issuance of this notice: (1) A copy of the water quality certification; (2) a copy of the request for certification, including proof of the date on which the certifying agency received the request; or (3) evidence of waiver of water quality certification. Please note that the certification request must comply with 40 CFR 121.5(b), including documentation that a pre-filing meeting request was submitted to the certifying authority at least 30 days prior to submitting the certification request. Please also note that the certification request must be sent to the certifying authority and to the Commission concurrently.

Dated: May 26, 2022.

Kimberly D. Bose,

Secretary.

[FR Doc. 2022–11867 Filed 6–2–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD10–12–013]

Increasing Market and Planning Efficiency Through Improved Software; 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 24, 2022, Commission staff will convene a technical conference on June 21, 22, and 23, 2022 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 Supplemental Notice is a final 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. ER21–2455–000

New York Independent System Operator, Inc. Docket No. ER21–2460–000

ISO New England, Inc. Docket No. ER22–983–000

PJM Interconnection, L.L.C. Docket No. ER22–962–000

Southwest Power Pool, Inc. Docket No. ER22–1697–000

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

The conference will take place virtually via WebEx, with remote participation from both presenters and attendees. Further details on remote attendance and participation will be released prior to the conference. Attendees must register through the Commission's website on or before June 10, 2022.[1] WebEx connections may not be available to those who do not register.

The Commission will accept comments following the conference, with a deadline of July 29, 2022.

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.*

[1] The attendee registration form is located at *https://www.surveymonkey.com/r/SHFLFKV.*

Dated: May 27, 2022.

Kimberly D. Bose,

Secretary.

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

Agenda

AD10–12–013

June 21–23, 2022

Tuesday, June 21, 2022

10:45 a.m. Introduction

Thomas Dautel, Federal Energy Regulatory Commission (*Washington, DC*)

Tuesday, June 21, 2022

11:00 a.m. Session T1

Enhancing Energy Assessment for ISO New England

Jinye Zhao, Principal Analyst, ISO New England (*Holyoke, MA*)

Tongxin Zheng, Director, ISO New England (*Holyoke, MA*)

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

Song Zhang, Lead Analyst, ISO New England (*Holyoke, MA*)

Thomas Knowland, Manager, ISO New England (*Holyoke, MA*)

Mallory Waldrip, Lead Energy Security Analyst, ISO New England (*Holyoke, MA*)

Cascading analysis for bulk power system operations

Slava Maslennikov, Technical Manager, ISO New England (*Holyoke, MA*)

Xiaochuan Luo, Manager, ISO New England (*Holyoke, MA*)

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

Tongxin Zheng, Director, ISO New England (*Holyoke, MA*)

Transmission Outage Predictions to Improve Operational Resilience and Situation Awareness

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

Xiaochuan Luo, Manager, ISO New England (*Holyoke, MA*)

Slava Maslennikov, Technical

Manager, ISO New England (*Holyoke, MA*)
Tongxin Zheng, Director, ISO New England (*Holyoke, MA*)

12:30 p.m. Lunch

1:30 p.m. Session T2

Improving uncertainty management through ancillary service products
Yonghong Chen, Consulting Advisor, MISO (*Carmel, IN*)
Benefit Evaluation of Multi-period Market Clearing
Jinye Zhao, Principal Analyst, ISO New England (*Holyoke, MA*)
Tongxin Zheng, Director of Advanced Technology Solutions, ISO New England (*Holyoke, MA*)
Jiachun Guo, Principal Analyst, ISO New England (*Holyoke, MA*)
Dane Schiro, Lead Analyst, ISO New England (*Holyoke, MA*)
Flexible Ramping Product Enhancements
Guillermo Bautista Alderete, Director of Market Analysis and Forecasting, California ISO (*Folsom, CA*)
Co-optimization of Reserve Requirements and Scheduling with Energy and Transmission Security
Matthew Musto, Technical Specialist, New York ISO and Hitachi Energy (*Rensselaer, NY*)
Edward O. Lo, Consultant, Hitachi Energy (*Rensselaer, NY*)

Tuesday, June 21, 2022

3:30 p.m. Break

4:00 p.m. Session T3

Jointly-Owned Unit Modeling
Tomas Tinoco De Rubira, Sr Power Systems Engineer—Development, California ISO (*Folsom, CA*)
Yannick Degeilh, Senior Power Systems Engineer, California ISO (*Folsom, CA*)
Better Operating Reserves Modeling to Accommodate Duct Burner-Equipped Combined Cycle Generators
John Meyer, Senior Energy Market Engineer, New York ISO (*Rensselaer, NY*)
Iiro Harjunkoski, Researcher, Hitachi Energy (*Mannheim, Germany*)
Energy Storage Resource Modeling Enhancements in CAISO Markets
Khaled Abdul-Rahman, Vice President of Power Systems and Market Technology, California ISO (*Folsom, CA*)
Tomas Tinoco De Rubira, Sr Power Systems Engineer—Development, California ISO (*Folsom, CA*)
Gabe Murtaugh, storage Sector Manager, California ISO (*Folsom, CA*)
Maintain Grid Reliability from Operations Planning to Real-time
Pengwei Du, Supervisor—Resource Forecasting and Analysis, ERCOT (*Taylor, TX*)

6:00 p.m. Adjourn

Wednesday, June 22, 2022

9:45 a.m. Introduction

10:00 a.m. Session W1

Practical challenges with the large penetration of Energy Storage Resources including SOC optimization, Pricing, Ancillary Services and Hybrid modeling within Production Costing software
Brian Thomas, Principal Engineer, PowerGEM LLC (*Clifton Park, NY*)
Boris Gisin, President, PowerGEM LLC (*Clifton Park, NY*)
Impact of Market Bidding and Dispatch Model over Energy Storage Utilization
Bolun Xu, Assistant Professor, Columbia University (*New York, NY*)
Ningkun Zheng, Research Assistant, Columbia University (New York, NY)
Joshua Jaworski, Research Assistant, Columbia University (New York, NY)
Gabe Murtaugh, Storage Sector Manager, California ISO (Folsom, CA)
Market design and cost recovery in a simple 100% RES system: Analytical insights
Guillaume Tarel, Engineer, Hydro Québec (*Montréal, Canada*)
Audun Botterud, Principal Research Scientist, Massachusetts Institute of Technology (*Cambridge, MA*)
Magnus Korpås, Professor, Norwegian University of Science and Technology (*Trondheim, Norway*)

11:30 p.m. Lunch

12:30 p.m. Session W2

Key concepts to promote operational flexibility: Comparison of approaches and recommendations
Erik Ela, Program Manager, Electric Power Research Institute (*Denver, CO*)
Phil de Mello, Senior Technical Leader, Electric Power Research Institute (*Davis, CA*)
Nikita Singhal, Technical Leade, Electric Power Research Institute (*Palo Alto, CA*)
Ben Hobbs, Pofessor, Johns Hopkins University (*Baltimore, MD*)
Mahdi Mehrtash, Assistant Research Professor, Johns Hopkins University (*Baltimore, MD*)
James Kim, Energy Policy Project Scientist, Lawrence Berkeley National Laboratory (*Berkeley, CA*)
Miguel Heleno, Research Scientist, Lawrence Berkeley National Laboratory (*Berkeley, CA*)
Price Formation in Zero-Carbon Electricity Markets: A Review of Challenges and Solutions
Zhi Zhou, Principal Computational Scientist, Argonne National Laboratory (*Lemont, IL*)
Audun Botterud, Principal Energy System Engineer, Argonne National Laboratory (*Lemont, IL*)
Todd Lovin, Team Lead, Argonne National Laboratory (*Lemont, IL*)
Risk-Aware Wind Bids with Distributed Optimization and Central Dispatch
Daniel Shen, Graduate Student, Massachusets Institute of Technology (*Cambridge MA*)
Marija Ilic, Senior Research Scientist, Massachusets Institute of Technology (*Cambridge, MA*)
Impacts of Multi-Interval Real-Time Dispatch on Generator Investment Incentives in PJM
Sushant Varghese, Graduate Research Assistant, Pennsylvania State University (*State College, PA*)
Anthony Giacomoni, Lead Market Strategist, PJM Interconnection LLC (*Audubon, PA*)
Aravind Retna Kumar, Graduate Research Assistant, Pennsylvania State University (*University Park, PA*)
Shailesh Wasti, Graduate Research Assistant, Pennsylvania State University (*University Park, PA*)
Mort Webster, Professor, Pennsylvania State University (*University Park, PA*)
Transitioning to Linked Swing-Contract Markets for Net-Zero 2050
Leigh Tesfatsion, Research Professor of Economics, Courtesy Research Professor of Electrical & Computer Engineering, Iowa State University (*Ames, IA*)

3:00 p.m. Break

3:30 p.m. Session W3

Assessing energy adequacy through scenario development for extreme events
Aidan Tuohy, Program Manager, Electric Power Research Institute (*Chicago, IL*)
Eamonn Lannoye, Program Manager, EPRI Europe (*Dublin, Ireland*)
Juan Carlos Martin, Senior Engineer, EPRI Europe, (*Madrid, Spain*)
Erik Smith, Engineer/Scientist III, Electric Power Research Institute (*Palo Alto, CA*)
Improving grid planning by modeling correlated generator failures
Dr. Sinnott Murphy, Research Engineer, National Renewable

Energy Laboratory (*Golden, CO*)
Integrated Modeling Framework For Multi-energy Systems' Planning
Violette Berge, Vice President, Artelys Canda Inc. (*Montréal, Canada*)
Tobias Bossmann, Project Director, Artelys Canada Inc. (*Montréal, Canada*)

5:00 p.m. Adjourn

Thursday, June 23, 2022

9:45 a.m. Introduction

10:00 a.m. Session H1

Real-Time Demand Response Market Co-Optimized with Conventional Energy Market
Bala Venkatesh, Professor and Director, Ryerson University (*Toronto, Ontario*)
Jessie Ma, Research Fellow, Centre for Urban Energy, Ryerson University (*Toronto, Ontario*)
Electricity retail rate design in a decarbonizing power system: an analysis of time-of-use pricing
Tim Schittekatte, Postdoctoral Associate, Massachusetts Institute of Technology (*Cambridge, MA*)
Dharik Mallapragada, Research Scientist, Massachusetts Institute of Technology (*Cambridge, MA*)
Richard Schmalensee, Professor of Economics, Emeritus, Massachusetts Institute of Technology (*Cambridge, MA*)
Paul Joskow, Professor of Economics, Emeritus, Massachusetts Institute of Technology (*Cambridge, MA*)
Improving Software to Allow End-users to Drive Impactful Procurement Decisions
Bryn Baker, Senior Director, Policy Innovation, Clean Energy Buyers Association (*Washington, DC*)
Latent distribution system flexibility offers bulk power system opportunities
Philip Court, Product and Company Strategist, Ecogy Energy (*Brooklyn, NY*)

12:00 p.m. Lunch

1:00 p.m. Session H2

Using E3's RESERVE Machine Learning Model to Advance the Calculation of Subhourly Ancillary Services Needs in Deeply Renewable Grids
Arne Olson, Senior Partner, Energy and Environmental Economics, Inc. (*San Francisco, CA*)
John Stevens, Senior Managing Consultant, Energy and Environmental Economics, Inc. (*San Francisco, CA*)
Jimmy Nelson, Associate Director, Energy and Environmental Economics, Inc. (*San Francisco, CA*)
Yuchi Sun, Senior Consultant, Energy and Environmental Economics, Inc. (*San Francisco, CA*)
Synergistic Integration of Machine Learning and Mathematical Optimization for Unit Commitment
Jianghua Wu, PhD student, University of Connecticut (*Storrs, CT*)
Peter B. Luh, Professor, University of Connecticut (*Storrs, CT*)
Yonghong Chen, Senior Engineer, Midcontinent ISO (*Carmel, IN*)
Bing Yan, Assistant Professor, Rochester Institute of Technology (*Rochester, NY*)
Mikhail A. Bragin, Research Assistant Professor, University of Connecticut (*Storrs, CT*)
Congestion and Overload Mitigation using Optimal Transmission Reconfigurations—Experience in MISO and SPP
Pablo A. Ruiz, CEO and CTO, NewGrid, Inc. (*Somerville, MA*)
Paola Caro, Principal Engineer, NewGrid, Inc. (*Somerville, MA*)
Mitchell Myhre, Manager—Transmission Planning and Regulatory Relations, Alliant Energy (*Madison, WI*)
Rodica Donaldson, Senior Director—Transmission Strategy & Analytics, EDF Renewables (*San Diego, CA*)
Xiaoguang Li, Director of Product, NewGrid, Inc. (*Somerville, MA*)
Demonstration of Potential Data/Calculation Workflows Under FERC Order No. 881's Ambient-Adjusted Rating (AAR) Requirements
Lisa Sosna, Economist, FERC *(Washington, DC)*
Tom Dautel, Deputy Director, Division of Economic and Technical Analysis, FERC *(Washington, DC)*
Ken Fenton, Physical Scientist, Global Systems Laboratory, National Oceanic and Atmospheric Administration *(Boulder, CO)*

3:00 p.m. Break

3:30 p.m. Session H3

GO Competition Challenge 2: Analysis and Lessons Learned
Brent Eldridge, Electrical Engineer, Pacific Northwest National Laboratory' (*Baltimore, MD*)
Stephen Elbert, Computational Scientist, Pacific Northwest National Laboratory (*Richland, WA*)
Arun Veeramany, Data Scientist, Pacific Northwest National Laboratory (*Richland, WA*)
Hans Mittelmann, Professor, Arizona State University (*Tempe, AZ*)
Jesse Holzer, Mathematician, Pacific Northwest National Laboratory (*Richland, WA*)
GO Competition Challenge 3: Goals and Formulation
Jesse Holzer, Mathematician, Pacific Northwest National Laboratory (*Richland, WA*)
Brent Eldridge, Electrical Engineer, Pacific Northwest National Laboratory (*Baltimore, MD*)
Stephen Elbert, Advisor, Pacific Northwest National Laboratory (*Richland, WA*)
Solving GO competition ACOPF problems
Daniel Bienstock, Professor, Columbia University (*New York, NY*)
Richard Waltz, Senior Scientist, Artelys, Inc. (*Chicago, IL*)
A Profit Maximizing Security-Constrained IV–AC Optimal Power Flow & Global Solution
Amro M. Farid, Visiting Associate Professor, MIT Mechanical Engineering (*Cambridge, MA*)
ABSCoRES, managing risk and uncertainty on electricity systems using Banking Scoring and Rating methodologies
Alberto J. Lamadrid L., Associate Professor, Lehigh University (*Bethlehem, PA)*

5:30 p.m. Adjourn

Conference Abstracts

Session T1 (Tuesday, June 21, 11:00 a.m., WebEx)

Enhancing Energy Assessment for ISO New England

Dr. Jinye Zhao, Principal Analyst, ISO New England (Holyoke, MA)
Dr. Tongxin Zheng, Director, ISO New England (Holyoke, MA)
Dr. Mingguo Hong, Principal Analyst, ISO New England (Holyoke, MA)
Dr. Song Zhang, Lead Analyst, ISO New England (Holyoke, MA)
Mr. Thomas Knowland, Manager, ISO New England (Holyoke, MA)
Mrs. Mallory Waldrip, Lead Energy Security Analyst, ISO New England (Holyoke, MA)

ISO New England performs a 21-day energy assessment providing an energy supply outlook given anticipated power system conditions of the region. The assessment takes into consideration major risk factors such as fuel supply and inventory, weather forecast and electricity demand. It was developed to improve situational awareness for the ISO and New England's market participants about regional energy adequacy. This presentation focuses on improvements to the modeling, process, and software of the 21-day energy assessment, enhancing solution efficiency and performance. Future improvements will also be discussed.

Cascading Analysis for Bulk Power System Operations

Dr. Slava Maslennikov, Technical Manager, ISO New England (Holyoke, MA)
Dr. Xiaochuan Luo, Manager, ISO New England (Holyoke, MA)
Dr. Mingguo Hong, Principal Analyst, ISO New England (Holyoke, MA)
Dr. Tongxin Zheng, Director, ISO New England (Holyoke, MA)

Clean energy transition is shifting the bulk power system operating paradigm from reliability-centered deterministic approaches to risk-based methods. Cascading analysis is one of the practical ways to facilitate such transition as it tries to assess the potential load and generation losses caused by an initiating contingency. Such a system impact measure is more informative than the traditional thermal and voltage violations estimated from conventional contingency analysis and could be more efficiently used for situational awareness and system risk mitigation. ISO New England has developed both the online and offline cascading analysis process for real-time system operation and planning. The online application runs every few minutes and evaluates system impact of higher order contingencies to supplement Real-Time Contingency Analysis. The offline application assesses the operational risk under different scenarios representing the variability and uncertainty of renewables as well as extreme weather conditions. Cascading analysis has also a potential to greatly increase the efficiency of outage coordination. This presentation discusses details and use cases of the cascading analysis under the operational time frame.

Transmission Outage Predictions to Improve Operational Resilience and Situation Awareness

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)

The northeastern U.S. has been frequently visited by harsh wintry and tropical storms that result in transmission outages due to precipitation, high winds, lighting and icing. In collaboration with the University of Connecticut Eversource Energy Center, ISO New England has been conducting real-time transmission outage prediction studies using the machine learning (ML) techniques to support situation awareness in real-time operation. Historic weather, transmission facility and topography, and transmission outage data are used to train the jointly-developed ML model. Outcome of the ML algorithms is further combined with mechanistic simulation results (fragility curves) that reflect extreme and rare conditions. Our early studies have produced promising results that will further improve with the availability of more collected data. The developed algorithms are being implemented in our Online Weather Look-ahead Study (OWLS) tool. OWLS performs look-ahead weather monitoring and transmission risk assessment to assist operational decision against extreme weather events.

Session T2 (Tuesday, June 21, 1:30 p.m., WebEx)

Improving Uncertainty Management Through Ancillary Service Products

Dr. Yonghong Chen, Consulting Advisor, MISO (Carmel, IN)

This presentation discusses recent work at MISO to improve ancillary service product design based on quantified uncertainties under different timeframe. Up ramp capability product requirement and demand curve are derived based on risks under normal and contingency conditions. The seasonal and hourly short term reserve requirements are derived with machine learning clustering algorithm based on aggregated real time uncertainties and real time commitment distributions. Similar approach is applied to derive seasonal and hourly sub-regional uncertainty events. It'll also give a brief introduction of on-going and future work on quantifying and predicting risks across operational timeframe with existing and upcoming resource mixes.

Benefit Evaluation of Multi-period Market Clearing

Dr. Jinye Zhao, Principal Analyst, ISO New England (Holyoke, MA)
Dr. Tongxin Zheng, Director of Advanced Technology Solutions, ISO New England (Holyoke, MA)
Dr. Jiachun Guo, Principal Analyst, ISO New England (Holyoke, MA)
Dr. Dane Schiro, Lead Analyst, ISO New England (Holyoke, MA)

Intertemporal constraints are inherent to almost all the resources participating in electricity markets. Currently, many electricity markets employ a sequential single-period market clearing process which does not fully recognize the intertemporal linkages among different market intervals. An efficient multi-period market clearing approach has been drawing attention recently due to its capability of simultaneously scheduling and pricing a market with multiple time intervals while respecting market coupling. This presentation discusses the differences between the two market clearing methods and presents a quantitative analysis of the multi-period approach on the ISO New England markets. An in-house market simulator was used to perform such analysis by using 2019 market data. The results demonstrate the benefits of the multi-period approach in terms of system reliability improvement, social surplus gain and uplift payment reduction.

Flexible Ramping Product Enhancements

Dr. Guillermo Bautista Alderete, Director of Market Analysis and Forecasting, California ISO (Folsom, CA)

The integration of renewable resources in the CAISO system requires market mechanisms to deal with the inherent uncertainty arising from the variability of load as well as wind and solar resources. The flexible ramping product is a market product that procures the ramp capability to address this uncertainty. This requires the CAISO to estimate uncertainty in both the upward and downward directions. Currently, CAISO utilizes a statistical methodology with historical uncertainty to assess procurement requirements. In this presentation, CAISO introduces an enhanced methodology, using a quantile calculation, to estimate uncertainty based on both historical uncertainty and forecasts of load as well as wind and solar output.

Co-Optimization of Reserve Requirements and Scheduling With Energy and Transmission Security

Mr. Matthew Musto, Technical Specialist, NYISO and Hitachi Energy (Rensselaer, NY)
Mr. Edward O. Lo, Consultant, Hitachi Energy (Rensselaer, NY)

With increasing variable resources in the generation mix, the need for more economic responsiveness and flexibility is growing. The NYISO and Hitachi Energy have been working on advanced design and optimization techniques for dynamically calculating reserve requirements based upon generation and transmission contingencies; as part of the overall system production minimization cost objective. This presentation will discuss initial design criteria as well as forward looking design and prototype efforts to ensure grid reliability. Topics include, use cases in the New York grid where dynamic reserves procurement can be applied as well as highlighting the complexities in formulation required to efficiently co-optimize reserve requirements with load/gen and transmission security.

Session T3 (Tuesday, June 21, 4:00 p.m., WebEx)

Jointly-Owned Unit Modeling

Dr. Tomas Tinoco De Rubira, Sr Power Systems Engineer—Development, California ISO (Folsom, CA)
Dr. Yannick Degeilh, Senior Power Systems Engineer, California ISO (Folsom, CA)

Efficient electricity markets require mathematical models that capture the physical and economic characteristics of resources. One important type of resource is a jointly-owned unit. It represents a physical generator that is owned and shared between multiple parties. At CAISO, as part of a pilot project, we have developed a mathematical model for representing such units and implemented the necessary market extensions for integrating and utilizing these effectively in the Energy Imbalance Market. This market software enhancement allows the scheduling coordinators that manage the different ownership shares to participate in the real-time financial markets independently, while automatically ensuring the physical capabilities of the underlying unit are not only respected but fully utilized. In this presentation, we describe the model implemented and highlight the challenges, lessons learned, and results of the pilot project.

Better Operating Reserves Modeling To Accommodate Duct Burner-Equipped Combined Cycle Generators

Mr. John Meyer, Senior Energy Market Engineer, NYISO (Rensselaer, NY) Dr. Iiro Harjunkoski, Researcher, Hitachi Energy (Mannheim, Germany)

The New York Independent System Operator (NYISO), in conjunction with Hitachi Energy, have been working on improvements to the scheduling and conversion of Operating Reserves products as applied to combined cycle generators equipped with Heat Recovery Steam Generator (HRSG) supplemental firing systems. These generator configurations have unique operating characteristics to consider in Energy and Operating Reserves optimization that present some modeling challenges. This presentation will discuss the challenges, review the approach to better model the true physical capabilities of these units, and elaborate on potential operational benefits identified during the concept development.

Energy Storage Resource Modeling Enhancements in CAISO Markets

Dr. Khaled Abdul-Rahman, Vice President of Power Systems and Market Technology, California ISO (Folsom, CA)
Dr. Tomas Tinoco De Rubira, Sr Power Systems Engineer—Development, California ISO (Folsom, CA)
Mr. Gabe Murtaugh, Storage Sector Manager, California ISO (Folsom, CA)

Organized electricity markets allow resource schedulers to bid a price that varies over the operating range of the resource. These operating ranges span from the minimum amount of power (MW) to the maximum amount of power that the resource is physically able or rated to generate at any point in time. Today, storage resources are becoming more prevalent within organized electricity markets and have additional physical constraints for operation compared to traditional resources. Notably, storage has limitations on the amount of energy (MWh) that it may store or discharge at any point in time. The California ISO is developing a framework for a new storage model that will allow bidding a price that varies over the operating range for energy—or state of charge—rather than power. This will allow storage resources to more closely convey true marginal costs of operation to the CAISO through bids, which in turn will allow for a more optimal dispatch and better resource performance.

Maintain Grid Reliability From Operations Planning to Real-Time

Dr. Pengwei Du, Supervisor—Resource Forecasting and Analysis, ERCOT (Taylor, TX)

This talk will present the operational reliability challenges at ERCOT and recent developments to improve the grid reliability from operations planning to real-time operaions.

Session W1 (Wednesday, June 22, 10:00 a.m., WebEx)

Practical Challenges With the Large Penetration of Energy Storage Resources Including SOC Optimization, Pricing, Ancillary Services and Hybrid Modeling Within Production Costing Software

Mr. Brian Thomas, Principal Engineer, PowerGEM LLC (Clifton Park, NY) Dr. Boris Gisin, President, PowerGEM LLC (Clifton Park, NY)

With rapid growth of Renewable and Battery Energy Storage System (BESS) resources it becomes more important to study BESS resources including hybrids in mid to long range Production Cost Modeling (PCM) Studies. BESS state of charge (SOC) optimization models vary between ISOs and PCM studies due to differences in SOC Management and how it is currently implemented. This presentation describes the challenges with modeling BESS in PCM environment including full SOC management model, enforcements of SOC targets, SOC limits and pricing run challenges. BESS resource can provide Ancillary services which makes it more important to manage SOC for Energy and Ancillary services in an optimal fashion and avoid infeasible operating conditions. Here we describe our experience implementing the BESS SOC model for Energy and different Ancillary products. BESS resources are essential to meet ramping requirements in severely ramp constrained regions. However, this requires pre-ramping algorithms in market clearing products to better manage ramps. This presentation describes our experience with pre-ramping modeling and possible solutions. This presentation also describes the challenges and approaches to model Hybrid Plants (within PCM studies) which is rapidly increasing in interconnection queues of many regions.

Impact of Market Bidding and Dispatch Model Over Energy Storage Utilization

Dr. Bolun Xu, Assistant Professor, Columbia University (New York, NY)
Mr. Ningkun Zheng, Research Assistant, Columbia University (New York, NY)
Mr. Joshua Jaworski, Research Assistant, Columbia University (New York, NY)
Mr. Gabe Murtaugh, Storage Sector Manager, California ISO (Folsom, CA)

This talk analyzes how different dispatch models and bidding strategies would affect the utilization of storage with various durations in deregulated power systems. We use a dynamic programming model to calculate the operation opportunity value of storage from price predictions, and use the opportunity value result as a base for designing market bids. We compare two market bidding and dispatch models in single-period economic dispatch: a power bidding model and a State of Charge-segment bidding model. We test the two storage dispatch models, combined with different price predictions and storage durations, using historical real-time price data from New York Independent System Operator. We compare the utilization rate with respect to results from perfect price forecast cases. Our result shows that modeling storage bids as dependent on State of Charge in single-period real-time dispatch will provide around 5–10% of improvement in storage utilization over all duration cases and bidding strategies, and higher renewable share will likely improve storage utilization rate due to higher occurrence of negative prices.

Market Design and Cost Recovery in a Simple 100% RES System: Analytical Insights

Dr. Guillaume Tarel, Engineer, Hydro Québec (Montréal, QC)
Dr. Audun Botterud, Principal Research Scientist, Massachusetts Institute of Technology (*Cambridge, MA*)
Dr. Magnus Korpås, Professor, Norwegian University of Science and Technology (*Trondheim, Norway*)

Modern power systems should meet the three criteria of affordability, security and sustainability. This largely explains why renewable energy sources (RES), whose costs and performance have improved dramatically during the last decades, are rapidly expanding. However, RES generation remains dictated by weather condition because of their very nature, and systems with very high shares of RES will have to rely on various sources of flexibility such as demand-response, interconnections, peakers and storage to balance supply and demand. Moreover, most RES technologies have zero marginal cost, impacting price formation in the electricity market. During this presentation, we will show an analysis of a simplified 100% RES systems based on wind generation and energy storage only. Using an analytical formulation based on net load duration curves, we analyze the equilibrium conditions for RES and storage. This leads to a discussion on how short-term market prices could be shaped to allow cost minimization for the system as a whole and cost recovery for market players.

Session W2 (Wednesday, June 22, 12:30 p.m., WebEx)

Key Concepts To Promote Operational Flexibility: Comparison of Approaches and Recommendations

Dr. Erik Ela, Program Manager, Electric Power Research Institute (Palo Alto, CA)
Dr. Phil de Mello, Senior Technical Leader, Electric Power Research Institute (Davis, CA)
Dr. Nikita Singhal, Technical Leader, Electric Power Research Institute (Palo Alto, CA)
Dr. Ben Hobbs, Professor, Johns Hopkins University (Baltimore, MD)
Dr. Mahdi Mehrtash, Assistant Research Professor, Johns Hopkins University (Baltimore, MD)
Mr. James Kim, Energy Policy Project Scientist, Lawrence Berkeley National Laboratory (Berkeley, CA)
Mr. Miguel Heleno, Research Scientist, Lawrence Berkeley National Laboratory (Berkeley, CA)

A variety of mechanisms are being proposed for promoting operational flexibility for bulk power systems. These include dynamic reserve requirements, flexibility products, extended sloped operating reserve demand curves, market clearing tool enhancements, and advanced participation models. The presentation will discuss key concepts for promoting flexibility to improve reliability and economic efficiency while aligning price signals with necessary operational decisions. It will also describe some case studies that compare flexibility products and operating reserve demand curves to describe their similarities and how they can be effectively integrated in electricity market design.

Price Formation in Zero-Carbon Electricity Markets: A Review of Challenges and Solutions

Dr. Zhi Zhou, Principal Computational Scientist, Argonne National Laboratory (Lemont, IL)
Dr. Audun Botterud, Principal Energy System Engineer, Argonne National Laboratory (Lemont, IL)
Dr. Todd Lovin, Team Lead, Argonne National Laboratory (Lemont, IL)

Future power systems dominated by zero-carbon generation resources may require significant revisions to electricity market designs to ensure capacity adequacy and market efficiency. In this presentation, we first conceptually outline key fundamentals underlying electricity market design and price formation and briefly review current operational practices in U.S. electricity markets. We then discuss a set of potential market design challenges in a grid dominated by zero-carbon resources with marginal cost profiles that differ compared to traditional thermal resources. Next, we review electricity market design solutions that have been proposed in the literature to ensure market efficiency in zero-carbon systems, along with policies and incentive schemes proposed or implemented to accelerate the transition. We also briefly discuss ongoing revisions to the seven regional electricity markets in the United States and review the intended goals and potential challenges of different market design options. Finally, taking hydropower resources as an example, we discuss the specific implications for flexible resources in a future zero-carbon system. In particular, we summarize the potential advantages and challenges that hydropower resources may face when participating in a competitive market framework dominated by resources with zero marginal costs or zero fuel costs. We conclude by summarizing key observations and establishing a set of research questions that should be addressed to improve our understanding of market design, price formation, and market efficiency in zero-carbon power systems.

Risk-Aware Wind Bids With Distributed Optimization and Central Dispatch

Mr. Daniel Shen, Graduate Student, Massachusetts Institute of Technology (Cambridge MA)
Dr. Marija Ilic, Senior Research Scientist, Massachusetts Institute of Technology (Cambridge MA)

Grid operators must integrate ever increasing amounts of stochastic, distributed generation in the form of wind and solar power. On the consumer side, demand response will also become an important component of grid operation. Unlike conventional fossil generation, these assets have time- and state- varying capacities, ramp constraints, and cost curves that add additional computation complexity to centralized dispatch algorithms. We propose a distributed optimization approach for dispatch that reduces the computation burden of the ISO's centralized dispatch algorithm and opens the possibility of running ACOPF for day-ahead and real-time dispatch. Key to our approach is that assets bid in a manner that internalizes their own operating constraints, instead of these constraints being part of the central optimization problem. We demonstrate this distributed dispatch on a NYISO 1576-bus system with risk-aware wind bids.

Impacts of Multi-Interval Real-Time Dispatch on Generator Investment Incentives in PJM

Mr. Sushant Varghese, Graduate Research Assistant, Pennsylvania State University (State College, PA)
Dr. Anthony Giacomoni, Lead Market Strategist, PJM Interconnection (Audubon, PA)
Mr. Aravind Retna Kumar, Graduate Research Assistant, Pennsylvania State University (University Park, PA)
Mr. Shailesh Wasti, Graduate Research Assistant, Pennsylvania State University (State College, PA)

Over the last several years, the PJM generation mix has shifted with some traditional fossil fuel generators being displaced by renewable resources. Given current state policy goals within the PJM region, this shift is expected to accelerate over the next several years. Most new renewable resources being built are wind and solar generators, which are inherently intermittent in nature. Absent large-scale deployments of new energy storage resources, one of the current challenges of integrating large amounts of intermittent renewable resources into the system is the provision of adequate intra-hour ramp capability from controllable resources to account for unexpected changes in their output. Ideally, the real-time market clearing should both provide sufficient flexibility in its energy and reserve schedules and revenues should reward the more flexible units that provide the needed flexibility, thereby guiding future investment decisions. Currently, PJM uses a single interval optimization that looks ahead 8–10 minutes to the target time in its real-time security constrained economic dispatch (RT–SCED). Given the short look-ahead period, RT–SCED is not able to anticipate potential changes in generation and load that may occur over subsequent intervals. One potential solution that has been implemented in other Independent System Operators (ISOs) is the use of a multi-interval real-time dispatch with a longer look-ahead period. A multi-interval real-time dispatch reduces system costs by optimally scheduling ramp capability on the system by prepositioning controllable generators to handle forecasted load and generation uncertainties. However, to date, all ISOs that have implemented a multi-interval real-time dispatch use single settlement procedures, in which prices are only set for the first interval from the RT–SCED's time horizon. The prices in later intervals from each model solution are advisory only. A question remains about whether the revenues from this approach are biased towards more or less flexible units. An alternative is a multi-settlement approach, in which every cleared quantity and price for the same demand interval from repeated model solutions are saved and all are used in determining the final settlement. This presentation will provide an overview of PJM's current dispatch practices in its Real-Time Energy Market and will compare them to a multi-interval real-time dispatch using both single- and multi-settlement approaches. Simulation results using a real-time model of the PJM system with a rolling window horizon will be presented. Results will compare the relative differences in net revenues for each generation technology class, as one indication of relative incentives for investment in more flexible resources.

Transitioning to Linked Swing-Contract Markets for Net-Zero 2050

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

The need for flexible dependable reserve provision in electric power systems has dramatically increased in recent years. Growing reliance on volatile renewable power resources and greater encouragement of more active demand-side participation has led to greater uncertainty and volatility of net load. Consequently, system operators are finding it harder to secure reserve with sufficient dependability and flexibility to permit the continual balancing of net load, a basic requirement for power system reliability. In this presentation I reconsider the design of U.S. RTO/ISO-managed wholesale power markets in light of these concerns. Four design principles are stressed: (i) U.S. RTO/ISO-managed wholesale power markets must necessarily be forward markets due to the speed of real-time operations; (ii) Only one type of product can effectively be transacted in U.S. RTO/ISO-managed wholesale power markets: Namely, reserve, an insurance product offering availability of net-load balancing services for future real-time operations; (iii) Net-load balancing services offered into U.S. RTO/ISO-managed wholesale power markets primarily take the form of RTO/ISO-dispatchable power-paths available for possible dispatched delivery at designated grid locations during designated future operating periods; (iv) All dispatchable power resources should be permitted to compete for the provision of power-paths in U.S. RTO/ISO-managed wholesale power markets without regard for irrelevant underlying technological differences. If these four principles are accepted, current trade and settlement arrangements for U.S. RTO/ISO-managed wholesale power markets need to be fundamentally altered. In this presentation I propose the transition to a new linked swing-contract market design, consistent with principles (i)–(iv), that could meet the future needs of U.S. RTO/ISO-managed wholesale power markets better than currently implemented designs.

Session W3 (Wednesday, June 22, 3:30 p.m., WebEx)

Assessing Energy Adequacy Through Scenario Development for Extreme Events

Dr. Aidan Tuohy, Program Manager, Electric Power Research Institute (Chicago, IL)

Dr. Eamonn Lannoye, Program Manager, EPRI Europe (Dublin, Ireland)

Mr. Juan Carlos Martin, Senior Engineer, EPRI Europe (Madrid, Spain)

Dr. Erik Smith, Engineer/Scientist III, Electric Power Research Institute (Palo Alto, CA)

While power system adequacy studies have traditionally focused on ensuring sufficient capacity is available to meet demand, recent events and projected changes to the system have shown that having sufficient energy as well as capacity is likely to become increasingly relevant. This can come in the form of gas availability during extreme cold, the likelihood of long periods of low wind and solar output, or energy storage availability in batteries and other forms of limited duration storage. As part of its ''Resource Adequacy for a Decarbonized Future'' initiative, EPRI has been examining how best to include energy adequacy considerations into the larger set of probabilistic resource adequacy metrics, such as loss of load expectation or expected unserved energy. While extreme events are important to consider, they may occur in the tails of the distribution and as such do not get attention in metrics that average outage likelihood over long periods of time. EPRI is currently working with its utility and ISO members on case studies related to these issues and initial results will be presented here. In this presentation, we will focus on a new tool, intended to be publicly available once validated, that is used to develop scenarios for adequacy studies. We will provide an overview of the modeling approaches, including how vulnerability models are being developed for each type of asset on the system, based on expert knowledge and historical performance. This results in a set of asset risk models, showing risk under different types of weather conditions. Such information can then be combined with historical and projected weather data to understand the periods when the system is most likely to be energy limited. The outputs of the tool are thus scenarios related to extreme events, that can then be studied using existing or under development adequacy assessment tools.

Improving Grid Planning by Modeling Correlated Generator Failures

Dr. Sinnott Murphy, Research Engineer, National Renewable Energy Laboratory (Golden, CO)

Recent academic research has identified correlated generator failures in the United States bulk power system, violating key assumptions made in system planning. Subsequent work demonstrated strong statistical relationships between generator outages and extreme temperatures, with particularly large outages observed during winter events. These temperature dependencies were then shown to be consequential for both planning reserve margins and the procurement of operating reserves. Unfortunately, standard resource adequacy modeling software tools used by grid planners are incapable of representing temperature-dependent outage rates and instead assume each generator's average reliability over a historical period (*e.g.,* five years) reflects its risk during peak load conditions, when temperatures are often at their most extreme. As a result, resource adequacy modeling generally understates the capacity levels needed to achieve a desired system reliability target. At the National Renewable Energy Laboratory, grid modelers employ the open-source Probabilistic Resource Adequacy Suite (PRAS) to perform resource adequacy assessments. Unlike most tools, PRAS allows users to define time-varying asset outage and recovery rates for all assets, including generators, storage resources, and transmission lines. Researchers can thus use PRAS to conduct adequacy assessments that are significantly more realistic than current industry practice. This enables more accurate identification of today's system capacity requirements as well as improved ability to assess and mitigate reliability risks of future systems. This talk will: 1. Present the empirical evidence of correlated failures in the U.S.; 2. Introduce the PRAS model and some of the studies it has supported; 3. Describe ongoing work to model temperature-outage relationships in the U.S.; and 4. Describe novel resource adequacy workflows enabled by PRAS.

Integrated Modeling Framework for Multi-Energy Systems' Planning

Mrs. Violette Berge, Vice President, Artelys Canada Inc. (Montréal, Canada)

Dr. Tobias Bossmann, Project Director, Artelys Canada Inc. (Montréal, Canada)

For the past 7 years, Artelys has been developing the METIS model on behalf of the European Commission's Directorate-General for Energy. METIS is the European model that allows to develop scenarios for the future of energy systems (electricity, gas, heat, etc). It enables to address questions like impact assessment of European Union energy policy proposals, cost benefit assessment of infrastructure projects, assessment of the potential role for a technology. While the first phase of the project consisted in developing the power and gas system/market model, the second phase of the project focused on better integrating distribution and transmission grids. Artelys developed a similar integrated modeling framework for the American Northeastern power grid, including Eastern Canadian provinces, New-York and New-England grids for strategic studies. In this talk, Artelys will present the METIS project and the American Northeastern model and discuss the benefits of using such a modeling framework for energy and climate policymaking.

Session H1 (Thursday, June 23, 10:00 a.m., WebEx)

Real-Time Demand Response Market Co-Optimized With Conventional Energy Market

Dr. Bala Venkatesh, Professor and Director, Ryerson University (Toronto, Ontario) Ms. Jessie Ma, Research Fellow, Centre for Urban Energy, Ryerson University (Toronto, Ontario)

In addition to procuring energy, consumers in electricity markets procure demand response (DR) services. Demand and supply of energy in the electricity market drives the demand for DR services. Through the Net Benefits Test (NBT), economic procurement of DR is limited to an amount that ensures that consumers benefit with the procurement of DR services. However, the NBT neither (a) recognizes the co-existence of the DR market with the energy market; nor (b) optimizes social welfare in the DR market in concert with that of the energy market. This lack of accounting for DR market surplus results in economic inefficiency. To address this shortcoming, we advance past works by: (a) Proposing a real-time DR market where the DR demand curve is a function of opportunity in the energy market; and (b) co-optimizing energy and DR markets such that the total social welfare derived from both markets is maximized simultaneously. We also present an optimal power flow formulation and process to implement our ideas in real-time electricity markets. The formulation is tested on a simple test case and a system based on actual PJM data. For the PJM case, total social welfare is increased by 1.41% to 3.05% over existing DR procurement strategies, resulting in $14.5M to $30.9M additional benefits per hour.

Electricity Retail Rate Design in a Decarbonizing Power System: An Analysis of Time-of-Use Pricing

Dr. Tim Schittekatte, Postdoctoral Associate, Massachusetts Institute of Technology (Cambridge, MA)

Dr. Dharik Mallapragada, Research Scientist, Massachusetts Institute of Technology (Cambridge, MA)

Dr. Richard Schmalensee, Professor of Economics, Emeritus, Massachusetts Institute of Technology (Cambridge, MA)

Dr. Paul Joskow, Professor of Economics, Emeritus, Massachusetts Institute of Technology (Cambridge, MA)

Increased electrification of heating and transport on the demand-side and high rates of intermittent renewable uptake on the supply-side increase the importance of retail electricity rates. Due to acceptability issues with the first-best solution, *i.e.,* retail rates passing-through wholesale prices, alternatives are being proposed. An important alternative is a time-of-use (TOU) tariff, possibly reinforced by critical peak pricing (CPP). Trabish (2022) reports that there were over 150 rate design policy initiatives in 2021 addressing new time-of-use (TOU) or time-varying rate (TVR) structures in the United States. TOU rates are predefined, *e.g.,* a year ahead, and vary according to fixed time blocks calibrated on historical data—see *e.g.,* Faruqui and Sergici (2013). Typically, time blocks are differentiated based on seasons, months, type of day (workdays or weekends), and/or time of the day (so-called peak, shoulder, or off-peak hours). The idea behind TOU rates is that consumers are to a certain extent exposed to the time-varying conditions in wholesale electricity markets while keeping rates predictable and protecting consumers from unexpected price shocks. Most academics investigating the TOU tariffs emphasize that such rates only capture a small fraction of welfare benefits when compared with prices passing through the wholesale price (Hogan, 2014; Borenstein, 2015; Jacobson et al., 2020). The metric of interest in these studies in the correlation between TOU prices and realized wholesale prices and/or they make the crucial assumption that demand is modelled as having a constant, rather low, elasticity in each (independent) hour. In our paper, we use data from different power systems in the US (ERCOT, CAISO and ISO–NE) for a period between 2010–2019 and we find indeed that the out-of-sample correlations between TOU prices and the realized wholesale prices are low. However, these correlations significantly improve when leaving out the unpredictable scarcity prices in the train and test data. More importantly, we argue that a very large fraction of demand response in the future will come in the form of ''load shifting'' rather than changes in load in independent hours. The major relevant technologies in that regard are electric vehicles (EVs), heat pumps (HPs) and air conditioning (ACs). The potential of TOU to induce (beneficial) load shifting is not well captured by looking at correlations. To estimate how effective TOU would be to shift load from one time block to another ''in the right direction'', with the realized wholesale price as a baseline, we propose to use the rank correlation metric. We simulate demand shifting and demand reduction under realized wholesale prices and under TOU prices. We show that show that rank correlations are an appropriate predictor of beneficial load shifting under TOU pricing. Conditional upon power system characteristics, TOU tariffs can lead to a high proportion of the potentially ideal load shifting volumes. We end the paper by discussing under what power system conditions TOU tariffs can be a reasonable second best to passing through wholesale prices and under what conditions this statement does not hold anymore.

Improving Software to Allow End-Users To Drive Impactful Procurement Decisions

Ms. Bryn Baker, Senior Director, Policy Innovation, Clean Energy Buyers Association (Washington, DC)

Energy customers, like corporates, government agencies, cities and universities, are becoming increasingly sophisticated and bidirectional in their interaction with the electricity grid (shifting loads, providing demand response, making consumption and siting decisions based on the grid profile) and they interested in driving greater emissions impact through their procurement and operational decisions. But these actions are hampered by lack of access to standardized, transparent and reliable grid and greenhouse gas emission data. One of the benefits of improving software for increased efficiency and reliability of the bulk power system is that it can help to collect, standardize and make available critical information to electricity customers, among others, including about emissions and delivered electricity profile. More granular, timely, and accurate grid and emissions data are needed. Electricity customers utilize data to perform carbon-optimized load shifting and accurately measure the decarbonization performance of renewable energy projects and help site those in the most impactful areas. Additionally, standardization across regions would make information more widely accessible and comparable. By improving software to increase market and planning efficiencies, it will improve critical datasets for a range of end-users seeking accessible, standardized, and accurate data from the grid.

Latent Distribution System Flexibility Offers Bulk Power System Opportunities

Mr. Philip Court, Product and Company Strategist, Ecogy Energy (Brooklyn, NY)

Mr. John Gorman, Asset Manager, Ecogy Energy (Brooklyn, NY)

Ms. Twiggy Hamilton, Policy Research Analyst, Ecogy Energy (Brooklyn, NY)

Mr. Joel Santisteban, Director of Platform, Ecogy Energy (Brooklyn, NY)

The bulk power system exists to serve distribution systems. But distribution systems are both consumers and service providers to the bulk power system. It is flexibility in these distribution systems which lets them behave as service providers. At a high level this presentation is all about unused technical capability and associated commercial desires in the distribution system and the opportunities that these could unlock if they are unleashed and then leveraged. At a lower level we will look at resources, either existing or proposed, that are not being fully leveraged. There is opportunity here to unleash flexibility that will be useful both within distribution systems and ultimately for the bulk power system. If we can expose this to date untapped flexibility and present it as a service to the bulk power system, we can use this service to deliver additional reliability and economic efficiencies. In this presentation we will define the nature of the opportunity, roughly quantify the size of it, explore what technology options can allow this to be achieved and finally what policy changes may be needed to accelerate this opportunity.

Session H2 (Thursday, June 23, 1:00 p.m., WebEx)

Using E3's RESERVE Machine Learning Model To Advance the Calculation of Subhourly Ancillary Services Needs in Deeply Renewable Grids

Mr. Arne Olson, Senior Partner, Energy and Environmental Economics, Inc. (San Francisco, CA)

Dr. John Stevens, Senior Managing Consultant, Energy and Environmental Economics, Inc. (San Francisco, CA)

Dr. Jimmy Nelson, Associate Director, Energy and Environmental Economics, Inc. (San Francisco, CA)

Dr. Yuchi Sun, Senior Consultant, Energy and Environmental Economics, Inc. (San Francisco, CA)

Accurately forecasting wind and solar power output poses challenges for deeply decarbonized electricity systems. Grid operators must commit resources to provide reserves to ensure reliable operations in the face of forecast errors, a process which can increase fuel consumption and emissions. To help address these issues, E3 worked with the California Independent System Operator (CAISO) under a grant from the ARPA–E PERFORM program to develop E3's open-source RESERVE machine learning model. This model expands the usefulness of median 15- and 5-minute market point forecast data currently used by the CAISO to execute the Western Energy Imbalance Market (EIM) by creating probabilistic distributions of short-term uncertainty in demand, wind, and solar forecasts that adapt to prevailing grid conditions. Machine learning-derived estimates of forecast errors are found to compare favorably to estimates based on incumbent methods. Reserves derived from machine learning are usually smaller than values derived using incumbent methods, which enables fuel savings during most hours. Machine learning reserves are generally larger than incumbent reserves during times of higher forecast error, potentially improving system reliability during extreme events. E3 tested RESERVE's performance using multi-stage production simulation modeling of the CAISO system. Machine learning reserves provide production cost and greenhouse gas (GHG) emission reductions of approximately 0.3% relative to historical 2019 requirements. Savings in the 2030 timeframe are highly dependent on battery storage capacity. At lower levels of battery capacity, savings of 0.4% from machine learning reserves are shown. Significant quantities of battery storage are expected to be added to meet

California's resource adequacy needs and GHG reduction targets. Addition of these batteries saturates reserve needs and results in minimal within-hour balancing costs in 2030.

Synergistic Integration of Machine Learning and Mathematical Optimization for Unit Commitment

Mr. Jianghua Wu, Ph.D. student, University of Connecticut (Storrs, CT)
Dr. Peter B. Luh, Professor, University of Connecticut (Storrs, CT)
Dr. Yonghong Chen, Senior Engineer, Midcontinent ISO (Carmel, IN)
Dr. Bing Yan, Assistant Professor, Rochester Institute of Technology (Rochester, NY)
Dr. Mikhail A. Bragin, Research Assistant Professor, University of Connecticut (Storrs, CT)

Unit Commitment (UC) is important for power system operations. With increasing challenges, *e.g.,* growing intermittent renewables and intra-hour net load variability, traditional mathematical optimization such as branch-and-cut (B&C) could be time-consuming. Machine learning (ML) is a promising alternative. Recently, multiple ''indirect'' ML methods for UC problems have been presented, *e.g.,* learning effective branching strategies for B&C or removing inactive transmission constraints. ''Direct'' methods have also been explored, *e.g.,* using graph neural networks and reinforcement learning. In view of the combinatorial nature of UC with an exponentially growing number of possible solutions, these ML methods have difficulties for large problems in terms of training data preparation and time required for training. To this end, synergistic integration of ML and mathematical optimization is explored by learning subproblems within our recent decomposition and coordination framework of Surrogate Lagrangian Relaxation (SLR) for deterministic UC problems. Compared to the original problem, a subproblem is much easier to learn, and it only requires solutions to be ''good enough'', *i.e.,* feasible to unit-level constraints and satisfying a convergence condition. Nevertheless, in view of many types of constraints, finding ''good enough'' subproblem solutions is still challenging. For simplicity, only system demand and unit initial statuses are assumed changing across days. The set of units, unit characteristics, and capacities of transmission lines are assumed constant across days. Under these simplifying assumptions, a deep neural network (DNN) of multilayer perceptron is adopted. For effective learning, dimensionality reduction is accomplished by aggregating Lagrangian multipliers and removing unnecessary variables. Moreover, an innovative specification of multiplier distributions is explored for effective training in the presence of binary decision variables. Furthermore, a loss function considering target values and constraint violations is designed for offline supervised training. After offline training, DNNs are used to help solve subproblems in daily operations. When facing patterns not yet learned, ML may not perform well, but graceful degradation of these cases is achievable by using B&C as a backup. Finally, to effectively exploit subproblem solutions available from daily operations, online self-learning is considered as supplementary learning. For ''positive'' cases which have good-enough solutions from DNNs as targets, the learning process is similar to that of offline learning. For ''negative'' cases which have no good-enough targets, a loss function that considers the satisfaction of SLR's convergence condition is innovatively developed, and this allows to obtain gradient to update DNN weights. Offline supervised learning and online self-learning are unified at the switching of the loss function. Since ML is used for the first time to learn subproblem solutions, the focus is to demonstrate the ability of ML to predict good-enough subproblem solutions, as opposed to demonstrating the ability of SLR+ML to solve large and practical UC problems. At this early stage, our goal is not for our method to outperform B&C in terms of solution quality or computation efficiency on low to medium-complexity problems. Nevertheless, we are confident that for very complex UC problems, *e.g.,* MISO's problem where B&C suffers from poor performance, the advantages of SLR will be apparent, and the speed advantage of applying ML for subproblem solving will be prominent. Although testing is limited to the IEEE 118-bus system, results demonstrate that ML speeds up the subproblem solving process of SLR while maintaining near-optimality of the overall solutions. This speedup can be improved through continual online self-learning. Our method thus opens a direction for integrating ML and mathematical optimization to solve large and complicated UC and beyond.

Congestion and Overload Mitigation Using Optimal Transmission Reconfigurations—Experience in MISO and SPP

Dr. Pablo A. Ruiz, CEO and CTO, NewGrid, Inc. (Somerville, MA)
Ms. Paola Caro, Principal Engineer, NewGrid, Inc. (Somerville, MA)
Mr. Mitchell Myhre, Manager—Transmission Planning and Regulatory Relations, Alliant Energy (Madison, WI)
Ms. Rodica Donaldson, Senior Director, Transmission Strategy & Analytics, EDF Renewables (San Diego, CA)
Mr. Xiaoguang Li, Director of Product, NewGrid, Inc. (Somerville, MA)

While the transmission grid configuration is continuously changing due to planned and unplanned outages, the transmission flexibility afforded by the existing circuit breakers is typically not used to purposely adapt the grid configuration to best meet changing system needs to mitigate overloads and congestion costs. At the same time, transmission needs are becoming more variable and are increasing rapidly to support the power system transition to integrate increasing levels of variable renewable resources. 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 increases the value of the existing transmission network as well as new transmission projects, from both reliability and market efficiency perspectives. This presentation will illustrate the flow relief, transfer capability and cost saving impacts of using reconfigurations to mitigate heavily congested constraints in MISO and SPP. A practical path for the adoption of topology optimization technology will be discussed.

Demonstration of Potential Data/Calculation Workflows Under FERC Order No. 881's Ambient-Adjusted Rating (AAR) Requirements

Ms. Lisa Sosna, Economist, Federal Energy Regulatory Commission (Washington, DC)
Mr. Tom Dautel, Deputy Director—Division of Economic and Technical Analysis, Federal Energy Regulatory Commission (Washington, DC)
Mr. Ken Fenton, Physical Scientist, Global Systems Laboratory, National Oceanic and Atmospheric Administration (Boulder, CO)

FERC Order No. 881, Managing Transmission Line Ratings, requires (among other things) that transmission providers use ambient-adjusted transmission line ratings (AARs) that are updated hourly to reflect ambient air temperature forecasts and the impact of solar heating during daytime periods. In this presentation, Commission staff will demonstrate one potential data/calculation workflow for implementing the AAR requirements of Order No. 881. In the demonstrated approach, NOAA weather forecasts from the National Blend of Models (NBM) and calculated daytime solar intensity are used to calculate AAR line ratings on the RTS–GMLC test system. Hourly ratings are inserted into a ratings database to comply with the data retention requirements of Order No. 881.

Session H3 (Thursday, June 23, 11:00 a.m., WebEx)

GO Competition Challenge 2: Analysis and Lessons Learned

Dr. Brent Eldridge, Electrical Engineer, Pacific Northwest National Laboratory (Baltimore, MD)
Dr. Stephen Elbert, Computational Scientist, Pacific Northwest National Laboratory (Richland, WA)
Dr. Arun Veeramany, Data Scientist, Pacific Northwest National Laboratory (Richland, WA)
Dr. Hans Mittelmann, Professor, Arizona State University (Tempe, AZ)
Dr. Jesse Holzer, Mathematician, Pacific Northwest National Laboratory (Richland, WA)

The Grid Optimization (GO) Competition Challenge 2 is nearly finished. This competition focused on a security constrained AC optimal power flow problem with fast start unit commitment, transmission switching, and a detailed post-contingency model. The Final Event trial finished in September 2021, and the Monarch of the Mountain ongoing trial will finish in October 2022. This talk reviews the results so far and presents some lessons learned regarding the impact of solver time limits, the value and computational difficulty of model features like transmission switching and flexible load, the challenges of working with confidential industry data, and other outcomes of the competition.

GO Competition Challenge 3: Goals and Formulation

Dr. Jesse Holzer, Mathematician, Pacific Northwest National Laboratory (Richland, WA)
Dr. Brent Eldridge, Electrical Engineer, Pacific Northwest National Laboratory (Baltimore, MD)
Dr. Stephen Elbert, Advisor, Pacific Northwest National Laboratory (Richland, WA)

The Grid Optimization (GO) Competition Challenge 3 has launched. This talk gives an overview of the model formulation and the questions we are aiming to address with it. The model includes multi-period unit commitment; AC bus/branch modeling; scheduling of energy and reserves; flexible loads; storage; and combined cycle generators. The model can be configured for use in an ISO/RTO context for applications of real-time (RT) look ahead, day ahead (DA) market clearing, and week ahead (WA) advisory. The model combines features that are considered in isolation in a sequence of models in current electricity industry practice, for example solving a DA unit commitment model with little regard for AC considerations, then solving an ACOPF with fixed commitments closer to RT. With this combined model and the solvers that competition entrants will develop, we want to ask and answer: Can the combined model be solved to high accuracy in a reasonable amount of time on practical instances? What are the incremental benefits to society of the combined solution, relative to the sequential approach? How will various industry trends, including increasing capacity of variable and uncertain generation resources, distributed energy resources, price sensitive load, and storage, affect the value of advanced computational tools for grid optimization?

Solving GO Competition ACOPF Problems

Dr. Daniel Bienstock, Professor, Columbia University (New York, NY)
Dr. Richard Waltz, Senior Scientist, Artelys, Inc. (Chicago, IL)

We describe the approach we deployed in the recent GO competition, in which we placed #2 overall. The GO competition addressed security-constrained Alternating Current Optimal Power Flow (ACOPF) problems in a modern formulation. This formulation included a number of integer variables used to model switching and transformer and shunt control. Many of the instances were quite large and involved many scenarios; additionally a strict time limit was involved. Our approach relied on the Knitro solver and deployed a number of domain-reduction techniques based on power engineering perspectives. We will describe our approach and document some of our experimental outcomes.

A Profit Maximizing Security-Constrained IV–AC Optimal Power Flow & Global Solution

Dr. Amro M. Farid, Visiting Associate Professor, Massachusetts Institute of Technology (Cambridge, MA)

Since its first formulation in 1962, the Alternating Current Optimal Power Flow (ACOPF) problem has been one of the most important optimization problems in electric power systems. Its most common interpretation is a minimization of generation costs subject to network flows, generator capacity constraints, line capacity constraints, and bus voltage constraints. The main theoretical barrier to its solution is that the ACOPF is a non-convex optimization problem that consequently falls into the as-yet-unsolved space of NP-hard problems. To overcome this challenge, the literature has offered numerous relaxations and approximations of the ACOPF that result in computationally suboptimal solutions with potentially degraded reliability. While the impact on reliability can be addressed with active control algorithms, energy regulators have estimated that the sub-optimality costs the United States ~$6–19B per year. Furthermore, and beyond its many applications to electric power system markets and operation, the sustainable energy transition necessitates renewed attention towards the ACOPF. This paper contributes a profit-maximizing security-constrained current-voltage AC optimal power flow (IV–ACOPF) model and globally optimal solution algorithm. More specifically, it features a convex separable objective function that reflects a two-sided electricity market. The constraints are also separable with the exception of a set of linear network flow constraints. Collectively, the constraints enforce generator capacities, thermal line flow limits, voltage magnitudes, power factor limits, and voltage stability. The optimization program is solved using a Newton-Raphson algorithm and numerically demonstrated on the data from a transient stability test case.

ABSCoRES, Managing Risk and Uncertainty on Electricity Systems Using Banking Scoring and Rating Methdologies

Dr. Alberto J. Lamadrid L., Associate Professor, Lehigh University (Bethlehem, PA)

In this presentation we will discuss the advancements done over the past year for a project funded by the Advanced Research Projects Agency-Energy, ARPA–E, under the PERFORM program. We are developing an Electric Assets Risk Bureau. Our framework allows to include asset and system risk management strategies into the current electricity system operations to improve economic efficiency, and include environmental considerations. Our approach is based on three main tenets: (1) We measure risk based on mathematical norms to calculate

Application of Banking Scoring and Rating for Coherent Risk Measures in Electric Systems (ABSCoRES) ratings and scores; (2) we developed novel data driven dispatch algorithms that integrate the ABSCoRES; (3) we establish a strategy for the application of the scores, and open the development of new products to mitigate incurred risks. We leverage scoring and ratings from banking and financial institutions alongside current optimization methods in dispatching power systems to help system operators and electricity markets schedule resources. Our approach is motivated by the observation that there are major differences between the power scheduled by a system operator and the actual power generated/consumed in real time. Moreover, the methodology can be used to develop scores that provide signals in high impact-low probability (HILP) events. Our framework counteracts two failures in existing electricity system: (i) Frictions in knowledge of assets (imperfect or asymmetric information regarding the risk they may induce in the system) and (ii) missing mechanisms (or markets) for products to mitigate risk incurred in the system. Generally having large differences from the expected operating conditions, sometimes augmented with unplanned contingencies, obeys to different reasons. We consider these reasons as potential risk sources. There are various sources, including: Increased participation of renewable energy generators and the associated integration schemes across balancing areas, different financial, environmental and risk preferences of power producers, consumers, and aggregators (*e.g.,* FERC Order Nos. 841 and 2222), loss of inertia, distributed energy resources, inter-dependencies with other systems and cybersecurity, and generally a more active demand side. Our proposed methodologies will improve economic efficiency of assets in the electricity system while recognizing limitations in assessing the distribution of information uncertainties affecting agents participating in these systems. A particularly attractive feature of our approach is its connection to economic theory of decision making under uncertainty. The trading of contingent claims in different states of the world in an Arrow-Debreu Economy with complete markets allows for full insurance coverage leading to a competitive equilibrium output. While this is a theoretical benchmark, the score calculation reduces the information asymmetries and can provide a way to better coordinate different agents and stakeholders.

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EXECUTIVE OFFICE OF THE PRESIDENT

Request for Information to Make Access to the Innovation Ecosystem More Inclusive and Equitable

AGENCY: White House Office of Science and Technology Policy (OSTP).

ACTION: Notice of Request for Information (RFI).

SUMMARY: The White House Office of Science and Technology Policy (OSTP), on behalf of the National Science and Technology Council (NSTC) Lab-to-Market (L2M) Subcommittee, seeks information to improve inclusive and equitable access to Federal programs and resources by broadly engaging stakeholders in the U.S. innovation ecosystem. The public input provided in response to this RFI will inform OSTP and NSTC on work with Federal agencies and other stakeholders to improve existing programs and/or develop new programs to improve inclusive and equitable access in the Federally-funded research and development-driven sector.

DATES: Interested persons and organizations are invited to submit responses on or before 5:00 p.m. ET on July 5, 2022.

ADDRESSES: Responses should be submitted electronically to *LabtoMarketRFI@ostp.eop.gov* and include ''L2M RFI Response'' in the subject line of the email. Due to time constraints, mailed paper submissions will not be accepted, and electronic submissions received after the deadline cannot be ensured to be incorporated or taken into consideration.

Instructions: Response to this RFI is voluntary. Each responding entity (individual or organization) is requested to submit only one response. Respondents need not reply to all questions listed. Responses must not exceed 6 pages in 12 point or larger font, with a page number provided on each page. Responses should include the name of the person(s) or organization(s) filing the comment, as well as the respondent type (*e.g.,* academic institution, advocacy group, professional society, community-based organization, industry, trainee/student, member of the public, government, other). Respondent's role in the organization may also be provided (*e.g.,* researcher, faculty, student, administrator, program manager, journalist) on a voluntary basis. Comments containing references, studies, research, and other empirical data that are not widely published should include copies or electronic links of the referenced materials. Please be aware that comments submitted in response to this RFI, including the submitter's identification (as noted above), may be posted on OSTP's website or otherwise released publicly. OSTP, therefore, requests that no business proprietary information, copyrighted information, or personally identifiable information be submitted in response to this RFI.

In accordance with FAR 15.202(3), responses to this notice are not offers and cannot be accepted by the Federal Government to form a binding contract. Additionally, those submitting responses are solely responsible for all expenses associated with response preparation.

FOR FURTHER INFORMATION CONTACT: For additional information, please direct questions to Kylie Gaskins at *LabtoMarketRFI@ostp.eop.gov* or 202–456–4444.

SUPPLEMENTARY INFORMATION: Our nation's people are rich with diverse experiences. However, there is tremendous untapped science, technology, engineering, and mathematics (STEM) innovative potential throughout the nation. Demographic and socioeconomic groups in every geographic region of the country are full of talent that should have access to Federal programs and resources that afford them opportunities to contribute to the nation's innovation enterprise. There is ample evidence that our nation's potential in the arenas of innovation and entrepreneurship can be enhanced by engagement with the untapped talent of people who belong to groups that have historically been and are currently underrepresented.

Through this RFI, the L2M Subcommittee seeks input from the public to identify and better understand: (1) Barriers that prevent innovators from underrepresented groups or underserved communities from participating in the innovation ecosystem; (2) Recommendations of methods to include and meet the specific needs of innovators from underrepresented backgrounds and communities to increase their participation in the innovation ecosystem; and (3) Examples of government programs or initiatives which have seen success in supporting