous perturbation techniques of differential privacy that strictly control the amount of privacy loss. Furthermore, we preserve the accuracy of original data through post-processing convex optimization. Our algorithms have many applications, including synthetic generation of transmission parameters and renewable generation records. We have open-sourced our algorithms to encourage their use by interested parties. For more information, please visit our GitHub repository at *https://github.com/wdvorkin/SyntheticData.*

Session W–A3 (Wednesday, June 28, 3:30 p.m.) (Commission Meeting Room)

Parallel Interior-Point Solver for Security Constrained ACOPF Problems on SIMD/GPU Architectures

Dr. Mihai Anitescu, Senior Mathematician, Argonne National Laboratory (Lemont, IL)
François Pacaud, Assistant Professor, Ecole des Mines (Paris, France)
Michel Schanen, Computer Scientist, Argonne National Laboratory (Lemont, IL)
Sungho Shin, Postdoctoral Scientist, Argonne National Laboratory (Lemont, IL)
Daniel Adrian Maldonado, Assistant Energy Systems Scientist, Argonne National Laboratory (Lemont, IL)

We investigate how to port the standard interior-point method for security constrained ACOPF problems, which are block-structured nonlinear programs with state equations, on SIMD/GPU architectures. Computationally, we decompose the interior-point algorithm into two successive operations: the evaluation of the derivatives and the solution of the associated Karush-Kuhn-Tucker (KKT) linear system. Our method accelerates both operations using two levels of parallelism. First, we distribute the computations on multiple processes using coarse parallelism. Second, each process uses a SIMD/GPU accelerator locally to accelerate the operations using fine-grained parallelism. The KKT system is reduced by eliminating the inequalities and the state variables from the corresponding equations, to a dense matrix encoding the sensitivities of the problem's degrees of freedom, drastically minimizing the memory exchange. Our experiments on SIMD/GPU with security-constrained AC optimal power flow problem show that the method can achieve a 50x speed-up compared to the state-of-the-art method.

The Need for More Rigorous Calculation of Shadow Prices and LMPs

Dr. Xiaoming Feng, Research Fellow, Hitachi Energy (Raleigh, NC)

LMPs (locational Marginal Prices) are used in nodal electricity markets to determine payments or charges to market participants. Due to the great monetary impact, it is imperative LMP is defined rigorously and calculated consistently. It has been observed the current method of shadow price and LMP calculation could produce values that are non-unique under certain conditions, which might signal non-economic incentives to the market. We start with formal definitions for shadow price and LMP and present the properties of the perturbation functions and their computational consequences. We use simple examples to illustrate the discrepancy between theoretical shadow price and the shadow price calculated by state-of-the-art optimization solvers. From the discussion, we make the case for more rigorous calculation of both shadow prices and LMPs.

Real-Time Market Enhancements for Reliability and Efficiency

Dr. Mort Webster, Professor of Energy Engineering, Pennsylvania State University (University Park, PA)
Dr. Anthony Giacomoni, Manager, Advanced Analytics, PJM Interconnection (Audubon, PA)
Aravind Retna Kumar, Ph.D. Candidate, Pennsylvania State University (University Park, PA)
Sushant Varghese, Ph.D. Candidate, Pennsylvania State University (University Park, PA)
Shailesh Wasti, Ph.D. Candidate, Pennsylvania State University (University Park, PA)

The projected trends in the U.S. power system, increasing wind and solar generation and retiring fossil fuel generation, will increase the net load variability and forecast uncertainty over the next several decades. There has been considerable research focusing on how to provide more flexibility to the power system. Within this line of research, numerous market design proposals have been explored: multi-interval dispatch, ramp products, stochastic market clearing, an increase in flexible resources (virtual power plants (VPP), energy storage). Although flexibility is often cited as an objective the outcomes of concern are reliability (unserved demand and reserve shortages), efficiency (reducing bid production cost and uplift payments), curtailment of renewable generation, and incentives for future flexible resources (*i.e.,* price formation). In the U.S., Independent System Operator (ISO) and Regional Transmission Organization (RTO) real-time market clearing and operations have the following properties: they operate on a rolling horizon basis throughout the operating day, face changing forecasts throughout the day with forecast errors, and frequently solve a real-time unit commitment (RUC), which is separate from the real-time dispatch. In contrast, most of the analysis and academic literature on market design enhancements neglect one or more of these characteristics in their analysis framework. The separation of commitment from dispatch raises the question: which market enhancement in which clearing engine? In this work, we present a simulation framework for the PJM wholesale energy markets with a rolling horizon and forecast errors. Specifically, we simulate the solution of the day-ahead market, followed by PJM's Intermediate-Term Security Constrained Economic Dispatch (IT–SCED) (real-time commitment process) every 15 minutes and PJM's Real-Time Security Constrained Economic Dispatch (RT–SCED) (real-time dispatch) every 5 minutes throughout the operating day. Net load forecasts change every 5 minutes. We use this framework to simulate several of the commonly discussed market enhancements applied to either IT–SCED, RT–SCED, or both. We consider multi-interval dispatch, ramp products, and stochastic market clearing. Our results demonstrate that market design changes are most successful if they addresses both commitment (bringing enough capacity and operating range online) and dispatch (using the online operating range effectively).

Economics of Grid-Supported Electric Power Markets: A Fundamental Reconsideration

Dr. Leigh Tesfatsion, Research Professor of Economics, Courtesy Research Professor of Electrical & Computer Engineering, Iowa State University (Ames, IA)

U.S. RTO/ISO-managed wholesale power markets operating over high-voltage AC transmission grids are transitioning from heavy reliance on fossil-fuel based power to greater reliance on renewable power. This presentation highlights four conceptually-problematic economic presumptions reflected in the legacy core design of these markets that are hindering this transition. The key problematic presumption is the static conceptualization of the basic transacted product as grid-delivered energy (MWh) competitively priced at designated grid delivery locations during successive operating periods, supported by ancillary services. The presentation then discusses an alternative conceptually-consistent ''Linked Swing-Contract Market Design'' that appears well-suited for the scalable support of increasingly decarbonized grid operations with more active participation by demand-side resources. This alternative design entails a fundamental switch to a dynamic insurance focus on advance reserve procurement permitting continual balancing of real-time net load. Reserve consists of the guaranteed availability of diverse power-path production capabilities for possible RTO/ISO dispatch during future operating periods, as protection against volumetric grid risk. Each reserve offer submitted by a dispatchable power resource m to a forward reserve market M(T) for a future operating period T is a two-part pricing swing-contract in firm or option form that permits m to ensure its revenue sufficiency.

Session W–B3 (Wednesday, June 28, 3:30 p.m.) (Hearing Room One)

Simulation of Wholesale Electricity Markets With Capacity Expansion and Production Cost Models To Understand Feedback Between Short Term Market Procedures and Long Term Investment Incentives

Dr. Jesse Holzer, Mathematician, Pacific Northwest National Laboratory (Richland, WA)
Dr. Abhishek Somani, Electrical Engineer, Pacific Northwest National Laboratory (Richland, WA)
Dr. Brent Eldridge, Electrical Engineer, Pacific Northwest National Laboratory (Bel Air, MD)

Diane Baldwin, Project Manager, Pacific Northwest National Laboratory (Richland, WA)

Wholesale electricity markets are undergoing rapid changes, including variability and uncertainty and low prices from wind and solar, load flexibility and price responsiveness, distributed energy resources, energy storage, and revenue adequacy concerns. In response to these changes, enhancements to electricity market procedures have been proposed, including new reserve product, sloped reserve demand curves, multi-settlement forward markets, and stochastic modeling in market clearing optimization engines. These enhancements have the potential to improve operational outcomes in the short term time scale of hours to days by enabling better market responses to the changing market conditions. But they also affect the long run incentives for investment in grid equipment that ultimately result in the mix and capacity of various grid technologies. This mix in turn influences short term market conditions. We use linked models of capacity expansion and production cost to explore this feedback between short term and long term market conditions and to shed light on how this feedback affects the assessment of market enhancements to address changing market conditions.

Making the Right Resource Choice Requires Making the Right Model Choice

Dr. Rodney Kizito, Senior Manager, Ascend Analytics (Boulder, CO)
Gary W. Dorris, Ph.D., CEO, Ascend Analytics (Boulder, CO)
David Millar, Director of Consulting Services, Ascend Analytics (Boulder, CO)

Production cost modeling simulates the operation of electric systems. It provides a lens into a highly uncertain future, allowing utilities to craft strategy and make critical decisions for their customers, shareholders, and stakeholders. The power and acuity of this lens will determine what resources will be deemed the most economic to provide a reliable, lower-carbon supply portfolio. Resource planning using production cost models that simulate the operation of power systems, once a straightforward exercise of deciding how many new power plants would be needed to meet future load growth, has become a much more complicated and challenging enterprise. The dramatic decline in the cost of renewables and storage technologies and the societal push for decarbonization means planners must model more complex and uncertain portfolio options. Renewables and their meteorologically determined fuel supply are creating new dynamics that highlight the need for more powerful modeling tools to capture the increasing variability in the power supply and the ensuing effect on market price volatility. This presentation highlights the benefits of using a new class of resource planning models to plan for a decarbonized future. Utilities, regulators, independent system operators, and other industry stakeholders rely heavily on modeling to support decision making for the allocation of scarce capital resources, as well as to ensure that the right resources are available to maintain a high level of reliability and resilience. This presentation argues that the older generations of models that remain widely in use today fail to capture the emerging dynamics of a power grid supplied primarily by renewable energy. For this reason, industry decision makers are unknowingly burdened by ''model-limited choice,'' which can lead to imprudent investments in assets liable to become functionally useless and ultimately disallowed. This presentation also provides a new terminology to classify a model's ability to capture the new market dynamics, high-definition production cost models (HD PCMs) versus traditional production cost models (PCMs). HD PCMs use simulation to capture the stochastic nature of load and electricity production generated by renew able energy sources, as well as to drill down to a 5-minute level of temporal and spatial (*i.e.,* nodal) granularity to capture the flexibility requirements of renewable integration. Further, HD PCMs mimic real-world uncertainty by simulating imperfect foresight of future system conditions between the day-ahead forecast and the real-time dispatch. Traditional PCMs are highly simplified because they were developed when computing power was a significant limitation. Today, resource planners can take advantage of the rapid increase in computing power provided by distributed computing to upgrade their analytical platforms to enable HD PCMs that provide more robust analysis.

Transmission Shortage Pricing By MW-Mile Based Demand Curve

Sina Gharebaghi, Graduate Research Assistant, Pennsylvania State University, Hitachi Energy (University Park, PA)

Dr. Xiaoming Feng, Research Fellow, Hitachi Energy (Raleigh, NC)

ISOs use transmission demand curves (TDC) in security constrained unit commitment (SCUC) to relax transmission constraints when no feasible solution exists with hard transmission constraints. TDC is a penalty curve administratively specified as a function of the amount of MW violation of the transmission line's limits. Use of TDCs to ensure non-empty feasible solution space can result in excessively high LMP when multiple TDCs are active. Researchers have studied a transmission constraint screening approach to remove 'redundant constraints' of serially connected transmission lines before the pricing run to avoid the accumulation of high shadow prices over multiple redundant constraints for LMP calculation. The screening approach alleviates to a large degree the occurrence of excessive LMP but has subtle and significant unintended consequences with respect to SCUC solution stability. We propose an alternative approach using MW-Mile based TDC to solve the transmission constraint violation problem and eliminate the root cause of excessive LMP without the need to remove redundant constraints. We discuss the economic justification of the MW-Mile based TDC approach and its advantage of solution stability with illustrative examples.

Grid OS—A Modern Software Portfolio for Grid Orchestration

Renan Giovanini, Ph.D., MBA, Transmission Product Marketing Director, General Electric (Edinburgh, United Kingdom)
Joseph Franz, Senior Marketing Manager, General Electric (Melbourne, FL)

The 21st century has brought new challenges for Transmission and Distribution Operators that were hardly perceived in the turn of the century. There have been fast increases in bulk and micro renewable resources in conjunction with international agreements on CO_2 emission targets. Severe droughts, and more frequent floods happening in the same country are driving needs also. An increasing number of changing weather patterns creating disruptions at several levels. Data tsunami has been created due to increasing types and number of sensors installed in the field. The grid itself was initially designed in the early 1900s based on a uni-directional flow requirement now is called to become bi-directional. Previous electric software solutions were created very organically since late 1970s/early 1980s addressing use-cases from that era. New tools were created over time, but always bolted-on to existent solutions. Energy Management Systems became more and more complex and started to present challenges in terms of scalability and maintainability leading to increasing staff and costs. Previous well defined siloes between Generation, Transmission and Distribution are becoming more blurred. In order to address all of these challenges, utilities and software companies started a journey to re-invent itself. Based on the most recent digital technologies, these companies created new modular and composable solution prepared for ultra-scaling and immense amounts of data ready to leverage the most modern mathematical algorithms and artificial intelligence methods available to date for assisted and automated control. The need for project executions in months as opposed to years has been taken carefully in consideration, creating a software solution ready for faster time-to-value. These solutions are already in production at a few customers and a number of new use-cases are currently under proof-of-concept, development or available for productization. The presentation will cover some of these latest software developments and highlight regulatory challenges to slowing the adoption of these technologies by utilities: 1. A new market system prepared to validate & clear more frequent and increasing number of bids with smaller amounts of power; 2. Digital twin technologies such as digital dynamic line ratings ready to integrate electrical and weather data to provide real-time and forecast ampacity for transmission lines integrated to real-time and look-ahead security assessment systems; 3. Advanced forecasting solutions based on AI for (1) renewable power production at T&D levels and (2) outage predictions for improved crew allocation and faster restoration times; 4. Optimal system restoration management in real-time in assisted and automated modes; 5. Exploration of Distributed Energy Resource to supply grid services at transmission level such as grid stabilization and blackstart restoration.

Day 3—Thursday, June 29

Session H1 (Thursday, June 29, 9:30 a.m.) (Commission Meeting Room)

Integration of DER Aggregations in ISO-Scale SCUC Models

Dr. Brent Eldridge, Electrical Engineer, Pacific Northwest National Laboratory (Bel Air, MD)
Jesse Holzer, Mathematician, Pacific Northwest National Laboratory (Richland, WA)
Abhishek Somani, Economist, Pacific Northwest National Laboratory (Richland, WA)
Eran Schweitzer, Electrical Engineer, Pacific Northwest National Laboratory (Richland, WA)
Rabayet Sadnan, Electrical Engineer, Pacific Northwest National Laboratory (Richland, WA)
Nawaf Nazir, Electrical Engineer, Pacific Northwest National Laboratory (Richland, WA)
Soumya Kundu, Electrical Engineer, Pacific Northwest National Laboratory (Richland, WA)

FERC issued Order 2222 in September 2020, which will require all ISOs in the U.S. to implement participation models for DER aggregators. Among other requirements, this rule required ISOs to lower the participation threshold for wholesale market participation to 0.1 MW. Wider participation of these resources can bring significant benefits to the grid, such as by locating energy supply closer to demand, opening up more participation from the demand side, and providing an additional flexibility source to balance intermittent renewables. However, DER aggregations will have unique characteristics that may pose challenges to the large-scale security-constrained unit commitment (SCUC) software used by ISOs. This presentation will focus on the formulation of a new mathematical model to represent the internal constraints of a DER aggregator and the study design that is intended to better understand the challenges associated with DER integration.

Current-Voltage AC Optimal Power Flow for Unbalanced Distribution Network

Dr. Mojdeh Khorsand Hedman, Assistant Professor, Arizona State University (Tempe, AZ)
Zahra Soltani, Ph.D. Candidate, Arizona State University (Tempe, AZ)
Dr. Shanshan Ma, Postdoctoral Research Scholar, Arizona State University (Las Vegas, NV)

With proliferation of distributed energy resources (DERs), distribution management systems (DMSs) need to be advanced in order to enhance the reliability and efficiency of modern distribution systems. This work proposes novel nonlinear and convex AC optimal power flow (ACOPF) models based on current-voltage (IVACOPF) formulation for an unbalanced distribution system with DERs. In the proposed formulation, untransposed distribution lines, shunt elements of distribution lines, and detailed representation of distribution transformers and DERs are modeled. The proposed nonlinear IVACOPF model is linearized and convexified using the Taylor series. The performance of the proposed nonlinear and convex IVACOPF approaches is compared with OpenDSS and the widely used LinDistFlow method for modeling unbalanced distribution systems. The proposed accurate convex IVACOPF model has multiple applications for distribution system management, planning, and operation. Applications of the proposed model on two key parts of advanced DMS, (i) DERs scheduling and (ii) simultaneous topology processor and state estimation, will be presented. Two models are developed including Quadratic Programming (QP) and linear programming (LP) for performing the distribution state estimation. The performance of the methods is compared. The proposed models are tested using distribution feeder of an electric utility in Arizona.

Empowering Electricity Markets Through Distributed Energy Resources and Smart Building Setpoint Optimization: A Graph Neural Network-Based Deep Reinforcement Learning Approach

Dr. You Lin, Postdoctoral Associate, Massachusetts Institute of Technology (Cambridge, MA)
Dr. Audun Botterud, Principal Research Scientist, Massachusetts Institute of Technology (Cambridge, MA)
Dr. Daisy Green, Postdoctoral Associate, Massachusetts Institute of Technology (Cambridge, MA)
Dr. Leslie Norford, Professor, Massachusetts Institute of Technology (Cambridge, MA)
Dr. Jeremy Gregory, Executive Director of Climate and Sustainability Consortium, Massachusetts Institute of Technology (Cambridge, MA)

Smart buildings play a pivotal role in the electricity market by boosting energy efficiency and demand flexibility by implementing advanced control strategies. In this study, a setpoint optimization model is proposed using a graph neural network-based deep reinforcement learning (DRL) algorithm that considers thermal exchanges among various zones within buildings. By intelligently scheduling the day-ahead temperature setpoints and adjusting the real-time setpoints in response to dynamic conditions and price signals, DRL-based controllers can optimize energy consumption while reducing overall costs. This strategic energy management not only benefits building occupants but also bolsters the electricity grid through load balancing and the provision of essential grid services. Through the testbed of MIT campus buildings, it is demonstrated that smart buildings employing DRL for setpoint optimization contribute to a more efficient, reliable, and sustainable electricity market.

Multi-Timescale Operations of Nuclear-Renewable Hybrid Energy Systems for Reserve and Thermal Products Provision

Jie Zhang, Associate Professor, University of Texas at Dallas (Richardson, TX)
Jubeyer Rahman, Ph.D. Student, University of Texas at Dallas (Richardson, TX)

This talk will present an optimal operation strategy of a nuclear-renewable hybrid energy system (N–R HES), in conjunction with a district heating network, which is developed within a comprehensive multi-timescale electricity market framework. The grid-connected N–R HES is simulated to explore the capabilities and benefits of N–R HES of providing energy products, different reserve products, and thermal products. An N–R HES optimization and control strategy is formulated to exploit the benefits from the hybrid energy system in terms of both energy and ancillary services. A case study is performed on the customized NREL–118 bus test system with high renewable penetrations, based on a multitimescale (*i.e.,* three-cycle) production cost model. Both day-ahead and real-time market clearing prices are determined from the market model simulation. The results show that the N–R HES can contribute to the reserve requirements and also meet the thermal load, thereby increasing the economic efficiency of N–R HES (with increased revenue ranging from 1.55% to 35.25% at certain cases) compared to the baseline case where reserve and thermal power exports are not optimized.

Session H2 (Thursday, June 29, 12:30 p.m.) (Commission Meeting Room)

Optimizing Stand-Alone Battery Storage Operations Scheduling Under Uncertainties in German Residential Electricity Market Using Stochastic Dual Dynamic Programming

Pattanun Chanpiwat, Doctoral Candidate, University of Maryland (College Park, MD) & Aalto University (Espoo, Finland) (Silver Spring, MD)
Fabricio Oliveira, Ph.D., Associate Professor, Aalto University (Espoo, Finland)
Steven A. Gabriel, Ph.D., Full Professor, University of Maryland (College Park, MD)

We present a new variation of the stochastic dual dynamic programming (SDDP) algorithm for solving multistage, convex stochastic programming problems considering uncertainties such as electricity prices, variable renewable energy generation, and residential demand in the electricity market. We approximate the convex expected-cost-to-go functions via a linear policy graph, to obtain optimal operational strategies for the battery storage usage of residential households. We develop a heuristic algorithm (*i.e.,* executable on edge-computing devices located at the households) of a residential electricity network with a flexible structure that allows residents to efficiently hedge their electricity consumption via community-shared battery storage while accounting for uncertainties and limitations of the energy system. We provide an economic assessment and insights into battery storage scheduling strategies and the model capabilities through case studies on a test network model of Southern German residential households. The results are compared with other mathematical models including a multistage stochastic convex optimization model with the assumptions of a perfect information case and/or a business-as-usual case.

Integration of Hybrid Storage Resources Into Wholesale Electricity Markets

Dr. Nikita Singhal, Technical Leader, Electric Power Research Institute (Palo Alto, CA)
Rajni Kant Bansal, Ph.D. Candidate, Johns Hopkins University (Baltimore, MD)
Dr. Erik Ela, Program Manager, Electric Power Research Institute (Palo Alto, CA)
Dr. Julie Mulvaney Kemp, Research Scientist, Lawrence Berkeley National Laboratory (Berkeley, CA)
Dr. Miguel Heleno, Research Scientist, Lawrence Berkeley National Laboratory (Berkeley, CA)

Electric storage resources and other technologies that are co-located and share a common point of interconnection are presently being incorporated into bulk power systems in increasing numbers, with more hybrid storage resources planned and under study within interconnection queues. Such hybrid storage resources are predominantly seen being combined with variable energy resources and are either being operated as two separate resources or as a single integrated resource. Market designers and system operators are presently researching ways to effectively integrate hybrid storage resources into their existing system operations and scheduling processes given the ambiguity around their impacts, particularly when high levels of hybrid resources are present. This research explores advanced market participation modeling options for integrating utility-scale hybrid storage resources into market clearing software in addition to discussing the economic and reliability implications of the different modeling options. This includes the consecutive impact of the participation models on the market clearing software solution and the dispatch and revenue of hybrid battery projects. The alternate participation models evaluated in this research include two separate resources ISO-managed co-located participation model, single integrated resource self-managed hybrid participation model and two separate resources ISO-managed linked co-located participation model.

Predicting Strategic Energy Storage Behaviors

Yuexin Bian, Ph.D. Student, University of California, San Diego (San Diego, CA)
Ningkun Zheng, Ph.D. Student, Columbia University (New York City, NY)
Yang Zheng, Assistant Professor, University of California, San Diego (San Diego, CA)
Bolun Xu, Assistant Professor, Columbia University (New York, NY)
Yuanyuan Shi, Assistant Professor, University of California, San Diego (San Diego, CA)

Energy storage are strategic participants in electricity markets to arbitrage price differences. Future power system operators must understand and predict strategic storage arbitrage behaviors for market power monitoring and capacity adequacy planning. This paper proposes a novel data-driven approach that incorporates prior model knowledge for predicting the behaviors of strategic storage participants. We propose a gradient-descent method to find the storage model parameters given the historical price signals and observations. We prove that the identified model parameters will converge to the true user parameters under a class of quadratic objective and linear equality-constrained storage models. We demonstrate the effectiveness of our approach through numerical experiments with synthetic and real-world storage behavior data. The proposed approach significantly improves the accuracy of storage model identification and behavior forecasting compared to previous blackbox data-driven approaches.

Energy Storage Participation Algorithm Competition (ESPA-Comp)

Dr. Brent Eldridge, Electrical Engineer, Pacific Northwest National Laboratory (Bel Air, MD)
Jesse Holzer, Mathematician, Pacific Northwest National Laboratory (Richland, WA)
Abhishek Somani, Economist, Pacific Northwest National Laboratory (Richland, WA)
Kostas Oikonomou, Electrical Engineer, Pacific Northwest National Laboratory (Richland, WA)
Brittany Tarufelli, Economist, Pacific Northwest National Laboratory (Laramie, WY)
Li He, Electrical Engineer, Pacific Northwest National Laboratory (Richland, WA)

Energy Storage Participation Algorithm Competition (ESPA-Comp) is an upcoming pilot competition that will challenge participants to develop innovative algorithms for energy storage participation in wholesale electricity markets. Energy storage technologies will play a critical role in making sure we have access to reliable and low-cost electricity. However, optimizing energy storage systems in wholesale electricity markets is a complex task that requires sophisticated algorithms to accurately predict electricity prices and account for the physical constraints of energy storage technologies. ESPA-Comp aims to bring together researchers, engineers, and students with expertise in AI/ML, optimization, and economics to develop algorithms that can effectively address these challenges. In this competition, participants will ''operate'' an energy storage resource in a simulated wholesale electricity market and will be awarded based on the profits they earn. Participants will need to submit algorithms that generate strategic offer curves, taking into account factors like weather, market competition, and network congestion. Competition results will help us to understand how different market designs can affect storage incentives and support the efficient use of storage resources.

Session H3 (Thursday, June 29, 3:00 p.m.) (Commission Meeting Room)

Congestion Mitigation With Transmission Reconfigurations in the Evergy Footprint

Dr. Pablo A. Ruiz, CEO and CTO, NewGrid, Inc. (Somerville, MA)
Derek Brown, Regulatory Affairs Manager, Evergy (Topeka, KS)
Jeremy Harris, Transmission Operations Planning Manager, Evergy (Topeka, KS)
German Lorenzon, Senior Engineer, NewGrid (Somerville, MA)
Grant Wilkerson, Director of Business Development, Evergy (Kansas City, MO)

Transmission needs are becoming more variable and are rising rapidly, as shown by significant increases in congestion management costs and in the frequency of transmission overloads. Further, transmission capability has been critical during recent extreme events, to support power transfers from less affected areas to the more affected ones. Topology optimization software is a grid-enhancing technology that identifies reconfiguration options to re-route power flow around transmission bottlenecks employing less utilized facilities and satisfying reliability criteria. These reconfigurations provide cost savings to power customers and increase the transmission network performance from both reliability and market efficiency perspectives. At the same time, the use of reconfigurations remains limited. For example, the usual practice in the Southwest Power Pool is to employ known reconfigurations as a last resort, after resource redispatch is exhausted and constraints are breached. This presentation will discuss the reliability and cost saving impacts of reconfigurations implemented in the Evergy footprint to mitigate congestion under the current SPP practice, as well as illustrate additional benefits that could be obtained if topology optimization opportunities were used proactively to address congestion.

Optimal Transmission Expansion Planning With Grid Enhancing Technologies

Swaroop Srinivasrao Guggilam, Senior Engineer, Electric Power Research Institute (Knoxville, TN)
Alberto Del Rosso, Program Manager, Electric Power Research Institute (Knoxville, TN)

The power system is evolving with a rapid increase in demand. It provokes rethinking ways to increase generation and expand the system's capacity to support it. This combination of fast-paced demand growth and supply has made the planning and expansion of the transmission system challenging in recent years. The futuristic hyperactive power system grid needs to be versatile. The grid should be able to host a variety of renewable energy resources, adapt to various system conditions, be highly secured under extreme events, and be dynamically responsive to make the power system reliable. All this is to be achieved at minimal cost to the customers and efficiently. The traditional transmission solutions will continue to be the backbone of the power system transmission grid, but upcoming state-of-the-art grid-enhancing technologies can significantly aid in supporting these ever-changing power system grid requirements with optimal cost and improved efficiency. Various grid-enhancing technologies include power flow control devices such as SmartValve devices and phase shift transformers, dynamic and adaptive transmission line ratings, and optimal topology control. The increasing penetration of distributed energy resources such as batteries also activates a different avenue to pursue being able to support transmission expansion planning needs. The term around the battery as a viable alternative is coined as a non-wire alternative solution. In many utilities, it's necessary to assess the non-wire alternative solutions such as batteries to meet FERC requirements. Developing and analyzing these various modern transmission solutions that work in tandem is challenging. One needs proper technical characterization of these technologies and assess the technology readiness. One also needs to evaluate its performance under normal and extreme conditions, the flexibility to deploy and install these technologies, calculate capital and operational costs, understand different available control options for these devices, and analyze potential limitations. Suitable analytical methods and high-performing software tools are needed to run the optimization simulations to enable integration and efficient use of these grid-enhancing technologies. EPRI has developed a software tool called CPLANET (Controlled PLANning Expansion Tool) that helps identify effective and low-cost solutions for mitigating thermal overloads in a power system over various operating scenarios. An optimal solution is determined from a given set of candidate projects, including various grid-enhancing technologies and traditional transmission expansion projects such as installing new transmission lines or upgrading existing substations. The software uses a mixed-integer linear programming formulation in the optimization engine to identify the least-cost solution for the grid's various physical and operating needs. The scope and goal of this presentation are to discuss the ongoing efforts at EPRI's forefront around grid-enhancing technologies. Showcase the current capabilities of the CPLANET tool and discuss case studies and share existing challenges and future goals.

The Key Role of Extended ACOPF-Based Decision Making for Supporting Clean, Cost-Effective and Reliable/Resilient Electricity Services

Maria Ilic, Professor Emerita, Carnegie Mellon University (Pittsburgh, PA)
Rupamathi Jaddivada, Director of Innovation, SmartGridz (Boston, MA)
Jeffrey Lang, Vitesse Professor, Massachusetts Institute of Technology (Cambridge, MA)
Eric Allen, Director of Engineering, SmartGridz (Boston, MA)

Societal objectives are rapidly moving towards decarbonized, affordable, and reliable/resilient electricity services. In this talk we first revisit these objectives by identifying basic changes and the related challenges taking place. In particular, decarbonization requires planning and operations of the changing electric energy systems so that seamless integration of clean resources, ranging across wind, solar, nuclear, geothermal, and hydro, is enabled. Notably, this must be done with an eye on generation adequacy. Also, these new resources present locational issues (NIMBY) in operating the existing power grid. Finally, the end users still must be served without interruptions and without being exposed to wide-spread blackouts. Similar challenges are related to ensuring cost-effective and reliable/resilient services. Second, we show how an extended (robust, adaptive, multi-temporal) ACOPF is essential for meeting these societal challenges. Pretty much any of the new software needed (for wind integration, resilient service, and preventing blackouts) requires effective optimization tools for identifying the main bottlenecks/obstacles to physical implementation and for advising operators and planners regarding the most effective remedial actions (new investments and/or flexible utilization). We illustrate potential benefits from utilizing ACOPF as a basic means of supporting software tools needed for meeting the societal challenges. We offer a taxonomy of such badly needed tools and illustrate the role of extended ACOPF estimated benefits on several real-world systems based on our work to-date.

Data & API Standards for Clean Energy Solutions and Digital Innovation

Priya Barua, Director of Market Policy and Innovation, Clean Energy Buyers Institute (Washington, DC)
Ben Gerber, President & CEO, M–RETS (Minneapolis, MN)

There is an opportunity for energy attribute certificate (EAC) issuing bodies in the U.S. and abroad to enable next generation carbon-free electricity (CFE) procurement solutions that accelerate grid decarbonization investments by capturing more attributes and better serving as a digital ''platform of platforms''. Energy customers who buy clean energy rely on EACs to assert ownership claims over each megawatt-hour of CFE they procure for auditing, reporting, and marketing purposes. EAC issuing bodies promote CFE procurement integrity and validation by issuing, tracking, and canceling EACs, which each represent a unique standardized tradable instrument representing one megawatt-hour of verified CFE generation. By adopting open data and automated programming interface (API) standards, EAC issuing bodies can improve data access and solutions for customers. This session will explore opportunities for EAC issuing bodies to establish consistent, modern automated programming interfaces (APIs), template legal agreements, and other tools that will make it easier for data providers to deliver data and for users to update the status of EACs through connected digital trading platforms— enabling innovation for CFE procurement solutions.

Mine Production Scheduling Under Time-of-Use Power Rates With Renewable Energy Sources

Dr. Daniel Bienstock, Professor, Columbia University (New York, NY)
Amy Mcbrayer, Ph.D. Candidate, South Dakota School of Mines (Rapid City, SD)
Andrea Brickey, Professor, South Dakota School of Mines (Rapid City, SD)
Alexandra Newman, Professor, Colorado School of Mines (Golden, CO)

Renewable energy use on active and reclaimed mine lands has increased dramatically in recent years. With mining companies focused on increasing efficiencies, reducing carbon intensity, and developing sustainable mining practices, opportunity exists to integrate data on electricity usage and demand into mine production schedules to capitalize on alternative energy sources and to take advantage of favorable pricing strategies. Utilizing real data from an active coal mine that has already integrated electric equipment into their loading fleet, we show the impacts of (i) seasonal power price fluctuations on a medium-term production schedule; and, (ii) hourly power price fluctuations on a short-term extraction schedule. Results reveal the economic potential both for: (i) the integration of renewable energy sources on reclaimed and active mine lands; and (ii), the corresponding synchronization of a production schedule with time-of-use energy pricing contracts.

[FR Doc. 2023–13168 Filed 6–20–23; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER23–2130–000]

Glover Creek Solar, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Glover Creek Solar, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is July 5, 2023.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to