Federal Energy Regulatory Commission

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

AD10-12-003
June 25 – 27, 2012

Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software (Docket No. AD10-12-003)

Federal Energy Regulatory Commission, 888 First Street NE, Washington DC

Draft Agenda (abstracts attached below)

Monday, June 25, 2012

8:15 AM	Arrive and welcome (Commission Meeting Room)
8:30 AM	Session MA (Commission Meeting Room) **Online Risk-Based Security-Constrained Economic Dispatch and Market Operation** James McCalley, Qin Wang, Iowa State University (*Ames, IA*) Tongxin Zheng, Eugene Litvinov, ISO New England (*Holyoke, MA*) **Prototyping and Testing Adaptive Transmission Rates for Dispatch** Slava Maslennikov, ISO New England (*Holyoke, MA*) Kwok Cheung, Alstom Grid (*Redmond, WA*) **Ramp Management and Participation of Storage Resources** Dhiman Chatterjee, Nivad Navid, MISO (*Carmel, IN*)
10:00 AM	Break
10:15 AM	Session MB (Commission Meeting Room) **Locational Ancillary Service Procurement and Transmission Constraints** Paul Gribik, Yonghong Chen, MISO (*Carmel, IN*) **Equilibrium of Electricity Market Efficiency and Power System Operation Risk - An IEEE Task Force Review** Hong Chen, PJM Interconnection (*Norristown, PA*) **Transmission Outage Economic Analysis Using Market Simulation Software** Lee Blaede, ISO New England (*Holyoke, MA*) Jim David, Boris Gisin, PowerGEM (*Clifton Park, NY*) **AC Optimal Power Flow: History and Formulations** Mary Cain, Federal Energy Regulatory Commission (*Washington, DC*)
12:15 PM	Lunch
1:30 PM	Session MC-1 (Commission Meeting Room) **Multi-Area Optimal Power Flow with Transmission Switching** Cong Liu, Jianhui Wang, Jieqiu Chen, Argonne National Laboratory (*Argonne, IL*) **Robust Corrective Transmission Switching Schemes** Kory Hedman, Akshay Korad, Arizona State University (*Tempe, AZ*) **Topology Control Algorithms (TCA): Economic and Corrective Applications** Pablo Ruiz, Charles River Associates (*Boston, MA*) Justin Foster, Michael Caramanis, Boston University (*Boston, MA*) Aleksandr Rudkevich, Newton Energy Group (*Newton, MA*) **Scheduling and Pricing Under Variable and Uncertain Power Systems** Erik Ela, Bri-Mathias Hodge, Michael Milligan, National Renewable Energy Laboratory (*Golden, CO*) Mark O'Malley, University College Dublin (*Dublin, Ireland*)
	Session MC-2 (Meeting Room 3M-3) **Stochastic Optimization for Market Clearing: Advances in Computation and Economic Implications** Victor Zavala, Mihai Anitescu, Argonne National Laboratory (*Argonne, IL*) John Birge, University of Chicago (*Chicago, IL*) **Computational Challenges in Financial Transmission Rights Markets** Joseph Bright, Mauro Prais, Narasimham Vempati, Nexant, Inc. (*Chandler, AZ*) **Advanced Methods for FTR** Stephen Elbert, Karanjit Kalsi, Kurt Glaesemann, Maria Vlachopoulou, Mark Rice, Ning Zhou, Pacific Northwest National Laboratory (*Richland, WA*) **Non-Stationary Stochastic Modeling and Learning for Large-Scale Failure and Recovery of Power Distribution Networks** Yun Wei, Chuanyi Ji, Georgia Tech (*Atlanta, GA*) James Momoh, Howard University (*Washington, DC*)
3:30 PM	Break

Monday, June 25, 2012

3:45 PM	Session MD-1 (Commission Meeting Room)
	Computationally Efficient Optimal Transmission Switching: Solution Space Reduction Clayton Barrows, Seth Blumsack, Penn State University (*University Park, PA*) Russell Bent, Los Alamos National Laboratory (*Los Alamos, NM*)
	Leveraging Block-Composable Optimization Modeling Environments for Transmission Switching and Unit Commitment John Siirola, Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, NM*) David Woodruff, University of California, Davis (*Davis, CA*)
	Islanding of Power Networks Using Line Switching and Mixed Integer Programming Ken McKinnon, Paul Trodden, Andreas Grothey, Waqquas Bukhsh, University of Edinburgh (*Edinburgh, United Kingdom*)
	New Operational and Planning Capabilities Based on the HELM Deterministic Load Flow Ross Harding, Toni Trias Bonet, Gridquant Inc (*Savannah, GA*) Jason Black, Battelle Memorial Institution (*Columbus, OH*)
	Session MD-2 (Meeting Room 3M-3)
	The Price of Energy Storage Michael Ferris, Jesse Holzer, Yanchao Liu, Lisa Tang, University of Wisconsin (*Madison, WI*)
	Dynamic Scheduling of Operating Reserves in Electricity Markets with Wind Power Zhi Zhou, Audun Botterud, Argonne National Laboratory (*Argonne, IL*)
	Multi-Settlement Simulation of Dynamic Reserve Procurement Robert Entriken, Electric Power Research Institute (*Palo Alto, CA*) Taiyou Yong, Eversource Consulting, Inc. (*Folsom, CA*) Russ Philbrick, Polaris Systems Optimization, Inc. (*Shoreline, WA*) Aidan Tuohy, Electric Power Research Institute (*Knoxville, TN*)
	Two-Stage Robust Optimization for N-k Contingency-Constrained Unit Commitment Yongpei Guan, Qianfan Wang, University of Florida (*Gainesville, FL*) Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, NM*)
5:45 PM	Adjourn

Tuesday, June 26, 2012

8:15 AM	Arrive and welcome (Commission Meeting Room)
8:30 AM	Session TA (Commission Meeting Room) **A Method for Assessing Relative Efficiency of Central Generation and Distributed Energy Resources (DERs) in Distribution Feeders** Marija Ilic, Carnegie Mellon University (*Pittsburgh, PA*) **Software Tools For Optimized AC Power Flow Modeling and Load/Resource Ranking Modeling** Soorya Kuloor, GRIDiant Corporation (*Raleigh, NC*) Richard E. Hammond, GRIDiant Corporation (*Berkeley, CA*) **Distributed Computing and Stochastic Control for Demand Response in the Day-Ahead and Real-Time Markets** Alex Papalexopoulos, ECCO International (*San Francisco, CA*) Steve Florek, ZOME Energy Networks (*Cambridge, MA*) Jacob Beal, Raytheon BBN Technologies (*Cambridge, MA*)
10:00 AM	Break
10:15 AM	Session TB (Commission Meeting Room) **A Linear-Programming Approximation of AC Power Flow Equations** Pascal Van Hentenryck, NICTA and University of Melbourne (*Melbourne, Australia*) Carleton Coffrin, NICTA (*Melbourne, Australia*) **Toward Reliable and Efficient On-Line Resource Management: A Ramp Rate-Limited AC Optimal Power Flow for Integrating Renewable Resources and Responsive Demand** Marija Ilic, Carnegie Mellon University/NETSS (*Pittsburgh, PA*) **The Linearized IV ACOPF** Richard O'Neill, Federal Energy Regulatory Commission (*Washington, DC*)
11:45 AM	Lunch
1:00 PM	Session TC-1 (Commission Meeting Room) **Exploration of the ACOPF Feasible Region for the Standard IEEE Test Set** Aaron Schecter, Federal Energy Regulatory Commission (*Washington, DC*) **Robust DC-OPF** Daniel Bienstock, Sean Harnett, IEOR and APAM, Columbia University (*New York, NY*) Michael Chertkov, Los Alamos National Laboratory (*Los Alamos, NM*) **Some Key Requirements for Practical OPF Calculations** Ongun Alsaç, Brian Stott, Joseph Bright, Mauro Prais, Nexant, Inc. (*Chandler, AZ*) **Applying Voltage/VAr Management to Support Energy Markets** Herminio Pinto, Joseph Bright, Mauro Prais, Brian Stott, Nexant, Inc. (*Chandler, AZ*) Martin Geidl, Swissgrid AG (*Laufenburg, Switzerland*)
	Session TC-2 (Meeting Room 3M-3) **The Evolution of Planning Software** Devin Van Zandt, Mark Walling, GE Energy (*Schenectady, NY*) **Locational Assessment of Resource Adequacy and Co-Optimization of Generation and Transmission Expansion** Aleksandr Rudkevich, Newton Energy Group (*Newton, MA*) **Evaluating the Wind/Solar Generation Variability and Forecast Error Mitigation Using Day-Ahead and Real-Time Market Interleaved/Sequential Simulations** Tao Guo, Energy Exemplar, LLC (*Roseville, CA*) Zheng Zhou, MISO (*St. Paul, MN*) **Auction Design for Wholesale Electricity Markets** Haso Peljto, EMCon2 - Energy Market Consulting, Inc. (*Brooklyn Park, MN*)
3:00 PM	Break

Tuesday, June 26, 2012

3:15 PM	Session TD-1 (Commission Meeting Room)
	An Efficient Computational Method for Large-Scale Operations Planning Javad Lavaei, Matt Kraning, Eric Chu, Stephen Boyd, Stanford University (*Palo Alto, CA*) Somayeh Sojoudi, Steven Low, California Institute of Technology (*Pasadena, CA*) Baosen Zhang, David Tse, University of California, Berkeley (*Berkeley, CA*)
	Branch Flow Model: Relaxations, Convexification, Computation Steven Low, Masoud Farivar, Subhonmesh Bose, Lingwen Gan, Mani Chandy, California Institute of Technology (*Pasadena, CA*)
	Conic Relaxations of ACOPF Chen Chen, Alper Atamturk, Shmuel Oren, University of California, Berkeley (*Berkeley, CA*) Richard O'Neill, Federal Energy Regulatory Commission (*Washington, DC*)
	Session TD-2 (Meeting Room 3M-3)
	Applying High Performance Computing to Multi Area Stochastic Unit Commitment for Wind Penetration Anthony Papavasiliou, Shmuel Oren, University of California, Berkeley, IEOR (*Berkeley, CA*)
	SMART-ISO: A Stochastic, Multiscale Model of the PJM Power Grid Warren B. Powell, Boris Defoumy, Hugo Simao, PENSA Laboratory, Pricenton University (*Princeton, NJ*)
	Scalable, Parallel Stochastic Unit Commitment for Day-Ahead and Reliability Operations Jean-Paul Watson, Ross Guttromson, Cesar Silva-Monroy, Sandia National Laboratories (*Albuquerque, NM*) David L. Woodruff, Roger J.B. Wets, University of California, Davis (*Davis, CA*) Sarah M. Ryan, Iowa State University (*Ames, IA*)
4:45 PM	Adjourn

Wednesday, June 27, 2012

8:15 AM	Arrive and welcome (Commission Meeting Room)
8:30 AM	Session WA (Commission Meeting Room) **Look-Ahead Unit Commitment with Robust Optimization** Xing Wang, Alstom Grid (*Redmond, WA*) Peter Nieuwesteeg, Paragon Technology (*Bellevue, WA*) **MIP Technology Improvements** Edward Rothberg, Gurobi Optimization (*Palo Alto, CA*) **Algorithms for Solving Large-Scale Stochastic Unit Commitment and Security-Constrained Economic Dispatch Problems** Dzung Phan, Ali Koc, Jayant Kalagnanam, IBM T.J. Watson Research Center (*Yorktown Heights, NY*) **Methods of Selecting the Desired Net Interchange Across Multi-Control Areas: Demonstration of Seams Solution for NPCC** Marija Ilic, Carnegie Mellon University/NETSS (*Pittsburgh, PA*)
10:30 AM	Break
10:45 AM	Session WB (Commission Meeting Room) **Uncertainty Characterization of Renewable Power, Stochastic Resource Scheduling, and Implication on DAH Market** Xiaoming Feng, ABB Corporate Research (*Raleigh, NC*) **Improving Real-Time System Performance and Reliability by Using Synchrophasor Data** Marianna Vaiman, V&R Energy (*Los Angeles, CA*) **Adaptive Middleware for Real-Time Distributed Stream Processing** Yan Liu, Pacific Northwest National Laboratory (*Richland, WA*) **Competitive Markets for Imbalances, Not Penalties** Mark Lively, Utility Economic Engineers (*Gaithersburg, MD*) **An Affine Arithmetic Method to Solve the Stochastic Power Flow Problem Based on a Mixed Complementarity Formulation** Mehrdad Pirnia, Claudio Canizares, Kankar Bhattacharya, University of Waterloo (*Ontario, Canada*)
1:15 PM	Adjourn

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

Abstracts

Monday, June 25

Session MA (Monday, June 25, 8:30 AM, Commission Meeting Room)

Online Risk-Based Security-Constrained Economic Dispatch and Market Operation

James McCalley, Harpole Professor of Electrical and Computer Engineering, Iowa State University (*Ames, IA*)
Qin Wang, PhD Student, Iowa State University (*Ames, IA*)
Tongxin Zheng, Engineer, ISO New England (*Holyoke, MA*)
Eugene Litvinov, Manager, ISO New England (*Holyoke, MA*)

We describe a real-time electricity market solver based on a new perspective in coordinating system traditional “N-1” criteria and system risk, where system risk is modeled to capture the system’s overall security level. The new solver is called the risk-based security-constrained economic dispatch (RB-SCED) and is based on extensive research and industry testing. Relative to the security-constrained economic dispatch (SCED) used in industry today, the RB-SCED finds operating conditions that are more secure and more economic. It does this by obtaining solutions that achieve better balance between post-contingency flows on individual circuits and overall system risk. The method exploits the fact that, in a SCED solution, some post-contingency circuit flows which exceed their limits impose little risk while other post-contingency circuit flows which are within their limits impose significant risk. The RB-SCED softens constraints for the former and hardens constraints for the latter, thus achieving simultaneous improvement in both security and economy. Studies have shown that replacing SCED with RB-SCED results in significant reduction in the risk of cascading, voltage instability, and angular instability. Although RB-SCED is more time-intensive to solve than SCED, we have developed an algorithm that allows RB-SCED to solve in sufficient time for use in real-time electricity markets. In contrast to SCED, which motivates market behavior to offload circuit flows exceeding rated flows, the use of RB-SCED provides price signals that motivate market behavior to offload circuit flows and to enhance system-wide security levels.

Prototyping and Testing Adaptive Transmission Rates for Dispatch

Slava Maslennikov, Principal Analyst, ISO New England (*Holyoke, MA*)
Kwok Cheung, Director, Automation Network Management Solutions, Alstom Grid (*Redmond, WA*)

The Adaptive Transmission Rating (ATR) concept intends to safely increase the utilization of transfer capability of power systems by accounting for corrective actions in the form of post-contingency dispatch. The effect is achieved via adaptive estimation of emergency ratings values which can be safely used for enforcing post-contingency transmission constraints in dispatch instead of traditionally used fixed

emergency rates. ATR addresses transmission constraints caused by thermal limitations only.

Enabling features of the ATR concept are (1) utilization of continuous transient emergency ratings characteristic of transmission element as a function of time and (2) modeling of post-contingency dispatch up to 60 minutes.

ISO New England and Alstom Grid have implemented the ATR technology in a Proof-Of-Concept prototype (ATR POC). The tool utilizes Alstom's EMS and Market components and uses real-time data from State Estimator, Contingency Analysis and Market system. ATR POC is a new standalone application, based on the Market Clearing Engine (MCE) and Simultaneous Feasibility Test (SFT) of the production version of market system of ISO New England, intended for evaluation of the ATR technology in close to real-time dispatch environment.

This presentation focuses on the details of ATR technology implementation, results of testing with real-time ISO New England system data and future plans for implementing the concept in production.

Ramp Management and Participation of Storage Resources

Dhiman Chatterjee, Senior Manager, Market Design and Delivery, MISO (*Carmel, IN*)
Nivad Navid, Consulting Engineer, Market Design and Delivery, MISO (*Carmel, IN*)

Maintaining power balance for a reliable power system operation can be very challenging in the face of a highly variable and unpredictable net demand especially with flexible interchange scheduling and large-scale integration of intermittent renewable resource. A systematic mechanism is desirable to manage the burden on fast ramping controllable resources in a cost effective manner. Such need will be more critical with the evolution in the resource portfolio as a result of EPA regulations and resulting changes in the selection of flexible and controllable resources in the commitment and dispatch processes. A Ramp Capability product has been designed which is integrated with the day-ahead and real-time commitment and dispatch processes and provides an efficient and transparent market mechanism for ramp management and improve reliability.

In addition to the conventional dispatchable generation and demand response resources, long-term storage resources such as pumped hydro storage plants are good candidates in providing ramp capability if adequately enabled for market participation. Modeling limitations currently restrict flexibility of offer by Market Participants and prevent efficient scheduling by the RTOs in the energy markets. Enhanced business rules can soften daily energy constraints and couple generation and loading in a reservoir-storage model. Energy is offered at an asset owners specified price curve which reflects the value of inter-temporal opportunity cost of retaining the energy in storage. This framework allows effective participation of such resources in the energy and ancillary service markets, improves overall efficiency and allows opportunity for efficient revenue recovery.

Session MB (Monday, June 25, 10:15 AM, Commission Meeting Room)

Locational Ancillary Service Procurement and Transmission Constraints

Paul Gribik, Consulting Advisor, MISO (*Carmel, IN*)
Yonghong Chen, Consulting Engineer, MISO (*Carmel, IN*)

MISO modified its energy and ancillary service co-optimization process to improve deliverability of reserves procured by modeling the impact of deployment on transmission constraints. MISO treated reserve requirements and deployment zonally. Demand for contingency reserves for a zonal event is based on the largest event expected in the zone. Impact of reserves deployed in a zone on a transmission constraint is modeled using the weighted average of the nodal shift factors from reserve qualified resources in the zone. Reserves are deployed in a pro-rata fashion, spinning reserves first followed by supplemental reserves. This approach improved MISO's ability to select reserves that can be deployed without violating transmission constraints. It significantly reduced manual disqualification of resources to avoid violating transmission constraints.

MISO encountered problems and implemented initial corrections. MISO is also investigating a more comprehensive solution, nodal modeling of reserve procurement and deployment. In modeling reserve deployment to meet an event in a zone, the co-optimization process deploys the reserves on a nodal basis with the impact of deployment at a node on a transmission constraint modeled by the shift factor for that node. It does not force a pro-rata deployment of reserves; different reserve deployment plans may be calculated for events in different zones. These changes should improve transmission constraint modeling.

When an event does occur, MISO could use a weighted-pro-rata reserve deployment method, with the weights dependent on the event's zone and a by-product of the market clearing process. This should be as fast and robust as the current pro-rata methodology.

Equilibrium of Electricity Market Efficiency and Power System Operation Risk - An IEEE Task Force Review

Hong Chen, Senior Consultant, PJM Interconnection (*Norristown, PA*)

With the objective to survey the practices on electricity market operation efficiency measures and provide recommendations, IEEE Task Force "Equilibrium of Electricity Market Efficiency and Power System Operation Risk" was created in 2009. The focus of the TF is to analyze the interaction between system operation and market operation, and emphasize on achieving the balance between operation risk mitigation and market efficiency. From 2009 to 2012, 24 panelists including well-known scholars in electricity market designs and experts from the industry, contributed to the TF at four panel sessions at IEEE PES General Meetings. The panel topics included "Equilibrium of electricity market efficiency and power system operation: state-of-the-art and tomorrow" (2009), "Risk-constrained power system operation: how far are we from market efficiency" (2010), "Measuring market efficiency in power systems operations: Transmission Perspective" (2011), and "Toward Efficient System

Operation: Generation Perspective" (2012). This presentation will summarize the topics addressed by the Task Force panelists, based on which a road map of defining the equilibrium of market efficiency and operation risk will be discussed.

Transmission Outage Economic Analysis Using Market Simulation Software

Lee Blaede, Lead Outage Coordinator, ISO New England (*Holyoke, MA*)
Jim David, Product Manager for Market Applications, PowerGEM (*Clifton Park, NY*)
Boris Gisin, Vice President, PowerGEM (*Clifton Park, NY*)

Transmission outages can have significant impact on the day ahead and real time market outcomes; congestion payments, FTR funding and uplift charges. Analyzing the economic impact of outages requires evaluation of numerous scenarios spanning multiple days, using software capable of reproducing full scale production network and market models.

ISO New England has developed processes for evaluating the market cost of owner-submitted transmission outages based on a version of PROBE market simulation software, created by PowerGEM LLC and customized for ISO New England market rules.

ISO New England's Long Term and Short Term Economic Analysis processes are unique in the wholesale electricity industry and provide a systematic approach to reschedule or cancel an outage consistent with ISO market rules. The process has resulted in load cost savings, enhanced market efficiency, and improvements in outage planning by transmission owners.

This presentation will cover the motivating factors, major milestones and the overall effectiveness of the Transmission Outage Economic Analysis process, as well as a discussion of the general study case set-up and implementation details. The concluding discussion will focus on further development needs and possible expanded applications.

AC Optimal Power Flow: History and Formulations

Mary Cain, Electrical Engineer, Federal Energy Regulatory Commission (*Washington, DC*)

The AC Optimal Power Flow (ACOPF) is at the heart of Independent System Operator (ISO) power markets, and is solved in some form every year for system planning, every day for day-ahead markets, every hour, and even every 5 minutes. It was first formulated in 1962, and formulations have changed little over the years. With advances in computing power and solution algorithms, we can model more of the constraints and remove unnecessary limits and approximations. Today, 50 years after the problem was formulated, we still do not have a fast, robust solution technique for the ACOPF. Based on a literature review, we lack a common understanding of the problem, its formulation, and objective functions. This paper seeks to better understand the ACOPF problem through clear formulations of the problem and its parameters. This paper defines and discusses the polar power-voltage, rectangular power-reactive power, and rectangular current-voltage formulations of the

ACOPF; different types of constraints; objective functions; and a literature review of ACOPF formulations. This paper lays the groundwork for further research on the convexity of the ACOPF solution space, a comparison of solution techniques, and a comparison of performance with different formulations.

Session MC-1 (Monday, June 25, 1:30 PM, Commission Meeting Room)

Multi-Area Optimal Power Flow with Transmission Switching

Cong Liu, Engineer, Energy Systems, Argonne National Laboratory (*Argonne, IL*)
Jianhui Wang, Computational Engineer, Argonne National Laboratory (*Argonne, IL*)
Jieqiu Chen, Argonne Scholar, Argonne National Laboratory (*Argonne, IL*)

We try to separate the whole network into several sub-networks and solve the multi-area optimal power flow with transmission switching problem by augmented Lagrangian relaxation. Lagrangian multipliers and quadratic penalty terms will be introduced to relax the boundary power flow variables of tie-lines between two adjacent areas. Then the dual problem of the original problem will be decomposed into several sub-problems associated with each area. With the updated Lagrangian multipliers, the dual problem is solved iteratively. The solution of the dual problem will provide a lower bound for the solution. After solving the dual problem in each loop, we fix the topology of the network and solve the security-constrained economic dispatch problem which can result in an upper bound for the solution. The program can stop once the gap between the upper and lower bounds satisfies a small predefined value.

Robust Corrective Transmission Switching Schemes

Kory Hedman, Professor, Arizona State University (*Tempe, AZ*)
Akshay Korad, PhD Student, Arizona State University (*Tempe, AZ*)

Corrective transmission switching has been proposed since the 1980s as a corrective mechanism for line overloads, voltage violations, and other constraint violations. PJM's transmission operations manual includes special protection schemes (SPSs) that involve corrective switching. While such implementation of corrective switching demonstrates its potential, corrective transmission switching is limited today. Corrective transmission switching is a complex nonlinear, non-convex combinatorial problem. Past research has proposed real-time corrective switching algorithms. While a real-time algorithm is preferred, it is too difficult to solve in real-time. Offline corrective switching algorithms have been proposed but these approaches require predicting the operating state. If the prediction is incorrect, the switching action may make the situation worse.

A robust corrective transmission switching framework is proposed to eliminate the drawbacks of these alternative approaches. Robust optimization involves the modeling of uncertainty sets, which allows the operating state to be modeled by an uncertainty set instead of a single state. The corrective actions are, therefore, guaranteed to be feasible for any operating state within that uncertainty set. This enables the operator to solve the robust corrective switching problem offline while guaranteeing its feasibility for a wide range of operating states. This process can be used to produce multiple candidate switching actions that can be fed into a dynamic security assessment tool, resulting in a real-time protocol that evaluates the offline proposed switching actions and determines, in real-time, the best switching action. The robust corrective switching model, its multi-stage optimization framework, and results will be presented.

Topology Control Algorithms (TCA): Economic and Corrective Applications

Pablo Ruiz, Associate Principal, Charles River Associates (*Boston, MA*)
Justin Foster, Graduate Student, Boston University (*Boston, MA*)
Michael Caramanis, Professor, Boston University (*Boston, MA*)
Aleksandr Rudkevich, President, Newton Energy Group (*Newton, MA*)

Transmission topology control is currently employed by power system operators mostly for reliability purposes, e.g., in special protection schemes, rather than for economic reasons. The standard economic dispatch (ED) minimizes production costs subject to a fixed transmission network topology. While the co-optimization of network topology and generation resources has been shown to provide significant congestion cost reductions, it requires the solution of a mixed integer program (MIP), which is intractable even for moderate-size systems. Our previous work developed near-optimal and yet tractable topology control algorithms (TCA) that employ sensitivity information readily available from the standard ED solution to determine candidate lines for disconnection. This presentation will report on advances to TCA, including the incorporation of sensitivities for line connections and simulation of TCA performance in corrective scenarios. Simulation results on the IEEE 118-bus test system found that, besides giving near-optimal generation cost savings of over 90% of the maximum attainable, TCA is very effective in providing corrective switching actions with minimal computational effort. In particular, in infeasibility situations after a forced outage, the algorithm quickly identifies few line connections (one or two in this test system) that would restore feasibility, making the switching actions relatively easy to implement. Current TCA activities, funded by DOE ARPA-E, include developing tractable policies that can be used in large systems such as PJM, and that meet stability and voltage reliability criteria.

Scheduling and Pricing Under Variable and Uncertain Power Systems

Erik Ela, Engineer, National Renewable Energy Laboratory (*Golden, CO*)
Bri-Mathias Hodge, National Renewable Energy Laboratory (*Golden, CO*)
Michael Milligan, National Renewable Energy Laboratory (*Golden, CO*)
Mark O'Malley, University College Dublin (*Dublin, Ireland*)

The National Renewable Energy Laboratory will provide an update of ongoing work on the modeling of power systems under variable and uncertain resources. Variability is the changing of system states that are known to occur. Uncertainty is the condition of encountering unanticipated states. Variability causes impacts when occurring at time resolutions the power system is not prepared for. For example, the collective ramp rates are insufficient, or the scheduling model resolution is slower than the variability. Uncertainty causes impacts when the realized state was not planned for. For example, scheduling towards multiple scenarios (stochastic scheduling) or incorporating contingency constraints can reduce the impact as more states are being planned for. Variability and uncertainty occur at multiple timescales and the impacts include frequency error, area control error, transmission overloading, and voltage violations, as well as costs. For both variability and uncertainty, specifications of operating reserves can be used to limit these impacts. Reducing time resolution of scheduling models and representing more scenarios in stochastic scheduling models can limit the impacts of variability and uncertainty, respectively, in a more efficient manner. However, both have computational costs. If more intelligent operating reserve determination were performed to reduce the impacts in a manner as close as possible as reductions in time resolution of the scheduling model and representations of more scenarios in stochastic scheduling models, the scheduling and the pricing that result should also be similar. We introduce some new scheduling and pricing proposals that show this affect using NREL's multi-timescale FESTIV model.

Session MC-2 (Monday, June 25, 1:30 PM, Meeting Room 3M-3)

Stochastic Optimization for Market Clearing: Advances in Computation and Economic Implications

Victor Zavala, Assistant Computational Mathematician, Argonne National Laboratory (*Argonne, IL*)
Mihai Anitescu, Computational Mathematician, Argonne National Laboratory (*Argonne, IL*)
John Birge, Professor, University of Chicago (*Chicago, IL*)

We present advances in stochastic unit commitment and economic dispatch. In particular, we present a new parallel simplex-based solver that exploits the structure of scenario-based formulations in distributed memory environments. In addition, we discuss how stochastic formulations can achieve more consistent day-ahead prices and can mitigate real-time market volatility.

Computational Challenges in Financial Transmission Rights Markets

Joseph Bright, Vice President, Nexant, Inc. (*Chandler, AZ*)
Mauro Prais, Principal, Nexant, Inc. (*Chandler, AZ*)
Narasimham Vempati, Vice President, Nexant, Inc. (*Chandler, AZ*)

Compared with other security-constrained optimal power flow (OPF) applications, the Financial Transmission Rights (FTR) auction calculation has a singular tendency towards rapidly-escalating amounts of computation. Among the more obvious reasons are: (a) large and increasing network model sizes, (b) the inclusion of FTR Options, whose network constraints are nonsparse, and (c) the massive numbers of individual bids that might be submitted, for speculative price discovery and/or in lieu of stepped and sloped bids.

Another reason for the rapidly-increasing computational challenge is the trend towards multi-period FTRs. In such an auction, the numbers of transmission constraints—hundreds of millions in some cases—increase with the number of periods. In addition, ISOs are finding that, to properly constrain FTR awards and to address difficulties with future flow gates, they need to simulate more contingency cases. Still further, uncertainties in transmission project in-service dates lead to the scaling of future incremental transmission capacity releases, which heavily increases the numbers of binding constraints.

One more contributor to high computational effort is the tendency of single and multi-period FTR auction OPF formulations to be degenerate. As a result, equally-eligible auction participants may receive awards of different amounts and values. This is very undesirable in a transparent, auditable FTR market. Making awards demonstrably equitable can be computationally expensive—degeneracy is often undetectable by calculation pre-processing and unfixable simply by post-processing.

Advanced Methods for FTR

Stephen Elbert, Pacific Northwest National Laboratory (*Richland, WA*)
Karanjit Kalsi, Pacific Northwest National Laboratory (*Richland, WA*)
Kurt Glaesemann, Pacific Northwest National Laboratory (*Richland, WA*)
Maria Vlachopoulou, Pacific Northwest National Laboratory (*Richland, WA*)
Mark Rice, Pacific Northwest National Laboratory (*Richland, WA*)
Ning Zhou, Pacific Northwest National Laboratory (*Richland, WA*)

Financial Transmission Rights (FTRs) help power market participants reduce price risks associated with transmission congestion. FTRs are issued based on a process of solving a constrained optimization problem with the objective to maximize the FTR social welfare under power flow security constraints. Security constraints for different FTR categories (monthly, seasonal or annual) are coupled and the number of constraints increases exponentially with the number of categories. Commercial software for FTR calculation can only provide limited categories of FTRs due to the inherent computational challenges. A novel non-linear dynamical system (NDS) approach is proposed to solve the optimization problem. The new formulation and performance of the NDS solver is benchmarked against the widely used linear programming (LP) solver in CPLEX™ and tested on large-scale systems using data from the Western Electricity Coordinating Council (WECC). The NDS based solver can be easily parallelized while exploiting the data structure of the revised formalism to avoid backfill of coupled blocks, maintain numerical stability, and simultaneously reducing computational complexity. The NDS is demonstrated to outperform the widely used CPLEX algorithms by over two orders of magnitude while exhibiting superior scalability.

Non-Stationary Stochastic Modeling and Learning for Large-Scale Failure and Recovery of Power Distribution Networks

Yun Wei, Graduate Student, Georgia Tech (*Atlanta, GA*)
Chuanyi Ji, Associate Professor, Georgia Tech (*Atlanta, GA*)
James Momoh, Professor, Howard University (*Washington, DC*)

A key objective of the smart grid is to improve reliability of utility provisioning to users. This, in particular, requires strengthening resilience of distribution networks that lie at the edge of the grid and are considered to be weak. The weakness of distribution networks is exposed under extreme conditions where electricity service to customers is disrupted repeatedly by external disturbances such as hurricanes, snow and ice storms. Systematic studies are lacking to characterize and to quantify resilience of distribution networks in response to large-scale disturbances. A challenge is that large-scale failure and recovery exhibit non-stationarity (randomness and time-dependency). It is an open problem how to characterize network resilience accordingly.

This work studies resilience of power distribution networks to large-scale disturbances in three aspects. First, a non-stationary random process is derived to characterize an entire life cycle of large-scale failure and recovery. Second, resilience is defined and analyzed based on the non-stationary the stochastic model. Third, the non-stationary stochastic model and the resilience metric are applied to real life examples of large-scale disruptions. Challenges and open issues will be discussed for further work.

Session MD-1 (Monday, June 25, 3:45 PM, Commission Meeting Room)

Computationally Efficient Optimal Transmission Switching: Solution Space Reduction

Clayton Barrows, PhD Candidate, Penn State University (*University Park, PA*)
Seth Blumsack, Penn State University (*University Park, PA*)
Russell Bent, Los Alamos National Laboratory (*Los Alamos, NM*)

Recent studies have shown that the dynamic removal of transmission lines from operation (“Transmission Switching”) can reduce the costs associated with power system operation. Smart Grid technologies introduce flexibility into the transmission network topology and enable state dependent co-optimization of generation and network topology. The optimal transmission topology problem has been posed in previous research on small test systems. However, the problem complexity and large system size makes optimal transmission switching (OTS) intractable on real power systems. We develop a screening method based on the un-switched system generator dispatch and linear distribution factors to identify switchable lines for congestion relief. The screen identifies the subset of transmission lines used as decision variables in the OTS problem. When compared to unscreened transmission switching, our screening method generates near-optimal generation dispatch and network topology solutions in a fraction of the time on the RTS-96 and IEEE 118-Bus benchmark networks.

Leveraging Block-Composable Optimization Modeling Environments for Transmission Switching and Unit Commitment

John Siirola, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)
Jean-Paul Watson, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)
David Woodruff, Professor, University of California, Davis (*Davis, CA*)

Computational tools for modeling mathematical programs are in wide-spread use for market optimization within both academia and industry. However, available commercial and open-source software packages broadly lack capabilities for specifying, manipulating, and solving hierarchically structured mathematical programs, e.g., in which sub-blocks of variables and constraints are composed to form a more complex, higher-level optimization model; ASCEND (http://www.ascend4.org) and Modelica (https://modelica.org) are notable exceptions. Our experience with real-world electric grid operations and planning problems indicates that this modeling capability is critical in a broad range of contexts, including developing a library of electrical system component models for supporting both DC and AC analysis of power systems, modeling investment, expansion, and switching decisions through approaches like Generalized Disjunctive Programming, and managing scenario structure and decomposition for stochastic optimization. In this presentation, we introduce a powerful mechanism for expressing, manipulating, and solving hierarchically or block structured mathematical programs. The mechanism is available in the Pyomo open-source Python modeling library, distributed as part of the broader Coopr project for optimization developed by researchers at Sandia National Laboratories, Texas A&M University, and the University of California, Davis. We demonstrate the use of this capability for expressing and solving stochastic unit commitment problems with transmission switching using a library of power flow models.

Islanding of Power Networks Using Line Switching and Mixed Integer Programming

Ken McKinnon, Professor, University of Edinburgh (*Edinburgh, United Kingdom*)
Paul Trodden, University of Edinburgh (*Edinburgh, United Kingdom*)
Andreas Grothey, University of Edinburgh (*Edinburgh, United Kingdom*)
Waqquas Bukhsh, University of Edinburgh (*Edinburgh, United Kingdom*)

In this talk, we present an approach to the problem of intentionally forming islands in a power network. Given an area of uncertainty in the network, the proposed approach uses mixed integer programming to isolate, by switching lines, the suspected components of the network, while minimizing the expected load shed and ensuring no system constraints are violated. When the DC power flow equations are used, the optimization problem is a mixed integer linear program. The solution to the optimization problem is islands that are balanced in load and generation, and satisfy power flow equations. Numerical examples on test networks up to 300 buses in size show that the method is computationally efficient.

New Operational and Planning Capabilities Based on the HELM Deterministic Load Flow

Ross Harding, CEO, Gridquant Inc (*Savannah, GA*)
Toni Trias Bonet, Founder, Gridquant Inc (*Savannah, GA*)
Jason Black, Research Leader, Battelle Memorial Institution (*Columbus, OH*)

The development of the Holomorphic Embedding Load Flow Method (HELM), provides a complete and always correct deterministic load flow solution. The speed and certainty of HELM has opened entirely new data views of real time and planning of grids and enables powerful decision tools. This presentation will overview the mathematical basis of HELM and examples of its application in planning and operations.

<u>Session MD-2 (Monday, June 25, 3:45 PM, Meeting Room 3M-3)</u>

The Price of Energy Storage

Michael Ferris, Professor, University of Wisconsin (*Madison, WI*)
Jesse Holzer, University of Wisconsin (*Madison, WI*)
Yanchao Liu, University of Wisconsin (*Madison, WI*)
Lisa Tang, University of Wisconsin (*Madison, WI*)

Uncertainty in forecasts and hourly fluctuations in demand are important stochastic effects that can be mitigated by storage (new batteries, pumping water uphill, charging EPVs). Determining the value of storage is a critical component to stimulate design and implementation of energy storage facilities and an associated market. We propose a multi-period stochastic MOPEC (multiple optimization problems with equilibrium constraints) formulation for the economic planning problem and exhibit the use of hydro, thermal, nuclear and renewable energy sources, coupled with mechanisms to store energy between periods and endogenously determine the price for storage. Extensions of the framework that facilitate hitting environmental goals within a non-cooperative generation capability will also be outlined.

Dynamic Scheduling of Operating Reserves in Electricity Markets with Wind Power

Zhi Zhou, Computational Engineer, Argonne National Laboratory (*Argonne, IL*)
Audun Botterud, Power System Engineer, Argonne National Laboratory (*Argonne, IL*)

Driven by increasing prices on fossil fuels and concerns about greenhouse gas (GHG) emissions, wind power is rapidly being introduced into the existing energy supply portfolio. However, the large scale integration of wind power into power systems gives rise to new challenges since the uncertainty from wind power adds to the overall level of uncertainty in the power system. One way to reduce the uncertainty is to use advanced wind power forecasting (WPF) methodologies to provide accurate wind power estimation. Besides WPF, we also need new operating reserve strategies to account for the new uncertainty and variability to ensure a reliable and cost-efficient system operation.

We propose a probabilistic methodology to estimate a demand curve for operating reserves which represents the amount that a system operator is willing to pay for these services. The demand curve is quantified by the cost of unserved energy and the expected loss of load, accounting for uncertainty from generator contingencies, load forecasting errors, and wind power forecasting error. The methodology addresses two key challenges in electricity market design, i.e. more efficient wind power integration and improved scarcity pricing.

In a case study, we apply the proposed operating reserve strategies in a two-settlement electricity market with centralized unit commitment and economic dispatch. We compare the proposed probabilistic approach to traditional deterministic operating reserve rules. In the case study, we use the Illinois power system to illustrate the efficiency of the proposed reserve market modeling approach combined with probabilistic wind power forecasting.

Multi-Settlement Simulation of Dynamic Reserve Procurement

Robert Entriken, Senior Project Manager, Electric Power Research Institute (*Palo Alto, CA*)
Taiyou Yong, President, Eversource Consulting, Inc. (*Folsom, CA*)
Russ Philbrick, President, Polaris Systems Optimization, Inc. (*Shoreline, WA*)
Aidan Tuohy, Senior Project Engineer, Electric Power Research Institute (*Knoxville, TN*)

This presentation uses a realistic system model to demonstrate how dynamic reserve requirements can be defined for real-time operation. Use of dynamic reserve requirements is especially beneficial for reliable and efficient integration of renewable generation. In this demonstration, the sequential dispatch process of vertically integrated utilities and energy markets was simulated using a multiple-cycle model that includes a day-ahead unit-commitment cycle with hourly intervals, an hour-ahead unit-commitment “pre-dispatch” cycle with 15-minute intervals, and a “real-time” 5-minute dispatch cycle. Dynamic reserve determination was applied to the hour-ahead cycle to identify reserves needed to mitigate errors in the forecast of renewable generation. The results demonstrate that dynamic reserve procurement is practical for both existing market systems and traditional utilities, and that dynamic procurement produces reserve-procurement policies that are more effective than less-dynamic, traditional policies.

Two-Stage Robust Optimization for N-k Contingency-Constrained Unit Commitment

Yongpei Guan, Associate Professor, University of Florida (*Gainesville, FL*)
Qianfan Wang, PhD Student, University of Florida (*Gainesville, FL*)
Jean-Paul Watson, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)

This paper proposes a two-stage robust optimization approach to solve the N-k contingency-constrained unit commitment (CCUC) problem. In our approach, both generator and transmission line contingencies are considered. As compared to the traditional approach using a given set of components as candidates for possible failures, our approach considers all possible component failure scenarios. We consider the objectives of minimizing the total generation cost under the worst-case contingency scenario and the total pre-contingency cost. We formulate CCUC as a two-stage robust optimization problem and develop a decomposition algorithm to enable tractable computation. In our algorithm, the master problem makes unit commitment decisions and the subproblem discovers the worstcase contingency scenarios. By using linearization techniques and duality theory, we transform the subproblem into a mixed-integer linear program (MILP). The most violated inequalities generated from the subproblem (in the form of primal cuts or dual cuts) are fed back into the master problem in each iteration. Our approach guarantees a globally optimal solution in a finite number of steps. In reported computational experiments, we test both the primal and dual cut approaches. Our computational results verify the effectiveness of the proposed approach.

Tuesday, June 26

Session TA (Tuesday, June 26, 8:30 AM, Commission Meeting Room)

A Method for Assessing Relative Efficiency of Central Generation and Distributed Energy Resources (DERs) in Distribution Feeders

Marija Ilic, Professor, Carnegie Mellon University (*Pittsburgh, PA*)

In this talk we present a systematic method for assessing potential benefits from integrating distributed energy resources (DERs) in distribution network systems. It is shown how to view DERs as multiple value products (MVPs) capable of reducing delivery losses, reducing stand-by reserve of central generation by scheduling selectively both distributed generation and responsive demand. The approach uses AI method for learning ahead of time the best combinations of actions by the DERs and reconfiguration of normally open switches during most likely faults for three classes of responsive users. The objective of the utility is to minimize the liability cost of not serving users according to their pre-specified priorities. An example of two IEEE standard feeders is simulated to provide illustration of the proposed method.

This presentation is based on the joint work with Ms. Siripha Julakarn, a doctoral student in the Engineering Public Policy at Carnegie Mellon University.

Software Tools For Optimized AC Power Flow Modeling and Load/Resource Ranking Modeling

Soorya Kuloor, CTO, GRIDiant Corporation (*Raleigh, NC*)
Richard E. Hammond, SVP, GRIDiant Corporation (*Berkeley, CA*)

The presentation will describe and demonstrate (through simulation) new software tools and methods offering applications of optimized AC power flow modeling and load/resource ranking to T&D network problems. The software tools and methods (i) facilitate development of detailed, nonlinear, 3-phase unbalanced models of distribution networks (or, alternatively, transmission or integrated T&D networks); and (ii) use a nonlinear, multi-objective optimization and load/resource ranking algorithm and engine, enabling calculation of the relative “value” (i.e., relative value to prescribed network performance optimization objectives) of any given dispatchable DER load/resource at any specific location (node or bus) of a power network, under specific network conditions, and under specified operating constraints and contingencies. The method’s optimization algorithm simultaneously combines optimization of the subject network for assigned network performance optimization objectives (e.g., minimize P and/or Q losses; optimize Volt/VAr; minimize voltage angle deviation; minimize branch current flow) with (a) comprehensive measurement of system resources, and/or (b) the amount of mathematical "stress" placed on each node of the network in meeting network-wide constraints; the sensitivity indices generated by the algorithm are used to index and rank resources and conditions at all individual nodes on the network with respect to their relative sensitivity to the network objectives specified under each optimization scenario. The presentation will describe use of the software to perform optimization and ranking runs of large combined transmission and distribution network models (to date, up to 95,000 - 115,000 buses) in near real-time, and demonstrate current applications to such problems as DER siting, integration, and mitigation.

Distributed Computing and Stochastic Control for Demand Response in the Day-Ahead and Real-Time Markets

Alex Papalexopoulos, President and CEO, ECCO International (*San Francisco, CA*)
Steve Florek, CTO, ZOME Energy Networks (*Cambridge, MA*)
Jacob Beal, Research Scientist, Raytheon BBN Technologies (*Cambridge, MA*)

Even though Demand Response (DR) participation has substantial benefits to the Day-Ahead and Real-Time markets, current DR programs suffer from a series of market, regulatory, infrastructure and technology problems, such as lack of scalability, privacy, precision and accuracy. DR can assist RTOs/ISOs to balance supply and demand by providing an alternative mechanism to dispatching high-supply resources to meet demand, thus reducing market prices and market volatility, can mitigates supply market power by increasing competition and putting downward pressure on generators' strategies to bid at high levels, and can enhance system reliability and resource adequacy.

In this presentation well present a fundamentally different approach than those currently adopted that is based on distributed computing and stochastic control. The proposed methodology solves many of the existing problems and has the potential to elevate DR resources into a potent capability that can improve the efficiency of the Day-Ahead and Real-Time energy markets.

The coordination problem of determining which devices should consume power at what times is solved through distributed aggregation and stochastic control. Under this approach, the consumer designates devices using "colors" that correspond to control plans. These "color" markings are then used to organize devices into priority groups, dictating when devices are available for demand shaping and the order in which classes of devices will be enabled or disabled. The algorithm operates by aggregating this demand flexibility information into a global estimate of total consumer flexibility. This approach can be integrated with dynamic pricing or other "service level" plans offered in other industries.

<u>Session TB (Tuesday, June 26, 10:15 AM, Commission Meeting Room)</u>

A Linear-Programming Approximation of AC Power Flow Equations

Pascal Van Hentenryck, Professor and Optimization Research Group Leader, NICTA and University of Melbourne (*Melbourne, Australia*)
Carleton Coffrin, NICTA (*Melbourne, Australia*)

The Linearized DC Model is a reasonable approximation of the AC power flow equations in normal operating conditions for various classes of applications.

However, its accuracy degrades rapidly when used in other settings. This talk proposes a linear-programming approximation of

the power flow equations that remedies (most of) these limitations and captures reactive power and voltages. The linearized DC model and the linear-programming approximation are compared experimentally to AC solutions providing a comprehensive evaluation of the accuracy of these linear models over a wide range of benchmarks and operating conditions. Applications to largescale power restoration and reactive support are discussed.

Toward Reliable and Efficient On-Line Resource Management: A Ramp Rate-Limited AC Optimal Power Flow for Integrating Renewable Resources and Responsive Demand

Marija Ilic, Professor, Carnegie Mellon University/NETSS (*Pittsburgh, PA*)

The results of today's static DC OPF are generally not implementable in the actual power systems operations. This is caused by at least three different problems: 1) typical optimization output requires adjustments everywhere in the system; 2) it is not possible to adjust computed changes without taking into consideration the rates at which controlled variables can change; and, 3) non-feasible AC power flow for the optimized real power generation. These problems leave to the mercy of system operators to make ad-hoc adjustments, which distort the optimization results. Not negligible is the fact that after-the-fact adjustments create major changes in LMPs, which are often referred as ``out-of-market" adjustments. To make matters even worse, the strictly static DC OPF is hard to use when balancing systems with uncertain demand response and stochastic wind power generation.

In this talk we present a new algorithm, which overcomes the above basic operational problems when attempting to manage diverse resources efficiently. The algorithm is based on a careful combination of a model-predictive distributed algorithm proposed and the Extended AC OPF that NETSS has developed and tested. The inter-temporal and stochastic variations in wind power and demand response can be internalized when bids are created. Subjecting them to the AC OPF, at which stage T&D voltage controlled equipment can be also used to enhance the available transfer capability of the grid, clears these bids. The results are illustrated on an IEEE test system.

The Linearized IV ACOPF

Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)

The AC Optimal Power Flow (ACOPF) problem is an important problem because a one percent improvement in dispatch saves roughly 1 to 5 billion dollars per year in the US and 4 to 20 billion dollars per year in the world. In this paper, we formulate the ACOPF in several ways, compare each formulation's properties, and argue that the current-voltage or "IV" formulation and its linear approximations may be easier to solve than the traditional quadratic power flow "PQV" formulation. This allows the use of MIP algorithms that are exceptionally fast and robust to better model the power markets.

Session TC-1 (Tuesday, June 26, 1:00 PM, Commission Meeting Room)

Exploration of the ACOPF Feasible Region for the Standard IEEE Test Set

Aaron Schecter, Operations Research Analyst, Federal Energy Regulatory Commission (*Washington, DC*)

The goal of our investigation is to gain some perspective on how non-convex the feasible region of the Alternating Current Optimal Power Flow (ACOPF) problem is. Frist, we will develop a metric for comparing how infeasible different solutions are. The set-up for this examination will be to generate convex combinations of feasible points, and determine how "far" thes new points are from the feasible region. We propose a metric based on the relative $\ell 2$-norm. This value will be compared over various regions around the optimal solution. Second, we would like to determine how elastic the area around the global optimum is; in other words, we will determine the largest range of values the optimization variables can take, given a small perturbation from the global solution. In doing so, we will find the elasticity of all optimization variables, which could give us insight into the structure of the feasible region.

Robust DC-OPF

Daniel Bienstock, Professor, IEOR and APAM, Columbia University (*New York, NY*)
Michael Chertkov, Los Alamos National Laboratory (*Los Alamos, NM*)
Sean Harnett, APAM, Columbia University (*New York, NY*)

We consider a power system incorporating uncertain power sources (e.g. wind farms) that are modeled as independent random variables. We propose a family of controls that automatically regulate the output of normal generators in order to match variability of the uncertain sources. This makes generator outputs and power flows into random variables, which may exceed their ratings. We show how a sparse formulation allows us to express moments (means, variances, etc.) of power flows as functions of the uncertain outputs; this makes it possible to formulate the optimal control problem (minimize expected cost of the generator operation) as a practicable optimization problem with chance constraints used to represent the line (and generator) ratings (a chance constraint states that an event happens with arbitrarily small probability). We present a number of experiments using realistic grids.

Some Key Requirements for Practical OPF Calculations

Ongun Alsaç, Consultant, Nexant, Inc. (*Chandler, AZ*)
Brian Stott, Consultant, Nexant, Inc. (*Chandler, AZ*)
Joseph Bright, Vice President, Nexant, Inc. (*Chandler, CA*)
Mauro Prais, Principal, Nexant, Inc. (*Chandler, AZ*)

Optimal power flow (OPF) calculations have become critical to power systems operation/control, markets, and planning. Modern OPF formulations address more and more complex and comprehensive problems, and OPF solutions are increasingly embedded in bigger calculations.

Powerful general-purpose commercial packages are in widespread use as OPF "central optimizers". At the same time, a large part of any practical OPF calculation process must take place outside the central optimizer. This part includes a great deal of solution-seeking and modeling logic that is substantially heuristic. It typically involves a series of major abrupt changes in constraints, controls and objective functions.

Vast amounts of R&D have been performed on OPF during the last fifty years. However, fully reliable and usable OPF solutions are still not easy to obtain. Better methods and software are continually being pursued. To obtain practically useful OPF solutions, it is necessary to satisfy multiple requirements such as reliability, speed and modeling veracity, with appropriate behavior in the face of infeasibility, degeneracy, and so on.

This presentation, based on the authors' decades of experience, briefly outlines some of these solution requirements from the viewpoints of (a) users seeking better OPF tools and (b) researchers and developers trying to provide such tools.

Applying Voltage/VAr Management to Support Energy Markets

Herminio Pinto, Application Manager, Nexant, Inc. (*Chandler, AZ*)
Joseph Bright, Vice President, Nexant, Inc. (*Chandler, AZ*)
Mauro Prais, Principal, Nexant, Inc. (*Chandler, AZ*)
Brian Stott, Consultant, Nexant, Inc. (*Chandler, AZ*)
Martin Geidl, Swissgrid AG (*Laufenburg, Switzerland*)

As day-ahead (DAM) and real-time energy (RTM) markets mature, there is increasing pressure to incorporate new services into them, particularly those related to ancillary services. One such service— voltage and VAr management (VVM) is currently receiving attention from ISOs and RTOs. This leads to the formulation and solution of appropriate types of optimal power flow (OPF) problems with full AC network models.

Advances have recently been made in powerful general purpose commercial optimization solvers, especially quadratically-constrained programming (QCP) and mixed-integer quadratically-constrained programming (MIQCP). It is tempting to imagine that these make AC-model optimal power flow solutions relatively straightforward, that VVM can be incorporated into DAM and RTM, and therefore that full AC-modeled DAM and RTM are around the corner. However, there are two pitfalls: (a) fully reliable and usable AC OPF solutions are still not easy to obtain, and (b) including voltage/VAr management services into energy markets can potentially cause price distortions.

In this presentation, the authors advocate the use of VVM loosely integrated to DAM and RTM as a support tool for reliability purpose. This approach can also allow ISOs and RTOs to assess the impact of VMM in energy markets, as a learning process on the way towards implementing VVM as an ancillary service in the future. As an illustration of the proposed VVM, we describe experience with it by the Swiss national transmission system operator (TSO) Swissgrid.

Session TC-2 (Tuesday, June 26, 1:00 PM, Meeting Room 3M-3)

The Evolution of Planning Software

Devin Van Zandt, Software Product Manager, GE Energy (*Schenectady, NY*)
Mark Walling, Application Engineer, GE Energy (*Schenectady, NY*)

The presentation will be focused on the future evolution of planning tools to meet the changing needs of the power industry. Future tools need to accommodate much larger systems, advanced scenario analysis, and strong visualization capabilities. The presentation will discuss the major industry drivers and how we are building capability into our planning tools for the future.

Locational Assessment of Resource Adequacy and Co-Optimization of Generation and Transmission Expansion

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

The resource adequacy evaluation of the bulk electricity supply is a critical driver of power system planning processes. Before the functional unbundling and deregulation of electricity markets, system planning was a centralized process for relatively self-sufficient concentrated territories served by vertically integrated utility companies. Since deregulation, generation supply has been de-centralized to competitive markets, driven by power purchase agreements and/or the establishment of capacity markets. Meanwhile, the responsibility for transmission planning remains primarily with regulated utilities, often coordinated in regional transmission organizations. The decoupling of generation and transmission planning requires more advanced means for resource adequacy assessment. Improvements to these processes are critical due to the need to integrate variable renewable generating resources on a massive scale combined with imminent retirement of a large portion of the existing coal-fired fleet. The proposed presentation will provide a formulation of the generation and transmission expansion problem which incorporates resource adequacy assessment into the stochastic optimization framework. The system expansion problem is considered as an auction resolved through a stochastic mixed integer linear problem in which generation and transmission expansion offers are explicitly identified on the electrical grid. In this formulation, locational resource adequacy indicators are derived as dual variables: shadow prices for reliability limiting transmission facilities and Locational Stochastic Reliability Prices (LSRPs). These indicators help to identify resource locations or transmission segments that are in need of expansion and/or reinforcement. The ideas on the co-optimization algorithm inspired by topology control approaches used in operational models will be discussed.

Evaluating the Wind/Solar Generation Variability and Forecast Error Mitigation Using Day-Ahead and Real-Time Market Interleaved/Sequential Simulations

Tao Guo, Manager of Tech Services, Energy Exemplar, LLC (*Roseville, CA*)
Zheng Zhou, Principal Engineer, MISO (*St. Paul, MN*)

Increasing wind and solar generation penetration in the deregulated markets presents a challenge to the market designer and operator. The Day-ahead (DA) market schedule produces hourly unit commitment schedule with the forecasted load, wind and solar generation. The real-time (RT) market dispatches the committed resources to accommodate the actual intra-hourly wind and solar generation that is different to that which was forecasted. The storage facilities are flexible resources that can be deployed in the real-time market for this purpose.

A DA-RT interleaved simulation algorithm is implemented in the Power Market Simulation software, PLEXOS®, to evaluate the effectiveness of the storage facilities to accommodate the wind and solar generation variability and forecast error. This feature is applied to value the benefit of a hydro-dominated utility participation in the MISO DA and RT markets. The interleaved run mode represents a significant technological advancement over traditional sequential DA-RT simulations.

This approach can be used to quantify the value of other measures in the markets to accommodate the wind and solar generation variability and forecast error: such as demand response programs, distributed generation facility, transmission expansion, etc. The operational reserve adequacy can be determined by using multiple-sample DA-RT simulation. In coupling with the stochastic optimization, the DA-RT interleaved stochastic unit commitment simulation will provide a means for the market designer to determine the committed on-line capacity with the least cost and risk.

Auction Design for Wholesale Electricity Markets

Haso Peljto, President, EMCon2 - Energy Market Consulting, Inc. (*Brooklyn Park, MN*)

The design of the existing wholesale electricity markets is limited in both financial and technological aspects. Even passing several evolving stages over last decades, the existing electricity markets are lacking high level of efficiency reflected in reduced competition, increased financial and operation risks, and strong market power. These departures from efficient market operation are dictated by political environments, market participant forces and electricity market development stage. The proposed auction design for wholesale electricity markets is based on the following four principles:

1. Economic Efficiency: Market commodity clearing is economically optimal for overall electricity market and based on Fenchel decomposition of convex hull model.

2. Incentive Compatibility: The best strategy for market participants is to submit truthful bids and offers. This eliminates market power instead of its mitigation.

3. Voluntary Participation: Market participation should not be harmful, i.e. each market participant have non-negative profit.

4. Budget Balance: Market commodity payments and charges are financially balanced without subsidiaries.

Market with these properties is impossible under general settings due to Impossibility Theorem. In this proposal, the settings are reduced to specifics of wholesale electricity markets and violations of above design principles are minimized and can be even eliminated in some market segments.

Session TD-1 (Tuesday, June 26, 3:15 PM, Commission Meeting Room)

An Efficient Computational Method for Large-Scale Operations Planning

Javad Lavaei, Postdoctoral Scholar, Stanford University (*Palo Alto, CA*)
Somayeh Sojoudi, PhD Candidate, California Institute of Technology (*Pasadena, CA*)
Steven Low, Professor, California Institute of Technology (*Pasadena, CA*)
Baosen Zhang, University of California, Berkeley (*Berkeley, CA*)
David Tse, Professor, University of California, Berkeley (*Berkeley, CA*)
Matt Kraning, PhD Candidate, Stanford University (*Palo Alto, CA*)
Eric Chu, PhD Candidate, Stanford University (*Palo Alto, CA*)
Stephen Boyd, Professor, Stanford University (*Palo Alto, CA*)

The operation of next generation electric grids will likely rely on solving large-scale, dynamic optimization problems involving hundreds of thousands of devices jointly optimizing millions of variables, on the order of seconds rather than minutes. More precisely, the distribution level of a smart grid will include various types of active dynamic devices, such as distributed generators based on solar and wind, batteries, deferrable loads, curtailable loads, and electric vehicles, whose control and scheduling amount to a very complex power management problem.

This presentation aims to propose an efficient numerical algorithm for solving large-scale optimizations related to operations planning (e.g., optimal power flow, state estimation and scheduling). First, we show that the non-convexity imposed by nonlinear physical laws can introduce inferior local solutions that are very far from the global solution. To address this issue, we derive various theories for both transmission and distribution networks, and then prove that the non-convexity can be eliminated by exploiting the physics of transmission lines and transformers. We also propose a scalable, parallelizable algorithm for solving the convexified problem. We finally discuss the implementation of this algorithm in our custom solver, which is able to solve a 10,000-bus optimal power flow problem in less than 1 second on a single core machine and a dynamic scheduling problem with 10,000,000 variables in less than 20 minutes on an 8-core machine.

Branch Flow Model: Relaxations, Convexification, Computation

Steven Low, Professor, California Institute of Technology (*Pasadena, CA*)
Masoud Farivar, Student, California Institute of Technology (*Pasadena, CA*)
Subhonmesh Bose, Student, California Institute of Technology (*Pasadena, CA*)
Lingwen Gan, Student, California Institute of Technology (*Pasadena, CA*)
Mani Chandy, Professor, California Institute of Technology (*Pasadena, CA*)

We propose a branch flow model for the analysis and optimization of mesh as well as radial networks. The model leads to a new approach to solving optimal power flow (OPF) problems that consists of two relaxation steps. The first step eliminates the voltage and current angles and the second step approximates the resulting problem by a conic program that can be solved efficiently. For radial networks, we prove that both relaxation steps are always exact, provided there are no upper bounds on loads. For mesh networks, the conic relaxation is always exact and we characterize when the angle relaxation may fail. We propose a simple method to convexify a mesh network using phase shifters so that both relaxation steps are always exact and OPF for the convexified network can always be solved efficiently for a globally optimal solution. We prove that convexification requires phase shifters only outside a spanning tree of the network graph and their placement depends only on network topology, not on power flows, generation, loads, or operating constraints. Since power networks are sparse, the number of required phase shifters may be relatively small. We present a simple scalable distributed solution that can be easily parallelized or implemented on a large power network. Finally, we relate this model to the popular bus injection model and semidefinite relaxation.

Conic Relaxations of ACOPF

Chen Chen, PhD Student, University of California, Berkeley (*Berkeley, CA*)
Alper Atamturk, Professor, University of California, Berkeley (*Berkeley, CA*)
Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)
Shmuel Oren, Professor, University of California, Berkeley (*Berkeley, CA*)

We examine the potential for conic relaxations to help find global optimal solutions to the Alternating Current Optimal Power Flow problem (ACOPF). Experimental and theoretical results suggest that various conic relaxations can provide either an exact solution, or else a good lower bound. Furthermore, we show that, despite being weaker than semidefinite relaxations, second-order cone relaxations can be effectively strengthened with the use of cutting planes.

Session TD-2 (Tuesday, June 26, 3:15 PM, Meeting Room 3M-3)

Applying High Performance Computing to Multi Area Stochastic Unit Commitment for Wind Penetration

Anthony Papavasiliou, University of California, Berkeley, IEOR (*Berkeley, CA*)
Shmuel Oren, Professor, University of California, Berkeley, IEOR (*Berkeley, CA*)

We use a two-stage stochastic programming formulation in order to schedule locational generation reserves that hedge power system operations against the uncertainty of renewable power supply. We present a parallel implementation of a Lagrangian relaxation algorithm for solving the stochastic unit commitment problem. The model we present addresses the uncertainty of wind power supply, the possibility of generator and transmission line outages and transmission constraints on the flow of power over the network. We present a scenario selection algorithm for representing uncertainty in terms of a moderate number of appropriately weighted scenarios and use a high performance computing cluster in order to validate the quality of our scenario selection algorithm. Our results indicate that minimizing the Lagrangian duality gap is as important as including a very large number of scenarios in the stochastic unit commitment formulation. We compare the performance of our approach to N-1 reliable unit commitment. We examine the dependence of the Lagrangian duality gap on the number of scenarios in the model and relate our results to theoretical bounds provided in the literature. We finally report results regarding speedup and efficiency and discuss the scalability of our proposed algorithm.

SMART-ISO: A Stochastic, Multiscale Model of the PJM Power Grid

Warren B. Powell, Professor, PENSA Laboratory, Department of Operations Research and Financial Engineering, Pricenton University (*Princeton, NJ*)
Boris Defoumy, Post-Doctoral Research Associate, PENSA Laboratory, Department of Operations Research and Financial Engineering, Pricenton University (*Princeton, NJ*)
Hugo Simao, Senior Professional Staff, PENSA Laboratory, Department of Operations Research and Financial Engineering, Pricenton University (*Princeton, NJ*)

We will describe the development of a detailed stochastic, dynamic model of the PJM power grid which is being designed with the goal of performing a wide range of simulations to test new policies, the effect of high penetration of renewables, distributed grid-level storage, advanced communication, and a variety of other questions facing grids of the future. SMART-ISO includes a full model of the PJM power grid, a robust day-ahead model for stochastic unit commitment, hour-ahead modeling for planning natural gas simulation, and economic dispatch solved at five minute increments for accurate modeling of ramp rates of natural gas units and variations in renewables. A central feature of the model is the careful handling of uncertainty. A stochastic model of wind is being developed for both day-ahead and hour-ahead forecasts. The day-ahead model uses a quantile-optimization algorithm with feedback learning to produce robust plans for steam generation, while the hour-ahead and economic dispatch models handle the dynamics (and uncertainty) of real-time operations. We will report on the status of this multi-year development effort, including a summary of what is working now and our goals over the coming year.

Scalable, Parallel Stochastic Unit Commitment for Day-Ahead and Reliability Operations

Jean-Paul Watson, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)
David L. Woodruff, Professor, University of California, Davis (*Davis, CA*)
Roger J.B. Wets, Professor, University of California, Davis (*Davis, CA*)
Sarah M. Ryan, Professor, Iowa State University (*Ames, IA*)
Ross Guttromson, Technical Manager, Sandia National Laboratories (*Albuquerque, NM*)
Cesar Silva-Monroy, Senior Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)

Market management systems (MMSs) determine which generation resources should be used to securely and optimally service expected load on the grid. At the heart of a modern MMS is a mixed-integer security-constrained unit commitment (SCUC) optimization algorithm operating in tandem with a security-constrained economic dispatch (SCED) optimization algorithm. Together, these algorithms are used by independent system operators (ISOs) to commit, price, and dispatch generation resources. The growing penetration of intermittent renewable generation necessitates a shift to stochasticvariants of the SCUC / SCED optimization algorithms, in order to deal with the inherent uncertaintyin power production. In this talk, we will describe the stochastic programming SCUC/SCED formulations and algorithms that are currently being developed and tested under an effort recently funded by the ARPA-e GENI program, for eventual use in commercial MMSs. Our focus is on scaling stochastic SCUC / SCED algorithms to realistic deployment environments. The work includes developing stochastic process models for load and variable generation from which probabilistic scenario trees will be generated to combine with deterministic SCUC/SCED formulations. Using scenario-based decomposition strategies implemented in Sandia National Laboratories' PySP library for stochastic programming, we are devising lower- and upper-bounding procedures to facilitate identification of near-optimal solutions to ISO-sized instances within reasonable computation times. The proposed algorithms leverage and are deployed on modest-scaling parallel computing resources, e.g., commodity clusters. We discuss challenges and solutions to the parallelization of scenario-based decomposition algorithms, including asynchronous computation and scenario bundling strategies.

Wednesday, June 27

Session WA (Wednesday, June 27, 8:30 AM, Commission Meeting Room)

Look-Ahead Unit Commitment with Robust Optimization

Xing Wang, Manager, Optimization Applications, Alstom Grid (*Redmond, WA*)
Peter Nieuwesteeg, Senior Specialist, Paragon Technology (*Bellevue, WA*)

Started from real-time resource initial status and network topology, Look-Ahead Security Constrained Unit Commitment (LA-SCUC) provides the system operator with incremental resource (mainly fast-start resources) commitment/de-commitment recommendations based on the day-ahead schedule, to manage the upcoming peak and valley demands and interchange schedules while satisfying transmission security constraints and reserve requirements.

We will present a Robust Optimization (RO) based LA-SCUC algorithm, in order to provide a more robust fast-start unit commitment recommendations that are immunized to the operational uncertainties in the look-ahead time frame.

The RO approach applied here is the approach based on Linear Decision Rules (LDR) which was originally proposed by Ben-Tal etc. in 2004. The LDR based approach makes the a priori assumption that the adjustable decisions depend linearly (affinely) on the uncertain parameters. This means that the dispatch decisions are no longer fully adjustable, but are restricted to values of the form provided by the LDR. The proposed method is implemented very conveniently by using a mathematical modeling tool, named AIMMS. Numerical examples are provided to compare the solution from the proposed RO LA-SCUC and the solution from the scenario based deterministic UC, in order to quantify the cost of robustness. Computational performance of RO LA-SCUC is benchmarked using real data from a large RTO system.

MIP Technology Improvements

Edward Rothberg, Chief Operating Officer, Gurobi Optimization (*Palo Alto, CA*)

This talk will consider some of the implications of continued improvements in MIP technology on power industry models.

Algorithms for Solving Large-Scale Stochastic Unit Commitment and Security-Constrained Economic Dispatch Problems

Dzung Phan, Research Staff Member, IBM T.J. Watson Research Center (*Yorktown Heights, NY*)
Ali Koc, Postdoctoral Researcher, IBM T.J. Watson Research Center (*Yorktown Heights, NY*)
Jayant Kalagnanam, Research Staff Member, IBM T.J. Watson Research Center (*Yorktown Heights, NY*)

Unit commitment (UC) and optimal power flow (OPF) problems lie at the core of planning and operational decisions faced by ISOs, RTOs, and utility companies. They determine optimal up and down schedules and corresponding generation levels of a set of generators over a planning horizon so that total cost of generation and transmission is minimized, the forecasted demand is satisfied, and a set of operating constraints is observed. We present a parallel branch-cut-price algorithm for the stochastic UC problem that features a new weighting scheme and a lower bounding method to improve the algorithm, a constructive heuristic to restore near-optimal solutions, and two parallelization techniques that achieve almost linear speedups. We also propose a new scenario reduction technique and a scenario tree generation method to reduce the size of the stochastic UC. The security-constrained OPF takes into account both the pre-contingency and post-contingency constraints, which is formulated as a large-scale nonconvex optimization problem. We propose global methods based on Lagrangian duality to solve this problem to optimality. For practical uses when handling large-scale instances, we investigate two decomposition algorithms based on adaptive Benders cut and the alternating direction method of multipliers. These schemes often generate solutions whose objective values are smaller than the conventional approach and are very close to the globally optimal points. In addition, we present a two-stage program for the stochastic OPF, and introduce decomposition outer-approximation algorithms. We prove these proposed schemes solve the nonconvex problem to optimality under certain conditions. We present numerical simulations implemented in parallel.

Methods of Selecting the Desired Net Interchange Across Multi-Control Areas: Demonstration of Seams Solution for NPCC

Marija Ilic, Professor, Carnegie Mellon University/NETSS (*Pittsburgh, PA*)

To solve the seams problem, NETSS has developed a systematic hierarchical IT architecture for assisting both the evolving energy markets and reliable physical delivery (transmission and distribution) in an open access environment. The information hierarchies are both temporal (needed to assist delivery of real-time, Day Ahead Market (DAM), mid—and long-term energy transactions), and spatial (needed to provide consistent information at the industry layers ranging from the end users, through transmission owners (TOs), utilities, ISOs/Control Areas, regions (RTOs, and the like) all the way through the U.S. interconnection). The IT-based solution to the seams problem is based on designing consistent on-line information structure in support of interactions among the various layers (both temporal and spatial) within this overall IT hierarchical framework. The layers themselves do not have to be identical in any way; it is the consistency of the IT-facilitated interactions among the layers that provides a basis for trading and delivering energy in an open access manner across the corporate and functional boundaries. The interconnection is otherwise very non-uniform with respect to the physical and institutional structures comprising the physical layers of the traditional Control Areas and the vertically integrated utilities, as well as the evolving spot markets. Viewed this way, the currently perceived short-term (operational) IT seams problem becomes only one component of a much broader IT seams problem. We present an illustration of this method for the 12,000 nodes NPCC system.

Session WB (Wednesday, June 27, 10:45 AM, Commission Meeting Room)

Uncertainty of Renewable Power, Stochastic Unit Commitment, and Implication on DA Market

Xiaoming Feng, Executive Consulting R&D Engineer, ABB Corporate Research (*Raleigh, NC*)

The intermittency and uncertainty in renewable power poses a big challenge to efficient resource scheduling in the electricity market, especially in the day ahead market. The reduction in efficiency is caused by the difficult to predict deviation from the postulated renewable power generation scenario for which the market resources are optimized. With high level of renewable power penetration, there are multiple technical challenges that must be addressed. How do we characterize the stochastic nature of renewable power? Is stochastic unit commitment the solution? Should we use two stage or multi stage stochastic unit commitments? Why? What are the implications on the traditional DA market settlement and how should the DA market price be determined? What are the data requirements? How do we quantify the benefits of stochastic commitment and dispatch schedules, in operation and in simulation? What are the computational challenges? Is current generation of optimization technology ready to handle such challenges? What are the alternatives? We will look at the problem systematically and critically and share our opinions.

Improving Real-Time System Performance and Reliability by Using Synchrophasor Data

Marianna Vaiman, Executive VP, V&R Energy (*Los Angeles, CA*)

Region Of Stability Existence (ROSE) is a boundary-based software, which addresses the problem of utilizing the synchrophasor data to increase the situational awareness of the operators and improve stability and reliability of transmission grid.

ROSE provides continuous monitoring of power system conditions by incorporating high rate synchrophasor data into calculation of stability margin and visualization, and alarms the operator of the changes in the power system conditions (whether the system is “moving” closer to the boundary) before the next State Estimator case arrives. If the operating point and the boundary are moving towards each other, ROSE automatically identifies and recommends to the operator minimal optimal remedial actions before the new State Estimator case arrives and before the system collapse.

ROSE identifies the range of phasor measurements or other system parameters for which the system may securely operate in terms of the accepted N-k security criteria. Inside the boundary is the region of stability existence of the system. Each point on the boundary corresponds to a “nose” point on the P-V curve, or a thermal or voltage constraint being violated. Operating within this region is secure; operating outside this region corresponds to unreliable operation of a power system.

ROSE calculates system steady-state limits in real-time under normal and contingency conditions, and computes MW/MVAr/MVA margin on the interfaces or at load pockets.

ROSE has been selected as the synchrophasor-based voltage stability application for ISO New England Synchrophasor Infrastructure and Data Utilization (SIDU) Project and Western Interconnection Synchrophasor Program (WISP).

Adaptive Middleware for Real-Time Distributed Stream Processing

Yan Liu, Pacific Northwest National Laboratory (*Richland, WA*)

At Pacific Northwest National Laboratory (PNNL), we are developing distributed systems architecture that leverages parallel computing capability to support the real-time computing demand of decentralized power models, such as distributed state estimation with PMU measurements. In our current development, we see the needs of real-time streaming middleware to correct errors and adapt the computation on PMU measurements in a distributed architecture. In this talk, we present our software prototype under PNNLs future power grid initiative for managing distributed PMU streams. In a specific example, we present how PMU streams can be communicated through the advanced middleware and then utilized by distributed state estimation. The distributed architecture and middleware solution is applicable to other distributed power applications with real-time and reliability demands.

Competitive Markets for Imbalances, Not Penalties

Mark Lively, Professional Engineer, Utility Economic Engineers (*Gaithersburg, MD*)

The growth in the number of highly variable resources and loads requires utilities and regulators to rethink the ways that imbalances are priced. The most prevalent approach is penalty based, in that the participant always faces an adverse price for imbalances. A simple change of variables would allow the imbalances to face a competitive price, where the price can either be adverse to the participant or can be a reward to the participant depending on the concurrent imbalance on the utility. Participant imbalances that reduce the utility's imbalances would be rewarded instead of punished under the standard approach to imbalances.

An Affine Arithmetic Method to Solve the Stochastic Power Flow Problem Based on a Mixed Complementarity Formulation

Mehrdad Pirnia, PhD Candidate, Electrical Engineering Department, University of Waterloo (*Ontario, Canada*)
Claudio Canizares, Professor, Electrical Engineering Department, University of Waterloo (*Ontario, Canada*)
Kankar Bhattacharya, Professor, Electrical Engineering Department, University of Waterloo (*Ontario, Canada*)

We propose an affine-based stochastic power flow problem to incorporate uncertainties associated with renewable energy integration. First, a novel optimization-based model of the power flow problem using complementarity conditions to properly represent generator bus voltage controls, including reactive power limits and voltage recovery is presented. This model is then used to solve the stochastic power flow problem to obtain operational intervals for power flow variables based on an Affine Arithmetic (AA) method to consider active and reactive power demand uncertainties. The proposed AA algorithm is tested on a 14-bus test system and the results are then compared with the Monte-Carlo Simulation (MCS) results. The AA method shows slightly more conservative bounds; however, it is faster and does not need any information regarding statistical distributions of random variables.