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

Agenda

AD10-12-004
June 24 – 26, 2013

Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software (Docket No. AD10-12-004)

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

Draft Agenda (abstracts attached below)

Monday, June 24, 2013

8:15 AM	Arrive and welcome (3M-2) **Richard O'Neill**, Federal Energy Regulatory Commission (*Washington, DC*)
8:45 AM	Session M1 (Meeting Room 3M-2) **Hybrid Approach for Incorporating Uncertainty in CAISO's Market Operations** Khaled Abdul-Rahman, Hani Alarian, Clyde Loutan, California ISO (*Folsom, CA*) **Applying Robust Optimization to MISO Look Ahead Unit Commitment** Yonghong Chen, MISO (*Carmel, IN*) Xing Wang, Alstom Grid (*Redmond, WA*) Yongpei Guan, University of Florida (*Gainesville, FL*) **Mixed Integer Programming (MIP) for Faster and More Optimal Solutions: The NYISO Proof of Concept Experience** Matthew Musto, Muhammad Marwali, NYISO (*Rensselaer, NY*) **Preventive-Corrective control for contingency modeling in AC PF based SCUC** Petar Ristanovic, California ISO (*Folsom, CA*) James Frame, Siemens (*Minneapolis, MN*)
10:45 AM	Break
11:00 AM	Session M2 (Meeting Room 3M-2) **External Network Model Expansion and Energy Imbalance Market at CAISO** Mark Rothleder, George Angelidis, James Price, California ISO (*Folsom, CA*) **Modeling, Simulation, and Computational Needs for RTOs: A PJM Perspective** Paul Sotkiewicz, PJM Interconnection, LLC (*Norristown, PA*) **Co-optimization of Congestion Revenue Rights in ERCOT Day-Ahead Market** Chien-Ning Yu, Vladimir Brandwajn, Show Chang, ABB/Ventyx (*Santa Clara, CA*) Sainath M. Moorty, ERCOT (*Taylor, TX*) **Pricing Mechanism for Time-Coupled Multi-interval Real-Time Dispatch** Tengshun Peng, Dhiman Chatterjee, MISO (*Carmel, IN*)
1:00 PM	Lunch
1:45 PM	Session M3 (Meeting Room 3M-2) **Practical Experience Developing Software for Large-Scale Outage Coordination** John Condren, James David, Boris Gisin, PowerGEM (*Clifton Park, NY*) **Automated Transmission Outage Analysis Using Nodal Based Model** Nancy Huang, Dan Moscovitz, PJM Interconnection (*Norristown, PA*) John Condren, PowerGEM (*Clifton Park, NY*) **Pricing Scheme for Two-Stage Market Clearing Model** Jinye Zhao, Eugene Litvinov, Tongxin Zheng, Feng Zhao, ISO New England (*Holyoke, MA*) **Stochastic Unit Commitment with Intermittent Distributed Wind Generation via Markovian Analysis and Optimization** Yaowen Yu, Peter B. Luh, Mikhail A. Bragin, University of Connecticut (*Storrs, CT*) Eugene Litvinov, Tongxin Zheng, Feng Zhao, Jinye Zhao, ISO New England (*Holyoke, MA*)
3:45 PM	Break
4:00 PM	Session M4 (Meeting Room 3M-2) **Multi-Area Security Constrained Economic Dispatch** Raquel Lim, Muhammad Marwali, New York Independent System Operator (*Rensselaer, NY*) **External Network Model Expansion at CAISO** Mark Rothleder, George Angelidis, James Price, California ISO (*Folsom, CA*) **An Application of High Performance Computing to Transmission Switching** Zhu Yang, Shmuel S. Oren, University of California,Berkeley (*Albany, CA*) Anthony Papavasiliou, Catholic University of Louvain Kory Hedman, Pranavamoorthy Balasubramanian, Arizona State University (*Tempe, AZ*)
5:30 PM	Adjourn

Tuesday, June 25, 2013

8:15 AM	Arrive and welcome (3M-2)
8:30 AM	Session T1-A (Meeting Room 3M-2) **SMART-ISO: Modeling Uncertainty in the Electricity Markets** Hugo Simao, Warren Powell, Boris Defourny, Princeton University (*Princeton, NJ*) **Multifaceted Solution for Managing Flexibility with High Penetration of Renewable Resources** Nivad Navid, MISO (*Carmel, IN*) **Secure Planning and Operations of Systems with Stochastic Sources, Energy Storage and Active Demand** Ray Zimmerman, C. Lindsay Anderson, Robert J. Thomas, Cornell University (*Ithaca, NY*) Carlos Murillo-Sánchez, National University of Colombia (*Manizales, Caldas, Colombia*) **Clustering-Based Strategies for Stochastic Programs** Victor M. Zavala, Argonne National Laboratory (*Lemont, IL*)
	Session T1-B (Meeting Room 3M-4) **Profit Maximizing Storage Allocation in Power Grids** Anya Castillo, Dennice Gayme, John's Hopkins University (*Baltimore, MD*) **Application of Semidefinite Programming to Large-scale Optimal Power Flow Problems** Michael Ferris, Daniel Molzhan, Bernie Leseiutre, Chris De Marco, University of Wisconsin (*Madison, WI*) **AC-Nonlinear Chance Constrained Optimal Power Flow** Daniel Bienstock, Columbia University (*New York, NY*) Michael Chertkov, Russell Bent, Los Alamos National Lab (*Los Alamos, NM*) **A Novel Parallel Approach to Solving Constrained Linear Optimization Problems** Stephen Elbert, Kurt Glaesemann, Karan Kalsi, Pacific Northwest National Laboratory (*Richland, WA*)
10:30 AM	Break
10:45 AM	Session T2-A (Meeting Room 3M-2) **Unified Stochastic and Robust Unit Commitment** Yongpei Guan, Chaoyue Zhao, University of Florida (*Gainesville, FL*) **Robust and Dynamic Reserve Policies** Kory Hedman, Joshua Lyon, Fengyu Wang, Muhong Zhang, Arizona State University (*Tempe, AZ*) **Stochastic Programming for Improved Electricity Market Operations with Renewable Energy** Audun Botterud, Canan Uckun, Argonne National Laboratory (*Argonne, IL*) John Birge, University of Chicago (*Chicago, IL*) **Compact Stochastic Unit Commitment Formulation** Germán Morales-España, Andres Ramos, Universidad Pontificia Comillas (*Madrid, Spain*) José M. Arroyo, Universidad de Castilla la Mancha (*Ciudad Real, Castilla la Mancha, Spain*)
	Session T2-B (Meeting Room 3M-4) **Computational Performance of Solution Techniques Applied to the ACOPF** Anya Castillo, John's Hopkins University (*Baltimore, MD*) Richard P. O'Neill, Federal Energy Regulatory Commission (*Washington, DC*) **Modeling of Hardware- and Systems-Related Transmission Limits: The Use of AC OPF for Relaxing Transmission Limits to Enhance Reliability and Efficiency** Marija Ilic, Jeffrey Lang, NETSS (*Sudbury, MA*) **Low-Rank Solution for Nonlinear optimization over AC Transmission Networks** Javad Lavaei, Ramtin Madani, Somayeh Sojoudi, California Institute of Technology (*Pasadena, CA*) **Valid Inequalities for the Alternating Current Optimal Power Flow Problem** Chen Chen, Shmuel Oren, Alper Atamturk, UC Berkeley (*Berkeley, CA*) Richard O'Neill, Federal Energy Regulatory Commission (*Washington, DC*)
12:45 PM	Lunch

Tuesday, June 25, 2013

1:30 PM	Session T3-A (Meeting Room 3M-2) **Assessing the Flexibility Requirements in Power Systems** Daniel Kirschen, Yury Dvorking, University of Washington (*Seattle, WA*) **Incorporating variability and uncertainty into reserve requirement methodologies** Erik Ela, Michael Milligan, Bri-Mathias Hodge, Brendan Kirby, Ibrahim Krad, Mark OMalley, National Renewable Energy Laboratory (*Golden, CO*) **Optimal Unit Commitment under Uncertainty in Electricity Markets** Fernando Alvarado, Rajesh Rajaraman **Large-scaled Optimal Power Flow with No Guarantee on Feasibility** Manuel Ruiz, Girardeau, Artelys (*Paris, France*) Maeght, Fliscounakis, Panciatici, RTE (*Paris, France*)
	Session T3-B (Meeting Room 3M-4) **Scalable Strategies for Large-scale AC-SCOPF Problems** Nai-Yuan Chiang, Victor M. Zavala, Argonne National Laboratory (*Lemont, IL*) Andreas Grothey, University of Edinburgh (*Edinburgh, United Kingdom*) **An AC-Feasible Linear Approximation Approach to Finding the Optimal Power Flow** Paula Lipka, UC Berkeley (*Albany, CA*) **Security Constrained AC Optimal Power Flow (SC-OPF): Current Status, Implementation Issues and Future Directions** Guorui Zhang, Quanta Technology (*Raleigh, NC*) Xiaoming Feng, ABB USCRC (*Raleigh, NC*) **Decomposition Approaches to Transmission Switching under N-1 Reliability Requirements** John Siirola, Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, NM*)
3:30 PM	Break
3:45 PM	Session T4-A (Meeting Room 3M-2) **Price Responsive Demand for Operating Reserves in co-optimized Electricity Markets with Wind Power** Zhi Zhou, Audun Botterud, Argonne National Laboratory (*Argonne, IL*) **Multi-Settlement Simulation of Stochastic Reserve Determination** Robert Entriken, EPRI (*Palo Alto, CA*) Taiyou Yong, Eversource Consulting (*Folsom, CA*) Russ Philbrick, Power System Optimization (*Shoreline, WA*) **An Affine Arithmetic Method to Solve Stochastic Optimal Power Flow Problems with Uncertainties** Mehrdad Pirnia, University of Waterloo (*Waterloo, Canada*) **A Synergistic Combination of Surrogate Lagrangian Relaxation and Branch-and-Cut for MIP Problems in Power Systems** Peter Luh, University of Connecticut (*Storrs, CT*) Joseph Yan, Gary Stern, Southern California Edison (*Rosemead, CA*) **N-1-1 Contingency-Constrained Grid Operations** Richard Chen, Jean-Paul Watson, Sandia National Laboratories (*Livermore, CA*) Neng Fan, University of Arizona (*Tuscon, AZ*)
	Session T4-B (Meeting Room 3M-4) **Optimal Feeder Reconfiguration** Steven Low, Qiuyu Peng, Caltech (*Pasadena, CA*) **Correcting Optimal Transmission Switching for AC Power Flows** Clayton Barrows, NREL (*Golden, CO*) Seth Blumsack, Penn State University (*University Park, PA*) Paul Hines, University of Vermont (*Burlington, VT*) **Advances in Topology Control Algorithms (TCA)** Pablo Ruiz, T. Bruce Tsuchida, The Brattle Group (*Cambridge, MA*) Michael C. Caramanis, Justin M. Foster, Evgeniy A. Goldis, Xiaoguang Li, Boston University (*Boston, MA*) C. Russ Philbrick, Polaris Systems Optimization (*Shoreline, WA*) Aleksandr M. Rudkevich, Newton Energy Group (*Newton, MA*) Richard D. Tabors, Across The Charles (*Cambridge, MA*) **Inclusion of Post-Contingency Actions in Security Constrained Scheduling** Peng Peng, Show Chang, ABB/Ventyx (*Santa Clara, CA*)
5:45 PM	Adjourn

Wednesday, June 26, 2013

8:15 AM	Arrive and welcome (3M-2)
8:30 AM	Session W1-A (Meeting Room 3M-2) **Study of Transmission Switching Under Contingencies: Formulations and Algorithms** Bo Zeng, Long Zhao, Wei Yuan, University of South Florida (*Tampa, FL*) **Security-Constrained Optimal Power Flow with Sparsity Control and Efficient Parallel Algorithms** Dzung Phan, IBM T.J. Watson Research Center (*Yorktown Heights, NY*) Andy Sun, Georgia Institute of Technology (*Atlanta, GA*) **Candidate Selection for Transmission Switching in Large Power Networks** Kwok Cheung, Jun Wu, Alstom Grid (*Redmond, WA*) **Transmission Switching for Improving Wind Power Utilization** Feng Qiu, Jianhui Wang, Argonne National Laboratory (*Argonne, IL*)
	Session W1-B (Meeting Room 3M-3) **Stochastic Unit Commitment: Scalable Computation and Experimental Results** Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, NM*) Sarah Ryan, Iowa State University (*Ames, IA*) David Woodruff, University of California Davis (*Davis, CA*) **MIP Based System Flexible Capacity Requirements Determination** Alex Papalexopoulos, ECCO International (*San Francisco, CA*) **Decomposition Methods for Stochastic Unit Commitment Problems** Suvtrajeet Sen, University of Southern California (*Los Angeles, CA*) **Stochastic Unit Commitment: Stochastic Process Modeling for Load and Renewables** David Woodruff, University of California Davis (*Davis, CA*) Sarah Ryan, Iowa State University (*Ames, IA*) Jean-Paul Watson, Sandia National Laboratories (*Albuquerque, NM*)
10:30 AM	Break
10:45 AM	Session W2-A (Meeting Room 3M-2) **Smart Wire Grid: Providing Advanced Power Flow Control for the Grid** Stewart Ramsay, Smart Wire Grid, Inc. (*Oakland, CA*) **HVDC Grid Technology - Benefits of Hybrid AC/DC Grids and Optimal Power Flow Modeling Considerations** Xiaoming Feng, ABB (*Raleigh, NC*) **Tres Amigas: Uniting the Electric Power Grid** Kenneth Laughlin, Tres Amigas, LLC. (*Santa Fe, NM*) **Beyond Real Time: the Computational Challenges of Forecasting Dynamic Line Ratings** Eric Hsieh, Nexans (*Bethel, CT*) Stuart Malkin, Nexans (*Portland, OR*) **Implementing DLRs in the control room at PacifiCorp - Technology Successes and Challenges** TBD, Pacificorp (*Portland, OR*)
	Session W2-B (Meeting Room 3M-3) **Scalable Parallel Analysis of Power Grid Models Using Swift** Ketan Maheshwari, Victor M Zavala, Justin Wozniak, Mark Hereld, Michael Wilde, Argonne National Laboratory (*Argonne, IL*) **Improving Market Planning and Efficiency Software Through Dynamic Integration of High Quality Data** Christopher Vizas, Nicholas Lagakos, Anjan Deb, Chris Vizas, Jack Barker, Victor Kaybulkin, SmartSenseCom, Inc. (*Washington, DC*) **Highly Dispatchable and Distributed Demand Response for the Integration of Distributed Generation** Amit Narayan, AutoGrid Systems (*Palo Alto, CA*) **Solving MPEC Models with the KNITRO Nonlinear Solver** Richard Waltz, Jorge Nocedal, Ziena Optimization LLC (*Evanston, IL*) Arnaud Renaud, Sylvain Mouret, Artelys (*Paris, France*) **New methods for measuring voltage stability limits utilizing HELM tools** Jason Black, Battelle (*Columbus, OH*)
2:00 PM	Adjourn

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

Abstracts

<u>Monday, June 25</u>

<u>Session M1 (Monday, June 24, 8:45 AM, Meeting Room 3M-2)</u>

Hybrid Approach for Incorporating Uncertainty in CAISO's Market Operations

Dr. Khaled Abdul-Rahman, Executive Director, California ISO (*Folsom, CA*)
Mr. Hani Alarian, Director, California ISO (*Folsom, CA*)
Dr. Clyde Loutan, Sr. Advisor, California ISO (*Folsom, CA*)

The California ISO has taken several measures to incorporate the uncertainty due to Wind and Solar variability into the unit commitment and dispatch algorithms used in market operations. A hybrid approach that recognizes the need to incorporate uncertainties in operation of Day-ahead and real-time markets is presented. The hybrid approach is based on leveraging different forecasting techniques related to supply, demand, system flexibility, and deliverability requirements for both day-ahead and real-time applications. Incorporation of different requirement uncertainties into specific optimization constraints is described.

Applying Robust Optimization to MISO Look Ahead Unit Commitment

Dr. Yonghong Chen, Consulting Engineer, MISO (*Carmel, IN*)
Dr. Xing Wang, Manager, Optimization Applications, Alstom Grid (*Redmond, WA*)
Dr. Yongpei Guan, Associate Professor, University of Florida (*Gainesville, FL*)

Many research efforts have been conducted on stochastic unit commitment ("UC") and robust optimization because of the uncertainty introduced by renewable integration. MISO is collaborating with Alstom and University of Florida to explore the possibility of applying robust and/or stochastic optimization based unit commitment to address real world operational issues caused by uncertainty. The project team developed a robust optimization based prototype on MISO Look-Ahead Security Constrained Unit Commitment (LAC) and configured the optimization model based on the discussion with MISO operations. LAC is used by MISO operators primarily to make decisions on the commitment of fast-start resources. The team is also implementing recently proposed "Unified Stochastic and Robust Unit Commitment" approach. The next step is to expand the prototype to Reliability Assessment Commitment so that the commitment of slow-start resources can ensure enough on-line capacity and fast-start resources available to cover the uncertainties in real time.

Mixed Integer Programming (MIP) for Faster and More Optimal Solutions: The NYISO Proof of Concept Experience

Mr. Matthew Musto, Senior Project Manager - Ops and Reliability, NYISO (*Rensselaer, NY*)
Dr. Muhammad Marwali, Manager of Energy Market Products, NYISO (*Rensselaer, NY*)

This presentation will describe the NYISO's experience replacing the legacy Lagrangian Relaxation (LR) with a Mixed Integer Programming unit commitment. We will describe the driving forces and technical hurdles associated with the migration while highlighting risks and rewards the proof of concept (POC) allowed us to take. Details of this presentation include; describing a novel approach to offloading computationally intensive workloads to a cluster of high performance Linux machines, various iterations of POC tests and feedback improving the next POC, added benefits to the NYISO market efficiency, and technology decisions which will allow more open and low cost exploration of advanced MIP, complex modeling and solution methodologies.

Preventive-Corrective control for contingency modeling in AC PF based SCUC

Mr. Petar Ristanovic, Vice President, Technology, California ISO (*Folsom, CA*)
Mr. James Frame, Senior Staff Engineer, Siemens (*Minneapolis, MN*)

The California ISO is in the process of enhancing the contingency model in its market optimization to handle the post contingency corrective actions. With this enhancement the market optimization advances from a pure preventive mode to a preventive-corrective mode, where both pre contingency dispatches and post contingency re-dispatches are co-optimized to meet the reliability standards. With the mandatory system operating limits standards incorporated into the market optimization, the need for operator's manual out of market interventions to comply with the system operating limit standards will significantly decrease.

<u>Session M2 (Monday, June 24, 10:30 AM, Meeting Room 3M-2)</u>

External Network Model Expansion and Energy Imbalance Market at CAISO

Mr. Mark Rothleder, VP, Market Quality and Renewable Integration, California ISO (*Folsom, CA*)
Dr. George Angelidis, Principal, Power Systems Technology, California ISO (*Folsom, CA*)
Dr. James Price, Senior Advisor Engineering Specialist, California ISO (*Folsom, CA*)

Due to several reliability-related recommendations by FERC, the California ISO has started a process of modeling the fully looped network of the external WECC entities in CAISOs Full Network Model. This initiative improves reliability modeling and market solution accuracy by accurately modeling loop flows of external area schedules through the ISO network in DAM, RTM, and EMS operation with reduced reliance on compensating injections calculation, enhancing contingency analysis by accurately enforcing contingency constraints and eliminating many nomograms that don't accurately reflect the operational changes in the network topology and the impact on nomogram coefficients and limit. In addition, the CAISO has started an effort for west-wide Energy Imbalance Market for the balancing areas in the westen interconnection which results in more efficient inter-regional dispatch across balancing authorities, especially with renewable integration.

Modeling, Simulation, and Computational Needs for RTOs: A PJM Perspective

Dr. Paul Sotkiewicz, Chief Economist, PJM Interconnection, LLC (*Norristown, PA*)

The design of wholesale electricity markets must account for the intent non-convexities that are endemic to power system operations and planning. Moreover, there are inherent uncertainties related short- and long-term load forecasting, intermittent renewable resource output in operations, and policy implementations that affect planning.

PJM's electricity markets endeavor to meet reliability criteria while offering the greatest possible flexibility to market participants introduces even more non-convexities and uncertainty that must be accounted for in electricity market design. To date, PJM has managed these challenges given the constraints of known software and algorithm limitations. However, recent events have shown that improvements in software and algorithms in combinatorial and stochastic optimization may enhance the efficiency of wholesale electricity markets, operations, and planning through faster solutions and more flexibility for market participants.

From PJM's perspective, there is still room for improvement with respect to combinatorial and stochastic optimization algorithms that can reduce computational burdens and clock time to solutions that will result in more efficient commitment of resources, better price formation, a reduction in uplift, and overall lower cost solutions. Improved algorithms and software may also permit the introduction of even greater flexibility for market participants and drive more optimal reliability solutions.

Co-optimization of Congestion Revenue Rights in ERCOT Day-Ahead Market

Dr. Chien-Ning Yu, Consulting Engineer, ABB/Ventyx (*Santa Clara, CA*)
Dr. Vladimir Brandwajn, Sr. Principal Consultant, ABB/Ventyx (*Santa Clara, CA*)
Dr. Show Chang, Sr. Principal Engineer, ABB/Ventyx (*Santa Clara, CA*)
Mr. Sainath M. Moorty, Principal, ERCOT (*Taylor, TX*)

In ERCOT Day-Ahead Market (DAM), Congestion Revenue Right (CRR) obligations and options are co-optimized with other energy and reserve bids and offers via a centralized auction. This enables market participants to acquire financial transmission rights in DAM to hedge their real-time congestion costs. ERCOT market results have demonstrated that incorporation of CRRs into the DAM has facilitated the convergence of the Day-Ahead and Real-Time Markets.

Due to the unidirectional flows incurred by CRR options, each option need to be evaluated separately instead of super-posing the option flows. This makes the CRR processing very time consuming. For example, the ERCOT model includes 2500 contingencies and for a case of 100 CRR options submitted for a 24-hour DAM run, the solution engine needs to perform 6 million fast forward/backward matrix operations. In order to reduce this prohibitive computational burden, a new contingency analysis procedure combined with modern parallel computing techniques is developed. This novel algorithm has resulted significant performance improvement of the CRR processing and has enabled timely solution of a large-scale Security Constrained Unit Commitment (SCUC) problem, including CRR co-optimization, within the DAM timeframe.

The presentation will discuss various practical issues related to the introduction of CRRs including: how to process bus splitting contingencies; how to deal with "dead-bus" gaming and virtual power flow divergence problems.

Pricing Mechanism for Time-Coupled Multi-interval Real-Time Dispatch

Ms. Tengshun Peng, Principle Engineer, MISO (*Carmel, IN*)
Mr. Dhiman Chatterjee, Manager, MISO (*Carmel, IN*)

Abstract: How to establish efficient price for the real time market is always a hot topic. Currently, MISO's real time dispatch and price are designed for a single dispatch interval ten minutes into the future. This will remain unchanged when FERC approved ELMP pricing logic is implemented in production. MISO is studying the ramifications of transforming from this single interval dispatch system to a time-coupled, multiple interval dispatch. This brings up a pricing calculation problem. Several key issues tied to the price formation process under a time-coupled multiple interval dispatch are under evaluation by MISO. For instance, how should cost incurred in the past affect current and future prices? Under what types of conditions will such past costs be treated as sunk costs? This presentation will summarize two options relating to the treatment of past costs under a time-coupled, multiple interval dispatch: A look-forward only option, and combined look-back and look-forward option. We will demonstrate the pricing and settlement impacts of these two options with simple examples.

<u>Session M3 (Monday, June 24, 2:00 PM, Meeting Room 3M-2)</u>

Practical Experience Developing Software for Large-Scale Outage Coordination

Dr. John Condren, Lead Consultant, PowerGEM (*Clifton Park, NY*)
James David, Market Applications Product Manager, PowerGEM (*Clifton Park, NY*)
Boris Gisin, Vice President, PowerGEM (*Clifton Park, NY*)

Analysis of transmission outages is a challenging and critical task performed by every ISO and transmission owner to prepare the grid for reliable and economic performance, especially for ISO day ahead and real time markets.

Outage coordination requires analysis of hundreds of outages spanning multiple future time horizons, utilizing automatically created load flow models to represent these future time periods. Analysis results must clearly show the transmission constraints impacted by the outage for the particular time period evaluated. The order of outage evaluation as well as the method for applying and evaluating outages depends on ISO accepted practices. Given the large scope, software vendors face major challenges in implementation.

This presentation will address the mathematical and software implementation issues for assessing reliability and economic impact of outage schedules. It will present an overview of the common solutions used now, and it will review applications that PowerGEM has been developing for several major US ISOs and TOs including ISO-NE, PJM, MISO, and TVA. Longer-term development possibilities to improve current methods will also be presented including stochastic approaches, post-contingency corrective actions, and corrective switching.

Automated Transmission Outage Analysis Using Nodal Based Model

Ms. Nancy Huang, Sr. Engineer, PJM Interconnection (*Norristown, PA*)
Mr. Dan Moscovitz, Engineer, PJM Interconnection (*Norristown, PA*)
Mr. John Condren, SR. Engineer, PowerGEM (*Clifton Park, NY*)

Outage Coordination impacts many facets of the PJM day ahead and real time markets and grid operations; congestion payments, FTR funding and grid reliability. With a footprint that covers 13 states + D.C. and a transmission system that exceeds 59 thousand miles, evaluating the transmission outages more efficiently and feeding the results to markets and customers on a timely manner is a challenge in PJM.

PJM has developed an automated process for Long Term and Short Term transmission outage studies based on a version of TARA software, created by PowerGEM LLC and customized for PJM outage study rules. The process is unique in that it runs automated powerflow outage analysis on top of PJM’s full EMS nodal model. The process has resulted in time and manpower savings, and improvements in outage coordination with, and between, transmission owners; therefore improving the overall market efficiency.

This presentation will provide an overview of the project motivating factors, major milestones and the benefits achieved to date. It will also discuss the general study case set-up and implementation details. The concluding discussion will focus on further development needs and possible expanded applications.

Pricing Scheme for Two-Stage Market Clearing Model

Mrs. Jinye Zhao, Senior Analyst, ISO New England (*Holyoke, MA*)
Mr. Eugene Litvinov, Chief Technologist, ISO New England (*Holyoke, MA*)
Mr. Tongxin Zheng, Technical Manager, ISO New England (*Holyoke, MA*)
Mr. Feng Zhao, Senior Analyst, ISO New England (*Holyoke, MA*)

Although alternative scheduling and dispatch mechanisms based on two-stage models, such as two-stage stochastic programming and multi-interval look-ahead problems, have been extensively explored, little attention has been paid to the pricing issue. In this presentation, a general pricing framework is proposed for two-stage models, followed by two alternative pricing schemes. Under the first scheme, the 1st-stage decision is settled at a marginal clearing price which contains all future information while the 2nd-stage decision is compensated in the pay-as-bid fashion. Under the second scheme, both the 1st and 2nd stage decisions are settled at marginal prices which reflect partial future information.

The proposed schemes are applied to a two-stage stochastic problem where energy and reserve are determined at the 1st stage and N-1 loss of generation contingencies are considered at the 2nd stage. This model resolves the reserve deliverability issue by explicitly modeling uncertainty instead of using reserve requirements. The first scheme leads to individual prices while the second one leads to nodal prices. Under truthfully bidding assumption, both schemes result in cost recovery for market participants and revenue reconciliation. Despite its price discrimination, the former is still deemed to be an attractive pricing scheme because market participants need no future information to make decentralized decisions while significant amount of information is needed under the latter.

Stochastic Unit Commitment with Intermittent Distributed Wind Generation via Markovian Analysis and Optimization

Mr. Yaowen Yu, Research Assistant, University of Connecticut (*Storrs, CT*)
Dr. Peter B. Luh, Professor, University of Connecticut (*Storrs, CT*)
Dr. Eugene Litvinov, Senior Director, ISO New England (*Holyoke, MA*)
Dr. Tongxin Zheng, Technical Manager, ISO New England (*Holyoke, MA*)
Mr. Mikhail A. Bragin, Research Assistant, University of Connecticut (*Storrs, CT*)
Dr. Feng Zhao, Senior Analyst, ISO New England (*Holyoke, MA*)
Dr. Jinye Zhao, Senior Analyst, ISO New England (*Holyoke, MA*)

To accommodate uncertain wind generation in unit commitment, stochastic programming models uncertainties as scenarios. However, it is difficult to balance computational requirements and the ability to manage high-impact rare events by selecting an appropriate number of scenarios. In this presentation, a new Markov-based stochastic unit commitment approach is presented based on wind states instead of scenarios. With congestion, wind generation at different locations is spatially modeled. To avoid the large number of possible power flow levels caused by various combinations of local states, our idea is to approximate the line flow by only using the voltage phase angles of the two nodes connecting the line. The difference between approximations and actual flow levels is handled by setting aside small amounts of capacity for conventional generators and transmission lines. To effectively solve the problem, branch-and-cut is synergistically embedded within our new Surrogate Lagrangian relaxation framework. The method guarantees convergence through a novel stepsizing formula without the need to know the optimal dual value in advance, and the relaxed problem can be approximately solved. Through extensive numerical testing, the approach is demonstrated to be efficient, scalable, and more robust against high-impact rare events as compared to conventional stochastic models. It thus represents a new and effective way to address stochastic problems without scenario analysis.

Session M4 (Monday, June 24, 3:45 PM, Meeting Room 3M-2)

Multi-Area Security Constrained Economic Dispatch

Ms. Raquel Lim, Supervisor,Operations Regional Market Coordination, New York Independent System Operator (*Rensselaer, NY*)
Dr. Muhammad Marwali, Manager, Energy Market Products, New York Independent System Operator (*Rensselaer, NY*)

One major goal of the power industry is to minimize production costs while maintaining a reliable power system. In recent years, there has been a shift from economically dispatching resources to solve for transmission constraints within one control area to joint dispatch coordination between neighboring control areas to address price convergence along the border.. This presentation will describe the use of a Transmission Demand Curve (TDC) within the Security Constrained Economic Dispatch (SCED) to model transmission constraints that are located in a neighboring control area. We will describe how the SCED models of both control areas work in concert to decrease the regional production costs in both systems while providing a more consistent pricing profile across both control areas.

External Network Model Expansion at CAISO

Mr. Mark Rothleder, Vice President, Market Quality & Renewable Integration, California ISO (*Folsom, CA*)
Mr. George Angelidis, Principle, Power Systems Technology Deve, CAISO (*Folsom, CA*)
Mr. James Price, Sr. Advisor Engineering Specialist, California ISO (*Folsom, CA*)

Due to several reliability-related recommendations by FERC, CAISO has started a process of moedling the fully looped network of the external WECC entities in CAISOs Full Network Model. This initiative improves reliability modeling and market solution accuracy by accurately modeling loop flows of external area schedules through the ISO network in DAM, RTM, and EMS operation with reduced reliance on compensating injections calculation, enhancing contingency analysis by accurately enforcing contingency constraints and eliminating many nomograms that don't accurately reflect the operational changes in the network topology and the impact on nomogram coefficients and limit. In addition, the CAISO has started an effort for west-wide Energy Imbalance Market for the balancing areas in the westen interconnection which results in more efficient inter-regional dispatch across balancing authorities, especially with renewable integration.

An Application of High Performance Computing to Transmission Switching

Ms. Zhu Yang, Ph.D Student, University of California,Berkeley (*Albany, CA*)
Dr. Anthony Papavasiliou, Assistant Professor, Catholic University of Louvain
Dr. Shmuel S. Oren, Professor, UC Berkeley (*Berkeley, CA*)
Dr. Kory Hedman, Assistant Professor, Arizona State University (*Tempe, AZ*)
Mr. Pranavamoorthy Balasubramanian, Ph.D Student, Arizona State University (*Tempe, AZ*)

Topology control, or transmission switching, is the problem of optimizing the topology of an electric power network in order to achieve a certain goal such as the minimization of operating cost or load losses in an emergency event. The optimal transmission switching (OTS) problem which formulates the transmission switching as a mixed-integer program (MIP), usually takes a long time to solve in practice. In this paper we present a parallel implementation of three transmission switching algorithms. The first is to switch a line at a time and solve a sequence of linear programs. The second is similar to the first algorithm except for that the sequence of lines to be switched are prioritized by a dual criterion. The third heuristic is to partition the lines into exclusive groups and solve a MIP of a smaller size for each group. The proposed algorithms are implemented in parallel and tested on IEEE118 test case. The results show a great saving in computation time as well as approximately the same cost savings as solving OTS directly. The computation time reduction shows that solving OTS for practical networks become possible with the help of parallel computing.

<u>Tuesday, June 26</u>

<u>Session T1-A (Tuesday, June 25, 8:30 AM, Meeting Room 3M-2)</u>

SMART-ISO: Modeling Uncertainty in the Electricity Markets

Dr. Hugo Simao, Research Staff, Princeton University (*Princeton, NJ*)
Dr. Warren Powell, Professor, Princeton University (*Princeton, NJ*)
Dr. Boris Defourny, Postdoctoral Fellow, Princeton University (*Princeton, NJ*)

We present a stochastic modeling framework that allows for the analysis of the behavior of the electricity markets for PJM. It is comprised of three intertwined models: a day-ahead unit commitment, an hour-ahead unit commitment, and a real-time economic dispatch model. Particular emphasis is placed on the careful modeling of the flow of information and uncertainty. The day-ahead model is solved at noon of each day, to decide which slow generators (predominantly steam) to use on the following day. The hour-ahead model runs every hour, to decide which fast generators (predominantly gas turbines) to turn on during the hour after next. The day-ahead model uses hourly time intervals, while the hour-ahead model uses five-minute intervals. The real-time economic dispatch problem is solved every five minutes. "Best-deterministic" policies produce solutions that are designed to accommodate uncertainty in forecasts. This allows for the study of the integration of high levels of renewable sources of energy (e.g. wind and solar), where sub-hourly variations may be significant. All models include approximations of the power flow in the grid, so that the impact of transmission congestion can be approximately evaluated. We will illustrate the application of the system through some preliminary results of a study on the integration of off-shore wind into the PJM market.

Multifaceted Solution for Managing Flexibility with High Penetration of Renewable Resources

Dr. Nivad Navid, Consultant Engineer, MISO (*Carmel, IN*)

High penetration of renewable generation and SMART Grid technologies introduces new challenges in scheduling and dispatching controllable resources to meet the system demand. It also increases level of variability and uncertainty forcing new trends in managing system flexibility:

- Increase reserve requirement
- Introduce new reserves
- Implement more complex operational procedures
- Enforce operational limits on renewable generation
- Involve renewable generation to provide system flexibility
- Market solutions incenting conventional generation and renewable resources to accommodate increased system flexibility needs

One major factor in all these solutions is the overall system costs. One might be mindful of applicability of the solution in different horizons.

In this presentation we will look at multi fold solution introduced by MISO:

- The conventional reserve requirements are not increased
- By creating new class of resourcs "DI" (Dispatchable Intermittent Resources), involve them in the solution
- Introducing new set of reserves focusing on rampable capability
- Enhancing current market mechanism to accommodate the flexibility needs and incenting flexibility offered by all resources.

A study case focusing on economic impacts of the proposed solutions based on MISO actual production data will be presented. These simulations show that in near future we might expect even product cost savings and setting the stage to absorb more renewable resources in the system.

Secure Planning and Operations of Systems with Stochastic Sources, Energy Storage and Active Demand

Dr. Ray Zimmerman, Senior Research Associate, Cornell University (*Ithaca, NY*)
Dr. Carlos Murillo-Sánchez, Professor, National University of Colombia (*Manizales, Caldas, Colombia*)
Dr. C. Lindsay Anderson, Assistant Professor, Cornell University (*Ithaca, NY*)
Dr. Robert J. Thomas, Professor Emeritus, Cornell University (*Ithaca, NY*)

This work presents a stochastic optimization framework for operations and planning of an electricity network as managed by an Independent System Operator. The objective is to maximize the total expected net benefits over the planning horizon, incorporating the costs and benefits of electricity consumption, generation, ancillary services, load-shedding, storage and load-shifting.

The overall framework could be characterized as a secure, stochastic, combined unit commitment and AC optimal power flow problem, solving for an optimal state-dependent schedule over a pre-specified time horizon. Uncertainty is modeled so as to expose the scenarios that are critical for maintaining system security, while properly representing the stochastic cost. The optimal amount of locational reserves needed to cover a credible set of contingencies in each time period is determined, as well as load-following reserves required for ramping between time periods. The models for centrally-dispatched storage and time-flexible demands allow for optimal tradeoffs between arbitraging across time, mitigating uncertainty and covering contingencies.

This paper details the proposed problem formulation and outlines potential approaches to solving it. An implementation based on a DC power flow model solves systems of modest size and can be used to demonstrate the value of the proposed stochastic framework.

Clustering-Based Strategies for Stochastic Programs

Dr. Victor M. Zavala, Assistant Computational Mathematician, Argonne National Laboratory (*Lemont, IL*)

We present interior-point strategies for convex stochastic programs in which inexpensive inexact Newton steps are computed from compressed Karush-Kuhn-Tucker (KKT) systems obtained by clustering block scenarios. Using Schur analysis, we show that the compression can be characterized as a parametric perturbation of the full-space KKT matrix. This property enables the possibility of retaining superlinear convergence without requiring matrix convergence. In addition, it enables an explicit characterization of the residual and we use this characterization to derive a clustering strategy. We demonstrate that high compression rates of 50-90% are possible and we also show that effective preconditioners can be obtained.

Session T1-B (Tuesday, June 25, 8:30 AM, Meeting Room 3M-4)

Profit Maximizing Storage Allocation in Power Grids

Ms. Anya Castillo, John's Hopkins University (*Baltimore, MD*)
Dr. Dennice Gayme, John's Hopkins University (*Baltimore, MD*)

In this study we investigate how LMPs drive distributed energy storage and storage dynamics on a power network. We model a multi-period optimal power flow (OPF) problem with charge and discharge dynamics for energy storage collocated with load and/or generation. We then apply a convex relaxation based on semidefinite programming (SDP) to solve the optimal control problem. We derive the Lagrangian dual problem and then decompose the Lagrangian to demonstrate the relationship between storage dynamics and the dual variables of the real power balance, which are associated with the LMP in realtime markets. With the dual variables we prove useful properties regarding energy storage placement and operation. We then illustrate these properties with a simple network model.

Application of Semidefinite Programming to Large-scale Optimal Power Flow Problems

Dr. Michael Ferris, Professor, University of Wisconsin (*Madison, WI*)
Mr. Daniel Molzhan, , University of Wisconsin (*Madison, WI*)
Dr. Bernie Leseiutre, Professor, University of Wisconsin (*Madison, WI*)
Dr. Chris De Marco, Professor, University of Wisconsin (*Madison, WI*)

The application of semidefinite programming (SDP) to the optimal power flow (OPF) problem has recently attracted significant research interest. When a convex SDP relaxation of the OPF problem has a zero duality gap solution, the relaxation is “tight” and a globally optimal OPF solution is obtained. While the SDP relaxation often yields zero duality gap solutions for many small problems, non-zero duality gap solutions do occur for some problems of interest.

This talk describes extension of the SDP relaxation to large-scale OPF problems. Specifically considered are enhancements to modeling flexibility and improvements to computational methods for exploiting power system sparsity. This talk also describes a sufficient condition test for global optimality that can be applied to a candidate solution obtained using traditional OPF solution techniques.

Results for large OPF problems with non-zero duality gap solutions show small active and reactive power mismatches at the majority of load buses while only small subsets of the network exhibit significant mismatch. This suggests that the non-convexities causing non-zero duality gap solutions to these problems are isolated in small subsets of the network.

AC-Nonlinear Chance Constrained Optimal Power Flow

Dr. Daniel Bienstock, Professor, Columbia University (*New York, NY*)
Dr. Michael Chertkov, Scientist, Los Alamos National Lab (*Los Alamos, NM*)
Dr. Russell Bent, Scientist, Los Alamos National Lab (*Los Alamos, NM*)

Typical implementations of OPF minimize (convex) cost of generation, subject to linearized power flow balance constraints, thermal capacity constraints (on power lines), ramping constraints, security constraints, etc. In recent work we have developed a chance constraint OPF (CC-OPF) that generalizes standard OPF to include uncertainties from fluctuations in the output of wind farms. This model manages risk in a rigorous fashion by allowing physical constraints (such as line rating) to be violated with small probability. In fact one can construct a robust version of CC-OPF -- optimal within the set of power flows valid for a range of parameters describing the probability distribution of wind output. We also have developed a fast algorithm that can solve large instances ofCC-OPF, such as on the 2746 bus Polish network, in 20 seconds using a desktop computer.

OPF models frequently use the linearized DC equations. In this paper, we extend the our prior approach to model some of the currently ignored nonlinearities present in the more realistic AC power flow equations. Second, we develop a chance constrained version of this model that includes fluctuations from renewable energy sources. Third, we show how to build a version of the AC CC-OPF which is robust with respect to uncertainty in parameterized probability distribution function of the renewables. All three models we derive remain convex and are amenable to fast algorithmic solution.

A Novel Parallel Approach to Solving Constrained Linear Optimization Problems

Dr. Stephen Elbert, Manager, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Kurt Glaesemann, Senior Research Scientist, Pacific Northwest National Laboratory (*Richland, WA*)
Dr. Karan Kalsi, Research Engineer, Pacific Northwest National Laboratory (*Richland, WA*)

The Parallel Adaptive Dynamical System (PADS) approach has been demonstrated to be more scalable and computationally efficient than alternative approaches, including dual simplex, in solving large Financial Transmission Rights optimization problems.

Here we explore the use of this approach in solving unit commitment and AC optimal power flow problems.

Session T2-A (Tuesday, June 25, 10:45 AM, Meeting Room 3M-2)

Unified Stochastic and Robust Unit Commitment

Dr. Yongpei Guan, Associate Professor, University of Florida (*Gainesville, FL*)
Ms. Chaoyue Zhao, Ph.D. Student, University of Florida (*Gainesville, FL*)

Due to increasing penetration of renewable energy and introduction of demand response programs, uncertainties occur in both supply and demand sides in real time for the current power grid system. To address these uncertainties, most ISOs/RTOs perform reliability unit commitment runs to ensure sufficient generation capacity available in real time to accommodate uncertainties. Two-stage stochastic unit commitment and robust unit commitment formulations have been introduced and studied recently to provide day-ahead unit commitment decisions. However, both approaches have limitations: 1) computational challenges due to the large scenario size for the stochastic optimization approach and 2) conservativeness for the robust optimization approach. In this paper, we propose a novel unified stochastic and robust unit commitment model that takes advantage of both stochastic and robust optimization approaches, i.e., this innovative model can achieve a low expected total cost while ensuring the system robustness. By introducing weights for the components for the stochastic and robust parts in the objective function, system operators can adjust the weights based on their preferences. Finally, a decomposition algorithm is developed to solve the model efficiently and the computational results verify the effectiveness of our proposed approach.

Robust and Dynamic Reserve Policies

Dr. Kory Hedman, Professor, Arizona State University (*Tempe, AZ*)
Mr. Joshua Lyon, Ph.D. Student, Arizona State University (*Tempe, AZ*)
Mr. Fengyu Wang, Ph.D. Student, Arizona State University (*Tempe, AZ*)
Dr. Muhong Zhang, Professor, Arizona State University (*Tempe, AZ*)

Operating reserves provide flexibility to restore frequency following random disturbances. However, transmission bottlenecks can limit reserve activation in ways that are difficult to predict. Conventional wisdom provides three general strategies to ensure system reliability: 1) ex ante definitions of zonal requirements to procure local reserves, 2) explicit modeling of transmission constraints over an uncertainty set, e.g., stochastic programming, and 3) ex post adjustments to egregious solutions, such as those that fail contingency analysis. These approaches are applied prior to, within, and after scheduling algorithms and are typically considered as independent problems. Stochastic programming is the most economical approach but is computationally burdensome; thus, it is worthwhile to develop a balanced approach between stochastic programming and reserve policies. This presentation will discuss and analyze new robust and dynamic reserve policies. We provide mathematical frameworks to determine reserve policies prior to, during (as part of a decomposition algorithm), or after scheduling algorithms. The methodology complements traditional reserve requirements and stochastic programming. This work is supported by the U.S. Department of Energy for The Future Grid to Enable Sustainable Energy Systems, an initiative of the Power Systems Engineering Research Center (PSERC), and by Sandia National Laboratory.

Stochastic Programming for Improved Electricity Market Operations with Renewable Energy

Dr. Audun Botterud, Energy Systems Engineer, Argonne National Laboratory (*Argonne, IL*)
Dr. Canan Uckun, Postdoctoral Fellow, Argonne National Laboratory (*Argonne, IL*)
Dr. John Birge, Professor, University of Chicago (*Chicago, IL*)

The rapid expansion of renewable resources creates more uncertainty and variability in the operation of the power grid. The goal of this project is to develop novel stochastic formulations for commitment and dispatch of supply and demand resources in the power grid, considering the uncertainty in renewable energy along with stochastic elements in load and thermal power plants. We investigate the potential benefits of stochastic programming compared to deterministic formulations at different stages of electricity market operations. Our objective is to develop a stochastic programming framework, with appropriate decomposition methods, which is capable of solving real-world problems efficiently.

We present initial work on scenario generation from probabilistic wind power forecasts and potential representations of decision stages in the unit commitment problem for the day-ahead market. Most stochastic unit commitment models are two-stage formulations, but in reality power plant scheduling is a multi-stage decision process. We investigate the challenges of developing accurate scenarios for forecast uncertainty combined with a realistic representation of the relevant decision stages. We also discuss potential implications for day-ahead prices of applying a stochastic scheduling approach. We illustrate the concepts on small-scale test networks.

Compact Stochastic Unit Commitment Formulation

Mr. Germán Morales-España, Ph.D. Student, Universidad Pontificia Comillas (*Madrid, Spain*)
Dr. José M. Arroyo, Professor, Universidad de Castilla la Mancha (*Ciudad Real, Castilla la Mancha, Spain*)
Dr. Andres Ramos, Professor, Universidad Pontificia Comillas (*Madrid, Spain*)

The stochastic unit commitment (UC) problem explicitly incorporates discrete scenarios of uncertainty (e.g. wind) realizations. To obtain reliable optimal results requires a large number of scenario samples, which considerably increases the computational burden. We present a compact stochastic UC formulation that considerably decreases the problem size of a traditional stochastic formulation. Consequently, the proposed formulation obtains the same results of a conventional stochastic model but considerably faster. This is achieved by reformulating the UC in such a way that it mainly depends on the dominating (stochastic-dependant) constraints; and by decomposing the scenarios in two sets, one affecting the regulating reserves and another influencing the resource availability for real-time markets. In addition, by taking into account how the AGC control deploys the regulating reserves, the scenarios affecting the regulating reserves are completely represented in the formulation without increasing neither the number of constraints nor variables.

Session T2-B (Tuesday, June 25, 10:45AM, Meeting Room 3M-4)

Computational Performance of Solution Techniques Applied to the ACOPF

Ms. Anya Castillo, John's Hopkins University (*Baltimore, MD*)
Dr. Richard P. O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)

In the over fifty years of studying ACOPF, there has been a lack of rigorous benchmarking of proposed solution approaches. In an effort to motivate better benchmarking and reporting standards, we report numerical results from testing the nonlinear solvers Conopt, Ipopt, Knitro, Minos, and Snopt on various sized test problems in which we apply various mathematically equivalent ACOPF formulations. We run simulations on numerous recorded starting points that include starting from a previous solution, randomized starting points, and the solution to a linearized model as an initialization. In this presentation we will discuss prior benchmarking studies, our experimental framework with main results. Our conclusions indicate a clear advantage to employing a multistart strategy, which leverages parallel processing in order to solve the ACOPF on large-scale networks for time-sensitive applications.

Modeling of Hardware- and Systems-Related Transmission Limits: The Use of AC OPF for Relaxing Transmission Limits to Enhance Reliability and Efficiency

Dr. Marija Ilic, Professor, NETSS, Inc (*Sudbury, MA*)
Dr. Jeffrey Lang, Professor, NETSS (*Sudbury, MA*)

In this talk we consider two qualitatively different causes of transmission limits. One type of transmission limit is thermal line flow limit, which mainly changes when the wind conditions and ambient conditions change. We refer to these as the transmission limits of the first kind. More complicated are systems conditions-related transmission limits, such as: (1) limits related to the inability to deliver power scheduled; (2) small signal instability problems; and/or (3) transient stability problems. We refer to these as the transmission line limits of the second kind. We illustrate how a combined use of: (1) on-line updates of thermal line flow limits of the first kind; and (2) the use of AC OPF for optimizing controllable equipment for relaxing the transmission limits of the second kind can be done to achieve more optimal performance than otherwise possible. The findings of on-line updating of transmission limits for the case of New York Control Area are used to illustrate potential benefits.

Low-Rank Solution for Nonlinear optimization over AC Transmission Networks

Dr. Javad Lavaei, Assistant Professor, Columbia University (*New York, NY*)
Mr. Ramtin Madani, PhD Student, Columbia University (*New York, NY*)
Dr. Somayeh Sojoudi, , California Institute of Technology (*Pasadena, CA*)

We have previously proposed a convex relaxation technique based on semidefinite programing (SDP) for solving nonlinear optimization problems (such as optimal power flow) over power networks. Although this method was shown to be very effective in simulations and was supported by rigorous theories for distribution networks, the capabilities of the SDP relaxation for transmission networks have not been fully understood. This talk aims to investigate this problem. First, we show that the SDP relaxation works for weakly cyclic networks with loops of size 3 and 4, implying that the previous counterexample of the SDP relaxation for a three-bus system was due to a bad formulation of the problem. Second, we prove that the SDP relaxation always has a low-rank solution for a "mostly" planar power network. Third, we show that there is a simple penalty method to enforce the SDP relaxation to produce a rank-1 solution. The main conclusion of this talk is that the SDP relaxation works well over AC transmission networks if the constraints of the optimization problem of interest are reformulated carefully. This talk demonstrates the huge potentials of the convex relaxation techniques and the benefits of replacing the existing local-search and approximation methods for solving optimal power flow and its variants.

Valid Inequalities for the Alternating Current Optimal Power Flow Problem

Mr. Chen Chen, Ph.D. Candidate, UC Berkeley (*Berkeley, CA*)
Dr. Richard O'Neill, Chief Economic Advisor, Federal Energy Regulatory Commission (*Washington, DC*)
Dr. Shmuel Oren, Professor, UC Berkeley (*Berkeley, CA*)
Dr. Alper Atamturk, Professor, UC Berkeley (*Berkeley, CA*)

We develop valid inequalities for a positive semidefinite matrix constraint, which also apply to the Alternating Current Optimal Power Flow (ACOPF) problem and its dual. Motivating this research is evidence that numerous instances of ACOPF can be solved exactly with its Lagrangian dual. The dual can be formulated as a Semidefinite Program and thus its global optimum can be approximated in polynomial time. However, a basic implementation will result in medium-scale problems with an impractically large decision matrix. Even without this issue, extending this conic power flow approach to problems such as Topology Control and Unit Commitment would result in a mixed-integer semidefinite program, for which there are limited tools. To address these issues we present valid inequalities for the positive semidefinite constraint. We implement these inequalities as cuts in a cutting plane algorithm, which approximates a semidefinite program by iterating over either convex quadratic or second-order cone programs. Sparse cuts that exploit network topology are employed to improve convergence times. On IEEE test cases, the cutting plane algorithm can take a copper-plate model and converge to the Lagrangian dual solution.

Session T3-A (Tuesday, June 25, 1:30 PM, Meeting Room 3M-2)

Assessing the Flexibility Requirements in Power Systems

Dr. Daniel Kirschen, Professor, University of Washington (*Seattle, WA*)
Mr. Yury Dvorking, PhD Student, University of Washington (*Seattle, WA*)

This presentation will propose a methodology to assess the effect of wind power production on the flexibility requirements of a power system. First, it will describe the probabilistic characteristics of the intra-hour net load variability and demonstrate that they are best captured by non-parametric statistics. Then, this non-parametric approach is used to determine simultaneously the hourly flexibility requirements at a given probability level for large and small, continuous and discrete disturbances. This approach allocates the required flexibility among primary, secondary, and tertiary regulation intervals. The usefulness of this method is then illustrated using actual 1-minute resolution net load data, which has been clustered to take advantage of seasonal and daily differences in flexibility requirements.

Incorporating variability and uncertainty into reserve requirement methodologies

Mr. Erik Ela, Acting Group Manager, Senior Engineer, National Renewable Energy Laboratory (*Golden, CO*)
Dr. Michael Milligan, National Renewable Energy Laboratory (*Golden, CO*)
Dr. Bri-Mathias Hodge, National Renewable Energy Laboratory (*Golden, CO*)
Mr. Brendan Kirby, National Renewable Energy Laboratory (*Golden, CO*)
Mr. Ibrahim Krad, National Renewable Energy Laboratory (*Golden, CO*)
Dr. Mark OMalley, National Renewable Energy Laboratory (*Golden, CO*)

The National Renewable Energy Laboratory is collaborating with the WECC Operating Committee, along with other utilities, ISOs, and balancing area authorities in the United States to understand how variability and uncertainty of load, and variable energy resources will impact the requirements needed for various categories of operating reserves. Operating reserves, in a definition we have taken, are active power capacity above and below a specific energy dispatch schedule that is reserved now, and are set aside with the ability to be deployed some time in the future. They are used for instantaneous events, noninstantaneous events, and during normal conditions to ensure frequency is at nominal schedule, and area control error is reduced to zero. The requirements are determined via simulation and statistics to ensure maintained reliability at some risk level, while still minimizing costs. The presentation will (1) show a brief literature review of operating reserve requirement methods in both academic literature and an industry background, (2) some results of the study and (3) important concepts in this regard which we believe will better prepare regions for increasing renewable penetrations.

Optimal Unit Commitment under Uncertainty in Electricity Markets

Dr. Fernando Alvarado
Dr. Rajesh Rajaraman

The generalized unit commitment problem under stochastic uncertainty for a large practical power system can result in enormous computational complexity. In this paper, we suggest a way of handling the uncertainty parameters based on Lagrangian relaxation (LR) ideas. Specifically, we propose that the uncertain stochastic parameters should be translated into an equivalent set of uncertain energy and reserve prices. However, since the energy and reserve prices are themselves the outputs of the unit commitment problem (the shadow values of the constraints), we propose that the translation could be an iterative LR-type process that starts off with an initial guess of the energy and reserve prices along with an associated probability distribution; the process would then iteratively refine estimates of energy and reserve prices and the associated probability distribution until convergence to a solution is reached. Specifically, we suggest the following iterative method. We start with an initial guess of the probability distributions of the price of energy and reserves for the electricity market. Then, given these probabilities of price distributions, there is an optimal strategy that any generator can follow to optimize its profits in an expected value sense. This self-commitment optimal strategy differs from the one based on certainty of prices. The optimal self-commitment schedules for every generator in the system will then be aggregated and compared to system requirements of energy and reserves. Then, the prices of reserves and energy and their associated probability distributions will be appropriately adjusted based both on the mismatch between aggregated generation schedules and system requirements as well as on the probability distribution of the given stochastic parameters, and this will be used as input in the next iteration of the optimal self-commitment process.

This presentation will not attempt to solve the generalized stochastic unit commitment problem. It will only formulate it and outline a method to solve it. The idea of self-commitment under uncertain prices has been described and demonstrated earlier by the authors. The presentation will be organized along the following lines:

- We will briefly present the general theme of unit commitment bLR.
- We will describe the optimal self-commitment problem under uncertainty, and describe how to solve it.
- We will then propose a method for integrating LR and optimal self dispatch under uncertainty to create an optimal integrated environment for unit commitment under uncertainty.
- Finally, we will show that if the above method converges, the solution has a number of desirable properties; e.g., at the optimal solution, all generators will be maximizing their expected profit.

Large-scaled Optimal Power Flow with No Guarantee on Feasibility

Mr. Manuel Ruiz, Optimization Consultant, Artelys (*Paris, France*)
Mr. Girardeau, Optimization Consultant, Artelys (*Paris,*)
Mr. Maeght, Research Engineer, RTE (*Paris,*)
Mr. Fliscounakis, Research Engineer, RTE (*Paris, France*)
Mr. Panciatici, Research Engineer, RTE (*Paris, France*)

In the scope of the iTesla European project (www.itesla-project.eu), large-scaled OPF with no guarantee on feasibility are under study. They will be embedded in Monte-Carlo simulations so it is necessary to assess reliable computation time and results.

A large set of instances of real European-wide high voltage network is used for this experiment, including a whole week of day-ahead (24 files per day) and snapshots (96 files per day), from five to ten thousand buses each. Modeling includes constraints on the intensity level on all branches (thermal limits), voltage and reactive bounds, and several tolerances criterions specified by TSOs. The goal is to flag each file: feasibility OPF leads either to a feasible point, to a point where load shedding or production curtailment are needed, or to an unfeasible point.

Computational experiments are done with KNITRO 8.1.1 and AMPL. Fine choices of KNITRO’s options will be presented; these choices are of major importance with interior point methods.

Modeling will be detailed; ways of handling thermal limits will be discussed, together with slacks variables. One key point was to force the solver to respect TSOs precision requirements but not to spend too much time for unnecessary precision.

As a conclusion, together with fine modeling and fine tuning of solver, interior point method behaves very well and their robustness could be assessed on a large set of real-world data.

Session T3-B (Tuesday, June 25, 1:30 PM, Meeting Room 3M-4)

Scalable Strategies for Large-scale AC-SCOPF Problems

Mr. Nai-Yuan Chiang, Postdoctoral appointee, Argonne National Laboratory (*Lemont, IL*)
Dr. Andreas Grothey, Senior Lecturer, University of Edinburgh (*Edinburgh,*)
Dr. Victor M. Zavala, Assistant Computational Mathematician, Argonne National Laboratory (*Lemont, IL*)

The aim of this research is to demonstrate some more efficient approaches to solve the n-1 security constrained optimal power ﬂow (SCOPF) problems by using structure-exploiting primal-dual interior point methods (IPM). We focus on the standard AC-SCOPF problem, which is a nonlinear and nonconvex optimization problem. A new contingency generation algorithm is presented, which starts with solving the basic OPF problem and then generates contingency scenarios dynamically during the solution process. It shows that this approach can detect all the active scenarios and signifficantly reduce the number of scenarios one needs to contain in the model. Additionally, we also apply graph partitioning techniques to analyze the network behavior and to decompose the network. This approach is designed to solve very large-scale network problem while it is able to speed up the parallel efficiency.

An AC-Feasible Linear Approximation Approach to Finding the Optimal Power Flow

Ms. Paula Lipka, Graduate Student Researcher, UC Berkeley (*Albany, CA*)

The solution of the optimal power flow problem is used by large regional energy markets to determine wholesale energy prices and dispatch of generators. However, the full alternating current optimal flow problem (ACOPF) is nonlinear, nonconvex, and very time-consuming to solve. We use a direct linear approximation of the voltage-current ACOPF formulation to find an AC-feasible solution. This approximation method finds solutions faster than the nonlinear formulation with total power costs very close to the nonlinear benchmark. We also explore how the linear approximation can be combined with transmission switching to produce transmission switching solutions that are AC feasible.

Security Constrained AC Optimal Power Flow (SC-OPF): Current Status, Implementation Issues and Future Directions

Dr. Guorui Zhang, Executive Advisor, Quanta Technology (*Raleigh, NC*)
Dr. Xiaoming Feng, Corporate Research Fellow, ABB USCRC (*Raleigh, NC*)

The AC Security Constrained Optimal Power Flow (SC-OPF) has been deployed to many Energy Management System (EMS) controls in North America and elsewhere. However, the utilization of the SC-OPF has been so far quite limited and its potential benefits have not been fully realized due to limited use. This presentation will review the current status and the main factors limiting the utilization of the AC SC-OPF applications in the EMS control centers based on our experiences in the R&D, deployment, commissioning and customer training of the SC-OPF in the control center environment. This presentation will also discuss the critical requirements and the practical expects of the R&D, demonstration and implementation for the AC SC-OPF in the next generation control center applications in the next 5 to 10 years.

Decomposition Approaches to Transmission Switching under N-1 Reliability Requirements

Dr. John Siirola, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)
Dr. Jean-Paul Watson, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)

While optimal (DC) transmission switching appears to be a tractable problem, combining transmission switching with explicit N-1 reliability requirements dramatically expands both the model size and the solution time. In this presentation, we explore approaches for decomposing the combined transmission switching with explicit N-1 reliability problem in order to obtain optimal or near-optimal solutions in a tractable time. Our decomposition approach is motivated by the block structure of unit commitment with N-1 reliability models, where the model can be thought of as a T-by-(N+1) grid of optimal power flow models with additional linking constraints. We observe that this block structure can be recast as a series of N single-contingency scenarios by combining the no-contingency unit commitment model with optimal power flow blocks representing a single contingency. This decomposition readily lends itself to (parallel) solution through approaches like Progressive Hedging. Finally, we demonstrate how a modified dynamic scenario bundling approach can improve both the overall solution time and the final solution quality, without loss of generality. We implement the model decomposition within the Pyomo modeling library and solve it using extensions to the PySP Progressive Hedging solver, both distributed within the open-source Coopr project for optimization developed by researchers at Sandia National Laboratories, Texas A&M University, and the University of California, Davis.

Session T4-A (Tuesday, June 25, 3:45 PM, Meeting Room 3M-2)

Price Responsive Demand for Operating Reserves in co-optimized Electricity Markets with Wind Power

Dr. Zhi Zhou, Computational Engineer, Argonne National Laboratory (*Argonne, IL*)
Dr. Audun Botterud, Power Systems Engineer, Argonne National Laboratory (*Argonne, IL*)

We propose a probabilistic methodology to estimate a demand curve for operating reserves, where the curve represents the value of operating reserves to consumers from the perspective of the sustained level of system reliability that additionally dispatched capacity can provide, with associated expected costs that customers would save. 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 forecast uncertainty. The methodology addresses two key challenges in electricity market design: integrating wind power more efficiently and improving 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 and co-optimization of energy and reserves. We compare the proposed probabilistic approach to price inelastic operating reserve rules. We use the Illinois power system to illustrate the efficiency of the proposed reserve market modeling approach when it is combined with probabilistic wind power forecasting. Specifically, the results show that the system operator tends to schedule more reserves with the proposed method. Moreover, the proposed demand curve results in more stable revenues to providers of operating reserves, which can contribute to cover their operational and investment costs.

Multi-Settlement Simulation of Stochastic Reserve Determination

Mr. Robert Entriken, Senior Project Manager, EPRI (*Palo Alto, CA*)
Mr. Taiyou Yong, Consultant, Eversource Consulting (*Folsom, CA*)
Mr. Russ Philbrick, Principal, Power System Optimization (*Shoreline, WA*)

With significant levels of renewable generation to be integrated in the future electric power systems, new balancing techniques and better forecasting are needed for system operators to maintain power system security. The impact of uncertainty and variability associated with renewable generation motivates the introduction of stochastic methods when determining reserve requirements. These methods enable operators to make better use of system flexibility in order to maintain system reliability and improve economic performance. In this study, a scenario-based stochastic unit commitment and energy scheduling tool was utilized to determine the reserve requirement dynamically. This presentation describes enhancements made to improve the tool's realism and usability as well as simulations performed with data adopted from the California 2020 renewable integration study.

An Affine Arithmetic Method to Solve Stochastic Optimal Power Flow Problems with Uncertainties

Mr. Mehrdad Pirnia, Ph.D. Candidate, University of Waterloo (*Waterloo, Canada*)

An affine arithmetic (AA) method is proposed to solve an optimal power flow problem with uncertain genration sources. In the AA-based OPF problem, all the state and control variables are treated in affine form, comprising a center value and the corresponding noise magnitudes, to represent forecase, model error, and other sources of uncertainty. Furthermore, the proposed AA-based OPF problem is applied to the determination of operational margins of the thermal generators in grids with wind and solar uncertain generation dispatch. The A-based approach is benchmarked against Monte-Carlo Simulation (MCS) intervals in order to determine the effectiveness of the presented method. The model is tested on a IEEE-30 bus benchmark system and also a real 1211-bus system.

A Synergistic Combination of Surrogate Lagrangian Relaxation and Branch-and-Cut for MIP Problems in Power Systems

Dr. Peter Luh, Professor, University of Connecticut (*Storrs, CT*)
Dr. Joseph Yan, Principal Manager, Southern California Edison (*Rosemead, CA*)
Dr. Gary Stern, Director, Southern California Edison (*Rosemead, CA*)

Mixed-integer programming problems are prevalent in power systems/markets planning and operation processes. Historically, they were solved by a combination of lagrangian relaxation and subgradient method. This approach exploits problem separability but convergence can be slow and computation can be expensive since the relaxed problem should be fully optimized to obtain a subgradient. The recent trend is to solve these problems by using the branch-and-cut method. Branch-and-cut exploits linearity of the problem, but its efficiency may be low for certain class of problems.

We recently developed an innovative Surrogate Lagrangian relaxation approach and the corresponding stepsizing formula that guarantees convergence without the need to know optimal dual value in advance. The idea is to make sure that distances between multipliers at consecutive iterations decrease while keeping stepsizes sufficiently large to avoid premature convergence. This approach is generic, and the relaxed problem can be approximately solved by using branch-and-cut with a warm re-start. It is powerful as it makes the best use of problem structures. In addition, local constraints can be efficiently handled locally. Numerical results on Stochastic Unit Commitment and Payment Cost Minimization demonstrated that the new approach is not only computationally efficient but also generates near-optimal solutions. The approach thus opens up a new direction for optimizing MIP problems in power systems and beyond.

N-1-1 Contingency-Constrained Grid Operations

Mr. Richard Chen, Principal Member Technical Staff, Sandia National Laboratories (*Livermore, CA*)
Mr. Jean-Paul Watson, Principal Member Technical Staff, Sandia National Laboratories (*Livermore, CA*)
Mr. Neng Fan, Assistant Professor, University of Arizona (*Tuscon, AZ*)

An N-1-1 contingency refers to the consecutive loss of two elements in a power system, with intervening time for system adjustments. In this talk we will describe the underlying contingency analysis and unit-commitment problems, the models, and the main components of our algorithms. Computational results for several IEEE test systems are reported.

<u>Session T4-B (Tuesday, June 25, 3:45 PM, Meeting Room 3M-4)</u>

Optimal Feeder Reconfiguration

Dr. Steven Low, Professor, Caltech (*Pasadena, CA*)
Mr. Qiuyu Peng, Student, Caltech (*Pasadena, CA*)

The optimal feeder reconfiguration problem seeks to configure the on-off status of sectionalizing switches to optimize certain objective such as minimizing power loss or maximizing a reliability criterium. The problem is a mixed integer problem with nonlinear AC power flow constraints, hence hard to solve. Most existing algorithms rely on linear approximation of power flow equations. We propose an algorithm that considers the full AC power flow equations and only requires solving at most three instances of optimal power flow problem through their convex relaxations. We prove optimality property of the algorithm for radial networks and present simulation results using real-world distribution feeders.

Correcting Optimal Transmission Switching for AC Power Flows

Dr. Clayton Barrows, Postdoctoral Energy Analyst, NREL (*Golden, CO*)
Dr. Seth Blumsack, Assistant Professor, Penn State University (*University Park, PA*)
Dr. Paul Hines, Assistant Professor, University of Vermont (*Burlington, VT*)

Optimal Transmission Switching (OTS) has demonstrated significant savings potential on test systems when formulated in a linearized DC power flow framework. However, OTS solutions generated from DC models have no feasibility guarantee when applied to AC power flow models. Additionally, AC-feasible OTS solutions may not generate cost savings as suggested in the DC model. We present a method to correct OTS solutions obtained in the DC model to ensure feasible AC power flow solutions. When applied to the RTS-96 benchmark network, the method achieves results that are both AC feasible and generate significant system cost reductions.

Advances in Topology Control Algorithms (TCA)

Dr. Pablo Ruiz, Senior Associate, The Brattle Group (*Cambridge, MA*)
Michael C. Caramanis, Professor, Boston University (*Boston, MA*)
Dr. Justin M. Foster, , Boston University (*Boston, MA*)
Mr. Evgeniy A. Goldis, , Boston University (*Boston, MA*)
Mr. Xiaoguang Li, , Boston University (*Boston, MA*)
Dr. C. Russ Philbrick, , Polaris Systems Optimization (*Shoreline, WA*)
Dr. Aleksandr M. Rudkevich, President, Newton Energy Group (*Newton, MA*)
Dr. Richard D. Tabors, , Across The Charles (*Cambridge, MA*)
Mr. T. Bruce Tsuchida, , The Brattle Group (*Cambridge, MA*)

Transmission topology control (line switching) is currently employed by power system operators on an ad-hoc basis, relying on either the operators' previous experience or on a set of fixed procedures linking congestion and topology changes, and fully depending on manual operator intervention. While the co-optimization of network topology and generation resources has been shown to provide significant congestion cost reduction, the problem 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 since our last report, including the development of a reduced MIP formulation using shift factor power flow models, and its properties including computational performance. A comparison will be made with the B-theta MIP formulation, employed in most publications on the subject. 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 the current thermal, stability and voltage reliability criteria.

Inclusion of Post-Contingency Actions in Security Constrained Scheduling

Mr. Peng Peng, Manager of Market Applications, ABB/Ventyx (*Santa Clara, CA*)
Dr. Show Chang, Sr. Principal Engineer, ABB/Ventyx (*Santa Clara, CA*)

Security constrained scheduling applications have been implemented in power system operations and competitive electricity markets for more than a decade. In order to satisfy the operational security requirements, transmission constraints are generally secured in a preventive manner in these applications. Long-term post-contingency ratings are directly imposed on the transmission network such that no post-contingency actions are needed should any contingency occur. As post-contingency correct capabilities of the controls are discounted, the scheduling would under-utilize the transmission capacity and, consequently, result in higher operating cost. In this presentation well describe an integrated process of including post-contingency actions in security constrained scheduling. The incorporation of post-contingency actions improves the scheduling efficiency by operating the transmission network based on short-term post-contingency ratings. The security criteria on which post-contingency actions are based and the formulation of deriving the actions will be described. Results obtained from an actual system will be presented to demonstrate the computational efficiency of the implementation.

Wednesday, June 27

Session W1-A (Wednesday, June 26, 8:30 AM, Meeting Room 3M-2)

Study of Transmission Switching Under Contingencies: Formulations and Algorithms

Dr. Bo Zeng, Assistant Professor, University of South Florida (*Tampa, FL*)
Mr. Long Zhao, University of South Florida (*Tampa, FL*)
Mr. Wei Yuan, University of South Florida (*Tampa, FL*)

Existing study has shown that transmission switching is a cost-effective approach to improve system reliability and dispatch capabilities. However, it has not been analytically investigated or fully adopted in system planning or operations under the N-k contingency reliability criterion, mainly because conventional scenario-based models fail to handle (i) a very large number of contingency scenarios; and (ii) MIP recourse programs employed to model binary switching decisions.

To provide a set of computationally tractable tools for planning and operations, (i) first we capture all contingency scenarios algebraically as mixed integer set(s) to avoid enumerations; (ii) then we build compact two-stage robust optimization formulations with DCOPF and switching as recourse operations under contingencies. Our formulations include a grid vulnerability analysis model, a capacity expansion model, and a reliable Unit Commitment model; (iii) further, given there is no exact algorithm (only heuristics) to solve robust model with a MIP recourse, we design and implement Nested Column-and-Constraint Generation method to efficiently derive optimal solutions for those two-stage formulations; (iv) also, we generalize and present a set of enhancement techniques for faster computing; (v) finally, through a set of numerical experiments, we not only verify the effectiveness of switching but also demonstrate that our algorithm performs an order of magnitude faster than many existing ones.

Security-Constrained Optimal Power Flow with Sparsity Control and Efficient Parallel Algorithms

Dr. Dzung Phan, Research Staff Member, IBM T.J. Watson Research Center (*Yorktown Heights, NY*)
Dr. Andy Sun, Assistant Professor, Georgia Institute of Technology (*Atlanta, GA*)

In this talk, we propose a new model for security-constrained optimal power flow problem (SCOPF), which can find post-contingency corrective actions with a minimum number of adjustments. The minimal reschedule feature is particularly desired by the system operator since it is more reliable to clear a contingency by adjusting only a few number of generators. To achieve this, we introduce the l1-regularization technique to the corrective SCOPF model. We develop an efficient decomposition scheme using an accelerated first-order algorithm for solving the new model.

Computational results comparing with the traditional SCOPF corrective model show that the l1-regularization model significantly reduces the number of rescheduled generators for post contingencies. This sparsification of the re-dispatch is always observed for large-scale electrical power test systems with a large number of contingencies. The sparse solutions obtained by the l1-regularization model also achieve essentially the same level of generation cost efficiency as the traditional corrective model. The proposed algorithm shows promising computational performance comparing to state-of-the-art interior-point solvers in terms of solution speed. The algorithm can be partially parallelized which will further improve the computation time, especially for large-scale power systems.

Candidate Selection for Transmission Switching in Large Power Networks

Dr. Kwok Cheung, R&D Director, Alstom Grid (*Redmond, WA*)
Mrs. Jun Wu, Power Systems Engineer, Alstom Grid (*Redmond, WA*)

Transmission lines are traditionally treated as non-dispatchable assets by electric utilities and regional transmission organizations. Co-optimizing transmission topology and generation dispatch could be a viable way to improve economic efficiency of market and system operations. Optimal transmission switching (OTS) can leverage grid controllability for enhancing system performance. This paper discusses the enhancement of mathematical model for optimal transmission switching within the context of a security-constrained economic dispatch algorithm, and present several criteria for selecting candidates for transmission-line switching to achieve better market surplus within a reasonable time frame. Using a combined set of selection criteria, our approach focuses on reducing production cost, congestion and violation penalties of transmission based on the model of Locational Marginal Pricing (LMP). The proposed method is tested using a large-scale power system. Simulation results will be presented to demonstrate the effectiveness of the proposed methods to select transmission line candidates for OTS.

Transmission Switching for Improving Wind Power Utilization

Dr. Feng Qiu, Postdoctoral Appointee, Argonne National Laboratory (*Argonne, IL*)
Dr. Jianhui Wang, Computational Engineer, Argonne National Laboratory (*Argonne, IL*)

Due to the significant variation of wind power over short time scales, high utilization of wind power can be problematic to power system operations. How to keep increasing wind penetration without jeopardizing the security and reliability of the power grid is critical in wind power integration. This study explores the possibility of changing transmission network topology, by transmission switching, to accommodate higher utilization of wind power and reduce the generation costs of thermal units. We assume that the uncertain wind power resources at every node are correlated and follow a certain probabilistic distribution. We model this transmission switching problem under uncertainty as a two-stage stochastic integer program, where the first stage determines which transmission line is switched and the second stage determines a feasible generation production schedule which satisfies the wind utilization requirement and a probabilistic risk constraint. We develop a deterministic approximation for this stochastic optimization problem using sample average approximation and formulate it as a mixed-integer linear program (MILP). We solve the MILP with cutting planes and branch-and-bound. We perform cost analysis and the results show that the proposed transmission switching has the potential to achieve the pre-specified wind utilization goal and reduce the power generation costs of thermal units.

Session W1-B (Wednesday, June 26, 8:30 AM, Meeting Room 3M-3)

Stochastic Unit Commitment: Scalable Computation and Experimental Results

Dr. Jean-Paul Watson, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)
Dr. Sarah Ryan, Professor, Iowa State University (*Ames, IA*)
Dr. David Woodruff, Professor, University of California Davis (*Davis, CA*)

This talk is the second in a two-part series describing work that is part of a large ARPA-e project on stochastic unit commitment that involves multiple researchers and institutions, including Sandia National Laboratories, the University of California Davis, Iowa State University, Alstom Grid, 3-Tier, and ISO-NE. The problem is to optimize day-ahead and intra-day electricity generation plans taking into account the uncertainty provided by both load and the high use of renewables. The resulting large scale stochastic programming problem presents serious computational challenges. We address these challenges using scenario-based decomposition techniques and modest parallel computing resources, achieving tractable run-times on moderate-scale instances. Our solver is embedded in a stochastic simulation environment, which is used to validate the model and to quantify cost savings relative to a standard deterministic unit commitment model. We describe full experimental results on the WECC-240 instance, in addition to preliminary results associated with an ISO-NE test instance and the recently released FERC test instance.

MIP Based System Flexible Capacity Requirements Determination

Dr. Alex Papalexopoulos, President & CEO, ECCO International (*San Francisco, CA*)

The high penetration of RES resources has created substantial market and operational challenges that require immediate attention. The following issues are at the center of the current debate. How many MW of dispatchable resources are needed to meet load and to simultaneously meet capacity flexibility requirements on several time scales? What is the optimal mix of new resources, given the characteristics of the existing fleet? What capacity of RES resources can be added without causing flexibility problems with the existing mix of thermal and hydro plants?

In this presentation well present a key breakthrough related to incorporation of the endogenous ramp and reserve policies directly into the MIP-based optimization engine. This approach makes it computationally feasible to consider the impact of operational constraints within long-term reliability studies. This is accomplished through the introduction of an Expected Flexibility Deficiency (EFD) function, to determine the anticipated amount of un-served energy caused by a lack of flexibility in the generating fleet. The EFD is computed before executing the unit commitment, and it is derived from historical system load/renewable data.

The proposed methodology allows us to simulate loss of loss events where the generation fleet is unable to follow the variations of the net load throughout the entire study period.

Decomposition Methods for Stochastic Unit Commitment Problems

Dr. Suvtrajeet Sen, Professor, University of Southern California (*Los Angeles, CA*)

Stochastic unit commitment models are a class of stochastic mixed-integer programs (SMIP). While deterministic mixed-integer programming (MIP) software has been very successful at solving the deterministic unit commitment problems, standard MIP solvers do not scale up in the stochastic setting. In this presentation, the speaker will first provide an overview of general purpose decomposition-based SMIP algorithms. These are not based on Lagrangian decomposition, but rather on results of combining Benders decomposition with Polyhedral Combinatorics - the same tools that have delivered tremendous progress in MIP solvers. He will also discuss how one can specialize these approaches to the case of stochastic unit commitment models. Computational experience comparing the deterministic equivalent, and the SMIP approach will be reported on instances with thousands of scenarios. In addition, the speaker will also describe how electricity prices can be predicted using these types of models.

Stochastic Unit Commitment: Stochastic Process Modeling for Load and Renewables

Dr. David Woodruff, Professor, University of California Davis (*Davis, CA*)
Dr. Sarah Ryan, Professor, Iowa State University (*Ames, IA*)
Dr. Jean-Paul Watson, Principal Member of Technical Staff, Sandia National Laboratories (*Albuquerque, NM*)

This talk describes work that is part of a large ARPA-e project on stochastic unit commitment that involves multiple researchers. The problem is to optimize day-ahead and intra-day electricity generation plans taking into account the uncertainty provided by both load and the high use of renewables. The large scale stochastic programming problem presents computational challenges. In addition, just as fish do not jump willingly into a frying pan, the world does not create data that jump willingly into a stochastic process model. We will discuss some optimization problems that result from creation of stochastic process models for load and available renewable energy. We will also discuss the extraction of probabilistic scenarios from the stochastic process models and evaluation of those scenario sets for use in the stochastic programming model, which will be described in a companion talk.

Session W2-A (Wednesday, June 26, 10:45 AM, Meeting Room 3M-2)

Smart Wire Grid: Providing Advanced Power Flow Control for the Grid

Mr. Stewart Ramsay, CEO, Smart Wire Grid, Inc. (*Oakland, CA*)

Smart Wire Grid provides advanced transmission control. Combining hardware, distributed series reactors (DSRs), software, and communications SWG's technology provides the means to actively monitor and control flows on transmission lines. Through deployment of DSRs along transmission or sub-transmission lines, SWG provides enhanced, precise and granular transmission switching by introducing impedance to divert power flow away from loaded lines. The devices report back to a stand-alone or EMS-integrated server for continuous updating of allowable flow ratings. The device settings can be updated dynamically so their control is based on realistic system representation. DSRs can be used to reduce wear on mechanical switching devices and can be configured to provide optimal transmission flows to maintain reliability and increase system stability margin. DSRs allow phase balancing and increased ATC, can be installed or removed quickly, and can be redeployed as load patterns change. DSRs can defer expensive infrastructure investments or help grid operators manage system conditions while infrastructure additions are being built. Future versions will be adapted to not only push flow from loaded lines but also to pull power as desired. The evolution of the technology will provide active, self-controlling, self-organizing DSRs, enhancing dynamic system control. Through integration into EMS/MMS or SCADA, SWG enables greater system reliability, congestion management, and reduced losses.

HVDC Grid Technology - Benefits of Hybrid AC/DC Grids and Optimal Power Flow Modeling Considerations

Dr. Xiaoming Feng, Corporate Research Fellow, ABB (*Raleigh, NC*)

Multi terminal HVDC grid based on voltage source converter is a fast developing technology. The advantage of DC transmission and flexibility in power flow control makes it a very attractive choice to connect large renewable power projects with multiple AC grids. The independent control of real power and reactive power of voltage source converters enables more optimal operation of the hybrid grids. The modeling considerations of HVDC grids for OPF will be discussed.

Tres Amigas: Uniting the Electric Power Grid

Mr. Kenneth Laughlin, Exectuve Director, Tres Amigas, LLC. (*Santa Fe, NM*)

Tres Amigas is a first-of-its-kind HVDC project to connect three power grids in the United States through asynchronous connections. A key success factor for the wholly-merchant transmission project is optimized deployment of power among the three grids and dynamic voltage support to interconnection points based on telemetered grid requirements. Using voltage sourced conversion (VSC) technology the connection allows rapid switching of power on a bidirectional basis and provides dynamic reactive support to maintain voltage levels in weak areas on a real-time basis. This technology, coupled with improved AC power flow optimization allows for fast and efficient deployment of energy and reactive support, helps the grids support each other and allows for integration of renewable energy from resource-rich areas. The ability for Tres Amigas to optimize the use of energy (primarily renewable solar and wind energy) between the three interconnects will depend significantly upon the transmission capabilities of the interconnections. Tres Amigas will provide further benefit with the integration of dynamic line ratings into the market operations in order to maximize the use of the existing transmission infrastructure and the proposed expansions.

Beyond Real Time: the Computational Challenges of Forecasting Dynamic Line Ratings

Mr. Eric Hsieh, Director, Market and Business Development, Nexans (*Bethel, CT*)
Mr. Stuart Malkin, Forecast Manager, Nexans (*Portland, OR*)

Dynamic Line Ratings (DLRs) have been shown to reduce congestion, improve market efficiency through increased usable transmission capacity and reliability through increased situational awareness. However, their usefulness can extend beyond real time operations to "Day of" operations and "day ahead" operations and markets.. This presentation presents a pilot project for a forecasting mechanism on a short term (30 minutes to 6 hours) and long term (up to 48 hours) time frame. A forecasting engine incorporates commercially available weather, specific information about the corridor and analytics to create both binary and continuously variable forecasts of future transmission capacity. The pilot project has demonstrated a very high usability rate, which can be adapted and used for both day-ahead and intra-hour scheduling.

Implementing DLRs in the control room at PacifiCorp - Technology Successes and Challenges

TBD, Pacificorp (*Portland, OR*)

TBD

<u>Session W2-B (Wednesday, June 26, 10:45 PM, Meeting Room 3M-3)</u>

Scalable Parallel Analysis of Power Grid Models Using Swift

Mr. Ketan Maheshwari, Postdoctoral Appointee, Argonne National Laboratory (*Argonne, IL*)
Mr. Victor M Zavala, Fellow, Argonne National Laboratory (*Argonne, IL*)
Mr. Justin Wozniak, Assistant Scientist, Argonne National Laboratory (*Argonne, IL*)
Mr. Mark Hereld, Senior Fellow, Argonne National Laboratory (*Argonne, IL*)
Mr. Michael Wilde, Senior Fellow, Argonne National Laboratory (*Argonne, IL*)

We present a scalable framework to analyze the behavior of optimization models arising in power grid applications using the parallel scripting language Swift.

Swift is a scripting language designed for composing ordinary programs into parallel applications that can be executed on clusters, clouds and supercomputers. Swift can transparently interface to one or more computing systems, move data and results from a local submit machine such as a laptop.

Critical features that Swift offers to optimization modelers is the ability to exploit non-obvious concurrencies arising in complex computational workflows and the ability to automatically manage load balancing issues in heterogeneous architectures.

We demonstrate that Swift enables nearly perfect scalability in several applications such as power flow analysis, benchmarking of optimization solvers, and inference analysis of stochastic unit commitment models. In addition, we demonstrate that these desirable features can be obtained with minimal programming effort from the user.

Improving Market Planning and Efficiency Software Through Dynamic Integration of High Quality Data

Mr. Christopher Vizas, Chairman, SmartSenseCom, Inc. (*Washington, DC*)
Dr. Nicholas Lagakos, , SmartSenseCom, Inc. (*Washington, DC*)
Dr. Anjan Deb, SmartSenseCom, Inc. (*Washington, DC*)
Mr. Chris Vizas, , SmartSenseCom, Inc. (*Washington, DC*)
Mr. Jack Barker, , SmartSenseCom, Inc. (*Washington, DC*)
Mr. Victor Kaybulkin, , SmartSenseCom, Inc. (*Washington, DC*)

SmartSenseCom will present on improving the power and capabilities of market planning and efficiency software through the dynamic integration of attainable real world data. To achieve grid automation, and realize associated reliability and efficiency improvements, the acquisition of timely and accurate data is critical. FERC, using the regulatory tools available to it, must seek to improve the quality of the data upon which enhanced software solutions can be developed.

FERC should encourage adoption of technologies that will provide the reliable, dynamic data needed to: (a) develop optimal transmission switching approaches within reliability limits; (b) optimize AC power flows and models; and (c) realize efficiencies in transmission networks by dynamically integrating real time load data with transmission line-rating software.

SmartSenseCom will focus on specific examples in which improvements in the underlying data may materially enhance existing software-based modeling approaches by decreasing system uncertainty and associated rates of error. Attention will be paid to the potential for integrated hardware and software based technologies to provide the data necessary to address issues associated with the widespread integration of distributed resources and improve system reliability. FERC's regulatory authority to encourage the adoption of data-driven technologies will also be explored.

SmartSenseCom will be represented by Chris Vizas and Jack Barker.

Highly Dispatchable and Distributed Demand Response for the Integration of Distributed Generation

Dr. Amit Narayan, Founder and CEO, AutoGrid Systems (*Palo Alto, CA*)

AutoGrid will discuss how DROMS-RT, a highly distributed Demand Response Optimization and Management System for Real-Time (DROMS-RT) power flow control, can support large scale integration of distributed renewable generation into the grid. Such a communications platform can provide ancillary services to the transmission grid, and once implemented, are significantly more cost effective that other forms of ancilliary service options.

We will demonstrate how DROMS-RT leverages Automated Demand Response (ADR) by fundamentally re-thinking the architecture of the DR platform from the ground up and by developing innovative new technologies in a number of areas related to DR. In addition, OpenADR which is a low-cost, open, interoperable DR signaling technology that can lower the cost of hardware. This allows DROMS-RT to provide dynamic price signals to millions of OpenADR clients.

- Traditional price-based DR missed vs. real-time DROMS and how DROMS-RT leverages target loads with load aggregation points to manage congested electric grids
- How cloud-based DROMS differs from traditional demand response solutions
- Statistically rigorous signal processing techniques that reliably detect load reductions
- Steps towards meeting renewable energy deployment goals that must be taken and DR's role in reaching those goals
- OpenADR and how it manages real-time requirements of providing ancillary services
- The cost and potential ROI associated with implement a demand response.

Solving MPEC Models with the KNITRO Nonlinear Solver

Dr. Richard Waltz, President, Ziena Optimization LLC (*Evanston, IL*)
Dr. Jorge Nocedal, , Ziena Optimization LLC (*Evanston, IL*)
Dr. Arnaud Renaud, , Artelys (*Paris, France*)
Dr. Sylvain Mouret, , Artelys (*Paris, France*)

Mathematical Programs with Complementarity Constraints (MPCC/MPEC) are increasingly used to represent discrete decisions in nonlinear models (NLP). Any MINLP model may be reformulated into an MPEC model thus making MPEC solvers an attractive solution for rapidly obtaining near-optimal solutions.

In this presentation, we will discuss the properties of MPEC models and common issues arising from solving MPEC models (non-convexities, local infeasibilities, etc.).

The implementation of MPEC solution strategies as part of the three nonlinear active-set and interior-point algorithms of KNITRO will be presented, as well as ongoing and future developments to improve the robustness and performance of KNITRO on such problems.

Examples of OPF models including generator startup/shutdowns events will be presented to illustrate the effectiveness of these MPEC strategies. Such nonlinear OPF models are also combinatorial due to the presence of minimum/maximum generator power constraints. Computational experiments are done with KNITRO 8.1.1 and AMPL.

New methods for measuring voltage stability limits utilizing HELM tools

Dr. Jason Black, Research Leader, Battelle (*Columbus, OH*)

To increase reliability and simultaneously uitilization of transmission capacity, improved methods for calculating voltage stability limits are needed. This talk will present several case studies demonstrating the use of Holomorphic Embedding Load Flow (HELM) tools to identify voltage limits for complex models and scenarios. HELM tools provide new visualization capabilities that allow for identification of specif nodes or sets of nodes that are closest to collapse for very large models. These tools also allow for exploration of any potential operational and contingency scenarios without the need for an initial solution seed. The case studies presented will illustrate the use of HELM tools to identify the collapse point for several complex scenarios, along with the specifc nodes responsible for collapse.