Advanced Workshop in Regulation and Competition

26th Annual Western Conference

Hyatt Regency, Monterey, California, on June 19-21, 2013

The Conference features some of the latest developments in the network industries, especially energy, including:

- ➢ Deregulation
- ➢ Market Structure
- ➢ Policy and Regulatory Issues
- ➢ Environmental Policy and GHG
- ➢ Telecommunications and Water
- ➢ Pricing and Demand Response
- ➢ Capacity and Reliability

Who should attend:

- ➢ Industry Economists, Consultants and Attorneys
- ➢ Marketing and Regulatory Managers
- ➢ Regulatory Commission Staff

Featured Speaker: Professor William E. Kovacic, George Washington University Law School

Dinner Speaker: Michael R. Peevey, President, California Public Utilities Commision

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WEDNESDAY, JUNE 19, 2013

2:00 - 4:00 Registration *MGB Terrace*

4:00 – 6:00 Welcome to Conference: Michael A. Crew
Jiong Gong and Baoming Dong: Public Infrastructure and Government Organizations
Joseph K. Tanimura, and C. Paul Wazzan: Forgoing Ratepayer Claims In Order to Promote Public Policy Which May Not be in the Public's Best Interests – The Case of Dynegy and Electric Vehicle Charging Stations
William E. Kovacic: Meaningful Disclosure: Sunshine Acts and the Effectiveness of Regulatory Commission Decision Making

6:00 - 7:00 Cocktail Hour *MGB Terrace*

7:00 – 9:00 **Dinner & Keynote Speech: Michael R. Peevey, President, Californial Public Utilities Commission** *Pacific*

9:00 – 10:00 Reception *MGB Terrace*

THURSDAY, JUNE 20, 2013

8:00 - 9:40 *Concurrent Sessions*

WHOLESALE MARKETS *Grove*
Chair: Karen Shea
Discussants: Jeffrey Nelson
Jeff McDonald, Eric Hildebrandt, and Keith Collins: Performance of Enhanced Local Market Power Mitigation in the California ISO's Day-Ahead Market
Kevin Woodruff: California Revisits Centralized Capacity Markets
R. Entriken, Philbrick, Tuohy, and Yong: Stochastic Optimal Power Flow for Reserve Determination

NATURAL GAS *Pacific*
Chair: Bishu Chatterjee
Discussants: Matthew Arenchild,
Janie Chermak, Robert Patrick, and James Crafton: Shale Gas Well Completion and Production Practices – Conservation, Environmental and Regulatory Implications
Catherine Elder: Fracking – The Sequel
Cliff Rochlin: Gas-fired Electric Generation's Aversion to Long-Term, Firm, Gas Transportation Contracts

9:40 – 10:00 Coffee Break *MGB Terrace*

10:00 - 11:40 *Concurrent Sessions*

RENEWABLE INTEGRATION I *Grove*
Chair: Janos Kakuk
Discussants: Gary Stern & Kevin Woodruff
Scott Harvey: Accounting for Uncertain Intermittent Output in the Unit Commitment and Dispatch
Udi Helman and Warren Katzenstein: Modeling Concentrating Solar Power (CSP) with Thermal Energy Storage in the Western U.S. Power Grid under 33% RPS
Tim Mount, Wooyoung Jeon, Alberto Lamadrid and Hao Lu: Evaluating the Effects of Different Flexible Ramping Products on the Total Cost of Supplying Electricity on a Power Grid

RATE RESPONSE *Pacific*
Chair: Dennis Keane
Discussants: Scott Mutishaw, Richard Song
Ahmad Faruqui Neil Lessem, and Sanem Sergici: An Impact Evaluation of a Southern Utility's Technology Enabled Smart Pricing Pilot
Stephen George and Nate Toyama: Interim Results from SMUD's Time Varying Pricing Experiment
Ross Gorman and Rob Landon: Rate Risk Management using a Hydroelectric Generation Adjustment Surcharge

11:40 - 1:00 Lunch Break

1:00 - 2:30   *Concurrent Sessions*

RENEWABLE INTEGRATION II   *Grove*
Chair:Nguyen Quan
Discussants: Larry Blank, Matthew Arenchild

Carl Silsbee: Assessing the Need for Flexible Resources to Manage Electric Grid Reliability

Paul Nelson and Justin Kubassek: Using Regression Estimation to Calculate Effective Load Carrying Capacity of Renewable Resources

R Entriken, M. Alexander, Davis, Fang, Halliwell, Lee, Mullen-Trento, Nieuwesteeg, Oren, and Wilson: Plug-in Electric Vehicle Fleet Valuation – Case Study

RESOURCE ISSUES   *Pacific*
Chair: Bruce De Berry
Discussants: Bishu Chatterjee

Sonika Choudhary, Sam Wade and Ray Williams: Combined Heat and Power

Glenn R. George: Application of Portfolio Theory to Electric Power Generation Assets – Recognizing Additional Value from Generation Diversity

Charlene Zhou: Structural Analyses of Emission Permit Auctions under Cap-and-Trade Programs in the United States

2:30 - 4:00   *Concurrent Sessions*

RENEWABLES   *Grove*
Chair: Peter Griffes
Discussants: Anne-Marie Cuneo, Robin Walther, Benjamin Chee

Robert Earle: Renewable Energy Credit Trading in the United States

Travis Kavulla and Jason Brown: Timing is Everything: Aligning Federal and State Wind Incentives with Utilities' Energy and Capacity Needs

Katie Sloan and Marc L. Ulrich: A Pricing Mechanism Substitute to Agency-Based Pricing: An Exploration of the Renewable Market Adjustment Tariff (Re-MAT)

WATER   *Pacific*
Chair: Fred Curry
Discussants: Carl Peterson, Richard McCann

Michael A. Crew and Rami S. Kahlon: Guaranteed Return Regulation: a Case Study of Regulation of Water in California

Jason Hansen and Jamie Chermak: Within our Means: Growth and Development under Water Scarcity

Marzia Zafar and Rich White: Water-Energy Nexus – How to Value Each Technology Class in order to Align Incentives

FRIDAY, JUNE 21, 2013

8:45 - 10:40   *Concurrent Sessions*

TRANSMISSION ISSUES   *Grove*
Chair: Joseph Abhulimen
Discussants: Gary Stern

Darryl Biggar and Mohammad Hesamzadeh: Designing Financial Transmission Rights to Facilitate Hedging in Wholesale Electricity Markets

Hung-Po Chao and Robert Wilson: Coordination of Electricity Transmission and Generation Planning – Structures, Incentives and Welfare Impacts

Amparo Nieto: Transmission planning and pricing in the US – What Else Can Be Done?

RATE MAKING I   *Pacific*
Chair: Bob Kelly
Discussants: Scott Murtishaw, Robert Levin

Larry Blank: Statistically Determining Proper Recovery of Demand-Related Costs through the Energy Charge

Cynthia Fang: Unbundling: A Needed Fix for Residential Rate Design

Jim Heidell and Mike King: Utility and Customer Economic Impacts of Net Metering for Distributed Renewables

10:40 – 11:00   Coffee Break   *MGB Terrace*

11:00 - 12:45   *Concurrent Sessions*

UTILITY INVESTMENT   *Grove*
Chair: Fred Curry
Discussants: Richard Aslin, Menahem Spiegel

Karl McDermott and Carl Peterson: Testing Alternative Theories of Capital Structure: The Case of the Electric Utility Industry

Andy Satchwell and Ryan Hledik: Analytical Frameworks to Incorporate Demand Response in Long-Term Resource Planning

Joe Wharton, Michael Vilbert, Toby Brown, and Rich Goldberg: The Impact of Decoupling on the Cost of Capital – an Empirical Investigation

RATE MAKING II   *Pacific*
Chair: Will Fuller
Discussants: Stephen St. Marie, Neil Lessem

Carl Danner and Robin J. Walther: Welfare Analysis of Conservation Rate Designs for Water

Brian Kim: Proper Rate Treatment of Energy Efficiency Investments

Eric Woychik, Mark S. Martinez, and Kenneth Skinner: Dynamic Market Response to Optimize Demand Management

12:45- 12:50   Concluding Remarks-Michael A. Crew

SPEAKERS DISCUSSANTS & CHAIRS

Joseph Abhulimen, Program Supervisor, DRA, Californial Public Utilities Commission

Marcus Alexander, EPRI

Matthew Arenchild, Director, Navigant Consulting, Inc.

Richard Aslin, Principal Strategic Analyst, PG&E

Darryl Biggar, Australian Competition and Consumer Commission

Larry Blank, Associate Professor of Economics, New Mexico State University

Hung-Po Chao, Director, Market Strategy and Analysis, ISO New England, Inc.

Bishu Chatterjee, California Public Utilities Commission

Benjamin Chee, Senior Consultant, NERA Economic Consulting

Janie M. Chermak, University of New Mexico

Sonika Choudhary, Sr. Analyst, Long Term Energy Policy, PG&E

Michael A. Crew, CRRI Professor of Regulatory Economics, Rutgers University and Director-CRRI

Anne-Marie Cuneo, Director of Regulatory Operations, Public Utilities Commission of Nevada

Fred Curry, Independent Consultant, San Franciso, CA

Carl Danner, Director, Berkeley Research Group, LLC

Bruce DeBerry, Program Manager, Water Division, California Public Utilities Commission

Robert L. Earle, Vice President, Analysis Group

Catherine Elder, Senior Associate, Energy Resource Analysis, Aspen Environmental Group

Robert Entriken, Senior Manager, Policy Analysis, EPRI

Cynthia Fang, Electric Rates Manager, San Diego Gas & Electric

Ahmad Faruqui, Principal, The Brattle Group

Will Fuller, Regulatory Case Administrator, SDG&E

Glenn R. George, Principal, KPMG LLP

Stephen S. George, Chief Executive Officer, Freeman, Sullivan & Co.

Jiong Gong, Associate Professor, University of International Business and Economics

Ross Gorman, Supervisor, Commodity Risk Management, Sacramento Municipal Utility District

Peter Griffes, Chief –Comprehensive Market Design, PG&E

Jason K Hansen, Assistant Professor of Economics, Naval Postgraduate School

Scott Harvey, FTI Consulting

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Justin Kubassek, Southern California Edison

Neil Lessem, Consultant, The Brattle Group

Robert Levin, Senior Analyst, DRA,California Public Utilities Commission

Mark S. Martinez, Customer Programs and Services, Southern California Edison

Richard McCann, Energy Resource Analysis, Aspen Environmental Group

Karl A. McDermott, Professor, University of Illinois – Springfield

Jeff McDonald, Manager, Market Analysis and Mitigation, California ISO

Timothy D. Mount, Professor, Cornell University

Scott Murtishaw, Energy Advisor to President Peevey, California Public Utilities Commission

Jeffrey Nelson, Principal Manager of Market Design and Analysis, Southern California Edison

Paul Nelson, Market Design Manager , Southern California Edison

Nguyen Quan, Manager - Regulatory Affairs Golden State Water

Amparo Nieto, Senior Consultant, NERA Economic Consulting

Robert H. Patrick, Associate Professor, Rutgers University

Carl Peterson, Assistant Professor, University of Illinois – Springfield

Cliff Rochlin, Market Advisor, Southern California Gas Company

Andrew Satchwell, Scientific Engineering Associate, Lawrence Berkeley National Laboratory

Karen Shea, Project Manager, Southern California Edison

Carl Silsbee, Manager of Regulatory Economics, Southern California Edison

Katie Sloan, Principal Manager, Southern California Edison

Richard Song, Southern California Edison

Menahem Spiegel, Professor, Finance and Economics, Rutgers University

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Marc L. Ulrich, Vice President of Renewable and Alternative Power, Southern California Edison

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Robin Walther, Profession Affiliate, Finance Scholars Group

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Kevin Woodruff, Principal, Woodruff Expert Services

Eric C. Woychik, Executive Consultant, Itron Inc.

Charlene Zhou, Associate, Analysis Group, Inc.

26th ANNUAL WESTERN CONFERENCE

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HOTEL RESERVATIONS

Sufficient Rooms are reserved at the Hyatt Regency Monterey for all of the Conference participants. Participants should register for the conference by returning registration forms to Portola Hotel & Spa. Reservations should be received by **May 20, 2013**. Hotel reservation can be made by using the following Passkey Link:

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If you are not making reservations through the link above please identify yourself as being held under the group block: Rutgers University CRRI Program.

REGISTRATION INFORMATION

To Register: Please complete and return the form to CRRI. Registrations are accepted by mail, email, fax, and telephone. Please confirm telephone registrations by sending in a completed and signed registration form. The deadline for registrations is May 2, 2013. Registrations received after May 2, 2013 will be admitted on a space available basis.

Volume discount: Second and subsequent applications received in the same envelope, fax, email, or made at the same time by phone will receive a 5% volume discount.

Payment Information: Make checks payable to **"Rutgers University"** and mail to the attention of at the above address. Fees include prescribed learning materials, dinner on Wednesday night, June 19, 2013, all receptions and coffee breaks, but do not include lodging and other meals. The government registration fee is available for government employees.

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Public Infrastructure and Government Organizations
Baoming Dong and Jiong Gong

Abstract: One of the main themes in Thomas Friedman's book "That Used to Be Us: How American Fell Behind in the World" is America's lack of investment in large public infrastructure projects. We establish a hierarchical organization model to study the decision process of such infrastructure projects, where public funding from the federal government (abbreviated as P) is used for local level investment initiated by a state government (abbreviated as A), but has to be approved and monitored by a regulatory authority (abbreviated as M) acting on behalf of the federal government. This setup is analogous to a simplified version of the "Centralization with Supervision (CM)" model in the organizational economics literature. In the example of a proposal for a high-speed railway project in California, the federal government is P, the state government of California is A, and the Department of Transportation is M. This model can be used to explore the impact of different state government structures on the public infrastructure project selection process. The state government can be an authoritarian government like in China, while the state government in the US must be a full-functioning democracy. We hypothesize that too many bad infrastructure projects are approved in the former case, while too few good infrastructure projects are approved in the latter case. We further extend the US example to a case where a small minority can challenge the state government's majority rule in court, and explore its implications to the public infrastructure decision process.

Meaningful Disclosure: Sunshine Acts and the Effectiveness of Regulatory Commission Decision Making

William E. Kovacic, Global Professor of Competition Law, George Washington University Law School

The federal government and many states have adopted "government in the sunshine acts" which state that a quorum of the members of independent regulatory commissions may not discuss official business unless such discussions take place in public meetings. With limited exceptions, sunshine acts preclude spontaneous conversations among board members if a quorum is present.

Sunshine acts assume that disclosure through mandated public meetings helps ensure that regulatory agents faithfully execute the commands of legislature principals. With public meetings, legislators and intermediaries (e.g., academics, advocacy groups, and journalists) can monitor agencies more effectively and spot lapses caused by sloth, capture, or corruption.

This paper suggests that sunshine acts can degrade, rather than improve, the quality of decision making. Most important, sunshine laws can frustrate the realization of benefits that are said to come from governance by a multimember commission, rather than governance by a unitary administrator. The paper also proposes alternative disclosure regimes that would permit commissions to fulfill their intended role as superior decision making mechanisms and to address the principle-agent problems that motivated the establishment of sunshine acts.

Title: Forgoing Ratepayer Claims In Order to Promote Public Policy Which May Not be in the Public's Best Interests: The Case of Dynegy and Electric Vehicle Charging Stations

Authors: C. Paul Wazzan, Joseph K. Tanimura, Ward Benshoof

Abstract:

In 2002, the California Public Utilities Commission ("CPUC") initiated litigation against Dynegy, Inc. and related parties, alleging they overcharged California rate-payers by approximately $1 billion during the 2001 energy crisis. In March, 2012, the CPUC announced it intended to settle the litigation for $20 million and NRG's (Dynegy's successor) agreement to invest over $100 million in NRG's own Electric Vehicle Charging Stations ("EVCS") infrastructure business in California. As part of the settlement proposal, NRG would retain exclusive access to this infrastructure for a period of time. Several important elements of this settlement agreement were raised in public policy discussions: 1) the agreement was reached in secret; 2) it constituted an unauthorized use of rate-payer assets (i.e., the claim); 3) the CPUC has no authority to regulate EVCS infrastructure which in effect this settlement does; and 4) the settlement creates the strong potential for granting NRG a monopoly in EVCS in California. After numerous legal filings, a petition for writ of mandate to block the settlement was denied by the California Court of Appeal.

This paper will focus on whether a public agency, established to protect the interests of rate-payers, should forgo monetary claims (which would ultimately be refunded to ratepayers) in order to implement public policy, the responsibility for which the Legislature has not only delegated to another agency, but the implementation of which presents a potential threat to competition in a nascent marketplace. We conclude with a discussion of the potential anti-competitive impact of the CPUC's actions with a particular focus on the network effects in the market for EVCS.

Title: Performance of enhanced local market power mitigation in the California ISO's day-ahead market

Jeff McDonald, Eric Hildebrandt, and Keith Collins

Abstract: One of the challenges in producing efficient nodal electricity prices is ensuring that locational price signals reflect relative scarcity under competitive conditions and are not influenced by the exercise of local market power. Spot market prices that embody market power can produce inaccurate price signals, result in inappropriate transfer of payments, inflate contract prices outside the spot market, and be used to manipulate financial instruments outside the organized market. Each of these impacts confound the original intent of organized, centralized spot electricity markets. The California ISO has developed and implemented an approach that identifies local market power through a pivotal supplier test that is performed within the market software leveraging actual current market and grid conditions. Further, the new approach identifies resources to be mitigated by decomposing the locational price into competitive and non-competitive components to determine if the resource can impact price at its location through uncompetitive bidding. This paper provides analysis of the performance of the new local market power mitigation approach in the California ISO day-ahead electricity market and focuses on the two-week heat wave in early August 2012.

California Revisits Centralized Capacity Markets

Kevin Woodruff
Principal, Woodruff Expert Services

The California Public Utilities Commission (CPUC) previously rejected implementation of centralized markets for electric capacity for its jurisdictional utility systems – often called Centralized Capacity Markets (CCMs). However, several key constituencies have encouraged – with some success – the CPUC to revisit CCMs starting in 2013. This paper will review the state's current electric capacity and energy markets, the frustrations some major parties apparently have with such existing markets and the apparent goals of parties supporting and opposing CCMs. The paper will assess whether these parties' goals can or will be achieved under current markets, CCMs or other alternatives. The above analyses will consider, among other topics, (a) factors unique to California's electricity market, such as its aggressive Renewable Portfolio Standard, (b) conflicting goals among CCM proponents, and (c) examples from the experience of other market operators.

Stochastic Optimal Power Flow for Reserve Determination: Enhancement on Dynamic Reserve Procurement

Robert Entriken, Russ Philbrick, Tuohy, Yong

This paper describes the dynamic reserve procurement method and its application in the energy scheduling and dispatch processes. A scenario-based stochastic unit commitment tool was implemented to determine the reserve requirement dynamically. It describes enhancements made to improve the computational efficiency and usability of the tool, and simulations performed with data adopted in the California 2020 renewable integration study. The work used this realistic system model to demonstrate how dynamic reserve requirements can be defined for near real-time operation. The use of dynamic reserve requirements is especially beneficial for reliable and efficient integration of renewable generation. In this demonstration, dynamic reserve determination was applied to control decisions performed by system operators one-hour ahead of actual operations (i.e., the hour-ahead "decision cycle") in order to identify reserves needed to mitigate the inherent errors in the renewable generation forecast. The results demonstrate that dynamic reserve procurement is practical for both existing market systems and traditional utilities, and that dynamic procurement produces reserve-procurement policies can be more effective than less-dynamic, traditional policies.

Shale Gas Well Completion & Production Practices: Conservation, Environmental & Regulatory Implications

Janie M. Chermak, James W. Crafton, Robert H. Patrick

Shale gas has rapidly become a factor in the US natural gas industry. Reserves that were unrecoverable in the 1990s have, through the advent of drilling and hydraulic fracturing technologies, become feasible. US shale gas production has increased from less than 0.4 trillion cubic feet (Tcf) in 2000 to more than 4.8 Tcf in 2010 (~23% of total US gas production). Shale gas reserves have the potential to alter not only the market structure within the natural gas producing industry, but also the longevity and competitiveness of the domestic US energy industry. However, in many cases the actual performance of shale gas wells has been less than expected, with large production declines in the early periods of production, resulting in substantially smaller ultimate recovery and higher than originally forecast costs.

This paper focuses on factors affecting early period production, including the characteristics of the well and completion and production choices made by the producer. We begin with a development of a theoretical model of capital investment and production, followed by an empirical analysis of completion and early period production employing data from 111 shale gas wells. We find that not only are reservoir characteristics statistically significant, but producer decisions are also statistically significant in the productivity of these wells. The implications of these impacts on competitiveness in the industry, as well as on regulation are explored. The impact of completion decisions on cumulative production is highly variable, depending on the completion technology. Also, we find completion and production choices may, in some cases, reduce recoverable reserves, which is at odds with the traditional tenet of resource regulation of conservation. Our results also suggest that profit and environmental and conservation goals may coincide to some degree, providing opportunities for the design of effective incentive mechanisms.

Fracking: The Sequel

Catherine Elder, Senior Associate Aspen Environmental Group

Baker-Hughes rig count data shows that use of vertical rigs to drill into conventional hydrocarbon formations has dropped to nearly zero, meaning that virtually all current natural gas drilling is using rigs capable of drilling the horizontal wells used to drill laterally across thin formations of shale rock. Nearly half of all U.S. natural gas production is now from shale deposits using high-volume slick-water fracturing and the reality is these wells are so profitable we should expect producers to continue preferring to drill downward to reach shale formations, then horizontally across them and apply fracturing techniques to complete the well and begin production. *Fracking: The Sequel* will look at additions to the fracturing debate in three key areas. First, what new science is available on impacts? The first phase of EPA's groundwater impacts review (which includes stormwater releases, use of surface impoundments and recycling of produced water) should have a progress report out; and some more work on fracture communication should be available. Second, enough production per well data when combined with depletion assumptions should now be available to construct scenarios on how many wells will have to be drilled and fracked to meet projected levels of natural gas demand. Third, more states have passed disclosure laws but what are some of the differences in these, in state-by-state regulation of well construction and efforts by the states to manage fracturing activities?

Gas-fired Electric Generation's Aversion to Long-Term, Firm, Gas Transportation Contracts

Cliff Rochlin – Southern California Gas Company

FERC has recognized three major changes in the electric generation industry with respect to natural gas: 1) the rapid decline in the cost of natural gas (making it cost-competitive with coal in the generation of electricity), 2) stricter environmental regulations on coal plants that will speed the retirement of aging coal plants, and 3) an increased use of gas-fired generation will be needed to support renewable resource integration into the electric grid. All three of these changes will lead to a greater dependency of electric generation on gas-fired resources. As a result of these changes, electric reliability will become more dependent on natural gas availability and deliverability. The shale gas revolution has almost eliminated the notion of a lack of gas availability. However, deliverability, adequate gas transmission capacity and access to the transmission, is an important issue for enhancing the coordination between gas and electric industries.

In FERC Docket No. AD12-12-000, the FERC sought Comments on the Coordination between the Natural Gas and Electricity Markets. One issue that was highlighted in the comments FERC received was the reluctance of gas-fired electric generation to sign firm gas contracts with natural gas pipelines and that weaning power generators off interruptible services could result in more reliable electric generation. However, reliability comes at a cost. For example, if the generator reserves too much transportation capacity, it pays for unused capacity. That is, from a generator's perspective, committing to a fixed capacity reservation on a gas pipeline entails an implicit penalty. To the extent that the generator faces a highly variable dispatch, the implicit penalty associated with a firm gas capacity reservation increases. This implicit penalty forms the basis of the generator's aversion to committing to a firm capacity reservation. The paper introduces a new, firm rate design, with a flexible explicit penalty that can mitigate this aversion.

Paper Title: Accounting for Uncertain Intermittent Output in the Unit Commitment and Dispatch

Scott Harvey

Traditional security constrained least cost dispatch minimizes the cost of meeting load over a five or ten-minute dispatch interval, without regard to the cost of meeting load in subsequent intervals. Inter-temporal optimization of the real-time dispatch as implemented by the Ontario IESO in 2004, the New York ISO in 2005, and the California ISO in 2009, also optimizes the dispatch over time to account for known or expected future ramp requirements such as those associated with top of the hour changes in net interchange, a pump storage unit going on or off-line, or a generation unit coming on-line or going off line. Forward looking intra-day unit commitment processes such as those used by the New York ISO and California ISO similarly optimizes the commitment of new resources over time to account for known or expected changes in load

High levels of intermittent resource output make it desirable to posture the electric system to be able to respond to large changes in output that could, but probably will not, occur over a particular time horizon. Explicitly accounting for the distribution of potential outcomes in unit commitment and dispatch processes would be complex and unworkable in the timeframe in which these processes must be carried out.

This paper will discuss the potential to make slight changes in the objective function of existing security constrained unit commitment processes and security constrained least cost dispatch processes that will better posture the electric system to respond to large, but uncertain, changes in intermittent resource output. The paper will draw upon simulation results and operational experience of the Midwest ISO and California ISO to discuss the conceptual and practical problems in successfully implementing such processes and their interaction with other elements of the market design. While the paper will focus on the use of these methods by ISOs, they could be applied by any system operator facing uncertain changes in intermittent resource output.

Modeling concentrating solar power (CSP) with thermal energy storage in the western U.S. power grid under 33% RPS: quantitative results from a regional power system model and regulatory recommendations

Udi Helman and Warren Katzenstein

Western U.S. utilities procuring renewable energy to meet policy requirements (e.g., Renewable Portfolio Standards) utilize both quantitative and qualitative valuation methods to determine the mix of different renewable technologies for their portfolios (Mills and Wiser, 2012a). In California, for utilities subject to the jurisdiction of the California Public Utilities Commission (CPUC), this valuation process is called "least-cost, best-fit" and requires quantification of the forward energy and capacity value of the renewable resource. Recently, efforts have begun to quantify additional aspects of economic costs and benefits, including provision of ancillary services and effects on changing system integration requirements as renewable penetration increases (California ISO, 2011; Mills and Wiser, 2012b). At the CRRI Western conference in 2012, Helman and Sioshansi presented a survey of the literature on economic valuation of concentrating solar power (CSP) with thermal energy storage. One of the gaps identified in the literature was modeling of the California power system under 33% RPS, to calculate the key benefits of a less variable, but not fully dispatchable, solar technology as system conditions change. Helman and Katzenstein have extended the California ISO (2011) methodology used to simulate renewable integration under the 33% RPS to include modeling of several large-scale CSP plants with thermal storage. With one of the CAISO/CPUC scenarios as a base case, the methodology (1) creates production profiles for a revised aggregate solar portfolio, (2) modifies the quantity of Regulation and load-following reserves carried to meet subhourly forecast errors and variability, and (3) dispatches the CSP plants in a production simulation to provide energy and ancillary services. The results are in process, and will include changes in production costs, and the re-allocation of ancillary service provision to the CSP plants. The paper will conclude with recommendations for reforms to the California least-cost, best-fit rules to accommodate more operationally flexible, but still partially dispatchable renewable resources.

Evaluating the Effects of Different Flexible Ramping Products on the Total Cost of Supplying Electricity on a Power Grid

Tim Mount, Wooyoung Jeon, Alberto Lamadrid and Hao Lu

Regulators have recently recognized that ramping (following net load = load – renewable generation) is an important issue associated with the integration of higher penetrations of wind and solar generation into a power grid. In fact, hearings are currently being held by the CAISO on introducing "Flexible Ramping Products" and how to pay for them. The current proposal treats ramping as a type of reserve capacity and the ISO determines how much is needed to cover a forecasted range of wind generation. The providers of ramping services will be paid ex post the opportunity costs of the forgone energy dispatched (the difference between the nodal price of energy and the offer for energy). An alternative approach to ramping is to treat it as an out-of-pocket expense when conventional generators provide actual ramping services (this is consistent with evidence from countries like Ireland with high penetrations of wind generation). With this approach, ramping capacity is paid in advance as a type of reserve capacity, and the nodal prices of energy reflect the realized costs of both energy and ramping. The objective of this paper is to evaluate the effects of the two approaches to ramping on total system costs using a stochastic form of Security Constrained Optimal Power Flow (SCOPF) and a reduction of the NPCC network. This framework makes it feasible to specify the stochastic characteristics of renewable generation realistically as inputs for the SCOPF. The results show that storage capacity is an efficient way to provide ramping services, and that distributed storage (deferrable demand), in particular, is the most effective way to reduce total system costs.

An Impact Evaluation of a Southern Utility's Technology Enabled Smart Pricing Pilot

Ahmad Faruqui, Neil Lessem, Sanem Sergici

The Southern Utility's Pricing Pilot was designed to measure the impact of innovative new "smart grid" technologies, while maintaining more "standard" smart grid applications. One treatment group was provided an information display, another treatment group was provided a home energy controller and third treatment group was provided a home energy controller and a critical-peak pricing rate. The first two treatments and the control group stayed on the standard rate which is a two-tier inclining block rate design. The home energy controllers allowed for disaggregated measurement and control of several end uses and employed a novel technological specification.

Using standard econometric techniques we examined whether any of the treatments induced conservation and/or load shifting impacts. We found no statistically significant impact from any of the treatments on overall energy consumption. Similarly, two of the three treatments did not yield any significant changes on customer load shapes. However, the third treatment, involving critical peak pricing and the home energy controller, yielded statistically significant impacts. The winter impacts were twice as large as the summer impacts. When the results were compared with those from other dynamic pricing experiments, we found that the summer impacts from the experiment tended to be lower than the average observed elsewhere for the same ratio of peak to off-peak prices. While we cannot account definitely for this low impact, the balance of evidence seems to show that technological failure may have been partly responsible. This highlights the importance of the underlying technology in reaching the full potential of the smart grid.

Interim Results from SMUD's Time Varying Pricing Experiment

Stephen George and Nate Toyama

In summer 2012, the Sacramento Municipal Utility District (SMUD) launched one of the largest and best designed pricing experiments ever conducted in the electricity industry. The experiment has been designed to assess the impact of three different pricing options: time-of-use (TOU), critical peak pricing (CPP) and a combination TOU/CPP tariff. The TOU and CPP tariffs were offered to customers chosen at random on an opt-in basis. The TOU/CPP tariff was offered on an opt-out basis. For the TOU rate, a control group was formed following enrollment using a "recruit and delay" approach, resulting in a sound randomized control trial (RCT) design. The CPP opt-in treatment cell and the TOU/CPP opt out cell were evaluated using both a "within-subjects" methodology and a randomized encouragement design (RED) framework. In addition, TOU and CPP tariffs were offered to separate randomly chosen groups of customers based on opt-out enrollment. Thus, for the first time, this experiment allows for a comparison of enrollment rates and load impacts for customers that were recruited from the same population using opt-in and opt-out enrollment methods.

The experiment also offered in-home displays (IHDs) to a subset of treatment customers to determine whether IHDs impact enrollment or demand response. IHDs were pre-commissioned so that customers only needed to turn them on once they were shipped in order to have the devices connect with the customer's smart meter. IHDs were only sent to customers who requested them. In spite of the low transaction cost and the voluntary nature of the process, only about 50% of customers who requested and received an IHD turned it on. This presentation will report on the impact of IHDs as well as some of the reasons why customers who asked for them did not use them.

Finally, the experimental design allows for a rigorous comparison of load impacts for the CPP rate developed using a within-subjects analysis (e.g., individual customer regressions and/or panel regressions) and using a RED framework. This is important because RED designs are typically more expensive to implement than a within-subjects design (due to much larger required sample sizes). If the impact estimates are very similar using the two approaches, this would validate the continued use of the common within-subjects design for selected rate options such as CPP.

Rate Risk Management using a Hydroelectric Generation Adjustment Surcharge

Ross Gorman and Rob Landon (Sacramento Municipal Utility District)

SMUD has been able to provide its customers with some predictability in rate levels over the last several years by securing in advance a substantial portion of its energy requirements at fixed prices. As a part of this effort, SMUD has purchased weather hedges to help offset the cost of replacement power when winter weather is dry and SMUD's hydro generation is less than budgeted. Changes in the energy market are making it both more difficult and more expensive to achieve the same level of rate predictability.

This paper describes a rate adjustment mechanism which is designed to mitigate the impact of uncertain hydro generation on the annual budget. This adjustment mechanism, known as the Hydroelectric Generation Adjustment (HGA) Surcharge, changes each year based on a formula tied primarily to precipitation measured at a local weather station. The rate adjustment appears on the customer bill as either a credit in years with excessive precipitation, or as a surcharge in years with insufficient precipitation. Subsequent annual adjustments occur after public disclosure, but do not involve formal workshops or rate hearings – it's primary appeal.

Title: Assessing the Need for Flexible Resources to Manage Electric Grid Reliability

Author: Carl Silsbee, Principal Manager, Resource Policy and Economics, Southern California Edison

With increasing generation from intermittent renewable resources coming on line in California over the next decade, there is a considerable amount of concern as to whether the remaining conventional resources are sufficient to manage the anticipated variability of resource supply. The author intends to develop an analytical structure in which the tradeoffs between the cost of maintaining an adequately reliability fleet of resources and the value of reliability to customers can be assessed. The author will also report on ongoing modeling efforts to quantify flexible resource needs in California.

Using Regression Estimation to Calculate Effective Load Carrying Capacity of Renewable Resources

Paul Nelson and Justin Kubassek

California energy policy is to obtain 33% of its energy needs from renewable resources by 2020. To achieve this policy goal, a significant amount of wind and solar resources are being built. The contribution to system reliability of these renewable intermittent resources has been a subject of debate in regulatory proceedings, such as California's Resource Adequacy. Effective Load Carrying Capacity is one metric for measuring a resource's contribution to system reliability and has historically been calculated using reliability simulation models. However, reliance on this approach for calculating ELCC in annual regulatory proceedings would be difficult and time consuming. The authors explore a method to calibrate a regression approach using results from reliability modeling for use in annual ELCC determination for resource adequacy proceedings.

Plug-in Electric Vehicle Fleet Valuation: Case Study

R Entriken, Alexander, Davis, Fang, Halliwell, Lee, Mullen-Trento, Nieuwesteeg, Oren, Wilson

This paper addresses the now-common question about how valuable a plug-in electric vehicle (PEV) can be as a grid resource. In particular, it scales from single vehicles to large fleets of vehicles in order to present to the grid a virtual resource of sufficient substance and in order to incorporate the variability and uncertainty associated with large fleets of vehicles.
The paper describes data sources and data processing that feeds a fleet simulator tool. The fleet simulator utilizes an advanced scheduling algorithm to first ensure that each vehicle has sufficient battery and gasoline energy for its primary transportation purposes and second to maximize the value of services that the entire fleet provides to the grid. The services are achieved through marginal interactions with wholesale energy and ancillary services markets and implement peak shaving, load shifting, and Regulation service.

Combined Heat and Power

Sonika Choudhary and Sam Wade

Combined Heat and Power (CHP) is the sequential production of electricity and thermal energy from the same fuel source. Historically, CHP has been perceived as an efficient technology and is promoted as a preferred electric generation resource by California's energy policy. However, as California continues towards an ever-cleaner energy future there is a need to revisit and understand under which circumstances CHP will actually reduce GHG emissions. CHP reduces GHG emissions if the CHP facility uses less fuel than the fuel needed to produce an equivalent amount of steam through separate heat and power production (e.g., steam produced using a boiler and power purchased from the electric grid). If deployed and operated in an inefficient way CHP, unlike renewable generation, has the potential to increase GHG emissions. Moreover, as more renewable power is added to the grid, GHG benefits from fossil-fuel CHP systems are expected to decline.

We have analyzed the GHG emissions reduction potential of CHP systems through 2020 over a variety of CHP system technologies such as micro-turbine, gas turbine, fuel cell, and reciprocating engines and sizes incorporating representative operating efficiencies. We have constructed two scenarios to capture optimistic and pessimistic system operation parameters such as hours of operation, heat rate degradation over time and learning rate of emerging technologies. We have also assessed the cost effectiveness of these CHP systems ($/MT CO_2e). The results of our analysis are designed to inform energy regulators regarding the sensitivities around GHG emissions reduction potential and cost effectiveness of CHP systems.

Application of Portfolio Theory to Electric Power Generation Assets: Recognizing Additional Value from Generation Diversity

Glenn R. George, P.E., Ph.D., KPMG LLP

Portfolio theory was developed to explain the risk-reward profile of intangible financial assets—securities—in the context of larger portfolios. This paper broadens portfolio theory to tangible financial assets and applies it to electric power generation assets. Generation companies hold generation assets in portfolios broadly analogous to portfolios of securities held by financial investors. Portfolio theory generally parameterizes an asset into volatility, asset concentrations, and asset correlations. Using a risk-reward efficient frontier paradigm, portfolio theory identifies overall risk-adjusted portfolio return maxima for a given investor's utility function, discount rates, and time horizons. In this paper, the authors consider individual power generation assets and portfolios of such assets using an analogous paradigm. Generation asset owners can trade off overall portfolio risk and rewards, as measured by economic profitability, safety, and environmental impact, through inclusion or exclusion of particular generation asset types in the broader portfolio. Such asset types include coal, natural gas, hydroelectric, nuclear, wind, and solar primarily.

Increasing the diversity of generation assets held in a portfolio is shown to reduce portfolio risk across a variety of scenarios. Asset diversity itself—even when it is derived from generation asset types which individually may possess undesirable risk characteristics—creates additional value for many generation asset owners. The results suggest that, for many generation companies, the broadest possible generation portfolio is a dominant strategy.

Practical implications of the theory are the subject of ongoing research.

Structural Analyses of Emission Permit Auctions under Cap-and-Trade Programs in the United States

Xiaoling Charlene Zhou

Sealed-bid multi-unit auctions are commonly used to distribute emission permits under cap-and-trade programs. Various auction formats have their merits or weaknesses in terms of allocative efficiency, revenue raising effectiveness, and price signal discovery. In particular, the discriminatory auction (a.k.a. "pay-as-bid" auction) may raise higher revenue but suffers from distributional inefficiency, while the uniform-price auction tends to be more efficient but may lead to underpricing of permits relative to their true market value. This paper empirically studies the emission permit auctions under two cap-and-trade programs in the United States to evaluate these issues.

With a structural approach, I analyze the actual auction data from the Acid Rain Program for SO2 and the Regional Greenhouse Gas Initiative (RGGI) program for CO2. Using detailed bidder-level bidding data of 17 EPA annual auctions of SO2 allowances, I estimate the efficiency loss of the discriminatory format and compare to the counterfactual revenue of a hypothetical truthful-bidding uniform-price auction based on a resampling method. The counterfactual results show that the discriminatory auction may not necessarily raise more revenue to compensate the efficiency loss in the SO2 allowance auctions. To analyze the first 8 RGGI quarterly auctions of CO2 allowances, I modify a uniform price auction model to show the interaction between the primary auction market and the secondary trading market, and then I propose a statistical procedure to calibrate the aggregate-level auction data. The counterfactual simulation shows that the participation of non-compliance bidders in the auctions helps alleviate the underpricing induced by the uniform-price format. Therefore, it is beneficial to open the auctions to general public to increase competition.

Based on above empirical results, several policy suggestions useful for designing future emission permit auctions are highlighted such as setting a reserve price, minimizing bidding costs, and limiting maximum bid capacity to prevent market manipulation.

Renewable Energy Credit Trading in the United States

Robert Earle, Vice President, Analysis Group

Over the past 10 years, thirty states have implemented renewable portfolio standards (RPS) for electric power utilities which generally require a certain percentage of electric power delivered to end-use customers come from renewable resources. To ease implementation of RPS, many states have created renewable energy credits (RECs) that separate the renewable or environmental attribute of the electric power from the electric power commodity itself. The ability of utilities to use RECs from other jurisdictions depends on state definitions of renewable power and limitations on the origin of RECs. In addition, varying state rules on the banking of RECs, or the ability to use RECs created in one year for a later year affect the ability to trade and the value of RECs. This paper reviews current evidence on the economic effects of the various rules imposed on RECs across jurisdictions in the United States.

Timing is Everything: Aligning federal and state wind incentives with utilities' energy and capacity needs

Travis Kavulla & Jason Brown

This paper has two parts. First, it surveys the intended and unintended consequences of the federal and state policies that support the wind industry. The federal production tax credit offers wind generators a $22 per megawatt-hour tax credit for the first decade of production. State renewable energy standards, meanwhile, typically require a prescribed percentage of a utility's total energy or capacity to come from renewables. These policies have succeeded in their core mission: the installation of renewable generating capacity. The Pacific Northwest has installed more than 4,000 megawatts of wind capacity in the past decade, far surpassing utilities' and regulators' expectations.

In some hours, wind farms have produced nearly one half of the electrons coursing through utilities' wires in the West; but in other hours, those same utilities see almost no "wind on the wires." Wind is naturally intermittent, but federal and state incentives have exacerbated nature's problematic tendency. Policy has encouraged developers to site wind farms in clusters, where gross energy production is greatest, regardless of whether it delivers at times when energy is in demand or not. Moreover, the clusters of development lead to a problem where wind tends either to be all "on" or "off" at once.

The result is a capacity shortage in the West. Utilities need enough dispatchable capacity to meet demand even if there is little or no wind online. That capacity must quickly ramp up or down in response to wind generation. If wind were more diversely located, production swings and extra capacity needs would diminish.

The second part of the paper is a case study of the responses to this problem that regulators and utilities in the Pacific Northwest have devised. Montana's new wind integration tariff, the first of its kind, charges wind farms different prices for integration service depending on location. LWind farms locating near large existing wind farms may produce more energy, but they will also have to pay higher costs for integration. . The tariff quantifies those prices and passes them along to the wind farms. The paper will also examine attempts by the Bonneville Power Administration, the Federal Energy Regulatory Commission, and others to encourage more accurate scheduling of wind resources to lessen deviations between scheduled wind output and wind's actual energy deliveries. The paper then moves to questions of regional integration in the West, which could reduce the impact of wind's sudden ramps by aggregating the variability that various clusters of wind farms exhibit. Such reforms, while controversial, would reduce the need for natural-gas and other fast-dispatching capacity that is currently set aside to meet the needs both of wind farms for integration and of load-serving utilities to meet their peak loads.

A Pricing Mechanism Substitute to Agency-Based Pricing: An Exploration of the Renewable Market Adjustment Tariff (Re-MAT)

Katie Slaon and Marc L. Ulrich, Ph.D.

Across the world various energy policies have led to a boom of renewable energy projects and billions of dollars in capital investment. These policies are occasionally changed in a sudden and unexpected ways due to cost sensitivities and customer revolt. The swing in policy has led to the coining of the term "solar-coaster" which describes the starts and stops in project development. At the core of the problem is the pricing mechanisms used in wholesale transactions. This paper explores the problems with agency-based pricing of wholesale electric transactions and a proposed solution in small-scale renewable projects in California.

The paper will present the pricing structure and program details of the pending Renewable Market Adjusting Tariff (Re-MAT). In this review the paper will explore the basic economic principles used in the program and how the program preserves the first-come first-serve policy preferences yet provides for competitive pricing. Other features are to be explored are how the program provides the right incentives to ensure projects are built but still protects the customers. Currently, "go-live" of the Re-MAT program is anticipated in early 2013 and to the extent results are available the paper will share experiences to date.

Guaranteed Return Regulation: a Case Study of Regulation of Water in California

Michael A. Crew, Rutgers University and Rami S. Kahlon, CPUC

There seems to be some agreement among economists that the intent of natural monopoly regulation is to reap the benefits of overwhelming scale economies but at the same time avoid monopoly exploitation by limiting the price that the monopoly may charge. However, achieving this objective is much easier said than done, as regulation is not an effective substitute for a competitive market. Three broad groups seek the monopoly rents – regulators and politicians, consumers and the firm. The result is that the rents get shared but they also get dissipated because the division of the spoils is not costless. In addition, the ways of sharing the rents are numerous and opaque.

This paper analyzes the incentives present and the resulting evolution of regulation. In unregulated markets the owner of the firm is the residual claimant and faces high-powered incentive in that revenue and cost are decoupled. Price-cap regulation (PCR) and performance-based regulation (PBR) were attempts to increase the power of the incentives compared to tradition cost of service regulation (ROR). If successful they would have resulted in lower prices and greater X-efficiency. In fact, regulation today has evolved into a system where incentives are definitely low powered. Cost and revenue are not decoupled. Far from it revenue is driven by Guaranteed Return Regulation (GRR) is becoming increasingly important.

Under GRR the firm is effectively insulated from what was previously a non-trivial risk, namely, weather dependency and other demand shortfalls. GRR is applied to energy and water utilities. It is an effective mechanism for redistributing rents. For the firm greater risk-adjusted profits may result. The evolution, incentives and effects of GRR are examined. The discussion is grounded in a case study of regulation of the California the water industry. Lessons are drawn for other industries and for the design of regulation in the future.

Within our Means: Growth and Development under Water Scarcity

Jason Hansen and Jamie Chermak

In many regions of the United States, economic growth objectives are considered independently of resource availability. Nowhere is this more evident than in communities in the arid southwest where the emphasis is on job growth and business development. For example, at the Albuquerque, NM Economic Development website, the mission is given as "…create, diversify and enhance job growth and…promote business development stability. EDD support business and the development of community within city government and between city agencies." At the same time, city utilities warn of water scarcity and emphasize cutting back on water usage by promoting conservation through rebate plans or through fine mechanisms. The difficulty with these approaches is that they are mutually exclusive. Economic development often assumes growth is always desirable and open-ended. Conservation programs often assume that conservation and reduced water use is always the desired outcome. These divergent policy approaches create a conundrum since in actuality water, land, and labor are necessary inputs into economic output. This means that well-considered economic growth objectives reflect resource availability.

We develop a dynamic theoretical model at the city level that considers labor and water as inputs into production. This allows us to consider the trade-offs between increased economic activity (with increased populations) and decreased water availability. In order to add salience to the problem, we develop a series of dynamic simulations, parameterized for Albuquerque, New Mexico, to consider not only the trade-offs between economic growth and resource scarcity, but also to find what optimal economic growth might look like under increasing resource scarcity. Preliminary results suggest that in many cases of scarcity economic expansion is not desirable or sustainable. In order to ensure a sustainable city, targeted growth that considers all aspects of the problem, including water scarcity, may be necessary.

Water-Energy Nexus: how to value each technology class in order to align incentives

Marzia Zafar and Rich White

The existence of the water-energy nexus is well known. In 2005 the California Energy Commission (CEC) published a report that established -the now commonly quoted statistic - that 19% of California electricity is used to provide water in California. This report, in part driven by concerns of water adequacy for thermal electric plants, qualified and quantified the water energy relationship. In 2006 a Department of Energy (DOE) Report to Congress extended this to the national level and showed where the dependencies occur both geographically and technologically and how these dependencies might change as we develop new resources. These reports were a clarion call to action. The underlying message in these reports was that we should manage these resources together.

Despite these and numerous other reports that have identified the scale and scope of the interactions, a well-established strategy for developing an integrated response to water energy challenges has not emerged. How we make tradeoffs between water energy is at the heart of the challenge, both when we consume water to supply energy and when we consume energy to provide water.

The CPUC is developing a framework that classifies water energy technologies based on where each sits in a "water energy matrix". The matrix distinguishes technologies and assess the relative value of water to energy based on the implicit type of water energy

tradeoff that each technology facilitates e.g. the value that a tradeoff implied by a decision to change from wet cooling technology to dry cooling technology. The matrix can cover a range of technologies in the W-E value chain from water and energy storage in hydro-plants, to water / energy conversions by water and electric utilities, to final endues in multiple consumer segments. By classifying technologies based on the value of the tradeoffs we can better align and focus incentives that recognize the implicit value of each technology class.

Designing Financial Transmission Rights to Facilitate Hedging in Wholesale Electricity Markets

Darryl Biggar and Mohammad Hesamzadeh

It is well known that in order to achieve efficient short-run production and consumption decisions in wholesale electricity markets, wholesale market participants (generators and retailers) must face a spot price which varies with market conditions both over time and across geographic locations. At the same time, to achieve efficient longer-run investment decisions, wholesale market participants must be able to hedge the risks they face from short-term wholesale spot price volatility. Conventional hedging instruments such as swaps and caps allow wholesale market participants to effectively hedge the risks they face from the time variation component in spot prices, but how can market participants effectively hedge the risks that arise from spot price variation across locations? This issue is important as wholesale market participants in the Australian electricity market have resisted attempts to introduce geographically-differentiated spot pricing (also known as nodal pricing), in part out of concerns that doing so will reduce liquidity in the hedge markets.

Several overseas markets make available an instrument for hedging locational price risk known as Financial Transmission Rights or FTRs. But we show that conventional fixed-volume FTRs cannot fully hedge locational price risk and are only an effective hedging instrument for fixed-volume transactions between locations. Most generators (especially peaking generators) have a level of production which varies with the local spot price. For these generators, firm FTRs are not a useful backing for the hedges they require. This paper proposes a new form of transmission right which in some respects mimics the operation of a "cap" hedge contract. This transmission right can be combined into a portfolio which provides the natural backing for the price-dependent volume-varying hedge that market participants require. Market participants are able to hedge geographic variation in wholesale spot prices as effectively as they currently hedge time variation in spot prices.

Importantly, unlike conventional FTRs, the total payout obligation on these new transmission rights reflects the total social benefit of transmission service. We show how these transmission rights can be used to develop financial incentives on transmission network businesses to maintain the availability of transmission services. We also show how, unlike conventional FTRs, the change in the value of a portfolio of such transmission rights following a network augmentation reflects the social benefit of that augmentation, suggesting a possible mechanism for decentralising transmission investment decisions. We consider that this new design of transmission rights offers promise as an approach for facilitating hedging and improving market outcomes in wholesale electricity markets.

Coordination of Electricity Transmission and Generation Planning – Structures, Incentives and Welfare Impacts

Hung-Po Chao and Robert Wilson ISO New England and Stanford University [1]

Abstract
Electricity transmission planning has been evolving since the creation of wholesale electricity markets and regional transmission organizations by the Federal Energy Regulatory Commission (FERC) in the U.S. Transmission planning is an iterative process that typically begins with annual 10-year studies assessing the capacity needs for reliable system operations under uncertain market conditions. Based on these assessments, planning studies are performed to determine cost effective transmission projects (or viable generation projects as alternatives) and develop regulated transmission solutions. The transmission solutions, along with transmission cost allocation plans, are reviewed, updated and voted by stakeholders in a regional planning process. At present, a key issue that remains open in transmission planning is how to coordinate regulated transmission solutions with competitive generation investments to promote an efficient and equitable outcome.

In this paper, we develop a framework for analyzing the coordination of transmission and generation capacity expansion plans focusing on the distribution of benefits and costs for evaluating incentives and welfare impacts among market participants under alternative planning approaches and structures. Using illustrative modeling assumptions, we study several scenarios for incremental investments in generation and transmission capacities, and their welfare impacts for producers and consumers at different locations in the network. The two main topics are (a) short-term system responses to modest changes at one location, such as retirement of an old generator or growth in demand or imports/exports, and (b) long-term sequencing of increments in transmission and generation capacities. Changes from a status quo with existing capacities are modeled via constant-elasticity demand and supply functions in a peak and an off-peak period, and affine cost functions for new transmission and generation capacities. Energy markets are modeled as competitive, so investments in new capacities are the only sources of market power. Welfare impacts on market participants are illustrated for two locations with transmission between them, using alternative transmission cost allocation methods if transmission is regulated.2 Each scenario with regulated transmission examines a first-best efficient plan (for both transmission and generation capacities) and two second-best plans obtained from alternative versions of Boiteux's formulation in which revenue from nodal price differences and/or injection charges must recover transmission costs. Other scenarios consider merchant investment by a transmission company, either generator, either load-serving utility, and several bilateral alliances among these. Long-term scenarios consider merchant generation investment at one or both (using a Cournot model) nodes.

The Impact of Decoupling on the Cost of Capital: an Empirical Investigation

Joe Wharton, Michael Vilbert, Toby Brown, and Rich Goldberg (The Brattle Group)

Revenue decoupling (or simply "decoupling") is an important modern form of regulated ratemaking that helps facilitate energy efficiency programs run by regulated utilities in the natural gas, electric and water industries. But recently this "cure" has been alleged in certain regulatory proceedings to substantial <u>lower</u> the cost of capital, as much as a 3% reduction (300 basis points) in the allowed return on equity. This paper will investigate whether any material inverse relationship between decoupling and the cost of capital can be measured by accepted techniques. An earlier paper studied the period from 2005 to 2010, and was posted on The Brattle Group website. This paper will update the period of study through the fall of 2012. This will add new data points where empirical estimates of the cost of capital are available for a large set of regulated utility holding companies that experience differing degrees of decoupling.

The initial findings of a rigorous empirical analysis for the period ending in summer 2010 did <u>not</u> support the proposition that utilities <u>with</u> decoupling have a lower cost of capital than utilities <u>without</u> decoupling. We made five specific estimates of the impact that decoupling has had on the cost of capital. Results were mixed as to even the sign of the impact. Thus, the empirical evidence at that time was that decoupling causes no material reduction in the cost of capital. The initial estimated impacts were vastly smaller than those proposed by certain interveners in cases dealing with the policy of decoupling. In this paper, we will update the estimates and further refine our understanding of the empirical relationship between decoupling and the cost of capital.

Statistically Determining Proper Recovery of Demand-Related Costs through the Energy Charge

Larry Blank, Center for Public Utilities, New Mexico State University

Rate class cost of service studies in electric rate cases assign and allocate costs to each rate class based, in part, on the classification of costs into one of the following three categories: customer-related costs, demand- (or capacity-) related costs, and energy-related costs. For those customers such as residential households, who do not have meters with maximum monthly demand reading capability and/or do not have demand charges, a long-running debate persists regarding the amount of fixed costs that should be recovered through the energy charge versus the fixed monthly customer charge. At one end of the spectrum in this debate are those who argue for a straight fixed-variable rate design in which all of the fixed costs (customer-related and demand-related) should be recovered through the fixed monthly customer charge. At the other end of the spectrum are small customer advocates who argue that the fixed monthly fee should be kept as low as possible to avoid increasing the electric bills for below-average users. The positive and significant correlation between household electricity kWh usage and maximum household demand for capacity (kW) suggests that neither of these polar arguments is correct. Utilizing statistical relationships between kWh (or average demand) and maximum monthly kW based on load research data at the household level, we develop a methodology by which one can objectively determine the portion of demand-related or capacity-related costs that should be recovered through the energy charge and the remaining portion for recovery through the customer charge. The results may also have implications for block rate design.

Unbundling: A Needed Fix for Residential Rate Design

Cynthia Fang

In Rulemaking (R.) 12-06-013, Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations, the California Public Utilities Commission (CPUC or Commission) determined that ,after almost a decade of heavily legislated rate design triggered by the California Energy Crisis, that there is now a need to re-examine the current residential rate design to determine whether it is able to meet the Commission's rate and policy objectives. The Commission's examination comes at a time of rapid growth in the rooftop solar market together with the introduction of many new technologies that will help customers better manage their energy use in response to price signals. Currently, the statutory constraints on utility ratemaking force customers that deploy these technologies to rely on extremely inappropriate price signals, both for considering potential investments in rooftop solar and for utilizing after meter services to better manage energy demand.

The current California residential rate structure is an inclining block rate structure with multiple tiers. Until 2010 with the implementation of Senate Bill (SB) 695, the first two tiers were frozen causing all cost increases for the residential class to be absorbed exclusively by the upper tiered rates. For San Diego Gas and Electric (SDG&E) which has a four tiered structure, from 2002 to 2012, the tiered rate differentials between Tier 1 and Tier 4 grew from approximately 40% to approximately 100%. This is a significant increase from the pre-2001 baseline/non-baseline differential of approximately 20%. This growing differential results in increasing and more volatile bills for customers with upper tier usage.

Unlike the residential class, commercial and industrial customers have an unbundled rate design, where fixed costs are recovered through fixed charges and capacity costs are recovered through demand charges.

This paper investigates "rate revolt" and the potential for "death spiral" uneconomic distributed generation bypass as a function of the mean and variance of bills and the percentage of customers affected. The paper further describes a rate design structure for residential customers that would create accurate price signals, better inform customers, and create the foundation necessary for sustainable growth in the rooftop solar generation market as well as the potential future market for other distributed energy resources. The paper analyzes the impacts of a more unbundled rate design structure for residential customers on bill levels and volatility for all customers in the residential class, the impacts such a rate design structure would have on the negative effects of the current rate design, and the extent to which such a rate design would better support California's Net Zero Energy construction and Net Energy Metering policy goals.

Utility and Customer Economic Impacts of Net Metering for Distributed Renewables

Jim Heidell and Mike King (NERA Economic Consulting)

Net metering policies are common in the United States; all but seven states have adopted them. After the adoption of net metering policy comes the implementation issues, which include: the appropriateness of customer charges, rate impacts on non-participants, the amount of load allowed under net metering (e.g. the amount of net metering), and the maximum customer system size eligible for net metering. This paper examines the economic benefits and costs from the utility, participant, and non-participant's perspective.

Historically, the costs and benefits associated with net metering have not been a significant issue as the penetration of distributed solar has been relatively small in relationship to utility load. The number of utilities that have reached tariff caps for net metering has

grown as a result of the declining cost of installed PV systems, increasing utility rates, and aggressive marketing and financing programs offered by PV developers. The trend is for utility commissions to raise the cap on net metering. Advocates for net metering claim that the program provides overall benefits and that charges beyond the standard customer charge are inappropriate. Others advocate that charges for recovery of use of the delivery system and back-up / supplemental generation service are appropriate. While a number of economic studies of net metering have been performed, the issue has not been extensively studied at higher penetration levels. Two state studies determined it was a net benefit and a study for California concluded that net metering was a net loss.

This paper summarize the literature related to the costs and benefits of net metering and then proceeds with a discussion of the both the efficiency and equity issues of different tariff treatments under a regime of high levels of distributed generation. Our analysis incorporates an assessment of policies necessary to protect the long-term financial health of the utility and costs and benefits associated with the rate-payer non-participants in net metering.

Testing Alternative Theories of Capital Structure: The Case of the Electric Utility Industry

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Capital structure choices remain somewhat mysterious with many different stories told about why firms choose different levels of leverage. The traditional trade-off theory (TOT) holds that firms recognize the cost of increased leverage in terms of equity and balance the lower cost of debt with the increased costs of equity to minimize overall financing costs. More sophisticated theories, such as the pecking-order theory (POT) and managerial theories (MT), incorporate notions of asymmetric information between shareholders and managers, and predict that leverage is used to address the asymmetry of information. In two earlier papers we examined economic and regulatory factors that influenced the choice of capital structure adopted by managers of electric utilities in the 1980's in the aftermath of nuclear construction and the stagflation of the 1970s Our findings generally supported the TOT during this period although some intriguing, but indirect, evidence was found that could be indicative of other possible explanations such as the POT and MT. We, however, did not have sufficient data to directly test these other theories. In the second paper we once again found some weak evidence that supported the TOTfor the period 1994-2011.In this paper we expand the data set to include more financial data for each utility that will enable us to conduct direct tests of manager's choices of leverage. Following Shyam-Sunder and Myers (1999) we use data from FERC Form 1 to evaluate different theories of capital structure for the period 1980 through 2011 in the electric industry. This was a time of tremendous stress in the industry from the post nuclear age to the wholesale and retail competition age. Restructuring played a central role in the later half of the data set and special emphasis will be placed on examining the effects restructuring has had on the financial choices of electric utilities. As in our early paper we will also control for different regulatory regimes across utilities.

Analytical Frameworks to Incorporate Demand Response in Long-Term Resource Planning

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Demand response serves as a resource to reduce or shift peak system load and defer or avoid generation capacity and transmission capacity. Such deferral or avoidance produces financial benefits for the utility, which in turn lowers the revenue requirement for utility customers, and provides environmental and other societal benefits. Many utilities are obligated by state regulatory or legislative requirements to incorporate DR into utility resource planning (e.g., integrated resource plans) and there is interest among regional reliability organizations and other system planners for long-term regional and national generation and transmission expansion planning.

There are several ways to incorporate DR into resource planning modeling (e.g., load decrement, competing supply option) and each has its advantages and disadvantages. In addition, the DR market is continuing to evolve in response to changes in RTO/ISO market rules that allow it to operate in the energy markets, and as a means to integrate variable generation resources (e.g., wind and solar) with DR resources responding sub-hourly (i.e., "fast" DR). Many of these evolutions will necessitate new approaches for incorporating DR into long-term resource planning. It is important to document both the existing methods, as well as identifying how new approaches may be necessary in anticipating the creation of new DR programs.

This paper builds on work for the Western Governors' Association (WGA) and Western Electricity Coordinating Council (WECC) in modeling DR in a production cost model. It explores the analytical frameworks for incorporating DR into long-term resource planning and the extent to which purported benefits of demand-side resources (e.g., avoided generation and transmission) are being realized. The paper also considers whether current approaches accurately and realistically model demand-side resources in capacity expansion and production cost models and whether barriers exist to incorporating DR into resource planning models in a more robust fashion.

Transmission planning and pricing in the US: What Else Can Be Done?

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It has been six years since FERC implemented section 219 by issuing Order No. 679, Promoting Transmission Investment through Pricing Reform. The need for transmission projects has been only become more critical since then, due to the increase in renewables-related projects. In evaluating the direction for future policy changes in the industry, the main questions to ask are: What are the obstacles that remain for an efficient expansion of the transmission system? How does the need of states to meet specific renewable policy goals impact the overall transmission planning process and cost allocation? What are the barriers that FERC cannot unilaterally overcome? What is the potential of FERC Order 1000 to improve coordination between ISOs, FERC and state regulators of the affected region? A regulatory environment will only be successful to attract capital if it provides non-discriminatory participation to interested parties in the transmission planning stage, and if there are provisions in place to avoid excessive uncertainty on prospects of timely implementation and cost recovery. Any incentive mechanisms directed to promote investments need to abide by certain principles and recognize the involvement of both federal and state regulatory bodies in the planning process and cost authorization. This paper discusses the key areas in transmission planning and pricing that require further work and provides suggestions for improvement.

Welfare Analysis of Conservation Rate Designs for Water

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California has adopted a statewide goal of 20 percent reduction in water use by customers of the privately owned water utilities. One means for pursuing this goal is the adoption of steeply tiered water usage rates where customers with larger demands are charged high marginal prices, even when the marginal cost of water delivery is low.

This paper articulates the analytic framework and data requirements for performing an economic welfare analysis of such water rate structures. We focus particularly on the impacts on customers of prices that induce substantial usage reductions, but also endeavor to provide a broader framework that can assess societal impacts where required data can be obtained. Numerical examples also are provided using a combination of parameter estimates from literature, and stylized values.

Proper Rate Treatment of Energy Efficiency Investments

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In recent years, the development of Energy Efficiency Resource Standards (EERS) or similar regulatory policies appears to be on the rise given jurisdictional preference for encouraging more efficient usage of electricity. Both electric utilities and regulators seem to acknowledge that these standards and policies help achieve system peak load reductions through demand-side management (DSM) programs.
However, in light of meeting EERS mandates, utilities must cope with the long-term fiscal impacts of retail sales losses given the paradox in traditional rate design, which tends to overemphasize recovery of fixed costs through volumetric retail customer charges. This creates the need for timely cost recovery mechanisms to recouping the unmitigated fixed costs often through formal rate requests. The lost revenue adjustment mechanism (LRAM) is one such cost recovery mechanism in practice that may allow utilities to recoup lost revenue margins resulting from DSM programs through estimation of retail sales losses. While the primary focus of such mechanisms is recovering the fixed costs from each customer rate class, the accumulated energy savings from different programs can fundamentally shift retail customer classes' load patterns over the long-term. This may necessitate having to reassess the rate structure of these classes to account for these patterns as a complement to cost recovery strategies.

As there are many factors that dictate how electric utilities may consider various revenue adjustment mechanisms, this paper analyzes trends seen by different utilities for administering the LRAM as part of overall cost recovery strategies. In addition, as DSM programs not only reduce system peak loads but can also impact customer class load patterns, this paper explores whether certain provisions as part of EERS can help address the impact of DSM programs towards a more integrated approach of allocating rate class impacts in conjunction with rate adjustment mechanisms.

Dynamic Market Response to Optimize Demand Management

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Grid modernization technology enables end to end dynamic load optimization from utility energy resources to customer end-use appliances. Two aims of optimization are 1) reduce utility costs (energy, capacity, T&D) through asset optimization and 2) improve customer satisfaction via control over comfort and convenience relative to customer value. Integral Analytics has performed a utility Demand Response (DR) analysis to estimate the size and scale of potential benefits from dynamic management of customer load in coordination with grid reliability. The DR portfolio is viewed not simply from the perspective of a resource to manage a single peak day, but with market fluctuations and weather uncertainty the portfolio must be available many days, for events that may or may not occur. A probabilistic assessment of the DR portfolio is used. Given expectations of limited customer tolerance for the number and duration of DR events, limits in coincident peak savings can be determined for the expected system load. Both the effective limit and the DR potential required to achieve the limit depend on the program design and customer performance, including the number and duration of events. Portfolio level and marginal cost effectiveness can be assessed and used in program design. Dispatch of DR can be reviewed at different price points, as uncertain yearly reliability events are projected. The optimal architecture involves dispatching the finite resource to maximize overall benefit subject to the assurance that DR will still be available for all system emergency or coincident peak events. This paper presents initial results, a framework to identify the most effective programs in the portfolio, and capabilities to better design DR in light of dispatch needs, while maintaining customer satisfaction and resource persistence. It highlights interactions between planning around forecasts and uncertainty in implementation due to weather, operational limits, and performance risk.

Business Implications:
- •Rise of third party energy management as a bundled service with non-energy applications.
- Do it or have it done to you

- Demand gaming by 3rd parties could force loads on in the morning, raising utility costs, and then collect windfall DR incentives in the afternoon
- Home/premise as a battery (pre-cool / pre-heat)
- The more efficient a premise, the more value it has as a distributed energy resource.
- Energy efficiency as an additional value-creator.

Regulatory Implications
- "Green Button" initiative
- Privacy of customer data
- Uniform market rules from Federal intervention (FERC Order 745)
- Integrated Resource Planning rules
- Appliance scheduling optimization (based on appliance survey data)
- Combinations of central A/C, clothes dryer, water heater, electric heat, and/or PEV.
- Monte-Carlo simulation using 30 years of weather, rates and market prices, and average U.S. home efficiency rating.
- Hourly arbitrage simulation (limited to 24hr look-ahead).
- Optimization limited by customer preferences for pre-heating and pre-cooling (e.g. 2o variation from set-point).
- Two independent model runs:
- Minimize customer bill (e.g. max customer benefit)

Maximize utility avoided costs (e.g. max utility benefit)
- Distributed photovoltaic systems with and without storage
- Advanced air-conditioning and heating system cycling programs
- Whole house optimization of end-use appliances
- Smart charging of electric vehicles
- Demand response for reliability and peak shaving
- Phase II will expand upon Phase I to include:
- Commercial and industrial "grid scale" optimization
- Integrated resource dynamic price impacts (e.g. prices will adjust as kW and kWh are optimized)
- Phase III may include:
- Distribution system impacts
- Micro grids
- Risk/benefit assessment
- The results from this work will be used to demonstrate the utility and customer benefits from pursuing a distributed optimization engine.

The appropriate valuation methodology for integrated demand side management (IDSM) options -- measures comprised of any two or more of energy efficiency, demand response, distributed generation, and storage -- has been a challenging topic for decades. In regulatory proceedings, the primary approach to value demand side resources is cost-effectiveness, which relies largely on deterministic (point estimate) avoided costs and the California Standard Practice Manual (SPM) methodology. However, the current constrained California economy has contributed to reduced energy load growth accompanied by lower avoided costs and market prices. This has now led regulators to more highly value job growth, mitigation of risk and uncertainty, and to integrate other values (e.g., CO_2 mitigation and embedded energy in water). Beyond deterministic cost-effectiveness, the process of value mapping can be used to define and to quantify additional streams of value. Value maps can be used to identify, translate, and quantify the major sources of program value and cost. In this way, risk drivers, risk/benefit profiles, and financial and economic factors can be incorporated. Moreover, the benefits and related performance, costs and related performance, and macro factors can be simultaneously combined. These program values and costs can then be incorporated into productivity curves. A next step in this work is to apply productivity curves to California's IDSM programs. Summary results from this work will be presented and compared to static use of cost-effectiveness under the SPM. The implications for more advanced assessment to satisfy regulatory requirements and IDSM needs will be discussed.