Market Redesign: Incorporating the Lessons Learned for Enhancing Market Design

Final Project Report

Power Systems Engineering Research Center

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Power Systems Engineering Research Center

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Executive Summary

The Market Redesign Project was conceived as a logical extension of the Market Mechanism Project completed in 2001. The Market Mechanisms Project focused on (1) the design of electricity auctions for energy and ancillary services; (2) the development of financial engineering based models for generation asset valuation; (3) the investigation of usable definitions of transmission rights; and (4) the study of methods for congestion management and of the formulation of price mechanisms and incentives for demand response. Many of the results of the earlier project have, by now, become part of the tools and concepts widely used in the market environment with major impacts on policy decisions. The Market Redesign Project has pursued further the continuation of this line of research while also incorporating the experiences to date in the operating markets in various U.S. and foreign jurisdictions. The principal focus was on issues that have been identified as open questions and on areas targeted as particularly being in critical need of improvement.

The principal objectives of the Market Redesign project were:

- to assess the interactions between the operational and commercial aspects of electricity markets;
- to study the impacts of the institutional market design on the experiences to date and to identify the key requirements in the reform of the market structure and specification of the appropriate *rules of the road*; and
- to propose a set of modifications to improve market design so as to fully harness the benefits of competition in electricity.

We carried out the work on this project as a series of separate and interdependent “mini-projects” that resulted in a large body of working papers, public lectures, and a significant number of publications in both conference proceedings and archival journals. The three main investigators contributed conceptual development and advancements in the state of the art of the following areas: general market design issues, bidding behavior and market power analysis in energy markets, congestion management and transmission rights, capacity-based ancillary service markets, and interactions between the forward and the spot-energy markets. Some of the resulting publications that have appeared in the economics and power system literature have become seminal works in the field. They have impacted policy decisions at FERC and also at some of the ISOs. As such, their influence is widely felt.

Overall, this project has provided:

- an improved understanding of existing markets and the identification of the remaining principal shortcomings to be overcome for operations with improved efficiency;
- an explicit evaluation of the commercial significance of technical constraints, and the interaction of the market rules and physical system operations for maintaining security;
- procedures for active demand-side participation for managing volatility and short term responsiveness flexibility;
- schemes for the monitoring of markets to assess situations of market power exercise, and identification of market design flaws; and

- a scope for the role of regulatory oversight in the operation of the various interrelated markets.

This report summarizes the key developments in the various mini-projects that constituted the work. We grouped the results of the project into five major thematic areas:

- General Market Design
- Energy Markets, Bidding Behavior and Market Power Analysis
- Congestion Management, Modeling, and Transmission Rights
- Ancillary Services
- Interaction between Forward and Spot Energy Markets

We describe the results of the mini-projects under each theme and also provide the relevant reference documents.

The performed studies have led to the formulation of recommendations that encapsulate the basic findings of this project. Each recommendation is based on the theoretical work and analytic evaluation of the wide practical experience in the various electricity markets in the U.S. and abroad. The following are the key recommendations:

1. It is neither possible nor desirable to separate market functions completely from reliability functions. Operating procedures must explicitly recognize that in a market-based system, the resources that are needed to ensure reliable operations must be procured effectively through markets.
2. It is neither possible nor desirable to entirely decouple short-term operational effects from long-term planning and ignore downstream constraints. Market design must recognize the existing constraints, including the downstream technical constraints, in each market.
3. The effects of the interactions between the zones of systems and interconnected systems must be explicitly considered in the design and analysis of markets. When a system has been organized into areas, zones and more, the geographic interactions between the constituent components must be explicitly considered in each market.
4. For the reliable and efficient operation of a market-based system, all scarce resources must be identified and priced, and the use of scarce resources must be co-optimized explicitly recognizing complementarities and substitutabilities.
5. The effective coordination of markets and system operations requires an appropriate allocation of labor between system operations and market operations. Under such an allocation, the power system engineers can identify the scarce resources and the binding constraints. Correct market designs can properly price such scarce resources to allocate risks, costs, and benefits according to the market players' preferences.

The results of this project are also useful in providing fruitful directions for future work. Key areas that are logical extensions of the results reported here are on the topics of:

- transmission and generation asset investment decision making,
- the closer coordination of system and market operations, interconnection seams issues,
- the effective regional planning of the increasingly larger ISO/RTOs under development,

- the analysis of risks and the schemes for their effective management, and
- the design of effective incentives in various parts of market operations and system planning.

We expect that these topics will be addressed in future projects.

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1. Introduction

The liberalization of the electricity industry in the U.S. and other parts of the world is rapidly and dramatically changing every aspect in the operations and planning of electricity. The introduction of competitive electricity markets is established in about half of the nation's states and in many countries around the world. In light of the experience to date with restructuring of the electricity industry, there are myriad changes underway in virtually all parts of the world leading to new ways in which electricity is bought and sold and investment in the electricity infrastructure is incentivized and paid for. As experience is gained in the operation of competitive electricity markets, it is becoming clear that the salient physical characteristics of electricity have significant impacts on the commercial aspects on the market. At the same time, the market design and specification of the *rules of the road* are bringing changes in the ways systems are operated. Most of the work done within the framework of this project is motivated by recognition that the primary objective of any market design is to achieve efficient and reliable operation of the system.

The implementation of competition in wholesale electricity markets is often accompanied by vertical unbundling of the generation, transmission and distribution sectors and the establishment of a so-called independent system operator (ISO) or a regional transmission organization (RTO). The ISO, an independent entity that operates and controls the transmission system in a region, has as its principal objective to enable the smooth functioning of competitive markets while ensuring that the reliability of the interconnected system is maintained. The first generation ISOs in the U.S. were created as nonprofit organizations that operate but do not own the transmission assets. FERC has provided the guidelines for evolving to the geographically broader Regional Transmission Organization (RTO) structure as a means of correcting a slew of problems arising from the implementation of FERC Orders 888 and 889 mandating transmission access. FERC provided considerable latitude in its Order No. 2000 for the means for implementing RTOs. An alternative form to the ISO concept is that of a for profit independent transmission company (ITC) that owns the transmission assets and often referred to as a TRANSCO. The National Grid Company (NGC) in the UK is an example.

There are numerous challenges with the design and implementation of RTOs and their associated market organizations. The unbundling of electricity in the competitive environment has created new markets in ancillary services. The new structures under competition have created a number of distinct markets that are strongly interrelated. In addition, market players may be involved in longer term contracts through forwards or contracts for differences for certain services and products. With the widening of electricity future markets, tools for hedging of market volatility have become available.

The objectives of this project were:

- to assess the interactions between the operational and commercial aspects of electricity markets;

- to explore ways to better align the reliability objectives of electricity systems with the procedures guiding market operations
- to study the impacts of the institutional market design on the experiences to date; to identify the key requirements in the reform of the market structure and specification of the appropriate rules of the road; and
- to propose a set of modifications to improve market design so as to fully harness the benefits of competition in electricity systems.

The work performed within the framework of this project consisted of a series of separate but interdependent “mini-projects” that resulted in working papers, public lectures and a significant number of conference proceedings and Journal publications by the three main investigators, Alvarado, Gross and Oren and their students. Dr. Mount, who was only nominally supported by this project, served as an adviser to the project and his own research work is credited to other PSERC projects.

Our work focused on the following general topics:

- General market design issues
- Energy markets: bidding behavior and market power analysis
- Congestion management modeling, and transmission rights
- Capacity-based ancillary service markets
- Interaction between forward and spot energy markets.

The remainder of the report is organized as follows. The next five sections describe various individual and group contributions to the five topics listed above. Because of the broad coverage of this project and the diversity of topics addressed we will present the various contributions in the form of an annotated review of the venous contributions, classified according to the topics listed above. Each of these individual contributions is summarized in abstract form or by paraphrasing the main results of the contributions. In each case, however, a link is made to a location where additional details can be obtained. Some of this work was co-sponsored by separate grants from the National Science Foundation and by DOE/CERTS funding channeled through NSF and PSERC memberships. The final section of this report attempts to unify these individual contributions into an overall picture of what has been learned and makes specific suggestions concerning the four primary objectives of the project, drawing on results from the specific contributions that we have listed.

2. General Market Design

In the general area of market design we have looked at various issues in the design of efficient markets and the centrality of transmission. A part of the work was the analysis of the FERC Standard Market Design initiative (the SMD NOPR). The major thrusts in the NOPR are:

- standardized transmission service
- organizational structure for transmission provision
- market operations and monitoring
- congestion management
- transmission planning
- resource adequacy.

We investigated a number of issues arising out of this important initiative. These are documented in several publications. The team was also active in writing comments addressing various issues raised by the SMD NOPR and in serving on some of the public workshops conducted by FERC on specific SMD related issues.

Members of the team have also active as invited speakers at international conferences, lecture tours and at technical workshops conducted by the California Public Utility Commision (CPUC), presentations to the Federal Energy Regulatory Commission (FERC) and by the Public Utility Commission of Texas (PUCT) on various aspects of electricity restucturing and market design. In the aftermath of the August 14, 2003 blackout, memebr of the team played a role in addressing and shedding light on question concerning the relationship between market design and reliability in light of the Blackout. Following are specific contributions falling under this gneral category:

Shmuel S. Oren. "The FTR vs. FGR Debate: Facts and Misconceptions." Comments to FERC in Docket RM01-12-000 (Standard Market Design). April 2002.
[PSERC 01-48]

This comment addressed specific issues concerning the treatment of congestion management and transmission rights. It highlighted some misconceptions concerning the use of FTR vs. flowgate rights (FGR) on the basis of research results obtained as part of this project. Specifically, the comment focused on the definition of transmission rights in FERC's working paper on Standardized Transmission Service and Wholesale Electric Market Design. The comment endorsed the following positions of the author. These recommendations do not necessarily represent the views of other team members of this project.

1. Support of FERC's recommendation to use of flowgate rights in conjunction with point to point rights for hedging congestion cost.

2. Recommended that point to point rights (FTRs) be defined only as two sided financial instruments and not be offered as options.
3. Recommended that flowgate rights (FGRs) be offered only as one sided instruments (options for the buyer and obligation for the seller)

C. Mensah-Bonsu and S. Oren. "California Electricity Market Crisis: Causes, Remedies, and Prevention." ***IEEE Power Engineering Review*****, Vol. 22, No. 8 (August 2002), pp. 4-5.** (Summary of a panel organized by the authors at the IEEE PES 2001 meeting.). [PSERC 02-67]

California confronted an unprecedented electricity crisis, which threatened to undermine the reliability of its electricity system, wreck its economy and cause collateral damage throughout the western part of the United States. The initial causes of the high wholesale market prices reflect a complex mixture of a faulty restructuring and legislative plan, stringent environmental regulations, dramatically higher natural gas prices, lack of sufficient generating capacity and transmission infrastructure, unanticipated increases in electricity demand growth, inadequate demand responsiveness or lack of demand elasticity, lack of forward contracting and forward scheduling. These anomalies have culminated into a perfect storm and consequently, leading to possible market power abuse. Increasing deterioration of the compounding potential financial insolvency of California's three investor-owned utilities (IOUs) has further shattered all vestiges of a "normal" deregulated electricity market. In a nutshell California has financial, legislative and electricity supply crisis. Effectively, the California Independent System Operator (CAISO), IOUs and state government overseers have been resorting to desperate measures in keeping the lights on in CA with the available limited resources, but with only limited success. In order to understand fully the causes, potential remedies and how to prevent similar crisis in other parts of the world, there was the need to understand the policy issues, economic as well as the operations perspective of the situation. The panel brought together individuals who had first-hand experience with various aspects of the California electricity market, either through analysis of its underlying cause or involvement in mitigation efforts. The panel speakers who were experts in their fields addressed a variety of issues including, the CAISO operations, electricity supply, demand side responsiveness, abuse of market power and its mitigation, long term contracting, regulation and the underlying policies in their quest to recommend solutions that are pertinent, particularly to the controversial California electricity market.

G. Gross. "The FERC Standard Market Design GigaNOPR: Research Needs." ***Proceedings of the NSF Workshop on Modernizing the National Electric Power Grid*****. New Orleans, November 18-19, 2002.** [PSERC Presentations Folder, 02-13a]

The Standard Market Design (SMD) Notice of Proposed Rule Making (NOPR) issued by the Federal Energy Regulatory Commission (FERC) in July 2002 is a bold attempt to map out the future structure, organization and functioning of electricity markets in the U.S. The FERC proposal is aimed at establishing a "standardized transmission service and wholesale electric market design" for all the market participants. In effect, the SMD is a set of rules for the wholesale electric market operations and for the structure for planning and resource adequacy. The NOPR's vision of the future electricity markets sets up a large number of challenges in the areas of research, development and policy analysis. The key issues in the areas of information availability and usage, market design, system reliability, incentives for transmission expansion, demand response implementation, validation of market design proposals and market monitoring are outlined. Particular emphasis is focused on the role that the academic power community can play. The presentation discusses some fruitful areas for future research.

Shmuel S. Oren. "Comments on the FERC SMD NOPR." FERC Filing in Docket RM01-12-000 (Standard Market Design). November 15, 2002. [PSERC 02-65]

This comment highlighted three specific details in the SMD NOPR that required attention. The comment identifies potential problems associated with the specific design features and recommends remedies that will improve the design while keeping with the stated objectives of the NOPR. I focused on the following three aspects of the SMD:

- Virtual bidding in the day ahead market.
- Management of congestion across seams
- Providing explicit economic signals for transmission investment.

With regard to virtual bidding the comment identified some unresolved gaming opportunities and proposed a remedy. As to managing congestion across seams the comment proposed a solution based on a paper supported by this project and detailed below. With respect to economic signals for transmission investment and incremental improvements, the comment advocated allowing transmission owners to sell short flowgate rights that could be used as backup for additional point to point FTRs. Under such an arrangement the transmission owner can gain if it manages to increase the thermal ratings on the flowgate it sold short and make the constraints non-binding.

R. Wakefield, F. Alvarado, H. Adams and T. Gentile of the IEEE-U.S.A Energy Policy Committee. "Response to Questions Posed by House Energy and Commerce Committee Concerning the Northeast Blackout of August 2003." Prepared by The Institute of Electrical and Electronics Engineers, United States of America (IEEE-U.S.A)**, August 29, 2003.**

F. L. Alvarado and R. Rajaraman, "The 2003 Blackout: Did the System Operator have Enough Power?"[PSERC 03-35]

The above paper and the responses to questions by the House Energy and Commerce Committee were written shortly after the blackout and provided a blow by blow exposition on how a well functioning market based system could have prevented the disastrous consequences by providing early signals of impeding shortages that would have enabled timely response that could have contained the problem.

G. Gross, IEEE Distinguished Lecturer Program in Irkutsk and Moscow, Russia, Bucharest, Romania and Budapest, Hungary, June 17-July 9, 2004. [Available from Author Upon Request]

A series of lectures on the role of transmission, market design and congestion management issues in the restructured electricity industry was undertaken at the request of the IEEE Power Engineering Society and presented in Russia, Romania and Hungary in Summer 2004.

G. Gross. "Challenges and Opportunities in the *New* Transmission Business." *Proceedings of AUPEC 2004*. University of Queensland, Brisbane, Australia, September 26-29, 2004. [Part 1, Part 2, "Assessment of Transmission Congestion Impacts on Electricity Markets"]

The rapid and wide-ranging changes in electricity restructuring have profoundly impacted all sectors of the power industry. The most profound changes, by far, have come to the critically important transmission sector. These changes affect all aspects of power system operations and planning, the structural organization of the sector, the design of markets, the economics of transmission investments and the formulation of appropriate regulatory policy. Such changes represent tremendous new opportunities for innovative problem solving and development of effective tools to lead to the removal of impediments to vibrant competitive markets. At the same time, an incontrovertible conclusion of the mega-blackout of August 14, 2003 is the fact that the transmission network is the weakest link of the restructured electricity business in the United States. In this presentation, we review some of the major challenges and opportunities in the evolving transmission business. In the short term, the physical constraints in the power transmission system are making it difficult to realize the potential economic benefits of restructuring. The advances of the current research on economically efficient congestion management and financial transmission rights that correctly accommodate the physical usage and market liquidity are discussed. In the longer term, the major issues focus on the need for incentives in investment in infrastructural components, the role of reliability, the improvement of system security and the effective integration of distributed energy resources (small local generation sources and demand participation). The discussion discusses some of the key challenges and the needs for interdisciplinary approaches due to the nature of the problems.

G. Gross. "Evolving Nature of Electricity Market Design in the U.S." *Proceedings of the IERE General Meeting and Central & Eastern European Forum.* Krakow, Poland, October 17-21, 2004. [PSERC 04-54]

The objective of this paper is to critically examine the FERC vision for achieving smoothly functioning electricity wholesale markets in the U.S. and the path taken toward the implementation of that vision. The FERC Order No. 2000 was a highly important initiative that came on the throes of the introduction of the blueprint for open access transmission operations laid out in the FERC Orders No. 888 and 889 in 1996. FERC directed all FERC-jurisdictional entities to establish new transmission structures called regional transmission organizations or RTOs. Subsequently FERC invested considerable time and effort to develop a robust wholesale market via the so-called standard design (SMD) proposed rule making. The SMD was a bold, overly prescriptive and overly ambitious undertaking that failed due to various political, regional and stakeholder pressures, including the opposition of those entities who have yet to accept the notion of markets in the electricity sector. FERC withdrew the proposed rulemaking and replaced it with the less ambitious White Paper on the Wholesale Power Market Platform (WPM). While many of the underlying SMD aspects were kept, the overall effect was to move away from the cookie-cutter approach and to encourage regional differences in the market design arena. This report assesses the thrusts of the SMP proposal and those of its redrafted version as presented in the WPM White Paper. The paper analyzes the key thrusts of the initiatives and evaluates the status of market design in the U.S.

3. Energy Markets, Bidding Behavior and Market Power Analysis

The main commodity traded in electricity markets is energy so modeling the structure of energy markets and analyzing the impact of market rules on bidding behavior is essential to understanding the function of dysfunction of competitive interaction in the restructured electricity industry. Our work has focused on several aspects of energy markets which are related to being able to detect market power abuse and gaming and to mechanisms that will mitigate market power and gaming so as to improve the efficiency of energy markets. Following is a detailed description of specific contributions to this subject area.

R. Rajaraman and F. Alvarado. "Optimal Bidding Strategy in Electricity Markets Under Uncertain Energy and Reserve Prices." ***Proceeding of SEPOPE 2002*****. Brazil**
[PSERC 03-05] [PSERC Presentation (Slides (pdf) | Audio-Slide production (zip)]

Regardless of market design, the generator's bidding (or self-scheduling) problem is complicated by several factors, in particular, the presence of multiple markets, market design rules, non-convexity of cost curves, inter-temporal constraints, and price uncertainty.

(1) A generator typically has a choice of multiple markets into which it can sell its capacity. For example, energy-limited hydroelectric generators must decide whether to allocate their output now or in later periods.

(2) The design of the electricity market auctions affects the bidding strategy of the generator. Markets where energy and reserve markets are simultaneously cleared require different strategies than markets where energy and reserve services are sequentially cleared.

(3) Non-convexity of cost curves complicates generator bidding behavior because generators are typically required to bid non-decreasing bid curves (as a function of MW offered).

(4) Inter-temporal constraints such as startup and shutdown times, total energy limits, ramp rate limits, etc. also complicate bidding strategies.

(5) Price uncertainty in later periods affects the generator's bids in the present period.

This paper solves the problem of finding the optimal bidding strategy for all these cases as an extension to the related but not identical unit commitment problem by means of backward NESTED dynamic programming.

R. Rajaraman and F. L. Alvarado. "(Dis)Proving Market Power." March 25, 2002. [PSERC 02-06]

This detailed paper establishes an accurate, systematic and rigorous methodology and framework for proving or disproving the exercise of market power in specific instances, and does so taking full consideration of all the realities of power markets.

The debate on market power has been influenced by a slew of articles in the recent past that claim to show that generating firms have exercised market power in deregulated markets (especially in California in 2000-2001). However, empirical studies that purport to find market power suffer from some significant shortcomings. Empirical studies that have analyzed market power typically use hourly simulation models to estimate competitive prices. These prices are then compared with actual historical prices; if the simulated prices are substantially below the observed market clearing prices, and the discrepancies between the two cannot be easily explained away, then there is a strong suspicion of the exercise of market power. However, implicit in such simulation studies are approximations, such as ignoring inter-temporal constraints, which have the potential to significantly affect the simulated prices. Moreover, the data requirements for such simulation studies could be quite stringent. Harvey and Hogan have argued forcefully that quantifying market power by such simulation studies is a difficult problem.

This paper estimates the presence/absence of market power by examining whether the behavior of each generator in the market participant's portfolio is indeed the behavior one would expect to observe if the generator were a price taker given the market design rules, multiple markets, non-convex operational constraints, non-convex cost structure, etc. in the presence of forecast uncertainty. This approach has the advantage of being practical and manageable.

The test that we propose for the detection of market power by a market participant has two main parts: (a) a quantitative model-based market test that can be used in most cases to help establish a "guilty" or "not guilty" answer to whether the market participant has exercised market power, and (b) a qualitative analysis part (for those cases that cannot be resolved by the model-based test) that examines the incentives (or perceived incentives) of the market participant to exercise market power. The model-based market power test solves an optimization problem that takes full account of inter-temporal constraints, generator cost information and forecast uncertainty to solve for a single generator's profit-maximizing commitment and dispatch policy given uncertain exogenous locational prices. This optimal generation dispatch and commitment policy can be used to formulate the optimal generator bidding strategy, and to understand generator behavior. This approach has the advantage of requiring minimal data; in particular, data related only to the generator(s) suspected of having exercised market power are needed. Based on this optimization, we give a test that can be used to show that a market participant is "not guilty" of exercising market power. A stricter "guilty" test must be met to show that market power was exercised. An implementation of these ideas is also described.

Shmuel S. Oren and Andrew Ross. "Designs for Ramp-Constrained Day-Ahead Auctions." ***Proceedings of the 36th Hawaii International Conference on Systems Sciences HICSS 36*****. Big Island, Hawaii. January 5-9, 2003.** [PSERC 02-37]

Some electric power markets allow bidders to specify constraints on ramp rates for increasing or decreasing power production. We show in a small example that a bidder could use an overly restrictive constraint to increase profits, and explore the cause by visualizing the feasible region from the linear program corresponding to the power auction. We propose two penalty approaches to discourage bidders from such a tactic: one based on duality theory of Linear Programming, the other based on social cost differences caused by ramp constraints. We evaluate the two approaches using a simplified scaled model of the California power system, with actual 2001 California demand data.

D. Hurlbut, K. Rogas and S. Oren. "Protecting the Market from 'Hockey Stick' Pricing: How the Public Utility Commission of Texas is Dealing with Potential Price Gauging." ***The Electricity Journal*****. April 2004. pp. 26-33.** [PSERC 04-52]

The paper describes a new approach adopted by the Public Utility Commission of Texas (PUCT) to curb the effects of ''hockey stick'' pricing in the spot electricity market run by the electric Reliability Council of Texas (ERCOT). The Texas model departs from the automatic mitigation procedure pioneered by the New York Independent System Operator (NYISO), incorporating a sunshine policy as a psychological deterrent and an automatic mitigation mechanism triggered by temporary market failure. The hockey stick strategy involves offers of a small, expendable quantity of energy or capacity well in excess of its marginal cost. This strategy, which is virtually risk-free to the generator, exploits short-term inelasticity of demand for balancing energy and ancillary services capacity when all offers for these services are exhausted. In markets where energy or capacity is purchased through a uniform price auction and all accepted offers are paid the same market clearing price (MCP), the presence of even one hockey stick offer can drive market prices to extremely high levels when nearly all offers are struck. The hockey stick offers may thus be viewed as an ''ambush strategy'' that exploits the rigidity of the system operator's procurement rules and the lack of demand response. Since the additional supply offered at the high price under the hockey stick strategy is very small, even slight flexibility on the demand side would forgo these few extra megawatts and avoid the resulting price spikes.

4. Congestion Management, Modeling and Transmission Rights

Congestion management and transmission rights are the center pieces (and arguably the most controversial aspects) of the standard market design proposed in the FERC SMD NOPR. Attempt to simplify congestion management in the early stages of the PJM operation, in the California original market design and in Texas have resulted in gaming and market dysfunction that eventually led to adoption or planned adoption of the Nodal Pricing paradigm. In many areas of the U.S. (such as the Southern Company territory and the Pacific Northwest), there is still strong resistance to the adoption of the nodal approach at the present time.

We have studied problems in the modeling and analysis of congestion and have analyzed the various schemes proposed to manage transmission congestion. On the modeling side our work focused on assessing the role and effectiveness of distribution factors in congestion applications. These factors – the injection shift factors (*ISF*s) and the power transfer distribution factors (*PTDF*s) – are linear approximations of the sensitivities of the active power line flows with respect to various variables. We analyzed the characteristics of these distribution factors and examined the range of conditions over which these factors can provide reliable approximations for large power system networks. We also carried out the first systematic comparative analysis of various schemes implemented to relieve congestion. The unified framework we developed provides the capability of evaluating different congestion management schemes using a consistent set of metrics. The framework overcomes the problems of the use of different *language* and interpretation used in the description of those schemes. The side-by-side comparison gives good insight on several aspects of the various schemes such as short-term efficiency and appropriateness of the economic signals for congestion removal. The unified framework is a powerful construct for putting on a consistent basis the various congestion management schemes.

In the locational-marginal-price (*LMP*)-based congestion management scheme, the transmission customers are exposed to uncertain congestion charges. In order to bring certainty to customers, congestion revenue rights (*CRR*) or as more frequently called *financial transmission rights* (FTR) are introduced. *CRR* are financial tools that provide the holder of the rights for the reimbursement of the congestion charges incurred, and thus afford price certainty to the holder of the rights. These rights are usually associated with the day-ahead market clearing, and are coupled to the real time markets by means of the coupling between these two markets provided by "virtual bidding." We have worked on the area of modeling and studied systematically the role and effectiveness of the distribution factors in *CRR* applications. In addition, we have constructed a very general mathematical framework for the design and analysis of the *CRR*.

CRR can be "packaged" as point-to-point rights or as "flowgate" rights. In our work we have made fundamental contribution to understanding the implications of different types of CRRs, specifically the relationship between point to point obligations and flowgate rights. We have also studied how one can mitigate the affect of loop flow across interregional boundaries ("seams").

While CRRs have desirable properties as property rights to the transmission system and as hedging instruments against congestion risk, empirical evidence suggest that there may be some inefficiencies associated with the auction procedures used by many ISO as a mechanisms for awarding CRRs. Our theoretical work indicates that inefficiencies in the common design of simultaneously feasible CRR auctions can create a potential bias between the auction prices of the CRRs and their realized value. This work supports the policy of allocating CRRs to loads based on historical use of the network.

Following is a detailed description of the various contributions under this general topic.

F. L. Alvarado. "State Estimation for the Detection of Market Parameters." IEEE/PES Summer Meeting, Vancouver, BC. July 16, 2001. [PSERC 01-49]

This paper presents two useful concepts for the estimation of significant market parameters based on commonly available information. It describes the problem of estimating system status based on published PTDF information, and it describes a method for estimating the cost elasticities of generators. The work reported in this talk was sponsored in part by PSERC.

F. L. Alvarado. "Creating Incentives for New Technologies in the Transmission System of the Future." Presentation to the Infocast Transmission Summit. January 31, 2002. [PSERC Presentation 02-13c]

This presentation describes the fact that optimal system expansion decisions must be based on estimates of surplus improvement. Thus, efficient expansion requires removing incentive to congest. Expansion incentives must exceed fixed costs for them to happen, but also any incentives to help expansion system must be smaller than the surplus gain, otherwise the entire surplus is absorbed by the entity expanding the system. In order to design appropriate expansion incentives, new views of "useful life" may be needed. The talks also illustrate how transmission expansion affects spot prices and the impact on investor decisions. Investors need to consider locational issues when deciding where to invest. Finally, this presentation also describes the impact of expansion on the protection system and the fact that expansion can increase short circuit duties. Expansion also alters the dynamic interactions between markets and the physical systems.

F. L. Alvarado, "Is System Control Entirely by Price Feasible?" ***Proceedings of the Hawaii International Conference on System Sciences (HICSS36).*** **January 2003. Also in** ***Decision Support Systems*****, 2004. [**PSERC 02-57]

This paper explores the theoretical feasibility of controlling a power grid entirely by means of price signals and nothing else. This work identifies the possibilities and limitations of a market structure where control of the grid is directly coupled to prices. In particular, it determines that limitations on the ability to control by price signal arise due to a number of factors, such as the presence of linear or declining costs, market power conditions, and complex cost structures. It describes means by which some of these issues can be addressed and resolved. The work reported in this talk was sponsored in part by PSERC.

J. Zuluaga and F. L. Alvarado, "Voltage Constraints and Power Nomograms," Presentation to the PSERC IAB, May 30, 2002. [PSERC Presentations 02-13b]

This work establishes that nodal prices depend on what constraints and limits are assumed for the operating point, and that the common practice of using nomograms where a flow limits is used in lieu of a voltage limit can result in prices that greatly depart from the correct nodal prices. Starting generators in order to meet reactive and voltage constraints can result in a significant "uplift" cost. If we replace voltage limits with flow limits, we get the same solution but the prices (i.e., the incentives) are different. Thus, the use of nomograms and other forms of surrogate limits yields the right solution but for the wrong reason and can lead to incorrect incentives. The work reported in this talk was sponsored in part by CERTS/DOE and in part by PSERC.

Shmuel S. Oren and Andrew M. Ross. "Economic Congestion Relief Across Multiple Regions Requires Tradable Physical Flow-Gate Rights." ***IEEE Transactions on Power Systems*****, Vol. 17, No 1, pp 159-165 (2002).** [PSERC 02-64]

This paper is concerned with market-based protocols for relieving congestion caused by transactions outside the control area in which the congestion occurred. One approach, proposed by Cadwalader et al. is based on dual decomposition in which out of area congestion is "priced-out" and added to the optimal power flow (OPF) objective function of the control area operator while the prices are determined iteratively via nodal energy adjustment bids. The paper demonstrates through a simple three node example that even with "correct prices" on out-of-area congested interfaces, the augmented AC-OPF objective function of a control area operator might not be locally convex at the optimal solution and hence the control area's optimal dispatch may violate the thermal constraints on out-of-area interfaces. That conclusion supports the alternative "flow-based" approach that enforces thermal limits more directly, which is consistent with North American Electric Reliability Council's (NERC's) FLOWBAT proposal for interzonal transmission load relief (TLR).

M. Liu and G. Gross. "Effectiveness of the Distribution Factor Approximations Used in Congestion Modeling." ***Proceedings of the 14th Power Systems Computation Conference*****. Sevilla, Spain. June 24-29, 2002. [**PSERC 02-66]

This paper addresses some modeling aspects of transmission. The distribution factors play a key role in the modeling of congestion in various market applications. These factors are linear approximations of sensitivities of variables with respect to various inputs and are computed for a specified network topology and parameter values. In practice, the factors are used over a wide range of system conditions. This paper investigates the analytical characteristics, the robustness and the quality of the approximations provided by key distribution factors such as injection shift factors (*ISF*s) and power transfer distribution factors (*PTDF*s). We examine the range of conditions over which these factors can provide a reliable approximation or large power system networks. This constitutes the first effort to systematically assess the impacts of errors in the distribution factors in the area of congestion modeling. The numerical simulation results indicate that the errors of the approximations stay in an acceptable range under a broad spectrum of conditions including contingencies used to establish *n-1 security.*

F. L. Alvarado. "Converting System Limits to Market Signals." ***IEEE Transactions on Power Systems*****. Vol. 18, No. 2, May 2003.** [PSERC 03-36]

This paper compares methods for converting system limits into market signals. One classification of methods is according to reliability driven (TLR and similar) versus market driven (LMP and similar) methods. A second classification is according to direct versus indirect methods. Direct methods deal with individual limits and constraints. Indirect methods include various ways of converting one type of limit to another, equivalent limit for purposes of making the handling of the limit more expeditious. An example of an indirect method is the conversion of a voltage limit to either a flow limit or an interface limit. Another example is the use of flow limits on interfaces as surrogates for stability limits. These transformed limits are often represented by nomograms. Conversion of one type of limit to another and the construction of nomograms has the advantage of reducing the problem of imposing system limits within a market context to a "previously solved" market problem. If a market already has learned how to cope with an import limit into a load pocket, conversion of a voltage limit into a load pocket import limit makes it easy for a market to react and respond to the condition. However, any conversion from one type of limit to another entails an approximation. This paper discusses the nature of some of these approximations. This work was sponsored in its entirety by PSERC.

E. Bompard, P. Correia, G. Gross and M. Amelin, "Transmission Congestion-Management Schemes: A Comparative Analysis Under a Unified Framework," *IEEE Transactions on Power Systems*, Vol. 18:1, pp. 346-352, February 2003. [PSERC 03-37]

The paper briefly reviews the congestion management schemes and the associated pricing mechanism used by the IGOs in five representative schemes. These were selected to illustrate the various congestion management approaches in use: England and Wales, Norway, Sweden, PJM and California. We develop a unified framework for the mathematical representation of the market dispatch and redispatch problems that the IGO must solve in managing congestion in these various jurisdictions. We use this unified framework to develop meaningful metrics to compare the various approaches so as to assess their efficiency and the effectiveness of the market signals provided to the market participants. We compare, using a small test system, side by side, the performance of these schemes.

G. Gross. "Assessment of Congestion Impacts on Electricity Markets." PSERC Seminar Presentation. November 2003. [Slides | Audio-Slide Production (03-06)]

Congestion in the transmission network has become a critical problem for electricity markets in the competitive power industry. Congestion has a wide range of impacts ranging from the way the system is operated to the behavior of each market player in the congestion-modified market. The presence of congestion may prevent the use of the lowest-priced resources to meet the demand and may, in addition, facilitate the attempt of a particular seller to exercise local market power. Many observers of the industry see congestion as a key barrier for the establishment of vibrant competitive markets. This presentation focuses on the impacts of congestion on the individual market players and the market as a whole, in general, and the quantification of these impacts when a seller attempts to exercise market power by varying its offer prices, in particular. Throughout the talk, we provide a good intuitive explanation of the impacts of congestion by explaining this phenomenon on a simple system. We also show the role of price-responsive demand in the mitigation of the possible exercise of market power. In terms of the individual players, there are other players who benefit from the attempt to exercise market power by a particular seller, the so-called free riders. Also, there are others who are negatively impacted. In terms of the entire market, there is a reduction in the market efficiency due to the attempt of a particular seller to exercise market power. A common characteristic found from the extensive simulations is the bounded ness of the congestion impacts in the presence of price-responsive demand due to their asymptotic nature. We illustrate quantitatively the congestion impacts using different test systems of various sizes.

M. Liu and G. Gross. "Framework for the Design and Analysis of Congestion Revenue Rights," *IEEE Transactions on Power Systems*. Vol. 19:1, pp. 243-251, February 2004. [PSERC 04-18]

In this paper, we construct a framework for the design and analysis of the CRR by marrying finance theory notions with salient characteristics of electric power systems and electricity markets. The framework consists of three interconnected layers with one layer each to represent the models of the transmission network, the commodity markets and the CRR financial markets. The interaction between the layers is represented as information flows. The framework has sufficient scope to allow the analysis of a broad range of problems associated with ensuring price certainty for transmission services. The structural modularity of the framework provides the flexibility to analyze issues and design structures for the provision of transmission services in the competitive environment. We introduce a new notion of CRR payoff parity and a practical pricing scheme, which are used as the basis for the design of more liquid CRR markets. The application of the framework is further illustrated by the analysis of the conditions that guarantee the revenue adequacy for the CRR issuer.

M. Liu and G. Gross. "Role of Distribution Factors in Congestion Revenue Rights Applications." *IEEE Transactions on Power Systems*. Vol. 19:2 pp. 802-810, May 2004. [PSERC 04-55]

The implementation of *congestion revenue rights* (*CRR*) or *financial transmission rights* requires appropriate modeling of the transmission network in which the distribution factors are extensively used. The factors are computed for a specified network topology and parameter values. In practice, the *PTDF*s used for the *CRR* issuance may be different from those used in the day-ahead market due to changes in the forecasted network conditions. The *PTDF* errors may impact the critical issuance quantities and the hedging ability of *CRR* as well as the revenue adequacy for the *CRR* issuer. In this paper, we explore analytical characteristics of these distribution factors and investigate their role in *CRR* applications. We study the nature of the *PTDF* errors and examine their impacts in these applications, both analytically and experimentally. Our results indicate that the impacts of the *PTDF* errors stay in an acceptable range under a broad spectrum of conditions including contingencies used to establish *n-1 security*.

E. S. Bartholomew, A. S., Siddiqui, C. Marnay, and S. S. Oren, "The New York Transmission Congestion Contract Market: Is it Working Efficiently", ***The Electricity Journal*****, November 2003, pp. 1-11.** [PSERC 03-34]

Afzal S. Siddiqui, Emily S. Bartholomew, Chris Marnay and Shmuel S. Oren, "On the Efficiency of the New York Independent System Operator Market for Transmission Congestion Contracts", ***Journal of Managerial Finance,*** **Vol. 31, No. 1, (2005) pp. 1-45. [**PSERC 04-38]

The physical nature of electricity generation and delivery creates special problems for the design of efficient markets, notably the need to manage delivery in real time and the volatile congestion and associated costs that result. Proposals for the operation of the deregulated electricity industry tend towards one of two paradigms: centralized and decentralized. Transmission congestion management can be implemented in the more centralized point-to-point approach, as in New York State, where derivative transmission congestion contracts (TCCs) are traded, or in the more decentralized flowgate-based approach. While it is widely accepted that theoretically TCCs have attractive properties as hedging instruments against congestion cost uncertainty, whether efficient markets for them can be established in practice has been questioned. Based on an empirical analysis of publicly available data from years 2000 and 2001, it appears that New York TCCs provided market participants with a potentially effective hedge against volatile congestion rents. However, the prices paid for TCCs systematically diverged from the resulting congestion rents for distant locations and at high prices. The price paid for the hedge not being in line with the congestion rents, i.e. unreasonably high risk premiums are being paid, suggests an inefficient market. The low liquidity of TCC markets and the deviation of TCC feasibility requirements from actual energy flows are possible explanations.

Shijie Deng, Shmuel S. Oren and Sakis Meliopoulos, "The Inherent Inefficiency of the Point-to-Point Congestion Revenue Right Auction", ***Proceeding of the 37th Hawaii International Conference on Systems Sciences HICSS 37.*** **Big Island, Hawaii, January 5-8, 2004.** [PSERC 05-09]

Empirical evidence shows that the clearing prices for point-to-point congestion revenue rights, also known as financial transmission rights (FTRs), resulting from centralized auctions conducted by Independent System Operators differ significantly and systematically from the realized congestion revenues that determine the accrued payoffs of these rights. The question addressed by this paper is whether such deviations are due to price discovery errors which will eventually vanish or due to inherent inefficiencies in the auction structure. We show that even with perfect foresight of average congestion rents the clearing prices for the FTRs depend on the bid quantity and therefore may not be priced correctly in the financial transmission right (FTR) auction. In particular, we prove that quantity limits on the FTR bids may cause the auction clearing prices to differ from the bid prices. This phenomenon which is inherent in the theoretical properties of the optimization algorithm used to clear the auction, is further illustrated through numerical simulations with test systems. We conclude that price discovery alone would not remedy the discrepancy between the auction prices and the realized values of the FTRs. Secondary markets or frequent reconfiguration auctions are necessary in order to achieve such convergence.

5. Ancillary Services

In the restructured U.S. electricity markets, Capacity-based ancillary services (AS) which include frequency control, load following and various types of reserves are procured by the system operators form generators as distinct product through auctions that are typically conducted in the day ahead. The downward substitutability of the various reserves which are categorized by response time creates unique challenges for the design of such auctions so as to induce truthful revelation of capability and facilitate economically efficient dispatch. We have investigated some key concepts in the effective procurement of hierarchical capacity-based AS on a competitive basis. Our work has resulted in a computationally efficient scheme for the acquisition of capacity-based AS. A salient feature of the proposed procedure is its ability to accommodate constraints such as ramp-rate, capacity and inter-zonal limits. In addition, the proposed procedure provides a good tool for market monitoring, since it establishes a reference basis for comparison purposes. We have also investigated a scheme for joint procurement of energy and reserves based on opportunity cost payment for reserves.

Reactive power is another form of ancillary service which is essential for system reliability but the lack of proper pricing for reactive power has so far defeated attempt to establish market based provision of that essential service. We have investigated the design of markets for reactive power and the implications of relying on market based procurement of that AS. Following is a detailed description of our contributions on this topic.

Rajnish Kamat, and Shmuel S. Oren, "Rational Buyer Meets Rational Seller: Reserves Markets Equilibrium Under Alternative Auction Design", ***Journal of Regulatory Economics*****, July 2001.** [PSERC 01-12]

We examine efficiency properties and incentive compatibility of alternative auction formats that an electricity network system operator may use for the procurement of ancillary services required for real time operations. We model the procurement auction as a hierarchical multiproduct auction and study several designs such as uniform price auction minimizing revealed social cost, a uniform price auction minimizing the system operator's cost (rational buyer) and a pay as bid auction minimizing revealed social cost. In our analysis we take into account that rational bidders will respond to any market design so as to maximize their expected profit from participating in the market. Under our assumptions we show that a uniform price auction that minimizing social cost is the only one that is incentive compatible and efficient. The other designs may lead to misrepresentation of capability or cost which can result in price reversal where a higher quality product clears at a lower price than a lower quality one and to inefficient use of resources.

Fernando L. Alvarado, “The Relationship Between Reliability, Reserves and Market Functionality,” The Institute of Public Utilities, 33rd Annual Regulatory Policy, Conference, October 29-31, 2001, Kingsmill Resort & Conference Center, Williamsburg, Virginia. [Available from Author Upon Request]

This talk describes how reserves policies affect the functioning of an energy market.

G. Chicco and G. Gross, "An Efficient Procedure for the Rational Buyer Approach for the Acquisition of Capacity-Based Ancillary Services," ***Proceedings of the 14th Power Systems Computation Conference,*** **Seville, Spain, June 24-29, 2002.** [PSERC 04-15]

This paper addresses the competitive procurement of capacity-based ancillary services (AS) in unbundled markets by the Independent Grid Operator (IGO). These AS include upward frequency control, load following and the range of reserve services, which may be procured from unloaded capacity offered by both on-line and off-line sources. The capacity-based AS are prioritized in order of ascending response times. Prioritization allows substitutability of the AS by automatically making the unused capacity of a higher priority AS usable for any lower priority AS without the need of submitting additional offers. This paper discusses the formulation of the auction structures for the acquisition of the prioritizable capacity-based AS and presents an efficient scheme for mminimizing the costs incurred by the IGO by using the *rational buyer* procedure. The proposed scheme adopts effective discrete programming techniques that exploit the structural characteristics of the problem for handling the multi-auction formulation. The proposed bounding scheme takes fully advantage of critical physical constraints such as ramp rate, capacity limits, and inter-zonal constraints. The effectiveness and computational efficiency of the proposed scheme are illustrated and discussed with numerical examples.

G. Chicco and G. Gross, “Competitive Acquisition of Prioritizable Capacity-Based Ancillary Services,” ***IEEE Transactions on Power Systems,*** **Vol. 19:1, pp. 569-576, February 2004.** [PSERC 04-17]

This paper presents significant improvements of the earlier work on the development of an effective discrete programming procedure for the rational buyer procedure for the competitive procurement of capacity-based ancillary services (AS) in unbundled markets by the Independent Grid Operator (IGO). The earlier efforts are extended in two important ways: the simplification and increased efficiency of the computational procedure and the presentation of appropriate illustrative examples in the application of the proposed scheme. We describe the improvements made to construct a computationally efficient scheme for the rational buyer procedure for the acquisition of the prioritizable capacity-based AS. The scheme allows the simultaneous determination of the successful offers in the multi-auction procedure through the effective deployment of discrete programming notions and the exploitation of the structural characteristics of the formulation. A key feature is the incorporation of physical constraints such as capacity, ramp-rate and inter-zonal constraints. The use of bounding techniques and procedures for the quick detection of infeasible combinations of the offer prices and the identification of avoidable calculations leads to reducing the computational burden. The effectiveness and computational efficiency of the scheme are illustrated with representative numerical results including case studies based on the IEEE 118-bus network.

Shmuel Oren and Ramteen Sioshansi, "Joint Energy and Reserves Auction with Opportunity Cost Payment for Reserves", ***Proceedings of the Bulk Power Systems Dynamics and Control VI*****, August 22-27, 2004, Cortina D' Ampezzo, Italy.** [PSERC 04-39]

System operators in the electricity industry are required to procure reserve capacity to deal with unanticipated outages, demand shocks, and transmission constraints. One traditional method of procuring reserves is through a separate capacity auction with two-part bids. We analyze an alternative scheme whereby reserves are procured through the energy market using only energy bids, and capacity payments are made based on a generator's implied opportunity cost. By using the revelation principle, we are able to derive the equilibrium bidding function in this market and show that generators have a clear incentive to understate their costs in order to capture higher capacity rents. We then show that in spite of making energy payments based on the marginally procured unit, the expected energy costs under our scheme are bounded by that of a disjoint auction. We then give a numerical example for a special case of uniform demand distributions.

6. Interaction between Forward and Spot Energy Markets

The relationship between forward and spot energy markets has been at the center of scholarly research, policy debate and litigations in the aftermath of the California energy crisis. Some of the key issues were: the extent to which forward markets can mitigate market power in the spot market, the incentives of market participants to enter into forward energy contracts and the extent to which a dysfunctional spot market can affect forward contract pricing. These questions were particularly relevant in view of the fact that FERC placed caps on spot prices in California but refused to intervene in the forward market so that holders of forward contracts that were signed during the crisis were adversely affected by a sudden drop in prices after the spot price caps were enforced. Our work focuses on modeling the interaction between forward and spot markets and the effect of congestion on that relationship. Following is a detailed description of our contributions on this subject.

Kamat Rajnish and Shmuel Oren, "Two-Settlement Systems for Electricity Markets Under Network Uncertainty and Market Power", ***Journal of Regulatory Economics,*** **25:1 5-37 (2004).** [PSERC 02-02]

We analyze welfare and distributional properties of a two-settlement system consisting of a spot market over a two node network and a single forward contract. We formulate and analyze several models which simulate joint dispatch of energy and transmission resources coordinated by a system operator. The spot market is subject to network uncertainty, which we model as a random capacity derating of an important transmission line. Using a duopoly model, we show that even for small probabilities of congestion (derating), forward trading may be substantially reduced, and the market power mitigating effect of forward markets (as shown in Allaz and Vila, 1993) may be nullified to a great extent. There is a spot transmission charge reflecting transportation costs from location of generation to a designated hub whose price is the underlying for the forward contract. This alleviates some of the incentive problems associated with the forward market in which spot-market trading is residual. We find that the reduction in forward trading is due to the segregation of the markets in the constrained state, and the absence of natural incentives for generators to commit to more aggressive behavior in the spot market (the 'strategic substitutes' effect). In our analysis, we find that the standard assumption of 'no-arbitrage' across forward and spot markets leads to very little contract coverage, even for the case with no congestion. We present an alternative view of the market where limited intertemporal arbitrage enables temporal price discrimination by competing duopolists. In this framework we assume that all of the demand shows up in the forward market (or that the market is cleared against an accurate forecast of the demand), and the forward price is determined using a 'market clearing' condition.

Fernando L. Alvarado and David Watts, "The Influence of Futures Markets on Real Time Price Stabilization in Electricity Markets," ***Proceedings of the Hawaii International Conference on System Science*** **(HICSS37) Big Island, Hawaii, January 2004.** [PSERC 03-21]

Markets can interact with power systems in ways that can render an otherwise stable market and an otherwise stable power system into an unstable overall system. This unstable system will be characterized not only by fluctuating prices that do not settle to constant values, but, more worrisome, it creates the possibility of inducing slow electromechanical oscillations if left unchecked. This will tend to happen as a result of "price chasing" on the part of suppliers that can react (and over-react) to changing system prices. This paper examines the role that futures markets may have on the clearing prices and on altering the volatility and potential instability of real time prices and generator output.

J. Yao, S. Oren and I. Adler, "Computing Two Settlement Cournot Equilibria in Electricity Markets" ***Proceeding of the 37th Hawaii International Conference on Systems Sciences HICSS 37*****. Big Island, Hawaii, January 5-8, 2004.** [PSERC 04-19]

We formulate a two-settlement energy pricing model in an oligopolistic electricity markets as a two period subgame-perfect Nash equilibrium in which each generation firm solves a Mathematical Program with Equilibrium Constraints (MPEC), given other firms' forward and spot strategies. We implement two computational approaches, one of which is based on a Penalty Interior Point Algorithm and the other is based on a steepest descent approach. We apply the algorithm to a six node illustrative example. The computational results sustain similar results obtained by Allaz and Villa (1993) for an uncongested system, showing that under rational expectations which eliminates arbitrage opportunities between the two markets, generators will have incentives to enter into forward contracts due to a prisoners' dilemma effect.

7. Conclusions and Recommendations

This section recaps the accomplishments of the project and draws conclusions leading to specific recommendations to the extent warranted by the nature of our findings. Because the results in some cases are either inconclusive or subject to different interpretations, we refrain from excessive simplification and generalization so as to provide guidance for those interested in the lessons learned in this project. We group our conclusions under four principal rubrics and provide the following synopsis for each rubric.

1. Assessment of the interactions between system operations and electricity markets

It is clear that there are strong interactions between systems operations protocols and market operations. It is equally clear that concerns raised about the use of distribution factors in managing congestion and pricing scarce transmission resources are unwarranted based on the extensive experimentation reported. Our work suggests that the use of distributions factors tends to work very well. This important set of findings is detailed in reports cited in section 3.

2. Alignment of reliability objectives and procedures to provide a guide for market operations

The evidence from our analysis of a variety of markets is that in properly designed markets, no conflict between reliability objectives and market operations needs to exist. The potential for conflict arises when, as a result of practical operational protocols or in certain cases computational limits considerations, the procedures implemented fail to properly align the objectives of markets and those of reliable power system operations. Conflicts may also arise due to failure by the system operator to identify all scarce resources and failure of the market design to price scarce resources, which leads to “out of market remedies” and cost uplifts.

3. Consideration of the impacts of institutional market design

From the extensive studies we undertook, it became very clear that market design has had significant influence on both the perception and the realities of reliability and market efficiency. Our studies, in fact, suggest that a basic element in the smooth operation of markets and the effective coordination of system and market operations is the foundation laid in the market design. A particularly insidious institutional issue that deserves further scrutiny is the issue of the impact that implied threats of regulatory intervention or the introduction of subsidized market players may exert on markets as a whole, regardless of the rationale for the threatened actions.

4. Proposals for improved market design that fully harness the benefits of competition

These findings lead to the logical conclusion that it is impossible to functionally separate reliability aspects of the system operations from market operations. It is likewise unwise to unbundle services any further than allowed by the nature of the system operations. In particular, there is no need to separate out as unbundled services those that in reality are effectively coupled together in system operations. This conclusion further applies to the various market designs that attempt to separate long-term from short-term objectives and ignore constraints in the first stage of a two-settlement system. Finally, the organization of systems into separately managed systems with disparate rules also begs the question of the extent to which the rules apply to adjoining different systems.

These findings were instrumental in the formulation of the recommendations provided as part of the work in this project.

- It is neither possible nor desirable to separate market functions completely from reliability functions. However, operating procedures must explicitly recognize that in market-based system, the resources that are needed to ensure reliable operations must be procured effectively through markets.
- It is neither possible nor desirable to entirely decouple short-term operational effects from long-term planning and ignore downstream constraints. Market design must recognize the existing constraints, including the downstream technical constraints, in each market.
- The effects of the interactions between the zones of systems and interconnected systems must be explicitly considered in the design and analysis of markets. The organization of a system into areas, zones and more, the geographic interactions between the constituent components must be explicitly considered in each market.
- For the reliable and efficient operation of a market based system, all scarce resources must be identified and priced and the use of scarce resources must be co-optimized explicitly recognizing complementarities and substitutabilities.
- The effective coordination of markets and system operations requires an appropriate allocation of labor between system operations and market operations. Under such an allocation, the power system engineers can identify the scarce resources and the binding constraints. The market designs can properly price such scarce resources so as to allocate risks, costs and benefits according to the market players' preferences.