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

Agenda

AD10-12-007
June 27 – 29, 2016

Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software (Docket No. AD10-12-006)
Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC
Draft Agenda (Abstracts Attached Below)

Monday, June 27, 2016

8:45 AM	Introduction (Meeting Room 3M-2) **Richard O'Neill**, Federal Energy Regulatory Commission (*Washington, DC*)
9:00 AM	Session M1 (Meeting Room 3M-2) **SPP Market and Software Overview** Sam Ellis, Southwest Power Pool (*Little Rock, AR*) **Improving Market Efficiency Through Modeling Improvement** Hong Chen, PJM Interconnection (*Audubon, PA*) **Improving Market Clearing Software Performance to Meet Existing and Future Challenges – MISO's Perspective** Yonghong Chen, Jeff Bladen, Alan Hoyt, David Savagea, Robert Marring, Midcontinent Independent System Operator (*Carmel, IN*)
10:30 AM	Break
10:45 AM	Session M2 (Meeting Room 3M-2) **Use of Online Cascading Analysis for Reducing the Risk of Blackouts** Slava Maslennikov, Xiaochuan Luo, Eugene Litvinov, ISO New England (*Holyoke, MA*) **NYISO Comprehensive Scarcity Pricing** Ethan Avallone, Thomas Golden, Michael DeSocio, Robert Pike, New York Independent System Operator (*Rensselaer, NY*) Hedayatollah Etemadi, Peng Peng, Khosrow Moslehi, ABB (*Santa Clara, CA*) **Scarcity Pricing in ERCOT's Real-Time Market** Resmi Surendran, Hailong Hui, Electric Reliability Council of Texas (*Taylor, TX*) William W. Hogan, Harvard University (*Cambridge, MA*) Chien-Ning Yu, ABB Inc. (*San Jose, CA*)
12:15 PM	Lunch
1:30 PM	Session M3 (Meeting Room 3M-2) **Ramp Capability Modeling in MISO Dispatch and Pricing** Congcong Wang, Dhiman Chatterjee, Rober Merring, Juan Li, Sen Li, Midcontinent Independent System Operator (*Carmel, IN*) **Proposal for Integrating DER into ERCOT (ISO) Operations - Addressing Reliability and Wholesale Market Impacts** Sainath Moorty, Oladiran Obadina, Electric Reliability Council of Texas (*Taylor, TX*) Khosrow Moslehi, ABB (*Santa Clara, CA*) **Demand Curves in Forward Capacity Market** Feng Zhao, ISO New England (*Holyoke, MA*)
3:00 PM	Break
3:15 PM	Session M4 (Meeting Room 3M-2) **Economic Selection and Dispatch of Spinning Reserves** Akshay Korad, Jeff Bladen, Dhiman Chatterjee, Oluwaseyi Akinbode, Midcontinent Independent System Operator (*Carmel, IN*) **NYISO Hybrid GT Pricing** Guangyuan Zhang, New York Independent System Operator (*Rensselaer, NY*) **Limited Fuel Resource Optimization** Cuong Nguyen, New York Independent System Operator (*Rensselaer, NY*) **Optimal Flow Control Resource Dispatch** Beibei Li, Midcontinent Independent System Operator (*Carmel, IN*)
5:15 PM	Adjourn

Tuesday, June 28, 2016

8:45 AM	Arrive and welcome (Meeting Room 3M-2)
9:00 AM	Session T1 (Meeting Room 3M-2) **Optimal Power Flow Competition Design Considerations** Timothy Heidel, ARPA-E, U.S. Department of Energy (*Washington, DC*) Feng Pan, Stephen Elbert, Pacific Northwest National Laboratory (*Richland, WA*) Chris DeMarco, University of Wisconsin - Madison (*Madison, WI*) Hans Mittlemann, Arizona State University (*Tempe, AZ*) **Data Repository for Power System Open Models With Evolving Resources (DR POWER)** Stephen Elbert, Pacific Northwest National Laboratory (*Richland, WA*) **From Deterministic Economic Dispatch to Secure Stochastic Unit-Commitment/Optimal Power Flow with MOST, the New MATPOWER Optimal Scheduling Tool** Ray Zimmerman, Daniel Muñoz-Álvarez, Cornell University (*Ithaca, NY*) Carlos E. Murillo-Sánchez, Universidad Nacional de Colombia (*Manizales, Colombia*) Alberto J. Lamadrid, Lehigh University (*Bethlehem, PA*)
10:30 AM	Break
10:45 AM	Session T2-A (Meeting Room 3M-2) **A Strong Semidefinite Programming Relaxation of the Unit Commitment Problem** Javad Lavaei, Alper Atamturk, Morteza Ashraphijuo, University of California, Berkeley (*Berkeley, CA*) **Visualizing the Feasible Spaces of Challenging OPF Problems** Daniel Molzahn, Argonne National Laboratory (*Lemont, IL*) **Power System State Estimation with a Limited Number of Measurements** Javad Lavaei, Ramtin Madani, Morteza Ashraphijuo, University of California, Berkeley (*Berkeley, CA*) Ross Baldick, University of Texas-Austin (*Austin, Texas*)
	Session T2-B (Meeting Room 3M-4) **Intra-day Co-optimization of the Natural Gas and Electric Networks: The GECO Project** Aleksandr Rudkevich, Newton Energy Group (*Boston, MA*) Scott Backhous, Anatoly Zlotnik, Los Alamos National Laboratory (*Los Alamos, NM*) **Hidden Power System Inflexibilities Imposed by Traditional Unit Commitment Formulations** Germán Morales-España, Delft University of Technology (*Delft, Holland*) Benjamin F. Hobbs, Johns Hopkins University (*Baltimore, MD*) **Power-Capacity and Ramp-Capability Reserves for Wind Integration in Power-Based Unit Commitment** Germán Morales-España, Delft University of Technology (*Delft, Holland*) Ross Baldick, University of Texas (*Austin, TX*) Javier García González, Andres Ramos, Universidad Pontificia Comillas (*Madrid, Spain*)

Tuesday, June 28, 2016

12:15 PM	Lunch
1:30 PM	Session T3-A (Meeting Room 3M-2) **Robust Risk-Constrained Unit Commitment with Large-scale Wind Generation: An Adjustable Uncertainty Set Approach** Feng Qiu, Cheng Wang, Jianhui Wang, Argonne National Laboratory (*Lemont, IL*) **Generating Cuts from the Ramping Polytope for the Unit Commitment Problem** James Ostrowski, Bernard Knueven, University of Tennessee (*Knoxville, TN*) Jianhui Wang, Argonne National Laboratory (*Argonne, IL*) **Strengthened MILP Formulation for the Edge-based Combined-Cycle Unit Model** Yongpei Guan, Kai Pan, University of Florida (*Gainesville, FL*) Yonghong Chen, Midcontinent Independent System Operator (*Carmel, IN*) Xing Wang, Alstom (*Redmond, WA*) Lei Fan, GE (*Schenectady, NY*)
	Session T3-B (Meeting Room 3M-4) **Incentive Compatible Pricing Mechanisms For Meeting Expected Ramp Capability In Real-Time Markets** Erik Ela, EPRI (*Palo Alto, CA*) Mark O'Malley, University College Dublin (*Dublin, Ireland*) **Dual Pricing Algorithm for Cost Allocation in Non-Convex Electricity Markets** Robin Broder Hytowitz, Johns Hopkins University/Federal Energy Regulatory Commission (*Washington, DC*) Richard O'Neill, Brent Eldridge, Federal Energy Regulatory Commission (*Washington, DC*) Anya Castillo, Sandia National Laboratories (*Albuquerque, NM*) **Modelling and Solving Security Constrained Optimal Power Flow in Parallel** Cosmin Petra, Mihai Anitescu, Argonne National Laboratory (*Lemont, IL*)
3:00 PM	Break
3:15 PM	Session T4-A (Meeting Room 3M-2) **Comparing the Performance of Explicitly Vs. Implicitly Scheduled Operating Reserve** Erik Ela, Eamonn Lannoye, Robert Entriken, Aidan Tuohy, EPRI (*Palo Alto, CA*) **Locational Resource Adequacy Assessment - Methodology and Case Study of the ISO New England System** Evgeniy Goldis, Alex Rudkevich, Alex Beylin, Newton Energy Group (*Boston, MA*) Russ Philbrick, Polaris Systems Optimization (*Seattle, WA*) Andrei Kharchenko, FOM Instituut voor Atoom- en Molecuulfysica (AMOLF) (*Amsterdam, The Netherlands*) **Europe: Benefits of Integrating Regions and Energies to the Security of Supply** Guillaume Tarel, Artelys (*Montreal, Quebec*)
	Session T4-B (Meeting Room 3M-4) **Dynamic Thermal Ratings in Real-Time Dispatch Market Systems** Kwok Cheung, Jun Wu, GE (*Redmond, WA*) **Transmission Topology Optimization Impacts in Day-Ahead Markets - Simulations in PJM** Pablo Ruiz, Xiao Li, NewGrid, Inc (*Somerville, MA*) Michael Caramanis, Boston University (*Boston, MA*) John Goldis, Aleksandr Rudkevich, Newton Energy Group (*Boston, MA*) T. Bruce Tsuchida, The Brattle Group (*Cambridge, MA*) Keyurbhai Patel, PJM Interconnection (*Audubon, PA*) C. Russell Philbrick, Polaris Systems Optimization (*Shoreline, WA*) **Using the National Energy with Weather System (NEWS) Simulator to Highlight and Address Upcoming Changes to the Electric Power System** Christopher Clack, Melinda Marquis, National Oceanic and Atmospheric Administration (*Boulder, CO*)
4:45 PM	Adjourn

Wednesday, June 29, 2016

8:45 AM	Arrive and welcome (Meeting Room 3M-2)
9:00 AM	Session W1-A (Meeting Room 3M-2) **Modeling and Solving Battery Operation Problems** Daniel Bienstock, Shuoguang Yang, Columbia University (*New York, NY*) Carsten Matke, Next Energy (*Oldenburg, Germany*) **Profitability of Merchant Investments in Battery Energy Storage** Daniel Kirschen, Yury Dvorkin, Ricardo Fernandez-Blanco, University of Washington (*Seattle, WA*) Hrvoje Pandzic, University of Zagreb (*Zagreb, Croatia*) Jean-Paul Watson, Cesar Silva-Monroy, Sandia National Laboratories (*Albuquerque, NM*) **Risk-Constrained Look-Ahead Strategic Energy Storage Bidding** Yishen Wang, Daniel Kirschen, Yury Dvorkin, Ricardo Fernández-Blanco, University of Washington (*Seattle, WA*)
	Session W1-B (Meeting Room 3M-4) **A Bundle Method for On-Line Transient Security Constrained Dispatch** Mihai Anitescu, Argonne National Laboratory (*Argonne, IL*) **Development of Fast Real-time Online Dynamic Security Assessment System** Mike Zhou, State Grid EPRI China (*Northville, MI*) XueWei Shang, Lin Zhao, Nari Beijing KeDong Com (*Beijing, China*) JianFeng Yang, DongYu Shi, EPRI China (*Beijing, China*) Ying Chen, Tsinghua University (*Bejing, China*) **Fast and Accurate Calculation of Dynamics Sensitivities Using a Discrete-Adjoint Approach** Emil Constantinescu, Abhyankar, Shrirang G., Mihai Anitescu, Hong Zhang, Cosmin Petra, Argonne National Laboratory (*Argonne, IL*)
10:30 AM	Break
10:45 AM	Session W2-A (Meeting Room 3M-2) **A Multiscale Optimization Framework for Economic Assessment of Emerging Market Participants** Alexander Dowling, Victor Zavala, University of Wisconsin-Madison (*Madison, WI*) **Optimal Participation of an Electric Vehicle Aggregator in Day-Ahead Energy and Reserve Markets** Miguel Ortega-Vazquez, Yury Dvorkin, Mushfiqur Sarker, University of Washington (*Seattle, WA*) **Coupling Pumped Hydro Energy Storage with Unit Commitment** Daniel Kirschen, Yury Dvorkin, University of Washington (*Seattle, WA*) Kenneth Bruninx, Erik Delarue, William Dhaeseleer, KU Leuven (*Leuven, Belgium*) Hrvoje Pandzic, University of Zagreb (*Zagreb, Croatia*)
	Session W2-B (Meeting Room 3M-4) **Towards Continuous-time Optimization Models for Power Systems Operation** Masood Parvania, University of Utah (*Salt Lake City, UT*) **Market Provision of Flexible Energy/Reserve Contracts** Wanning Li, Leigh Tesfatsion, Iowa State University (*Ames, IA*) **Towards a Price-Based Optimization Formulation in RTO Markets** Shangyou Hao, PA Consulting (*Walnut, CA*)
12:15 PM	Adjourn

Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software

Abstracts

Monday, June 27

Session M1 (Monday, June 27, 8:45 AM, Meeting Room 3M-2)

INTRODUCTION

Dr. Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, District of Columbia*)

MARKET EFFICIENCY CHALLENGES AND OPPORTUNITIES IN SPP

Mr. Sam Ellis, Director, System Operations, Southwest Power Pool (*Little Rock, AR*)

The presentation will consist of an overview of challenges and opportunities encountered by SPP with an evaluation of planned and potential software enhancements supporting increased efficiency in SPP's Integrated Marketplace. The presentation will touch on areas including price formation, potential improvements in constraint management, reducing solution times, and an evaluation of operational efficiency with reduced operating reserves.

IMPROVING MARKET EFFICIENCY THROUGH MODELING IMPROVEMENT

Dr. Hong Chen, Senior Consultant, PJM Interconnection (*Audubon, PA*)

ISO/RTO markets are implemented with the help of various market softwares. Therefore, market modeling has key impact to market efficiency. This presentation will review and discuss current modeling practices, as well as challenges and future improvement. Modeling accuracy, consistency among different softwares, approximation, as well as complexity will be covered in the presentation, especially in terms of their market impact.

IMPROVING MARKET CLEARING SOFTWARE PERFORMANCE TO MEET EXISTING AND FUTURE CHALLENGES – MISO'S PERSPECTIVE

Dr. Yonghong Chen, Principal Advisor, Market Services, MISO (*Carmel, IN*)
Mr. Jeff Bladen, Executive Director, Market Services, MISO (*Carmel, IN*)
Mr. Alan Hoyt, Director, IT Strategy and Infrastructure, MISO (*Carmel, IN*)
Mr. David Savagea, Manager, Day Ahead Market Administration, MISO (*Carmel, IN*)
Mr. Robert Marring, Manager, Market Engineering, MISO (*Carmel, IN*)

This presentation introduces MISO's short term and long term initiatives to improve market clearing software performance. It includes the on-going effort and progress to reduce DA solving time for FERC Order 809 compliance; the next step to collaborate with vendors to develop parallel computing friendly SCUC platform; and the ARPA-

E project with PNNL, GE and Gurobi to develop high performance computing based next generation optimization algorithm.

Session M2 (Monday, June 27, 10:45 AM, Meeting Room 3M-2)

USE OF ONLINE CASCADING ANALYSIS FOR REDUCING THE RISK OF BLACKOUTS

Dr. Slava Maslennikov, Principal Analyst, ISO New England (*Holyoke, MA*)
Dr. Xiaochuan Luo, Technical Manager, ISO New England (*Holyoke, MA*)
Dr. Eugene Litvinov, Chief Technology Officer, ISO New England (*Holyoke, MA*)

Traditional Security Constrained Economic Dispatch based on N-1 security criteria cannot help in preventing uncontrolled cascading outages in a fast developing situation. Complex contingencies beyond N-1, such as stuck breaker or two or more contingencies happening within a few minutes, can trigger a slowly developing cascade into the fast and uncontrolled phase. The online ability to identify and mitigate such critical contingencies causing cascading failures is the most practical way to reduce the risk of blackouts at a marginal increase of production cost.

ISO New England is developing an online cascading analysis process targeting to identify and mitigate the critical contingencies beyond N-1 which can trigger the fast developing uncontrolled outages. Online cascading analysis could also be used to improve the Inter Regional Operational Limit (IROL) compliance. The presentation dicusses the methodology, software and experience of using the cascading analysis online.

NYISO COMPREHENSIVE SCARCITY PRICING

Mr. Ethan Avallone, Energy Market Design Specialist, NYISO (*Rensselaer, NY*)
Mr. Hedayatollah Etemadi, Software Engineer, ABB (*Santa Clara, CA*)
Mr. Peng Peng, Manager, Market Applications, ABB (*Santa Clara, CA*)
Dr. Khosrow Moslehi, Director, Product Management, ABB (*Santa Clara, CA*)
Mr. Thomas Golden, Manager, Energy Market Design, NYISO (*Rensselaer, NY*)
Mr. Michael DeSocio, Senior Manager, Market Design, NYISO (*Rensselaer, NY*)
Mr. Robert Pike, Director, Market Design & Product Mgmt., NYISO (*Rensselaer, NY*)

As part of the Comprehensive Scarcity Pricing initiative, the NYISO is changing its scarcity pricing mechanism by removing the current ex post logic in favor of a real-time optimization methodology, which will improve consistency between resource schedules and pricing outcomes. This enhancement also reflects the impact of scarcity pricing at the interchange Proxy Generator Buses, which will more appropriately value import/export transactions during Demand Response (DR) activations.

DR resources are called upon to reduce load in real-time when a shortage of reserve is anticipated by the NYISO. Comprehensive Scarcity Pricing entails increasing the 30-minute reserve requirement in DR activation areas. Additionally, existing reserve demand curves are modified, or new reserve demand curves created, to price the increased reserve requirement. Software changes to effectuate this market design enabled normally static reserve requirements and reserve demand curves to change throughout DR activations. Including a Scarcity Reserve Requirement and a Scarcity Reserve Demand curve within the optimization drives more efficient pricing outcomes during reliability DR activations.

SCARCITY PRICING IN ERCOT REAL-TIME MARKET

Ms. Resmi Surendran, Senior Manager, ERCOT (*Taylor, TX*)
Dr. William W. Hogan, Professor, Harvard University (*Cambridge, MA*)
Dr. Hailong Hui, Supervisor, ERCOT (*Taylor, TX*)
Dr. Chien-Ning Yu, Senior Consulting Engineer, ABB Inc. (*San Jose, California*)

Appropriate shortage pricing is crucial for the success of not just energy-only market but also for energy markets that have associated capacity markets. This is especially critical for ERCOT's energy only market with high retail competition and negative prices nearly 5% of the time from nearly 50% penetration of wind. This presentation discusses ERCOT's recent efforts on improving shortage pricing in the Real-Time market to provide appropriate incentives and align prices with reliability needs.

First, in 2014, ERCOT enabled Load Resources to participate in the Real-Time market. This provides loads the opportunity to set prices reflecting its wiliness to consume energy.

Second, to send out price signals that reflect the scarcity of reserves in price signals, ERCOT implemented the Operating Reserve Demand Curve (ORDC) based on the Value of Lost Load (VOLL) and the Lost of Load Probability (LOLP) at the remaining reserves in the system. The LOLP parameters are determined using historical Real-Time market data.

In 2015, a reliability deployment price adder was included in Real-Time LMP to offset the effect of out-of-market deployments like Emergency Response, RMR, RUC Commitments and Load Resource ancillary service deployments that may inappropriately reduce market prices in times of scarcity.

Recent market data have shown that the above enhancements have provided better Real-Time pricing signals and improved overall operational reserves in ERCOT market.

<u>Session M3 (Monday, June 27, 1:30 PM, Meeting Room 3M-2)</u>

RAMP CAPABILITY MODELING IN MISO DISPATCH AND PRICING

Dr. Congcong Wang, Senior Engineer Market Design, MISO (*Carmel, IN*)
Dr. Dhiman Chatterjee, Director Market Evaluation & Design, MISO (*Carmel, IN*)
Mr. Rober Merring, Sr. Manager Market Engineering, MISO (*Carmel, IN*)
Dr. Juan Li, Senior Advisor Market Engineering, MISO (*Carmel, IN*)
Ms. Sen Li, Principle Engineer Market Engineering, MISO (*Carmel, IN*)

This presentation highlights MISO's recent development of Ramp Capability Product to manage system ramping needs arising from net load variations and uncertainties.

A brief review of the product design and how it improves dispatch that effectively manages variations and uncertainties will first be provided. The improvement of price formation and the economic incentive for resources to provide their flexibility will then be elaborated by aligning the reliability requirement with market requirement. With the new product in place, the challenge of post-implementation analysis given system dynamics will be discussed and MISO's experiences will be shared, including its development of value metrics and performance measurements by leveraging available software.

PROPOSAL FOR INTEGRATING DER INTO ERCOT (ISO) OPERATIONS - ADDRESSING RELIABILITY AND WHOLESALE MARKET IMPACTS

Mr. Sainath Moorty, Principal, Market Design and Development, ERCOT (*Taylor, TX*)
Oladiran Obadina, Principal, Systems Development, ERCOT (*Taylor, TX*)
Khosrow Moslehi, ABB (*Santa Clara, CA*)

This presentation provides an overview of the current status of the analysis ERCOT has undertaken to identify ISO software system changes and market changes that may be required with significant penetration of Distributed Energy Resources (DERs). DER penetration in the ERCOT footprint is increasing, and global trends point to an acceleration of adoption rates, despite the low energy prices in ERCOT due to low Natural Gas prices. To address the reliability and wholesale market implications of increased DER penetration, ERCOT and its stakeholders are currently analyzing potential reliability impacts and the need for wholesale market rule changes. ERCOT in 2015 published a concept paper on integrating DERs into the wholesale markets, envisioning direct participation by some DERs in the wholesale markets for energy and ancillary services. This is a different approach from that being considered by some regions, where DER participation may require an intermediate entity such as a Distribution System Operator or a Distribution System Platform based market. In addition, ERCOT's proposed approach does not model the distribution network down to the DERs, rather would "map" DERs to the applicable modeled transmission load typically representing the step down transformer from the modeled transmission network down to the distribution voltage level. At significant levels of DER penetration, various ISO system software changes will be required to address reliability impacts.

DEMAND CURVES IN FORWARD CAPACITY MARKET

Dr. Feng Zhao, Lead Analyst/Engineer, ISO New England (*Holyoke, MA*)

ISO-NE runs a multi-zone Forward Capacity Market (FCM) to maintain system reliability and address the missing-money issue. Installed capacity requirement or Capacity demand in FCM is determined by the ISO to meet the Loss of Load Expectation (LOLE) criterion of 1 day in 10 years. Under the fixed capacity demand, an administrative cap price applies when the market clears less than the demand, and a floor price applies when the market clears more than the demand. Such price volatility introduces significant risk for investment decisions. To alleviate the problem, FERC has asked the ISO to consider demand curves in its FCM. In the absence of demand bids for capacity, the challenge is to design meaningful demand curves that align with economic fundamentals and reliability theory. Our approach is to first calculate the Marginal Reliability Impact (MRI) of different capacity levels using GE's Multi-Area Reliability Simulation (MARS) tool. Due to the interdependency of one capacity zone's MRI on the capacity levels of other zones, approximation is used to obtain individual MRI curves for capacity zones. The MRI curves are then scaled to become demand curves with the scaling factor estimated based on long-term market equilibrium. Our approach has been tested with the previous FCM data and obtained good results.

Session M4 (Monday, June 27, 3:15 PM, Meeting Room 3M-2)

ECONOMIC SELECTION AND DISPATCH OF SPINNING RESERVES

Dr. Akshay Korad, Engineer, Market Services, MISO (*Carmel, IN*)
Mr. Jeff Bladen, Executive Director, Market Services, MISO (*Carmel, IN*)
Dr. Dhiman Chatterjee, Director, Market Services, MISO (*Carmel, IN*)
Mr. Oluwaseyi Akinbode, Engineer, Market Services, MISO (*Carmel, IN*)

In MISO's day-ahead and real time Energy and Operating Reserve market, spinning reserves are cleared solely based on resources' spinning reserve offers. When resources are deployed for providing spinning reserve and if the associated revenue is not sufficient to recoup energy offers, in that case, resources are compensated with a make-whole payment. The objective of the proposed market enhancement is to minimize (or eliminate) this make-whole payment by improving spinning reserve selection process and/or enhancing spinning reserve deployment logic. As per the MISO IMM, the estimated value creation with this market enhancement is about $1 million per year.

NYISO HYBRID GT PRICING

Mr. Guangyuan Zhang, Market Engineer, New York Independent System Operator (*Rensselaer, NY*)

The hybrid Gas Turbine (GT) logic is designed to compromise the need for blocked GT to set price and its physical characteristic. In this presentation, we will present the NYISO's hybrid GT pricing implementation and the effort to improve it. The NYISO hybrid GT pricing comprises of 2 economic dispatch steps: hybrid pass and pricing pass. The hybrid pass is to identify the eligibility of the blocked GT to set the price in the subsequent pricing pass and the pricing pass calculates the Locational Based Marginal Price (LBMP) and reserve price. The comparison between the model with and without hybrid GT will be presented. Some potential improvements to the current pricing will also be presented.

LIMITED FUEL RESOURCE OPTIMIZATION

Dr. Cuong Nguyen, Senior Engineer - Technology Development, New York Independent System Operator (*Rensselaer, NY*)

The Polar Vortex events of winter 2013/14 revealed some market efficiency problems when resources with limited fuel can only manage their fuel supply with the standard bidding and optimization processes available in the markets today. Limited-fuel resources may include pumped storage hydro, oil-fired generators, and gas-fired generators on critical winter days.

In the NYISO's day-ahead market, resources with limited fuel supply must make a prediction as to when best to utilize their limited fuel so as to maximize their expected revenues, and then reflect their fuel constraint in hourly offers. As a result, limited-fuel resources may not be fully utilized during the times of highest value to the system and Security Constraint Unit Commitment (SCUC) may not be able to produce the most efficient solution over the day.

As part of its Fuel Assurance Initiative, the NYISO conducted a study to develop day-ahead market design concepts and prototyped algorithms that would allow resources to explicitly reflect their fuel limitations in their day-ahead offers so as to allow the SCUC to better optimize over the 24-hour scheduling horizon. Two options for offering fuel-limited resources in the day-ahead market will be discussed in details and case studies will be presented to showcase market efficiency gains:

1. Total Energy Curve where the constraint is energy output (MWh);
2. Fuel Cost and Efficiency Curve where the constraint is fuel input (e.g. MMBtu or cubic feet of water).

OPTIMAL FLOW CONTROL RESOURCE DISPATCH

Ms. Beibei Li, Advisor, MISO (*Carmel, IN*)

There are two DC transmission lines operated within the MISO market footprint to transfer bulk energy from generating stations located in North Dakota to load centers located in Minnesota. Because the flow on DC lines is scheduled rather than a function of conditions on the power system, MISO has elected to allow market participants to offer energy generated at the generating stations into the day-ahead market at the DC terminal substations via pseudo generators. The pseudo generator limits are reflections of DC line properties rather than physical generator properties, and thus adding to the problem of DA committing different physical capacity than what is actually available. This presentation is primarily designed to address MISO's effort to improve the DC line dispatch in real-time based on real-time price signal at the DC terminal substation.

Tuesday, June 28

Session T1 (Tuesday, June 28, 9:00 AM, Meeting Room 3M-2)

OPTIMAL POWER FLOW COMPETITION DESIGN CONSIDERATIONS

Dr. Timothy Heidel, Program Director, ARPA-E, U. S. Department of Energy (*Washington, DC*)
Dr. Feng Pan, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Stephen Elbert, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Chris DeMarco, Professor, University of Wisconsin - Madison (*Madison, WI*)
Dr. Hans Mittlemann, Professor, Arizona State University (*Tempe, AZ*)

ARPA-E, in collaboration with Pacific Northwest National Laboratory, University of Wisconsin-Madison and Arizona State University, is designing a formal competition to test and compare new and emerging Optimal Power Flow (OPF) and other grid optimization algorithms. We believe a competition could substantially reduce the barriers to the testing and adoption of new strategies for grid optimization and control, enabling increased grid flexibility, reliability, and efficiency. Fair, transparent, and inclusive competitions are particularly difficult to design well. In this talk we will present a detailed "straw-man" proposal for the initial competition design. We will describe and solicit feedback on the baseline problem specifications, competition rules, eligibility for participation, scoring metrics, criteria for winning, prize structure options, and the on-line competition computational platform design details. The goal is to have an open competition with an open formulation (the competitors will formulate their own solution to a clearly stated problem) and open, industry relevant data sets. The selected optimization problem should have industry relevance, a reasonable learning curve for general participants, specific and broad impact on applications.

DATA REPOSITORY FOR POWER SYSTEM OPEN MODELS WITH EVOLVING RESOURCES (DR POWER)

Dr. Mark Rice, Principal Investigator, Pacific Northwest National Laboratory (*Richland, WA*)

The ARPA-E GRID DATA program is creating two repositories for the open data sets generated by the five teams producing the models and data. DR POWER is building a repository that will collaboratively evolve high-fidelity power system models by providing open-access to the data sets and the capability to uniquely review, annotate, and verify submitted data sets; ensure sustainable model and data set dissemination and evolution through user-defined data set creation and validation tools; and integrate and extend NRECA's success with Open Modeling Framework (OMF) to include transmission modeling. A web portal will provide open-access to the repository tools for data set generation, modification, versioning, citation, review, annotation, documentation, verification, curation, access statistics, discovery, and visualization. Digital Object Identifiers (DOIs) will be assigned to data sets to facilitate citations. Data sets will be available in their native formats as well as others through conversion tools developed by the authors and the repository. An active curation plan, based on the Digital Curation Center Lifecycle Model, will engage community participation in reviewing models and data sets and also develop taxonomy and ontology documents and procedures to facilitate feature discovery. User validation and feedback will be continually solicited to develop a sustainable organization that will have a strategic impact on the entire power grid community.

FROM DETERMINISTIC ECONOMIC DISPATCH TO SECURE STOCHASTIC UNIT-COMMITMENT/OPTIMAL POWER FLOW WITH MOST, THE NEW MATPOWER OPTIMAL SCHEDULING TOOL

Dr. Ray Zimmerman, Senior Research Associate, Cornell University (*Ithaca, NY*)
Dr. Carlos E. Murillo-Sánchez, Professor, Universidad Nacional de Colombia (*Manizales, Colombia*)
Mr. Daniel Muñoz-Álvarez, Graduate student, Cornell University (*Ithaca, NY*)
Dr. Alberto J. Lamadrid, Assistant Professor, Lehigh University (*Bethlehem, PA*)

MATPOWER, the popular open-source power system toolbox, now includes a new generalized optimization and scheduling framework called the MATPOWER Optimal Scheduling Tool, or MOST for short. It can handle problems as simple as a deterministic, single-period economic dispatch problem, or as complex as a secure, stochastic combined unit-commitment and multiperiod optimal power flow with storage and deferrable demand.

This talk will describe the formulation used and give some illustrative examples of the use of this new free open-source tool.

Session T2-A (Tuesday, June 28, 10:45 AM, Meeting Room 3M-2)

A STRONG SEMIDEFINITE PROGRAMMING RELAXATION OF THE UNIT COMMITMENT PROBLEM

Dr. Javad Lavaei, Assistant Professor, University of California, Berkeley (*Berkeley, CA*)
Dr. Alper Atamturk, Professor, University of California, Berkeley (*Berkeley, CA*)
Mr. Morteza Ashraphijuo, Ph.D. student, University of California, Berkeley (*Berkeley, CA*)

The unit commitment (UC) problem aims to find an optimal schedule of generating units subject to the demand and operating constraints for an electricity grid. The majority of existing algorithms for the UC problem rely on solving a series of convex relaxations by means of branch-and-bound or cutting planning methods. In this paper, we develop a strengthened semidefinite program (SDP). This approach is based on first deriving certain valid quadratic constraints and then relaxing them to linear matrix inequalities. These valid inequalities are obtained by the multiplication of the linear constraints of the UC problem such as the flow constraints of two different lines. The performance of the proposed convex relaxation is evaluated on several hard instances of the UC problem. For most of the instances, globally optimal integer solutions are obtained by solving a single convex problem.

Since the proposed technique leads to a large number of valid quadratic inequalities, an iterative procedure is devised to impose a small number of such valid inequalities. For the cases where the strengthened SDP does give a global integer solution, we incorporate other valid inequalities, including a set of Boolean quadric polytope constraints. The proposed relaxations are extensively tested on various IEEE power systems in simulations.

VISUALIZING THE FEASIBLE SPACES OF CHALLENGING OPF PROBLEMS

Dr. Daniel Molzahn, Computational Engineer, Argonne National Laboratory (*Lemont, IL*)

Optimal power flow (OPF) is one of the key optimization problems in power systems engineering. OPF problems that use an AC power flow model can have non-convex feasible spaces that challenge both traditional local solution techniques and emerging convex relaxations. Visualizing these feasible spaces can aid in understanding these non-convexities and their relevance for various solution algorithms. Recent work towards developing such visualizations leverages the Numerical Polynomial Homotopy Continuation (NPHC) algorithm, which is guaranteed to find all power flow solutions. By discretizing the inequality constraints, repeated power flow solutions using NPHC enables calculation of the feasible spaces for small OPF problems. Using this approach, this presentation illustrates both the feasible spaces of several challenging OPF problems and the performance of various solution algorithms.

POWER SYSTEM STATE ESTIMATION WITH A LIMITED NUMBER OF MEASUREMENTS

Dr. Javad Lavaei, Assistant Professor, University of California, Berkeley (*Berkeley, CA*)
Dr. Ross Baldick, Professor, University of Texas-Austin (*Austin, TX*)
Dr. Ramtin Madani, Postdoctoral Fellow, University of California, Berkeley (*Berkeley, CA*)
Mr. Morteza Ashraphijuo, PhD Student, University of California, Berkeley (*Berkeley, CA*)

This work is concerned with the power system state estimation (PSSE) problem, which aims to find the unknown operating point of a power network based on a given set of measurements. The measurements of the PSSE problem are allowed to take any arbitrary combination of nodal active powers, nodal reactive powers, nodal voltage magnitudes and line flows. This problem is non-convex and NP-hard in the worst case. We develop a set of convex programs with the property that they all solve the non-convex PSSE problem in the case of noiseless measurements as long as the voltage angles are relatively small. This result is then extended to a general PSSE problem with noisy measurements, and an upper bound on the estimation error is derived. The objective function of each convex program developed in this paper has two terms: one accounting for the non-convexity of the power flow equations and another one for estimating the noise levels. The proposed technique is demonstrated on several systems such as the 1354-bus European network.

Session T2-B (Tuesday, June 28, 10:45AM, Meeting Room 3M-4)

INTRA-DAY CO-OPTIMIZATION OF THE NATURAL GAS AND ELECTRIC NETWORKS: THE GECO PROJECT

Dr. Aleksandr Rudkevich, President, Newton Energy Group (*Boston, MA*)
Dr. Scott Backhaus, DOE/OE and DHS Critical Infrastructure Program, Los Alamos National Laboratory (*Los Alamos, NM*)
Dr. Anatoly Zlotnik, Scientist, Los Alamos National Laboratory (*Los Alamos, NM*)

Joint or well-coordinated optimization of natural gas and power markets is highly challenging mathematically, computationally, informationally and institutionally. Mathematically, we are dealing with a dynamic non-linear mixed integer optimal control problem in which some control objects are represented by partial differential equations. Computationally, solution times are limited by application. No institutional entity possesses sufficient information to solve this problem.

The Gas-Electric Co-Optimization (GECO) project funded by ARPA-E is will develop the analytical frameworks and market designs to coordinate gas and electricity markets. In this presentation we describe GECO's objectives and approach, outline the novel methods for optimization of natural gas transportation networks, discuss computational and institutional challenges, and provide numerical examples illustrating the essence and the capabilities of the proposed framework. We base pipeline optimization methods on a Reduced Network Flow (RNF) representation of partial differential equations for compressible gas flow dynamics in large-scale pipeline systems. As preliminary studies demonstrate, computationally efficient optimal controls using the RNF could be applied to natural gas pipeline networks in a transient optimization framework with unprecedented efficiency, scalability, and accuracy.

We will discuss market design options made possible by intra-day co-optimization of gas and electric infrastructure.

HIDDEN POWER SYSTEM INFLEXIBILITIES IMPOSED BY TRADITIONAL UNIT COMMITMENT FORMULATIONS

Dr. Germán Morales-España, Postdoctoral Researcher, Delft University of Technology (*Delft, South Holland*)
Dr. Benjamin F. Hobbs, Professor, Johns Hopkins University (*Baltimore, MD*)

Approximations made in traditional day-ahead unit commitment (UC) model formulations can result in suboptimal or even infeasible schedules for slow-start units and inaccurate predictions of actual costs and wind curtailment. With increasing wind penetration, these errors will become economically more significant. Here, we consider inaccuracies from three approximations: the use of hourly intervals in which energy production from each generator is modeled as being constant; the disregarding of startup and shutdown energy trajectories; and optimization based on expected wind profiles. The results of UC with those assumptions are compared to models that: (1) use a piecewise-linear power profiles of generation, load and wind, instead of the traditional stepwise energy profiles; (2) consider startup/shutdown trajectories; and (3) include many possible wind trajectories in a stochastic framework. The day-ahead hourly schedules of slow-start generators are then evaluated against actual wind and load profiles using a model real-time dispatch and quick-start unit commitment with a 5 minute time step. We find that each simplification usually causes expected generation costs to increase by several percentage points, and results in significant understatement of expected wind curtailment and, in some cases, load interruptions. The inclusion of startup and shutdown trajectories often yielded the largest improvements in schedule performance.

POWER-CAPACITY AND RAMP-CAPABILITY RESERVES FOR WIND INTEGRATION IN POWER-BASED UC

Dr. Germán Morales-España, Postdoctoral Researcher, Delft University of Technology (*Delft, South Holland*)
Dr. Ross Baldick, Prefessor, University of Texas (*Austin, TX*)
Dr. Javier García González, Associate Professor, Universidad Pontificia Comillas (*Madrid, Spain*)
Dr. Andres Ramos, Professor, Universidad Pontificia Comillas (*Madrid, Spain*)

Here, we present a power-based network-constrained unit commitment (UC) model as an alternative to the traditional deterministic UCs to deal with wind generation uncertainty. The formulation draws a clear distinction between power-capacity and ramp-capability reserves to deal with wind production uncertainty. These power and ramp requirements can be obtained from wind forecast information. The model is formulated as a power-based UC, which schedules power-trajectories instead of the traditional energy-blocks and takes into account the inherent startup and shutdown power trajectories of thermal units. These characteristics allow a correct representation of each unit’s ramp schedule, which defines its ramp availability for reserves. The proposed formulation significantly decreases operation costs compared to traditional deterministic and stochastic UC formulations while simultaneously lowering the computational burden. The operation cost comparison is made through 5-min economic dispatch simulation under hundreds of out-of-sample wind generation scenarios.

Session T3-A (Tuesday, June 28, 1:30 PM, Meeting Room 3M-2)

ROBUST RISK-CONSTRAINED UNIT COMMITMENT WITH LARGE-SCALE WIND GENERATION: AN ADJUSTABLE UNCERTAINTY SET APPROACH

Dr. Feng Qiu, Computational Engineer, Argonne National Laboratory (*Lemont, IL*)
Mr. Cheng Wang, Visiting Student, Argonne National Laboratory (*Lemont, IL*)
Dr. Jianhui Wang, Computational Engineer, Argonne National Laboratory (*Lemont, IL*)

This work addresses two important issues which are barely discussed in the literature on robust unit commitment (RUC): 1) how much the potential operational loss could be if the realization of uncertainty is beyond the prescribed uncertainty set; 2) how large the prescribed uncertainty set should be when it is used for RUC decision making. In this regard, a robust risk-constrained unit commitment (RRUC) formulation is proposed to cope with large-scale volatile and uncertain wind generation. Differing from existing RUC formulations, the wind generation uncertainty set in RRUC is adjustable via choosing diverse levels of operational risk. By optimizing the uncertainty set, RRUC can allocate operational flexibility of power systems over spatial and temporal domains optimally, reducing operational cost in a risk-constrained manner. Moreover, since impact of wind generation realization out of the prescribed uncertainty set on operational risk is taken into account, RRUC outperforms RUC in the case of rare events. Three algorithms based on column and constraint generation (C&CG) are derived to solve the RRUC. As the proposed algorithms are quite general, they can also apply to other RUC models to improve their computational efficiency. Simulations on a modified IEEE 118-bus system demonstrate the effectiveness and efficiency of the proposed methodology.

GENERATING CUTS FROM THE RAMPING POLYTOPE FOR THE UNIT COMMITMENT PROBLEM

Dr. James Ostrowski, Assistant Professor, University of Tennessee (*Knoxville, TN*)
Dr. Jianhui Wang, Section Lead - Advanced Power Grid Model, Argonne National Laboratory (*Argonne, IL*)
Mr. Bernard Knueven, Ph.D. Student, University of Tennessee (*Knoxville, TN*)

We present a perfect formulation for a single generator in the unit commitment (UC) problem. This generator can have characteristics such as ramping constraints, time-dependent start-up costs, and start-up/shut-down ramping. The perfect formulation is polynomially large, so we use it to create a cut-generating linear program for a single generator. We test the computational efficacy of these cuts in a utility-scale UC MIP model, based on the FERC generator set and 2015 hourly data from PJM, creating 362 24-hour UC instances. We find that although these cuts from the ramping polytope are not very helpful for today's UC problems, they may be more beneficial for tomorrow's. Using the same data, we created 362 different 24-hour UC instances under the assumption of 30% wind penetration. These high-wind instances are more computationally difficult. For the 356 high-wind instances that solved within 30 minutes, we demonstrate a 5% reduction in mean run-time and a 28% reduction in mean node count. On 15 high-wind instances that solve within the time limit but take more than 10 minutes for either method, we show a 24% mean reduction in run time and a 39% reduction in mean node count. For the 6 high-wind instances that did not solve in the time limit we see a modest reduction in final MIP gap. Additionally, these cuts may yet be beneficial for the more complex UC models used by ISOs today because they reduce the enumeration needed to enforce a generators technical constraints.

STRENGTHENED MILP FORMULATION FOR THE EDGE-BASED COMBINED-CYCLE UNIT MODEL

Dr. Yongpei Guan, Professor, University of Florida (*Gainesville, FL*)
Dr. Yonghong Chen, Principle Advisor, MISO (*Carmel, IN*)
Dr. Xing Wang, Manager, Alstom (*Redmond, WA*)
Dr. Lei Fan, Power Engineer, GE (*Schenectady, NY*)
Mr. Kai Pan, Ph.D. student, University of Florida (*Gainesville, FL*)

There are emerging needs of accurate and computationally efficient models for gas-fired combined-cycle units, due to increasing utilization of them for power generation in US wholesale electricity markets. Our recently proposed edge-based formulation for combined-cycle units can help accurately describe the operations of combine-cycle units including capturing the transition processes and physical constraints for each turbine. In this companion paper, we derive tighter constraints and several families of strong valid inequalities to tighten the edge-based mode, by exploring the physical characteristics of combined- cycle units and utilizing the edge-based modeling framework. The computational experiment results indicate that our derived formulation significantly reduces the computational time because the improved linear programming relaxation of our proposed formulation reduces the root node gap significantly. These results verify that the proposed constraints and strong valid inequalities are very effective, and the final formulation is very tight.

Session T3-B (Tuesday, June 28, 1:30 PM, Meeting Room 3M-4)

INCENTIVE COMPATIBLE PRICING MECHANISMS FOR MEETING EXPECTED RAMP CAPABILITY IN REAL-TIME MARKETS

Dr. Erik Ela, Senior Technical Leader, EPRI (*Palo Alto, CA*)
Dr. Mark O'Malley, Professor, University College Dublin (*Dublin, Ireland*)

This presentation discusses a pricing mechanism to incentivize ramp capability to resources that provide ramping in real-time markets that use time-coupled multi-period security-constrained economic dispatch. Two concepts are proposed: the cross-interval marginal price and the dynamic look-ahead. The cross-interval marginal price incentivizes resources that back down in the binding interval in order to provide ramping in future intervals. This occurs without a loss of the impact of ramping costs to the LMP when the advisory interval becomes the binding interval. The dynamic look-ahead corrects an issue that the length of the look-ahead interval can have an impact on what the binding interval LMP is, when ramping periods last for extended periods of time. An overall assessment of mechanisms for incentivizing ramp capability will be discussed as part of this presentation as well.

DUAL PRICING ALGORITHM FOR COST ALLOCATION IN NON-CONVEX ELECTRICITY MARKETS

Ms. Robin Broder Hytowitz, Ph.D. Student, JHU/FERC (*Washington, DC*)
Dr. Richard ONeill, Chief Economic Adviser, FERC (*Washington, DC*)
Dr. Anya Castillo, Research Scientist, Sandia National Laboratories (*Albuquerque, NM*)
Mr. Brent Eldridge, Operations Research Analyst, FERC (*Washington, DC*)

Improved market design continues to be an important issue in ISOs. When costs are allocated too broadly they dilute the price signal needed to stimulate investment in better alternatives. We present an axiomatic approach to efficient prices and the cost allocation issues in an auction market that is revenue neutral, and non-confiscatory. Cost allocation occurs through uplift that, for the purpose of our proposed work, includes make-whole payments and penalties. The general framework presents a cost allocation scheme that can be further conditioned in order to incorporate equity and cost causation criteria, which are left to the system operator and market participants' discretion. We illustrate how conditioning can be calibrated for such purposes. The proposed approach is more transparent than current practice, which spreads costs widely across time and topology. The pricing mechanism is post unit commitment (including optimal dispatch) and minimizes uplift payments at the efficient dispatch solution. The approach can be integrated into current ISO market software. The strength in the proposed approach is that the algorithm maintains the maximum market surplus and efficient dispatch, while providing flexibility in how costs are allocated fairly and adequately to market participants. The formulation only consists of linear constraints based on the axiomatic approach to pricing and cost allocation, and therefore it is computationally efficient.

MODELLING AND SOLVING SECURITY CONSTRAINED OPTIMAL POWER FLOW IN PARALLEL

Dr. Cosmin Petra, Asst. Comp. Mathematician, Argonne National Laboratory (*Lemont, IL*)
Dr. Mihai Anitescu, Computational Mathematician, Argonne National Laboratory (*Argonne, IL*)

We will present a computational framework, StructJuMP, for the fast and easy specification of very large, structured optimization problems in parallel on memory-distributed computing platforms. Motivated by the security constrained optimal power flow problems (SCOPF) with a large number of contingencies, StructJuMP allows distributing very large such problems (thousands of buses and contingencies) across the computational nodes and facilitate the interaction with the optimization solver, similarly to existing algebraic modeling languages (e.g., AMPL or GAMS), but without any memory limitations.

StructJuMP is an extension of JuMP (https://github.com/JuliaOpt/JuMP.jl) algebraic modeling language embedded in Julia with performance and syntax similar to AMPL.

In StructJuMP we developed and implemented algorithms for efficient automatic computation of the derivatives in parallel and also interfaced with the parallel optimization solver PIPS. Therefore StructJuMP provides an integrated, modelling+solving, computational framework for SCOPF problems. We present preliminary computational experiments using SCOPF instances based on existing IEEE cases.

Session T4-A (Tuesday, June 28, 3:15 PM, Meeting Room 3M-2)

COMPARING THE PERFORMANCE OF EXPLICITLY VS. IMPLICITLY SCHEDULED OPERATING RESERVE

Dr. Erik Ela, Senior Technical Leader, EPRI (*Palo Alto, CA*)
Dr. Eamonn Lannoye, EPRI (*Palo Alto, CA*)
Dr. Robert Entriken, EPRI (*Palo Alto, CA*)
Dr. Aidan Tuohy, EPRI (*Palo Alto, CA*)

This research is a continuation of research that has been presented over the last few years on the optimal levels of operating reserve for systems with increased levels of variable energy resources. In this presentation, we will present the three central needs for operating reserve: variability occurring within the scheduling interval; variability occurring beyond the scheduling interval, and uncertainty occurring around the interval. For each of these needs we compare the performance of explicitly scheduled reserve, which is done through reserve inequality constraints to meet the associated impact, with the implicitly scheduled operating reserve, that in which the reserve is scheduled inherently by advanced scheduling applications. We have set up and performed case studies on evaluation power systems as well as practical large-scale systems to compare performance in terms of cost efficiency and reliability.

LOCATIONAL RESOURCE ADEQUACY ASSESSMENT - METHODOLOGY AND CASE STUDY OF THE ISO NEW ENGLAND SYSTEM

Dr. Evgeniy Goldis, CTO, Newton Energy Group (*Boston, MA*)
Dr. Alex Rudkevich, President, Newton Energy Group (*Boston, MA*)
Dr. Alex Beylin, Senior Data Scientist, Newton Energy Group (*Boston, MA*)
Dr. Russ Philbrick, President, Polaris Systems Optimization (*Seattle, WA*)
Dr. Andrei Kharchenko, FOM Instituut voor Atoom- en Molecuulfysica (AMOLF) *(Amsterdam, The Netherlands)*

The concept of resource adequacy (RA) of the bulk electricity supply is a critical component of power system reliability, which sets criteria for the type, level and location of system reserves to ensure the feasible and reliable operation of the power system. Existing tools address these problems at a broad regional level and are incapable of providing reliability information at the locational level. These tools cannot differentiate locations within a region and assume that siting new generating capacity anywhere within a region has the same impact on system reliability. Additionally, they do not directly measure the RA impact of transmission limitations or provide signals on which transmission segments need reinforcement to sustain the

RA of the system. As a result, system planners, operators and project developers receive inadequate locational signals, which leads to inefficient generation planning, transmission planning and investment decisions.

In this presentation we describe Grid Locational Reliability Analyzer (GLORA), a Monte Carlo simulator that computes locational RA indicators using a full transmission network representation of the power system and includes contingency analysis, variable resources and generation and transmission outages. We give an overview of GLORA's GPU/CPU architecture, key variance reduction techniques that significantly reduce the number of SC OPFs required for convergence and preliminary locational RA results for the ISO New England system.

EUROPE: BENEFITS OF INTEGRATING REGIONS AND ENERGIES TO THE SECURITY OF SUPPLY

Dr. Guillaume Tarel, Vice President, Artelys (*Montreal, Canada*)

The European Climate Foundation (ECF) is an organization whose aim is "to help Europe foster the development of a low-carbon society". Last year, ECF has assigned Artelys and its partners to analyze least cost-lowest risks infrastructure investments to meet gas security of supply in Europe. In addition Artelys had to address how using the flexibility of the power system can help meeting gas security of supply at a lower cost.

This is particularly relevant, in a context with a substantial risk of supply disruption and, in turn, major investment projects being contemplated.

To address this issue, Artelys has used advanced hourly supply-demand equilibrium models and capacity expansion algorithms for gas and electricity grids for all European countries. In addition to evaluating the resilience of Europe to gas supply disruptions, Artelys has analyzed what are the benefits of coordinating gas and power grids in those places where gas security of supply concerns do occur. For report and presentation: http://www.energyunionchoices.eu/

<u>Session T4-B (Tuesday, June 28, 3:15 PM, Meeting Room 3M-4)</u>

DYNAMIC THERMAL RATINGS IN REAL-TIME DISPATCH MARKET SYSTEMS

Dr. Kwok Cheung, Principal, Software Arhitect, GE (*Redmond, WA*)
Mrs. Jun Wu, Power Systems Engineer, GE (*Redmond, WA*)

Traditionally, static line rating (SLR) of a line is conservatively calculated under the "worst-case" operating conditions and are updated infrequently. These conservative assumptions may restrict the line capacity whenever the real weather condition is less stressful. More accurate assessment of transmission flow limits will directly impact the efficiency of system and market operations. Weather-based real-time dynamic line rating (DLR) is the current limit determined by real-time measurements of weather conditions surrounding the conductor. DLR has the potential to increase the line rating, reduce transmission congestion and enhance market efficiency. In North America, RTOs are fundamentally reliant on optimization techniques to dispatch generation resources and serve the native load in large geographical regions. This paper applies DLR to the optimization problem of a real-time market (RTM) and simulations of case studies are carried out for a large power network. The benefits of DLR in RTM are presented to demonstrate the effectiveness in reducing transmission congestion and generation costs.

TRANSMISSION TOPOLOGY OPTIMIZATION IMPACTS IN DAY-AHEAD MARKETS - SIMULATIONS IN PJM

Dr. Pablo Ruiz, President and CTO, NewGrid, Inc (*Somerville, MA*)
Dr. Michael Caramanis, Professor, Boston University (*Boston, MA*)
Dr. John Goldis, Partner, Newton Energy Group (*Boston, MA*)
Mr. T. Bruce Tsuchida, Principal, The Brattle Group (*Cambridge, MA*)
Mr. Xiao Li, Director of Software, NewGrid, Inc (*Somerville, MA*)
Mr. Keyurbhai Patel, Senior Lead Engineer, PJM Interconnection (*Audubon, PA*)
Dr. C. Russell Philbrick, President, Polaris Systems Optimization (*Shoreline, WA*)
Dr. Aleksandr Rudkevich, President, Newton Energy Group (*Boston, MA*)

Transmission topology optimization (line switching) supports congestion management by routing power flow away from congested/overloaded facilities to the rest of the system which has spare capacity. The result is an increase in transfer capabilities from low-cost resources to demand centers with significant potential for economic and reliability benefits. However, due to the computational complexity of the problem, its use has been limited, employed on an ad-hoc basis and relying on operators' previous experience or a set of fixed procedures. Our previous work developed near-optimal and tractable topology optimization algorithms for use with operations decision processes in which unit commitment is pre-specified, including real-time market optimization, transmission and generation outage coordination and scheduling, and development of operating guides in seasonal contingency planning. We have also reported results of topology optimization over a limited set of lines, in combination with security-constrained unit commitment solutions. This presentation will report on simulation results of topology optimization impacts on historical PJM day-ahead market models over a broad set of switchable lines. The addition of transmission topology decisions to the security-constrained unit commitment model in the day-ahead market optimization provides more efficient outcomes while meeting reliability standards.

USING THE NATIONAL ENERGY WITH WEATHER SYSTEM (NEWS) SIMULATOR TO HIGHLIGHT AND ADDRESS UPCOMING CHANGES TO THE ELECTRIC POWER SYSTEM

Dr. Christopher Clack, Research Scientist, University of Colorado (*Boulder, CO*)
Dr. Melinda Marquis, Program Manager, National Oceanic and Atmospheric Admin. (*Boulder, CO*)

The NEWS simulator is a new blended capacity expansion and production-cost model for the entire contiguous US. It can be expanded to other areas of the US, or adjoin with the Canada grid.

It was recently used in a study for Nature Climate Change to show how geographic scale and natural gas fuel costs affect renewable energy development. The model can be run in various states to highlight issues or changes that are needed within the grid infrastructure. It has been designed from the ground up to incorporate high volumes of weather data for renewable generators, as well as including the features of conventional generation. It includes transmission, and can be expanded to feature high resolution AC modeling. The NEWS simulator shows that atmospheric sciences are critical throughout the electricity supply chain, from early planning all the way through real-time dispatch of the market. The simulator has the ability to test run systems before deployment in thousands of scenarios to test its resiliency, reliability, and accuracy. In the near future, it can be used in quasi real-time mode to depict efficiency savings within the market. From NEWS simulator, new insight is gleaned with regards to each aspect of the electric infrastructure, and facilitates consideration of realistic representation of constraints, uncertainty, flexibility, dispatch, and expansion. Specifically, with regards to how atmospheric sciences will interact with each of these areas.

Wednesday, June 29

Session W1-A (Wednesday, June 29, 9:00 AM, Meeting Room 3M-2)

MODELING AND SOLVING BATTERY OPERATION PROBLEMS

Dr. Daniel Bienstock, Professor, Depts of IEOR and APAM, Columbia University (*New York, NY*)
Mr. Shuoguang Yang, Student, Columbia University (*New York, NY*)
Mr. Carsten Matke, Researcher, Next Energy (*Oldenburg, Germany*)

We present robust optimization models for battery operation problems in transmission and distribution systems. We consider combined multiple time-period (e.g. 1/2 hour intervals in a 24 hour period) and multiple scenario (winter, summer) problems. The key decisions involve battery placement, sizing and (time- and scenario- dependent) charge/discharge rate. We use robust optimization techniques to account for load and renewable variability.

We will present modeling, methodological and computational results.

PROFITABILITY OF MERCHANT INVESTMENTS IN BATTERY ENERGY STORAGE

Dr. Daniel Kirschen, Close Professor of Electrical Engineering, University of Washington (*Seattle, WA*)
Mr. Yury Dvorkin, Research Assistant, University of Washington (*Seattle, WA*)
Mr. Ricardo Fernandez-Blanco, Research Associate, University of Washington (*Seattle, WA*)
Mr. Hrvoje Pandzic, Assistant Professor, University of Zagreb (*Zagreb, Croatia*)
Dr. Jean-Paul Watson, Staff Member, Sandia National Laboratories (*Albuquerque, NM*)
Dr. Cesar Silva-Monroy, Staff Member, Sandia National Laboratories (*Albuquerque, NM*)

Battery energy storage systems (BESS) have been proven to be a technically feasible solution to improve the utilization of renewable generation. However, the capital cost of these devices remains relatively, if not prohibitively, expensive and this naturally raises concerns over whether merchant BESSs are economically viable in a market environment. This presentation will describe two multi-level optimization models that explicitly guarantee the profitability of merchant investment decisions on BESSs siting and sizing. Numerical simulations carried out on models of the ISO New England and WECC systems demonstrate that considering the profitability of merchant BESSs also leads to improvements in market efficiency as measured in terms of operating cost and reduced out-of-market corrections.

RISK-CONSTRAINED LOOK-AHEAD STRATEGIC ENERGY STORAGE BIDDING

Mr. Yishen Wang, Research Assistant, University of Washington (*Seattle, WA*)
Dr. Daniel Kirschen, Close Professor of Electrical Engineering, University of Washington (*Seattle, WA*)
Mr. Yury Dvorkin, Research Assistant, University of Washington (*Seattle, WA*)

Dr. Ricardo Fernández-Blanco, Postdoctoral Researcher, University of Washington (*Seattle, WA*)

The profitability of merchant battery energy storage systems (BESSs) in a day-ahead electricity market depends on the energy state-of-charge set points at the first and last operating hour of the optimization horizon. Profit opportunities should also be balanced between the day ahead (DA) and the following day (DA+1). This presentation will describe a bi-level model that optimizes price-quantity offers/bids submitted by merchant BESSs to the system operator in a way that maximizes its total expected operational profit during DA and DA+1 and its conditional value-at-risk (CVaR) due to the market clearing uncertainty. Unlike other models, our approach does not fix the state of charge at the last and first operating hours of each day. Instead, these quantities are optimized using a look-ahead window. The CVaR term is used to control the risk averseness of the merchant BESS. To speed up computations, the proposed bi-level model is solved using a Benders decomposition. Numerical results obtained using a modified IEEE Reliability Test System demonstrate the usefulness of the proposed approach and highlight the importance of using accurate forecasts.

Session W1-B (Wednesday, June 29, 9:00 AM, Meeting Room 3M-4)

A BUNDLE METHOD FOR ON-LINE TRANSIENT SECURITY CONSTRAINED DISPATCH

Dr. Mihai Anitescu, Computational Mathematician, Argonne National Laboratory (*Argonne, IL*)

The inclusion of dynamic stability constraints is the nominal objective of many optimization-based power system analyses. In current practice, this is typically done off-line. We present an approach for the on-line inclusion of dynamic constraints in power grid optimization problems. The approach is based on an encapsulation that allows for a loose coupling between operations optimization and dynamic security assessment, given the latter is equipped to return sensitivities with respect to the involved control parameters. System dynamics are accounted for on the basis of a detailed time domain decomposition, and an adjoint method is used to efficiently compute sensitivities. This setup allows for a first order oracle function to directly account for dynamic security in optimization problems such as the day ahead unit-commitment and real-time economic dispatch. We define a bundle algorithm to solve the extended formulation, where the sequential optimization process gradually gathers information on the system stability and provides, as a bi-product, an outer-approximation of the underlying stability region. Numerical results are provided for transient security constrained economic dispatch computations, on a time scale compatible with near-real-time operations.

DEVELOPMENT OF FAST REAL-TIME ONLINE DYNAMIC SECURITY ASSESSMENT SYSTEM

Mr. Mike Zhou, Chief Scientist, State Grid/EPRI China (*Northville, MI*)
Mr. XueWei Shang, Managing Director, Nari/Beijing KeDong Co. (*Beijing, China*)
Mr. Lin Zhao, Director of Technology, Nari/Beijing KeDong Co. (*Beijing, China*)
Mr. Jian Yang, Director of DSA Technology, EPRI China (*Beijing, China*)
Mr. DongYu Shi, Engineer, EPRI China (*Beijing, China*)
Mr. Ying Chen, Associate Professor, Tsinghua University (*Bejing, China*)

The national grid of China currently is modeled using a 40K-bus power network model in their Dynamic Security Assessment (DSA) analysis system. A round DSA trip, including SCADA, State Estimation and DSA computation currently takes about 10 minutes. With the development of the ultra-high voltage AC/DC grids in China, we have seen the need for a fast real-time online DSA system. A new DSA development project, sponsored by the State Grid of China, has been started. The primary goal is to reduce the overall DSA round trip time, from data acquisition to complete the analysis, from the current 10 minutes to less than 60 seconds.

A distributed data grid based data space technology is used to speed up the data acquisition process. A in-memory real-time power network model is used to track the grid operation state and its change in real-time. A complex event processing engine listens to grid state change events to perform situation awareness analysis through event-driven rule evaluation and pattern-matching to identify potential system operation risk. The situation awareness analysis implementation is based on search of existing power system simulation cases, a data-driven approach, produced in the off-line studies and the on-line simulation, and stored in a Hadoop based power system simulation study case knowledge base.

This presentation will discuss the high-level solution architecture of and implementation approaches used in the project.

FAST AND ACCURATE CALCULATION OF DYNAMICS SENSITIVITIES USING A DISCRETE-ADJOINT APPROACH

Dr. Emil Constantinescu, Computational Mathematician, Argonne National Laboratory (*Argonne, IL*)
Abhyankar, Shrirang G., Computational Engineer, Energy Systems Division, Argonne National Laboratory (*Argonne, IL*)
Dr. Mihai Anitescu, Senior Computational Mathematician, Mathematics and Computer Science Division, Argonne National Laboratory (*Argonne, IL*)
Hong Zhang, Postdoctoral Assistant, Mathematics and Computer Science Division, Argonne National Laboratory (*Argonne, IL*)
Cosmin Petra, Assistant Computational Mathematician, Mathematics and Computer Science Division, Argonne National Laboratory (*Argonne, IL*)

Inclusion of stability constraints in economic dispatch problem has been explored by the power system research community over the last two decades. Semi-infinite programming (SIP) is arguably the most promising direction as it significantly reduces the size of the overall problem and, thus, offers a potential for adoption in real-time market operations where time to solution is constrained. However, the fast and accurate calculation of sensitivities of power system dynamics with respect to the dispatch decisions, a central component of the SIP-based approach, remains a challenge. This existing approaches for sensitivity calculation become untenable even for moderate-sized problems, as their computational complexity grows linearly with the number of dispatch variables. Moreover, the discontinuities in dynamics have not been paid attention in the existing work and as such the sensitivities may be questionable. In this talk, we present the fast and accurate calculation of dynamics sensitivities using a discrete adjoint approach. The proposed approach is highly efficient as its computational complexity is independent of the number of parameters and it includes the necessary sensitivity jump conditions for handling discontinuities in dynamics. We will compare the computational efficiency of the adjoint approach for sensitivity calculation on several test systems, and postulate the expected performance for this method and we address the problem of estimating the uncertainty.

Session W2-A (Wednesday, June 29, 10:45 AM, Meeting Room 3M-2)

A MULTISCALE OPTIMIZATION FRAMEWORK FOR ECONOMIC ASSESSMENT OF EMERGING MARKET PARTICIPANTS

Dr. Alexander Dowling, Postdoctoral Research Associate, University of Wisconsin-Madison (*Madison, WI*)
Dr. Victor Zavala, Richard H. Soit Assistant Professor, University of Wisconsin-Madison (*Madison, WI*)

Emerging market participants, such as energy storage systems and demand response, are expected to provide additional flexibility to electricity grids, resulting in improved efficiency and lower prices for consumers. Despite the clear benefits for grid operators, complex market rules and physical constraints make economic assessments from the perspective of system owners/operators difficult. We present a mathematical programming framework to estimate revenues from both energy and ancillary service sales in electricity markets operating on multiple timescales for emerging energy systems. With this framework, we seek to quantify the value of dynamic flexibility of non-traditional energy systems (e.g., demand response from manufacturing facilities) and understand the impact of uncertainty (e.g., market prices, "fuel source" availability such as natural gas or solar irradiation) on revenue estimates. Furthermore, large historical market and meteorological data sets may be analyzed using paradigms from stochastic programming. Applications include HVAC systems with integrated electrical storage, solar power systems with energy storage and industrial demand response.

OPTIMAL PARTICIPATION OF AN ELECTRIC VEHICLE AGGREGATOR IN DAY-AHEAD ENERGY AND RESERVE MARKETS

Dr. Miguel Ortega-Vazquez, Assistant Professor, University of Washington (*Seattle, WA*)
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Aggregators of electric vehicles (EVs) can provide services to the power grid by combining energy storage capabilities of individual EV batteries. These services are beneficial to both, the system and the aggregator. On the one hand, the system gets competitive ancillary services and the aggregator a new stream of revenue, in which the potential revenue gains outweigh the expected battery degradation costs. This presentation describes an optimal bidding strategy for a large-scale EV aggregator that aims to maximize its profits from participating in competitive energy and ancillary services markets. This strategy accounts for the uncertainty on market clearing outcomes for different bids of the EV aggregator and the battery degradation costs that need to be reimbursed to individual EV owners. The mutual value of the strategy is quantified for both the EV aggregator and power system using a modified IEEE Reliability Test System (RTS) with representative market clearing data from the ERCOT market, and with a large ensemble of EVs modelled using driving patterns from the 2009 National Household Travel Survey (NHTS). Results demonstrate the optimal strategy favors participation of the aggregator in the ancillary services markets instead of energy market, since the former incurs lower ex-post battery degradation costs. It is also shown that the trade-off between participation in energy and ancillary services markets is sensitive to the battery capital and degradation costs.

COUPLING PUMPED HYDRO ENERGY STORAGE WITH UNIT COMMITMENT

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As a result of the large-scale integration of renewable generation, electric grids require extra flexibility to deal with the stochastic nature of renewable generation. The usefulness of pumped hydro energy storage (PHES) as a flexibility provider has been demonstrated over the course of several decades. The operational flexibility of PHES is limited by hydraulic constraints that should be accounted for in the day-ahead scheduling problem. This presentation will describe how the PHES constraints can be integrated with deterministic and interval unit commitment (UC) formulations. In each formulation, we address the issue of limited energy and ramping capacity of PHES and consider two operating strategies: i) when PHES provides spatiotemporal energy arbitrage only and ii) PHES provides both spatiotemporal energy arbitrage and regulation services. Numerical simulations carried out on a model of the Belgian power system demonstrate that the proposed deterministic and interval UC formulations with PHES constraints can be used for approximating the cost-efficient solution of the stochastic UC formulation at a considerably lower computational burden.

Session W2-B (Wednesday, June 24, 10:45 AM, Meeting Room 3M-4)

TOWARDS CONTINUOUS-TIME OPTIMIZATION MODELS FOR POWER SYSTEMS OPERATION

Dr. Masood Parvania, Assistant Professor, University of Utah (*Salt Lake City, UT*)

Power system operation planning is a continuous-time, stochastic, mixed integer optimization problem that is broken into different time scales, each mapped into a corresponding discrete time approximation, taking care of certain finite set of commitment variables and operation schedules.

The decision variables of this complex optimization problem are continuous-time in nature, and the physical constraints governing the operation of power systems should hold in continuous-time. However, the current approach to solve this continuous-time (variational) optimization problem is to approximate the continuous-time variables with hourly samples, implying that generating units shall follow piecewise constant generation trajectories from one hourly schedule to the next. This schedule does not fully capture the flexibility of resources to balance the sub-hourly variations of the load and renewable resources.

In this presentation, we introduce a different approach to sampling the information and decision variables in power system operation, and particularly in the unit commitment (UC) problem. Our proposed UC model reduces the approximation error in describing the continuous-time ramping in the day-ahead operation, capturing more accurately the essential information available about the day-ahead net-load evolution in time, while revealing the potential operational flexibility of units that have significant impact on day-ahead operation solution, but is not captured by current UC model.

MARKET PROVISION OF FLEXIBLE ENERGY/RESERVE CONTRACTS

Ms. Wanning Li, Research Assistant, Iowa State University (*Ames, IA*)
Dr. Leigh Tesfatsion, Professor, Iowa State University (*Ames, IA*)

The need for flexible service provision has dramatically increased in recent years due to the increased penetration of variable energy resources, as has the need to ensure fair access to service provision from an increasingly diverse array of resources.

In response to these needs, this study develops a new analytic optimization formulation for the clearing of day-ahead markets based on swing contracts for the combined flexible provision of energy and reserve services. The swing contracts based new power markets explicitly value the flexibility, which provides a better way to compensate flexibility and attract flexible resources. The market design permits two-part pricing for appropriate market compensation of availability and performance, ensure an even playing field for all market participants and reduce dependence on out-of-market compensation.

This new optimization formulation is a mixed integer linear programming (MILP) problem that can be solved using standard MILP solution software. A numerical day-ahead market example will be presented to illustrate the potential of this new optimization formulation for real-world implementation.

TOWARDS A PRICE BASED OPTIMIZATION FORMULATION IN RTO MARKETS

Dr. Shangyou Hao, Principal Consultant, PA consulting (*Walnut, CA*)

Current RTO market operators in Northern American use optimization based approach to commit and dispatch resources. The formulations of various resources scheduling are almost all based maximization of social welfare value constructed using the complex bid data of the resources.

A fundamental aspect of the above formulation is that the pricings are the by-products of the optimization process: they are not explicitly used in the formulation of the problems. As a result, pricings are treated as after-thoughts, they are not used directly to influence the dispatching decision, much more about compensating mechanism for resources.

We would like to present a price based optimization formulation where the prices are direct control variables in making decisions for resources in the markets and where transmission network models are present for capturing the locational impacts.

Maximize f (P, X) subject to

H(P, X) =0

G(P, X)/=0

Where P is the newly introduced price vector and X is the rest of the state variables; H and G are the equality and inequality constraints.

We will discuss:

- How this formulation can incorporate locational prices and network related prices as the direct control variables with appropriate constraints?
- Examples to illustrate the application of the new formulation;
- Contrast to the cost based formulation;
- Why this formulation will be superior;
- and Further researches needed.