THE VIRTUAL UTILITY:
Accounting, Technology & Competitive Aspects of the Emerging Industry

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THE VIRTUAL UTILITY:
Accounting, Technology & Competitive Aspects of the Emerging Industry

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To Erich and Lilly Awerbuch

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PREFACE

In the winter of 1996, after 4 years of planning and research, the *Symposium on the Virtual Utility* was held in Saratoga Springs, New York. It was sponsored by *Niagara Mohawk Power Corporation*, Co-sponsored by *CSC Index* and the *New York State Energy Research and Development Authority* and hosted by *Rensselaer Polytechnic Institute*, Troy, NY. The symposium sought to identify new areas of inquiry by presenting cutting-edge academic and practitioner research intended to further our understanding of the strategic, technologically-driven issues confronting the electricity production and distribution process. The program sought to offer new insights into rapid changes in the utility industry, in part, by examining analogues from manufacturing and telecommunications.

In addition to identifying new research areas, the symposium yielded a number of important findings and conclusions. This volume contains the presented papers of the meeting, the discussant reports and two special papers prepared by the meeting rapporteurs who performed superbly in analyzing, synthesizing, explaining and generally bringing a cohesive perspective to the interesting yet complex set of ideas presented at this unique meeting.

We would like to acknowledge the people and organizations that contributed to this effort. We thank *Niagara Mohawk Power Corporation* and Albert Budney, its President & Chief Operating Officer for sponsoring this project, and Andrew Vesey, Vice President,[1] whose vision, support and championing made this project possible. Mr. Vesey helped define the context for this effort and coined the term *Virtual Utility*. We thank our principal co-sponsors, *CSC Index* and *NYSERDA* and our other sponsors for their generous financial support. We also thank our advisory committee who assisted in programming and manuscript selection, and William A. Wallace of Rensselaer for hosting the Symposium.

[1] Mr. Vesey is now a Vice President of *Entergy Corporation*, New Orleans, Louisiana.

We are indebted to Jane Weissman, National Director of *Photovoltaics for Utilities* and Executive Director of the *Interstate Renewable Energy Council*, a long-standing colleague and friend, who contributed enormously to this project beginning with its inception in 1992. Finally, we thank Maryteresa Colello, Jennifer LaFrance and Paula Popson, all of whom attended to thousands of details and problems in order to make this volume possible.

Shimon Awerbuch
Alistair Preston

Part I

Introduction

EDITOR'S INTRODUCTION AND READER'S GUIDE TO THIS BOOK

Shimon Awerbuch
Energy Finance and Economics

INTRODUCTION

The Context: What Is the Virtual Utility?

The current transformation of the US electric utility industry is not dissimilar to the significant changes undergone by US manufacturers over the last two decades. During this period the industry has changed radically by abandoning previous mass-production protocols and adopting flexible, computer-integrated or *"just in time"* manufacturing.[1] A considerable body of literature has investigated this transformation. The virtual utility (VU) is a flexible collaboration of independent, market-driven entities that provide efficient energy service demanded by consumers without necessarily owning the corresponding assets. The VU becomes a metaphor for *lean, flexible* electricity production/delivery and flexible, customer-oriented energy service provision. The VU construct provides a context for examining the issues surrounding the current transformation of the industry in part by adapting and using important concepts developed in the "new manufacturing."

[1] Sometimes called "lean production," perhaps after the usage by Womack, et. al [1991].

S. Awerbuch et al. (eds.), *The Virtual Utility*

Background—Towards a Virtual Utility

New technologies, including solar/renewable resources and other modular options coupled with improved telecommunications capabilities suggest the possibility of fundamental changes in the electricity generation and delivery process. These changes, which reflect the declining minimum scale of production facilities, involve a transition away from traditional, vertically integrated central-station sources to more flexible operations consisting of distributed generation, conservation and power purchase/futures arrangements. Interestingly, these changes may be similar to those in manufacturing, where new information-based processes led to a shift away from mass production to more flexible, computer-integrated manufacturing often involving novel arrangements with other producers and suppliers.

The distributed-utility (DU) concept is a first step towards the broader *virtual utility* idea. The DU integrates solar and other technologies into a network of "smart-substations" that may more precisely meet demand for particular types of electric energy thus providing better flexibility and demand-supply balance than previous mass-production-based generation concepts which rely solely on large-capacity, inflexible, central station generators characterized by high transactions costs and irreversibility. While under ideal conditions the central-station system may be able to provide power at lower average cost, an increasingly dynamic energy market calls such perceived advantages of this system into question.

While the DU offers a more flexible supply concept, it is not sufficiently broad to properly characterize the emerging utility organization. The virtual utility (VU) idea, by contrast, seeks to shape an electric generation and delivery process that fully avails itself of the special attributes and complementarities of modular generating technologies thus representing a *re-engineering* effort in the sense of Hammer [1990] which seeks to design production around the new technology, as opposed to merging the technology into the existing processes. In order to reorganize around these new technologies utilities will need to develop new skills and capabilities. The re-engineered utility may be a supply and distribution network that involves many smaller, minimum-cost corporate entities. Some of its assets may be intangible, involving futures delivery and other contractual supply arrangements which, along with telecommunications support, combine to create a set of capabilities to meet specific customer energy needs. It remains to be determined whether control of such a diverse organization leads to more or less centralization as compared to current dispatch control procedures.

Evaluating the VU's Benefits

Our ability to understand and evaluate the benefits of the virtual utility is impeded by several factors including the use of accounting-based cost definitions such as avoided cost and busbar costs which tend to ignore many of the risks and cost-drivers of utility generation, especially in competitive markets. The benefits of newer renewable generating technologies, in particular, are not well understood. Potentially, these technologies present a set of marginal cost and risk-return opportunities considerably different from those traditionally experienced in electric utility regulation. In addition they present a variety of complementary benefits in the sense of Milgrom and Roberts, [1990] and, potentially, a set of capability options for service delivery in the sense of Baldwin and Clark [1991]. However, as is frequently the case with new technology, the full range of complementary benefits is precluded by existing organizational "threshold" structures [Baldwin and Clark, 1991] and production processes. This leads to the problem that current evaluation methodologies, which use accounting schemes based on traditional generating technologies, ignore some of the broader benefits of solar and other modular technologies when they are deployed in an organizational setting designed to fully exploit their benefits.

The current utility resource evaluation process relies on present-value revenue requirements ($/kWh). For a given capacity addition, those technologies that meet the load with the with the lowest projected cost per kWh are selected to the exclusion of others. Yet the largest single cost factor—generally fuel—is also the least predictable. The procedure is therefore roughly equivalent to buying stocks on the basis of which ones performed well yesterday. Moreover, the current capacity selection process ignores some of the most important cost drivers and transactions costs, such as the likelihood of supply-demand imbalance (i.e. excess capacity) attributable to a particular technology choice or the administrative costs of clean-air compliance.

Understanding the so-called "distributed-benefits" of modular generating technologies requires an evaluation of their particular attributes. Some of the attributes already identified and, to some extent, evaluated in the literature, include: modularity; investment flexibility and reversibility; reduced or avoided transmission and distribution needs, and, for renewables, an absence of fuel-price risk. Some of these benefits, especially those pertaining to avoided transmission and distribution costs, have been examined in the context of previous distributed utility analyses, including the Kerman Station Analysis [Wenger and Hoff, 1994]. Modularity/flexibility issues have also been studied in the context of the Kerman Station [Applied Decision Analysis, 1993] as well as more generally, [e.g.: Pindyck, 1991; Kaslow and Pindyck, 1994; Trigoris, 1993].

Limitations of Existing Accounting

The experience in flexible computer-integrated manufacturing, however, suggests that there exists another set of benefits which have not been examined. Some of these are difficult to evaluate given the traditional cost-accounting procedures used by utilities. These procedures do not properly capture and reflect overheads and transactions costs as a function of technology and/or customers. For example, solar-based generation may reduce fuel purchasing and inventory requirements and yield potential reductions in overhead and working capital. In addition, it may enable the utility to more readily provide new or specialized differentiated services to meet specialized customer needs.

It is nearly impossible to evaluate such issues without revised accounting systems, such as activity-based-costing (ABC) which i) map costs to various utility outputs, as opposed to current systems, which view the utility as producing only one generic output—kilowatt-hours, and ii) capture overhead and transactions costs as a function of various technology choices. For example, the planning and execution of large, central-station resources entails significant cost—mostly in the form of overheads. Decentralized sources are more incremental in nature thus simplifying the planning process. In order to understand this difference one need only examine the process by which local telephone companies upgrade and expand central office equipment; as compared to the planning of a large power plant, these are routine, low-level decisions made on an ongoing basis.

Purpose of This Book

Experience in manufacturing suggests that traditional engineering and accounting-based approaches to valuing radical innovations such as the VU are limited in that they fail to consider the full spectrum of benefits that new technologies may yield when fully exploited in a new production process. The purpose of this symposium is to identify new areas of research by presenting new academic and practitioner research intended to further our understanding of the strategic, technologically-driven issues confronting the electricity production/distribution process. This volume seeks to address a number of specific questions including:

1. What models or experience from other industries (such as manufacturing) help us predict or better understand the nature and the ultimate benefits of flexible, decentralized generation under the virtual utility concept?

   In the case of manufacturing, new value concepts were created in order to analytically understand some of the benefits of flexible, computer-integrated process technology including: i) the value of flexibility, ii) the cost quality, iii) the importance of throughput and iv) the value of strategic options. Similar concepts may be needed to value the VU.

2. What are the information and telecommunications requirements of the virtual utility? Does the VU increase or decrease the amount of central control and information processing needed?

3. What organizational changes are needed to accommodate and fully exploit new technology under the VU concepts? What capabilities must be developed? Does the virtual utility have the potential of linking minimum-cost production facilities in an efficient manner?

   Experience suggests that new technology cannot be fully exploited absent significant organizational restructuring. For example: the early 1960's office could not fully exploit word processing, which was originally installed in the office 'typing pool' and perceived simply as a better typewriter.[2] It took

[2] For an example involving the steel industry's conversion to the Bessemer process in the early 1800's see: Kim Clark [1987].

nearly two decades to learn how to fully exploit word-processing technology. This involved significant value changes within the office.

4. What performance and other characteristics strategically differentiate flexible generation? What does the set of performance measures look like?

   Photovoltaics and other modular technologies are conceived of and valued as simple substitutes for conventional, fossil-fired generation, much as the word-processor was conceived and initially used only as a typewriter-substitute. The early 1960's office relied on intermediation—secretaries and stenographers. In this environment it was not easy to imagine executives and professionals "keyboarding" themselves and sending messages directly through E-mail. Indeed the formality of business communication of the era would have made the notion of E-mail—which affords direct informal access to virtually anyone—almost unimaginable.

   In similar fashion, current efforts at valuing flexible generation and other new electricity production concepts conceive and value these in engineering terms, as substitutes for existing generation and distribution systems. This fails to incorporate new capabilities and strategic options that may be afforded by the VU.

5. Do existing accounting measurement systems favor traditional, central station technology over renewables?

   Traditional cost-accounting systems, with their focus on direct costs, failed to identify some of the important benefits of new manufacturing process technologies such as computer-aided-design and computer-integrated-manufacturing. It may therefore be reasonable to presume that utility accounting systems, which were largely designed to insure careful accounting of rate-base additions versus recoverable expenses [see: Awerbuch, Preston and Carayannis in this volume], are inadequate for understanding the ultimate benefits of the VU and its potential for reducing excess capacity, and reserve requirements.

6. Can the VU enhance the information-content of electricity thus producing fewer, "smarter" higher-value kilowatt-hours?

   Peter Drucker argues that global competitiveness in manufacturing has reduced labor and material content while raising the information content of manufactured products which creates greater value for consumers. Is there an analog for the VU?

7. What new capabilities and strategic options, if any, does flexible generation provide especially towards the provision of enhanced or differentiated services?

8. What does the set of distributed benefits look like and how do we value these?

A READER'S GUIDE TO THE PAPERS IN THIS VOLUME

Part II: Historic and Strategic Perspective: From Monopoly Service to Virtual Utility

1. Consensus, Confrontation and Control in the American Electric Utility System

Richard Hirsh sets the historic perspective for the works presented in this volume. His paper explains why the monolithic utility industry of the past can no longer function and why a highly diverse industry with distributed control makes sense. **Hirsh** shows that, beginning with Edison and Insull, utility executives were able to manage and control new technologies, successfully incorporating them into the electric production/delivery system. The industry's growth, he finds, has always been tied to control over technology. Beginning in the late 1960's, however, utilities began to lose control of new technologies so that for the first time new technology became a threat to the industry: technology made it possible for new suppliers to provide energy at lower costs than the traditional utilities. This sets the stage for a diverse industry with many participants and stakeholders including independent power producers and environmental activists.

2. The Virtual Utility: Strategic and Managerial Perspectives

The transformation in the utility industry is not dissimilar to changes in other industries as firms move from mass-production to the information age. **Andy Vesey** argues that traditional utilities (and manufacturers) were *mechanical-view* organizations that efficiently operated *mechanical conversion* processes which transformed raw materials into finished products using energy and labor. This fundamental process, which was the basis of the mechanical-age firm, is supported by deeply rooted organizational, accounting and management ideas.[3]

The virtual utility, or indeed any other information-age firm, will be challenged by rapid changes in markets and technology. In this environment information gathering and processing become highly important capabilities and, argues **Vesey,** firms that can best process and synthesize new information to develop market opportunities will be the "winners."[4] This information environment requires new *cognitive-view* organizational structures which can capitalize on emerging information and

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[3] Awerbuch, Preston and Carayannis similarly argue that deeply rooted accounting ideas stem from the previous technological era and do not serve current-vintage technologies well.

[4] This is analogous to Brian Arthur's recent conclusions; [see: "The New Rules of the Road," , *U.S. News and World Report* July 8, 1996, page 47].

market opportunities. Here success is not measured in terms of traditional engineering input-output efficiency, but in terms of the speed and quality of decision-making.

3. Being Virtual: Beyond Utility Restructuring and How We Get There

A number of rapidly converging trends, including growing global electricity demand, deregulation, dematerialization, the information explosion, environmentalism, population growth and technological innovation are shaping the utility industry's future. **Karl Rabago** explores the "convergence zone" of these major trends and finds that "virtualness" is indeed consistent with more innovative, customer focused service which delivers less energy with more information content. Rabago outlines the regulatory agenda for "getting there," which includes: i) proper cost allocation for stranded investment,[5] ii) restructuring regulatory institutions, iii) addressing the public-goods aspects of the utility system, iv) instituting industry structures that ensure technological progress, and v) addressing market imperfections.

Part III. The Virtual Utility: Planning And Strategic Investment Analysis[6]

This chapter examines the investment valuation procedures used by utilities in light of the recent changes in manufacturing where the industry has moved towards flexible, information based process technology. American manufacturers, however, were late in adopting new technologies, in part because traditional project valuation analyses generally found that these were not cost effective—a result that, with hindsight, was incorrect. The manufacturing experience therefore offers important lessons regarding the valuation of radically new technological and organizational options in electricity production and delivery.

Awerbuch, Preston and Carayannis (APC) observe that traditional project valuation (capital budgeting) tools proved to be relatively useless in helping manufacturers understand the true benefits of new production technologies and processes, in large measure because the valuation tools focus on direct cost savings in labor and materials. While this cash-flow approach worked reasonably well for the previous half century, new passive, information-based production technologies often do not provide direct cost savings and hence do not lend themselves to this type of valuation. Rather, their benefits are in the form of reduced overheads and better quality. In addition, such technologies usually enhance flexibility by enabling rapid

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[5] Ilic, et. al. [in this volume] offer alternative prescriptions regarding stranded costs.

[6] **Shimon Awerbuch, Alistair Preston,** and **Elias Carayannis** "The Virtual Utility: Some Introductory Thoughts on Accounting, Technological Learning and the Valuation of Radical Innovation;" **Raj Aggarwal**, "Justifying Investments in New Manufacturing Technology: Implications and Lessons for Utilities;" **Richard Bower**, "Discussion."

response to fast changing market conditions and customer preferences. Finally, the new technologies often produce strategic capability options which allow firms to invest in subsequent technologies at a lower cost, or to develop capabilities to serve new market and customers not previously envisioned.

Raj Aggarwal explicitly incorporates such strategic option values in an enhanced technology valuation model and provides a highly readable and useful review of theoretical issues affecting the valuation of new technology. His paper thus gives us an analytic framework for valuing non-traditional benefits. **APC**, by contrast, argue that such benefits are nearly impossible to measure because traditional cost accounting does not recognize or record the cost (or activity centers) dealing with outputs such as "added capability," "flexibility" or "quality." Indeed new computer based manufacturing technologies were fully understood only after accounting and other concepts were created to explicitly express these benefits. Drawing on these lessons **APC** and **Aggarwal** both suggest qualitative approaches and further research to better understand such benefits.

Part IV. Risk Management, Options and Contracting for a Virtual Utility[7]

6. Integrating Financial and Physical Contracting in Electric Power Markets

Chitru Fenrnando and Paul Kleindorfer explore a novel aspect of this issue: can new electric options and futures help short and long run decision-making in an open-access transmission grid. The VU idea requires that large numbers of power producers be able to access transmission and possibly distribution networks, and that an *independent system operator* (ISO) will be responsible for ensuring that the network functions properly. Concurrently, increasing availability of financial options and futures in electricity markets creates new possibilities for managing both short and long term power needs on the grid. **Fernando** and **Kleindorfer** demonstrate that currently conceived structures which charge the ISO with short and long-run responsibilities, have poorly thought-out incentive structures for extending or enhancing the network. As a result the contemplated market structure will lead to better management or use of existing assets rather than to decisions to improve the network.[8]

7. Capacity Prices in a Competitive Power Market

Frank Graves and **James Read Jr.** tackle the value of capacity and demonstrate that energy and capacity, which have long been held to be two distinct concepts, are

[7] **Chitru Fernando** and **Paul Kleindorfer,** "Integrating Financial and Physical Contracting in Electric Power Markets;" **Frank Graves and James Read, Jr.**, "Capacity Prices in a Competitive Power Market;" **Thomas Hoff** and **Christy Herig**, "Managing Risk Using Renewable Energy Technologies," **Mark Reeder**, " Discussion."

[8] As a case in point: nobody wants to build transmission in Argentina because they haven't figured out how to pay for it in a competitive market; *Wall Street Journal,* June 19, 1996.

indistinguishable with the availability of well functioning electricity futures and options markets. **Graves** and **Read** find that the traditional distinction can no longer be sustained since in the new environment a contract for future delivery of power incorporates both a commitment for energy as well as capacity. Their findings are based on an options valuation approach: they argue that a competitive market implies that capacity must be a derivative asset which provides an *option* for generating/delivering electricity in the future. It's value, therefore, is a function of the value of the electricity it will produce over its remaining life. The paper, which is accessible to those not familiar with options theory, develops illustrative capacity values under a variety of assumed energy futures. Capacity values are shown to vary with energy price volatility and asset remaining life.

8. Managing Risk Using Renewable Energy Technologies

Tom Hoff and **Christy Herig** deal with risk, although in a broad sense their paper deals with the issue of whether there is a role for renewables in a competitive, bottom-line driven world. The paper contributes to the recent literature which argues that renewable technologies posses financial risk characteristic that can enhance a portfolio of generating assets. One approach to risk management therefore, might be to identify various arbitrary (unsystematic) risk factors and deploy technologies that cost-effectively manage such particular risks. Hoff and Herig examine a number of renewable technologies and develop analytic approaches to estimate their potential value in mitigating diversifiable risk.

Part V. Industrial Organization, Technological Change and Strategic Response to Deregulation[9]

9. Monopoly and Antitrust Policies in Network-based Markets such as Electricity

A number of states are pursuing deregulation strategies. **William G. Shepherd** uses an industrial organization perspective to assess how quickly regulators should deregulate. His engaging paper offers powerful, yet surprisingly simple and direct policy recommendations. **Shepherd** finds that deregulating too early will simply create an entrenched, dominant single firm: the former regulated utility. Ironically, therefore, aggressive deregulation which fails to incorporate industrial organization issues can significantly *undermine* progress towards competition.[10] Several regulatory issues are embedded in this paper: i) We don't want deregulation that allows incumbents to entrench themselves; ii) Regulators must make sure there are enough

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[9] **William G. Shepherd**, "Monopoly and Antitrust Policies in Network-based Markets Such as Electricity," **Shmuel Oren & Dennis Ray**, "Services in an Unbundled and Open Electric Services Marketplace"; **Bridger Mitchell & Peter Spinney**, "Technological Change and the Electric Power Industry: Insights from Telecommunications"; **Jan Hamrin**, Discussion.

[10] This is the clear lesson that ensues from the recent debacle surrounding Canadian tele-communications deregulation: a number of the most prominent competitors went bankrupt within a year.

players in the generating game and must not allow existing distribution companies to become, by default, the dominant VU's. iii) Regulators must assure that the committees that control ISO's do not make decisions in order to simply preserve the value of assets owned by the majority of the committee members. For example, certain members would benefit if their ISO does not make transmission investments which might bring additional generation into the market.

10. Services in an Unbundled and Open Electric Services Marketplace

A flexible VU-based industry structure most likely requires that services be unbundled so they can be efficiently rebundled for sale based on consumer needs and preferences. The idea is to give consumers choice and to let them decide when and how much bundling they want. This raises several important policy issues about efficient unbundling/bundling policies. **Shmuel Oren** and **Dennis Ray** present a very accessible and interesting analysis of the economics of unbundling. They illustrate the welfare implications and show when bundled goods and services make economic sense for customers with different preferences. Their paper analyzes the circumstances under which monopolists might want to bundle goods into a single product. The approach developed by **Oren and Ray** can be directly used by public policy makers to test the types of unbundling and rebundling that should be required or encouraged under industry restructuring.

11. Technological Change and Industry Structure: Insights from Telecommunications

Telecommunications deregulation presents an obvious case study for electric utility restructuring. **Bridger Mitchell** and **Peter Spinney** present an excellent industrial organization-based analysis that explores the differences and similarities of the two industries. **Mitchell** and **Spinney** define a number of distinguishing characteristics between the two industries including: product diversity, rates of technological change, geographic barriers to service delivery, entry costs, capital intensity and externalities in order to determine what lessons from telecommunications are applicable. Generally their findings indicate that: i) technological change affects industry structure; ii) customers accept unbundling/rebundling; iii) Disaggregated or broken-up firms approach the world differently and see markets in new ways which gives rise to new services; iv) cross subsidies ultimately get squeezed out, and v) with technological change certain products and technologies can simultaneously be both substitutes and complements to existing products and technologies,

Part VI. Network Architecture and Standardization[11]

12. Interconnected System Operations and Expansion Planning in a Changing Industry: Coordination vs. Competition

Much attention is currently focused on stranded costs, which are estimated in the range of $135 billion and more. These estimates are all static and accounting based, i.e.: they are the result of comparing current book values to market values based on continued use of assets as they are now being used. **Marija Ilic, Leonard Hyman, Eric Allen, Roberto Cordero and Chien-Ning Yu** (IHACY) show that restructuring and competition may drastically alter electric rates and the way in which generating assets are used. For example, transmission constraints to certain regions (which Mark Reeder calls *load-pockets*) creates a special need for local generation. The transmission is lacking in such regions because it is too expensive to site and erect, a situation, **IHACY** find, that significantly enhances the value of older inefficient assets with higher operating costs. While these assets do not generate at the lowest cost consistent with the marginal-cost principles of economic dispatch, they are extremely valuable in that they can serve as the low-cost method for voltage support and other system enhancements. Extending the results, it may be possible to argue that market-based solutions might be used to substantially mitigate the stranded cost problem.

IHACY raise some interesting and important questions regarding the effectiveness of reasonable pricing systems in providing appropriate incentives for support services. The paper forces us to wonder whether it is always possible to rely exclusively on market forces to keep the network running during highly congested periods. The network pricing literature suggests mechanisms for dealing with congestion, etc. These are similar to traditional congestion pricing such as setting tolls on a bridge to minimize peak-hour delays. There are some crucial differences however. A properly designed bridge toll will minimize congestion most of the time. Occasionally traffic will be higher than expected, but the result is not catastrophic: there is congestion, drivers have to wait in line, but the bridge does not collapse. By contrast, **IHACY** find that relying on such pricing mechanisms to operate the power network is risky: when loads exceed expectations the results may be catastrophic system failure—the bridge may indeed collapse.

13. Rules of the Road and Electric Traffic Controllers: Making a Virtual Utility Feasible

The VU concept presumes interaction among multiple suppliers and customers all of whom need access to the transmission grid. This raises numerous grid or net-

[11] **Marija Ilic et. al.,** Interconnected System Operations and Expansion Planning in a Changing Industry: Coordination vs. Competition; **Fernando Alvarado** Rules of the Road and Electric Traffic Controllers: Making a Virtual Utility Feasible; **Hyde Merrill, Ramon Nadira, and Steven Balser,** Discussion.

work-related security and other concerns. **Fernando Alvarado** focuses on the idea that the VU is always dependent on the transmission network. His paper gives us an excellent set of insights into the problems that will be incurred in making the system accessible to a large number of suppliers. These concerns range from continuously maintaining system voltage balance under dynamic conditions to avoiding overloads which can quickly cause the system to become unstable and possibly collapse. Alvarado's paper gives us the basic systems engineering concepts and develops specific ISO responsibilities in response to particular system interactions for three specific operational time frames: instantaneous, intermediate (short) and long time frame. He also shows us how to formally measure and quantify various interactions among virtual utilities and customers; each of these interactions affects system losses and other conditions and thereby has an effect on all users. The open-access grid that underlies the VU idea therefore requires solutions to a number of technical and economic problems such as appropriate pricing to properly signal congestion and other grid costs. Nonetheless, some congestion, somewhere along the grid, will be an ongoing state of affairs. This means that the electricity market will not be homogeneous, but rather, will always have individual sub-market areas at any given time. This underscores the need for flexible distributed capabilities.

Part VII. From Monopoly Service to Virtual Utility

14. The Future Structure of the North American Utility Industry

Michael Weiner, Nitin Nohria, Amanda Hickman and Huard Smith (WNHS) provide us with an expert look into a future in which the traditional electricity value chain will be divided among different firms and "value networks." The paper yields a very useful definition of "virtualness." In **WNHS**'s world, energy firms will have to decide on strategies, i.e.: on what sort of business they want to be. They will have to think in terms of value disciplines and concentrate on what they do best in order to define where they fit in the divided value chain..

Part VII: Perspectives[12]

The reports of the symposium rapporteurs, Carl Weinberg and Leonard Hyman, raise a number of important points:

1. Competition will lead to new products via virtual utilities; new generation of customers, familiar with information technologies, will have few problems making energy choices that today seem too complex.

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[12] **Leonard Hyman** *The Bottom Line: A Summary and Analysis of the Virtual Utility Conference;* **Carl Weinberg** *The Virtual Utility and Environmental Stewardship.*

2. Renewable technologies do not stand a chance without VU's.

3. The price of energy will decline.

4. The right solution to the stranded cost problem emerges with the proper pricing of all services.

5. Regulated pricing will distort transmission issues.

Nashua, NH, June, 1996.

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Part II

Historic and Strategic Perspective: From Monopoly Service to Virtual Utility

1

CONSENSUS, CONFRONTATION AND CONTROL IN THE AMERICAN ELECTRIC UTILITY SYSTEM:

AN INTERPRETATIVE FRAMEWORK FOR THE VIRTUAL UTILITY CONFERENCE

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ABSTRACT

The turmoil in today's electric utility system can be understood by examining the changing nature of political and economic power held by various parties. Early in the 20th century, Progressive-era politicians and power company managers came to a consensus that established the structure of the monopoly market and the vertically-integrated industry. With other stakeholders supporting the broad terms of the consensus, utility managers obtained effective control of the system, including domination over supposedly independent regulatory commissions. But the stresses of technological stasis, the 1970s energy crisis, and rise of environmentalism challenged this control. By the early 1990s, regulators, legislators, independent power producers, free-market advocates, and environmental organizations gained status as political "elites" who questioned whether the utility consensus still made sense. As

S. Awerbuch et al. (eds.), *The Virtual Utility*

the newly empowered participants in the utility system jockey for influence, a new consensus appears unlikely.

INTRODUCTION

Today's electric utility system is in turmoil. Once-monopolistic power companies compete against other regulated power utilities and unregulated independent power producers for sales to large customers. At the same time, energy services firms and other companies offer "negawatts" instead of kilowatts and reduce potential sales from all power suppliers. To deal with competitive pressures, some utility companies have begun merging with others, while other firms seek to buy parts of deregulated power companies in foreign countries. Meanwhile, imaginative thinkers suggest transforming existing power firms into entities that create alliances with various companies and broker supplies and services from a host of competitive providers. This last approach constitutes the model for the "virtual utility," the subject of this conference.

Of course, the utility system has not always seen such flux.[1] In fact, until the early 1970s, power company managers and their customers enjoyed a happy consensus concerning the industry and market structures of the utility system.[2] The consensus gave centralized and vertically-integrated, investor-owned utility companies the right to sell power in a non-competitive market—the complete antithesis of the virtual utility model—while requiring them to pass along the benefits of monopoly in the form of low-cost electricity and good service. Customers, on the other hand, accepted the legitimacy of utilities' unusual market status and agreed to pay rates high enough to sustain their financial viability. State legislatures, meanwhile, established regulatory commissions to ensure that utility companies and customers enjoyed the proper exercise of their rights and fulfilled their obligations to each other. For decades, the arrangement appeared to work wonderfully.

This paper provides a broad interpretive framework for the virtual utility conference. It will explain how concepts such as the virtual utility could emerge in a util-

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[1] The notion of a the electric utility *system* stems from discussions of technological systems by Thomas P. Hughes. He argues that a system consists of a "seamless web" of elements that a casual observer might label economic, educational, legal, administrative and technical. System builders strive to maintain their creation by "construct[ing] or ...forc[ing] unity from diversity, centralization in the face of pluralism, and coherence from chaos." (Hughes 1987, 52). See also Hughes (1983). The electric utility system, therefore, consists of more than the utility industry. It includes the entire spectrum of stakeholders and interests involved in the production and use of electricity.

[2] In this paper, market structure refers to a business' relationship between buyer and seller. Under the utility consensus, a single firm provided electricity to numerous buyers within a geographical region. Industry structure refers to the number and type of entities producing and selling electricity. Though the utility industry in the United States consists of federal, state, and municipal producers and sellers of electricity, along with federally-assisted cooperatives, it is still dominated by large, vertically-integrated firms owned by investors. This paper primarily deals with this last category.

ity system that was once characterized by consensus and later by confrontation. In the first sections, the paper will describe the origin of the utility consensus as the result of negotiations between "elite" representatives of interest groups and politicians. It will further detail the means by which power company executives quickly became the controlling parties within the utility system. Next, the paper will detail how events external to the system, such as the energy crisis and passage of the Public Utility Regulatory Policies Act of 1978, combined with the emergence of technological stasis and technological novelties to dethrone utility mangers and set the stage for confrontation among a new set of elites. The paper concludes by noting that confrontation still characterizes the system today, with old and new participants seeking to gain control as they debate the new industry and market structures of the utility system. The erosion of the former consensus and lack of a replacement creates an environment in which the virtual utility and other novel concepts can gain (and lose) currency.

THE UTILITY CONSENSUS AND THE ENVIRONMENT IN WHICH IT EMERGED

The consensus that established the unusual market structure of the electric utility system emerged during a period of economic and political change at the beginning of the 20th century. Losing influence since the conclusion of the Civil War, Adam Smith's decentralized market system, in which prices established through competition brought the efficient allocation of resources, gave way to a flourishing corporate-based economy. Large multi-level companies exploited the power of new communications and transportation technologies to manage production and distribution of quantity-produced goods, thus dominating the formerly prevalent family-owned and operated businesses. To deal with overproduction and ruinous price competition, managers of companies merged with former rivals or created trust agreements with them. By 1904, only one percent of companies in the United States controlled nearly half the production of manufactured goods (Eisner 1995, 99). Railroad companies took advantage of similar techniques to enlarge their control over the market. Though literally the economic "engine" of the post-Civil War economy, the railroad industry became despised by much of the public. The companies frequently consolidated with erstwhile enemies, discriminated in their pricing among customers, provided often-poor and unsafe service, and cultivated political favoritism and corruption.

When first established, electric utility companies did not seem to be in the same class as the hated interstate railway conglomerates or their local cousins, the urban streetcar companies. After all, when Thomas Edison established his Pearl Street, New York City power station in 1882, he used direct current at about 110 volts to illuminate lights within a radius of about one mile from generators. Distribution of electricity beyond that radius incurred huge power losses, which suggested an industry structure characterized by a host of small stations scattered about cities competing for customers (some of whom generated power themselves) within restricted circles of service.

But technological innovation changed the relatively benign character of the electricity supply business. Overcoming the distance limit imposed by direct current, alternating current equipment produced by the Thomson-Houston and Westinghouse companies distributed electricity at high voltage through the use of newly available transformers in the late 1880s and allowed firms to build large, centralized plants that produced power for expansive networks. The growing use of compact steam turbines as prime movers, replacing bulky and noisy reciprocating steam engines, further encouraged centralization as the new machines offered tremendous economies of scale. In other words, as the turbines produced larger capacities of power, the unit cost of electricity declined over a wide range of output. Serving as a model for other electrical entrepreneurs, Samuel Insull, the British-born secretary to Edison, embraced steam turbines and alternating current for his small Chicago Edison Company. When he took over the firm in 1892, Chicago sported 20 competitive electric supply companies. By 1907, Insull employed the new technology to consolidate all of them into the renamed "Commonwealth Edison Company" (Insull 1915, 54).

During the "Progressive era" in American politics, a period lasting from about 1896 to the beginning of World War I, the notion of unrestrained and powerful monopoly was attacked on several fronts. Federal law makers and state legislators dealt with railroads and huge companies—the primary objects of popular scorn—by passing anti-trust laws. Congress also passed new laws in the early 1900s to bolster the ineffective Interstate Commerce Commission, created in 1887 to end (in theory) abusive behavior of large railroad companies. At the same time, state leaders dissatisfied with the status quo instituted a series of reforms that irrevocably altered the political system. They passed laws for direct election and recall of political candidates (and amended the Constitution to allow direct election of U.S. Senators); they introduced the referendum; and they created regulatory bodies that would control, for the public good, the operation of companies providing essential services.

To deal with the monopolies that came to call themselves "public utilities," such as urban streetcar companies and electric supply firms, two models of action dominated. One consisted of city ownership and operation of the firms, while the other allowed the companies to remain in private hands with some form of government regulation. Debate over the different models became a policy issue because utility companies appeared unable to operate within the traditional competitive market environment. These firms required construction of capital-intensive facilities that limited the number of rivals to just a few who could secure financing, while competition among the firms had already led to efforts to bribe officials for franchise rights. To avoid destructive competition that would erode profits by competing firms, moreover, the utilities made efforts to consolidate, gain economies of scale to reduce costs, and increase profits. At the same time, academic political economists had been developing the notion throughout the late-19th century that these public service businesses constituted (rightly or wrongly) "natural monopolies"—i.e., that they that could provide services most efficiently and at the lowest cost only if they remained free from competition. Municipal ownership seemed to be an obvious solution for obtaining the benefits of monopolization without suffering the abuses of a privately-owned monopoly. Indeed, many cities had already established municipal water and gas systems. By 1907, cities already owned more than 1,000 electric networks ("Municipal Electric Systems" 1949, 15–16).

While government ownership of electric utilities had its advocates, it also had its detractors. Critics argued that city-run utilities would remain subject to the same corrupt political machines that the reformers hoped to eliminate, while others feared municipal ownership constituted a step toward socialism and the end to free enterprise. Perhaps the greatest exponents of private ownership were the executives of utility companies themselves. Clearly, their interests lay in maintaining autonomy in operating the power companies, though they also realized that public opinion and politicians viewed monopoly as evil. Consequently, some of the more politically adept "elite" utility leaders understood that they would need to form a consensus between them and powerful progressive politicians on the state level so they could avoid municipalization. Creation of consensus among elite groups of politicians and representatives of resource-rich special interest groups was becoming more commonplace during the Progressive era, despite the opposite (and popular) view of power being disseminated to the public at large.[3] The agreement the utility and political elites had in mind would share with their customers the benefits of monopolization (such as lower-cost power arrived at through use of large-scale equipment) in return for legal sanction as non-competitive companies.

To ensure that the terms of the deal would be fulfilled, some executives advocated regulation by state-created commissions. The greatest expounder of such an arrangement was Samuel Insull, who as early as 1898 argued that government oversight through regulatory commissions would confer legitimacy to a utility as a monopoly and would end (or at least reduce the number of) calls for municipal takeovers (Insull 1915, 34–47). Moreover, Insull observed that regulation would allow utilities to reduce their cost of financing. "Acute competition necessarily frightens the investor," he warned, "and compels corporations to pay a very high price for capital. The competing companies invariably come together, and the interest cost on their product (which is by far the most important part of their cost) is rendered abnormally high, owing partly to duplication of investment and partly to the high price paid for money borrowed during the period of competition." The answer, he suggested, was monopoly control and franchises. "In order to protect the public," Insull noted, "exclusive franchises should be coupled with the conditions of public control, requiring all charges for services fixed by public bodies to be based on cost plus a reasonable profit (Insull 1915, 44–5; McDonald 1964, 114.)." Over the next few years, Insull pressed his views forcefully, and by 1907, the bulk of utility managers viewed regulation by expertly-trained men as the means by which the companies could achieve legal monopoly status and avoid the threat of municipal expropriation.

[3] For the purposes of this paper, power can be defined as the employment of resources by individuals and groups to harness the agency of others to comply with one's own ends. Such a definition is based upon the work of Anthony Giddens (Giddens 1979, 262).

Several Progressive politicians also saw regulation as the means by which a satisfactory arrangement could be devised to deal with utility companies. Leery of the municipal corruption he had seen early in his political career, Wisconsin governor Robert La Follette preferred state regulation of public services over city ownership. As a first step, he pushed through his state's legislature a bill in 1905 to create the Wisconsin Railroad Commission, which had jurisdiction over rates, schedules, service, construction, and maintenance of the state's railroad companies (Commons 1905, 76–9; Maxwell 1956, 75–7). Though he had become a U.S. Senator at the end of 1906, La Follette in 1907 still had influence with the state legislature, which extended regulation to electric utility companies in July 1907 (Commons 1907, 221). Meanwhile, another Progressive politician, Charles Evan Hughes, came to the public's attention because of his investigation of pricing abuses of gas and electric companies in New York City in 1905. Elected governor in 1906, Hughes pushed through legislation, signed in June 1907, creating a strong regulatory body for railway and utility companies (Wesser 1967, 154–69).[4] Support for regulation came from other elite groups, such as the National Civic Federation, a reform-minded organization whose membership included of a diverse set of corporate heads, labor leaders, lawyers, advocates of public ownership of utilities, and university professors. Soon after Wisconsin and New York created regulatory commissions, other states followed. By 1914, 45 states had established some form of apparatus for regulation utility companies (though not always regulating electric power companies) (Sharfman 1914, 3–5). The regulatory model appeared to have won the day.

BROADENING SUPPORT FOR THE CONSENSUS AND UTILITY MANAGER CONTROL

Though originally a consensus that established the relationship between utility companies and their customers, other groups of stakeholders broadened the base of support for the agreement as the market structure benefited them as well. Investment bankers, for example, became party to the consensus as they profited from funneling money into the highly capital-intensive industry. They also helped create holding companies, which offered operating firms access to both financial resources and professional management expertise. Other stakeholders included manufacturers of electrical equipment, along with their research and development laboratories, which stood to gain as utility companies expanded and required more advanced technologies. General Electric Company and Westinghouse, for example, became early suppliers to the growing industry as well as manufacturers of appliances and other end-use equipment. As the utility networks expanded and as customers consumed more power, their businesses flourished. And to train utility executives and

[4] The New York law actually called for creation of two commissions, one for New York City and another for the rest of the state. In 1921, the two commissions were combined into one ("New York Goes Back to Single Commission" 1921, 952).

middle-managers, universities such as MIT and Cornell "enrolled" in the consensus as demand for trained electrical engineers exploded. Utility customers in the cities, meanwhile, appeared happy, as the benefits of electrification gave people greater choice (in terms of living conditions and entertainment, for example) and as a culture of electricity emerged that equated lower cost power with material and social progress (Hirsh 1989, 26–35). In other words, a variety of other social groups implicitly supported the terms of the utility consensus. While not participating in creation of the consensus, they saw that their interests could also be served well through operation of a system that the agreement helped establish.

As support for the consensus broadened, utility managers quickly took effective control. They did so partly because of the absence of leadership demonstrated by other participants involved in the consensus' creation. The elite politicians and civic reform groups of the early 20th century, for example, simply became indifferent to utility affairs after the initial fervor of Progressive reform had ended. With their careers and millions of investment dollars at stake, on the other hand, utility managers maintained interest. Moreover, as outside attention flagged, they used extensive public relations propaganda campaigns after World War I to maintain the image that they served their customers' to the best of their abilities.[5] Under the guise of "education," Samuel Insull and a host of other utility executives distributed information, hired college professors as consultants, and endowed faculty fellowships so the educators would spread the good word about utilities and so they could influence the "coming generations of bankers, lawyers, journalists, legislators, public officials, and the plain, ordinary 'men in the streets.' (Parker 1923, 29)"[6] The committees also campaigned against public school textbooks that represented the utility industry in a bad light, and they directed propaganda to authors and publishers. They published literature for use in elementary schools and addressed women's groups. As another means to encourage positive feelings toward utilities, they successfully campaigned to sell utility stock to customers (Gruening 1964).

The growing power of utility managers quickly eclipsed the control exerted by regulators. Fulfilling multiple functions as quasi-legislators, administrators, and judges, state commissioners had a sworn duty to enforce the agreement that supposedly benefited customers and utility companies alike. But beyond this official reason to be supporters of the consensus, regulators generally wanted to retain (and strengthen, if possible) a bureaucratic system that gave them control over elements

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[5] As the cost of electricity declined and as its availability increased, the customer base eventually became the general public. When the utility industry began in the 1880s, the high cost of power limited its use to factory owners, who saw productivity increase through the use of electrified machinery, and business, hotel, and movie house owners as well as street-car operators, who needed electricity to attract and retain customers. These customers of electricity viewed the commodity largely as a producer good—a raw material necessary for the production of a good or service. As prices declined and as utility companies promoted power usage for homes, electricity became a consumer good, being used by a larger segment of the population to offer convenience and comfort-giving services. Once electricity made its way to rural America in the 1930s, the customer base had been extended pretty much to all the members of the public.

[6] The payments made to professors were defended in an *Electrical World* editorial ("Those Naughty Professors" 1929, 1271).

of society. Besides seeking financial resources from state legislatures to perform their duties, regulators hoped to augment their place in society by winning the good graces of the press and public.

But by the 1920s, regulators had already begun to lose the element of prestige and control they enjoyed during the formative years of regulation. For one thing, the enthusiasm for reform movements had faded as the Progressive era before World War I turned into the "Roaring Twenties" of the post-war decade. The thriving business activity of the period appeared to please state legislators, who balked at expanding the authority of regulatory commissions. Urban customers also seemed happy as rates declined while their incomes rose (Troxel 1947, 72).[7] At the same time, state regulators did not perceive the public relations and holding company abuses of utility firms and the need for augmented powers. "The decade [of the 1930s] was nearly finished" observed Emory Troxel in his 1947 book on public utility economics, "before both the legislatures and commissions seemed cognizant of holding-company practices, irresponsible issuance of many securities, careless accounting practices, and excessive earnings of many companies (Troxel 1947, 72)." And even if they had been aware of utility problems, state regulatory commissions would have been hard pressed to do much about them given their absence of authority over the interstate activities of holding companies.[8]

The lack of prestige and support for regulators contributed to the loss of whatever real control they exerted within the utility system. But utility company managers could not afford to watch regulation be weakened to the point that it was perceived as being totally ineffective. After all, the existence of commissions legitimated in the public's eye the industry's special market structure and the standing held by utilities as natural monopolies. Hence, the utility industry and its allies deliberately gave regulators excessive credit in their advertising campaigns for the work commissions performed in providing cheap and reliable electrical service to customers. When contesting the legislation leading to passage of the Public Utility Holding Company Act of 1935, for example, utility leaders warned that new federal oversight would destroy state regulation and all the advantages, such as low-cost power, that it had already made possible ("Utilities by the Fireside" 1935, 1177; "State Regulation has a Future" 1935, 2670). Even if regulatory control were largely a fiction, then, it was a fiction needed by utility companies to ensure that legislators would not return to the policy-making arena and upset the system that clearly benefited the power companies.

Utility managers consolidated their control over the utility system by "capturing" the state regulatory commissions. According to one school of thought, regulators became captured by the interests they supposedly oversaw because of their need to gain political support after the fervor of public outrage subsided. Regulators struck

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[7] Electric power had not generally reached rural areas, a fact that helped spur the Rural Electrification Administration's creation as part of President Roosevelt's New Deal programs.

[8] After the holding company abuses became well known, some state legislatures gave commissions greater power to require disclosure of operating companies' affiliations with holding companies and to improve regulation of the operating companies' securities (Marlett and Traylor 1935, 177–86).

an implicit bargain with industry because the legislators and executives who once excitedly worked for regulation became impassive after their success in creating commissions, leaving the industry as the only source of political power. By giving the utility industry favorable treatment for construction plans, rate-base valuations, and rate reduction requests, which served as a form of competition against other fuels, regulators by the 1920s had already been co-opted, captured, and controlled by utility managers. Regulators still performed an important function in the utility system, however. Because of their supposed oversight of utility actions, they helped legitimate the industry's market structure—i.e., the special standing held by utilities as natural monopolies.

Finally, utility managers retained control and their dominant position by encouraging "conservative" inventions, i.e., creation of new technology that preserves the existing system. As described by Hughes, the electric utility industry made good use of academics and professional inventors in its early years, from 1870 to about 1920, to help create a technological superstructure that remained essentially intact for another 50 years. As perhaps their greatest achievement, these system builders developed steam turbine-generators, whose incrementally improving efficiencies and scale contributed so much to the industry's productive growth (Hirsh 1989, 40–4). At the same time, the system's controlling stakeholders—utility managers and their allies in the research and development arms of the manufacturing firms—attempted to stifle radical invention, which often originates outside the system and which might otherwise have initiated competing systems. Utility company managers viewed radical inventions outside this engineering realm as inimical to established financial and intellectual interests. Radical inventions would disrupt the technological hegemony managers wielded over the system and would possibly lead to stranded investments—i.e., capital expenditures whose usefulness had passed before they could be fully amortized and bring a satisfactory rate of return. Consequently, the power companies came to rely more heavily on the conservative output of corporate engineers at the big manufacturing firms, who were perhaps more fettered by entrenched ways of seeing problems, than on free-spirited individual inventors (Hughes 1987, 56–62; Hirsh 1989, 26–35).

In short, utility managers succeeded in influencing much of the environment in which they operated. They won dominance relatively early in the 20th century over a system that could be considered "closed" by Hughes. In other words, managers created a system that effectively no longer felt the outside environment—a situation in which "managers could resort to bureaucracy, routinization, and deskilling to eliminate uncertainty—and freedom (Hughes 1987, 53)." The fact was not lost on the editors of the *Electrical World* as early as 1921. "The electrical industry," they wrote:

> stands in a wonderful position. It has economic stability. It has already, though young in years, gained a scope and volume that indicate a future staggering to the imagination. It is organized on a high intellectual plane to which the inventive mind, the scientific mind, the engineering mind and the financial mind have contributed the background and the machinery for progress. It has prestige. It has prosperity. It has strength and power ("The Unique Economic Position of the Electrical Industry" 1921, 1347).

THE GOLDEN YEARS AFTER WORLD WAR II

Despite setbacks in the 1930s, when holding company and propaganda abuses spurred Congress to establish restrictions on power company financing and organization, utility managers retained their power and dominance until the 1970s. They did so partly by encouraging manufacturers to develop conservative inventions—a step that should not be underestimated. Conservative development of steam turbines and generators, for example, brought huge scale economies and cost reductions as the machinery "grew" from 5 MW of output in 1905 to 1,000 MW in 1965. At the same time, manufacturers employed new metal alloys and higher-temperature and -pressure steam to increase the thermal efficiency of power plants. Edison's 1882 Pearl Street station converted about 2.5% of the energy contained in fuel to electricity, while by 1960, the best power unit converted about 40% of raw energy into electricity (Hirsh 1989, 4–5). Combined with the use of high-voltage transmission systems and reliability-increasing interconnections between power plants of different companies, beginning during World War I, the use of improved power generation equipment boosted the industry's productivity dramatically. Between 1899 and 1953, productivity grew 5.5% per year, a rate higher than seen in any other American industry (Hirsh 1989, 83 note 6). The greater efficiency in producing and distributing electricity meant that costs—and rates to customers—declined precipitously. In 1892, residential customers paid about 92 cents per kWh, in adjusted 1967 terms. That price dropped to 13 cents in 1927, 10 cents in 1937, and 4.6 cents in 1947. By 1967, when rates hit bottom, residential customers paid only 2 cents for the equivalent amount of electricity. By lowering prices, utilities stimulated demand, which bounded upward at a 12% annual growth rate from 1900 to 1920 and at a 7% annual rate from 1920 to 1973 (Hirsh 1989, 82–3 notes 2 and 3).

Power company managers remained in control of the utility system also because they retained support from the traditional backers of the utility consensus. Manufacturers and consulting engineers clearly profited as construction of new facilities accelerated, especially after World War II when power companies tried to meet the exploding demand by industrial and residential customers. R&D units and manufacturing facilities at GE, Westinghouse, and other suppliers to the utility industry kept busy increasing the scale of power generation equipment and making other advances in associated technology, while consulting engineering and construction firms maintained full work schedules. And customers clearly appeared to enjoy declining rates, even though they usually compensated for lower prices by consuming more electricity, thus keeping their bills from plunging altogether. At the same time, regulatory commissions luxuriated in a long era after the 1930s of little controversy and relatively easy work. After all, utilities continued to provide electricity at declining real rates, countering the general trend of increasing costs for other living necessities. What could be better? As the chairman of the West Virginia commission noted in 1972, the improving productivity of utility companies "made the job of the regulatory commissions the relatively simple one of approving rate reductions (Hallanan 1972, 3)."[9]

STRESSES OF 1970S

The charmed lives of utility managers did not last forever. Starting in the 1960s, they encountered a series of "stresses" that challenged both the utility system and the executives' control of it. Technological change (or lack thereof) combined with the energy crisis to spur a re-examination of the utility consensus that had appeared to benefit all stakeholders. As new stakeholders gained political standing, regulators awoke from their decades-long stupor to re-establish their positions as mediators of the consensus or to create new roles as facilitators in the formation of a new consensus. At the same time, politicians reasserted themselves as policy makers in the system, further diminishing the power held by utility managers. By the end of the 1980s, power company managers found that they had essentially lost control over the utility system. Instead of dictating policy, managers constituted one of many parties trying to create a new consensus. They watched as the monopolistic market structure dissipated and as a host of novel elite powers began negotiating a new industrial organization for the utility system of the 1990s and beyond.

As the first stress that challenged power executives' authority, the utility industry in the 1960s and 1970s encountered technological "stasis," the apparent end of productivity-enhancing technological improvements. Thermal efficiency gains in traditional steam-turbine-generator technology seemed to reach a plateau, as metals could not be manufactured that would reliably withstand the higher-temperature and -pressure steam needed to achieve thermodynamic gains. Meanwhile, economies of scale in building power plants appeared to dissipate. Utilities ordered ever-larger steam turbine-generators, but after a point—around 600 to 1,000 MW—their complexity and reduced reliability contributed to higher unit costs. The once-hoped-for savior of the industry—nuclear power—also suffered from the effects of technological stasis. Instead of producing power that was "too cheap to meter," nuclear plants also suffered as unit size increased. And with safety concerns intensifying, especially after the 1979 accident at the Three Mile Island unit, nuclear plants grew increasingly complex and expensive, thus adding to—rather than reducing—the cost of generating electricity. Because costs of producing power could no longer be brought down, as had occurred for decades, stasis nullified the value of traditional utility practices. In particular, it meant that continued use of growth-oriented strategies would no longer yield benefits to all stakeholders (Hirsh, 1989).

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[9] Of course, utility company managers did not necessarily view the period as "golden" at the time. Managers complained in their trade press of regulatory bodies' relatively slow action to decide cases, especially when it dealt with approval of accounting methods that would benefit utilities, such as the use of "fair value" as the basis for rates instead of initial cost of equipment ("What's Wrong with Regulation?" 1960, 79–82).

Next, the energy crises of the 1970s focused attention on the wastefulness of American energy production and consumption. With long lines at gasoline stations and fuel prices that escalated by several hundred percent in just a few months after the oil embargo of 1973, some Americans realized that growth in electrical consumption—the approach that previously contributed to lower-cost power—had little merit. In the political frenzy of the decade, the crisis led to passage of innovative pieces of federal legislation that diminished the control held by utility managers. Perhaps most important, the Public Utility Regulatory Policies Act (PURPA) of 1978 unintentionally challenged the utility consensus and the market and industry structure of the power business. With the stroke of President Carter's pen, vertically-integrated utilities lost their privilege to serve as the monopolistic supplier of power within a region. Now, a host of small, non-utility companies that produced excess power as part of industrial cogeneration processes—and with thermal efficiencies greater than those attained by utility plants—could sell electricity through the grid created and maintained by power companies. In effect, PURPA deregulated the generating sector of the utility business and invalidated part of the utility consensus. Meanwhile, PURPA also motivated technological innovation on small-scale and renewable technologies among people not normally associated with the utility industry.

At the same time that PURPA deregulated part of the utility system, it also empowered state regulators and gave them increased control over events dealing with power companies. The legislation required commissioners to develop specific arrangements and pricing mechanisms by which non-utility generators would produce and sell their electricity to regulated utility companies. In some cases, utility managers howled as regulators mandated that the new class of "PURPA producers" earn rates that equaled the highest "avoided costs" incurred by utilities if they had to produce the power themselves. So unpopular were these arrangements that some utilities challenged them—albeit unsuccessfully—in cases brought to the Supreme Court (FERC v. Mississippi 1982; American Paper Institute v. American Electric Power, 1983). The cases reflected the unease of power company elites who saw regulators playing new and more active roles after passage of PURPA, a law that appeared to have the dual effects of deregulating and "hyper-regulating" the utility system (Serchuk 1995).

As a third stress, the modern environmental movement gained increasing popularity and stridency during the 1970s. Long-established groups such as the Sierra Club railed against excessive consumption of finite energy resources. They were joined by groups such as the Environmental Defense Fund and the Natural Resources Defense Council, which used the legal system to press their values onto utility managers and other stakeholders. As a result of activities pursued by environmental advocates, formerly counter-culture values of conservation and energy efficiency became incorporated into innovative legislation and regulation that restricted utility managers' pursuit of previously accepted business strategies. Regulatory commissions and legislatures, which had complaisantly approved of utility managers' practices for decades, for example, began harmonizing in the 1980s with environmentalists who argued that conservation techniques could displace the need for constructing expensive new power plants. Regulators, who had been trying unsuccessfully to balance the needs of customers with those of utility companies under the terms of the original consensus, sometimes found these new approaches appealing.

ATTEMPTS TO ASSIMILATE INNOVATIONS CONSERVATIVELY: WINDPOWER AND DSM

Throughout this period of stress, utility managers struggled desperately to shape conservatively these frequently interacting policy and technological innovations. While prevailing in some of their attempts until the mid-1990s, the outlook for further success in retaining control is unclear. At the same time, regulators, environmental advocates, and other players also see an uncertain future as some free-market notions threaten to undermine their newly acquired authority.[10]

Attempts to assimilate windpower technology and demand-side management (DSM) exemplify utility managers' efforts to maintain control of a stressed utility system. Both windpower and DSM emerged on the scene after the 1973 energy crisis wreaked havoc on the energy infrastructure and as environmental values gained ascendancy in American culture. And both were viewed more than skeptically by the utility managers who claimed that these approaches might be useful sometime in the distant future. In the 1970s, however, they remained visionary and unattractive measures carrying anti-establishment baggage.[11] Despite this resistance, managers ultimately digested the potentially radical threats, though with various degrees of success.

A technology having origins in the tenth-century, windpower flourished in the United States after passage in 1978 of President Carter's National Energy Plan (Serchuk 1995). Responding to the economic dislocations caused by the energy crisis, the plan contained several elements supporting windpower. The Public Utility Regulatory Policies Act provided unexpectedly strong encouragement to small-scale non-utility generators, while companion legislation offered a variety of tax advantages for renewable energy systems. Under the leadership of Governor Jerry Brown, a spirited crusader of values espoused by the growing environmental movement, the state of California offered windpower advocates further benefits. The state's Public

[10] While I argue that participants seek to retain control within the utility system, I am cautious about imputing conscious political motives to players who advocate one position or another. Certainly, no executive or advocate has admitted to me that his or her institution pursues policies to enhance control or diminish other players' power. Nor am I sure what such an admission would mean, since the intentions of historical actors, or rather their first-person accounts of their intentions, offer problematic historical evidence at best. Nevertheless, the *effect* of the participants' actions is often to seek greater control. It is the effect, and not the intent, that interests me.

[11] In its *1978 Annual Report*, Pacific Gas and Electric observed that "a significant portion of US electric energy needs by the year 2020 could come from solar cells," while "[w]ind energy may some day become an economical and practical supplemental source of electricity (Pacific Gas and Electric Company 1978, 9–10)."

Utility Commission, which had become imbued with environmental values through Brown appointments, encouraged windpower development by requiring utilities to offer lucrative "Standard Offer 4" contracts to PURPA qualified facilities, for example.[12] Largely as a result of these incentives, the state became host to 85% of the *world's* wind powered capacity by the end of the 1980s (Weinberg and Williams, 1990, 147).

Though windpower was sometimes portrayed as a "soft-path" technology (Lovins 1976, 77) that conformed with decentralized and "hippie" lifestyles, utility managers ultimately gained partial control of the potentially destabilizing technology. It is true that PURPA ended utility managers' almost absolute control over new technology introductions by eliminating the barrier to entry in the generation sector. But utilities bought power from entrepreneur-owned windfarms just as if they had obtained electricity from their central generating plants or from conventional power sources owned by non-utility companies. Since windpower-generated electricity flowed into the California grid, to be transmitted and distributed on utility-owned lines, most customers had no idea that some electrons flowing into their homes had environmentally privileged origins. In other words, windpower turned out to be transparent to customers and little different than other forms of power purchased by utilities. It became part of the modified, but still relatively traditional, structure in which utilities sold power from large central stations to customers. Windpower, in other words, had been largely co-opted and turned into a conservative innovation by the power elites within the traditional utility industry.

Somewhat less successfully, managers retained control of energy efficiency. Evolving from efforts in the 1960s to "save the earth," energy efficiency became a sophisticated and mainstream business concept by the early 1980s. It emphasized the value to consumers of energy services, such as heating, lighting, and mechanical motion; previously, many customers viewed electricity as an energy commodity measured in kilowatt-hours. Moreover, energy efficiency won legislative and regulatory support from federal and state governments as part of integrated resource planning efforts.[13] In the early 1980s, energy-efficiency programs pursued by utilities earned a new name—"demand-side management." It became part of an arsenal of weapons employed by increasingly activist regulatory commissions for dealing with apparent boondoggles in power-plant construction that caused rates to escalate. But utility managers still resisted DSM, since it challenged standard practice that had been ingrained in regulatory rate-making procedures, namely that utilities profited only when they sold power. Moreover, DSM refuted managers' previously-held, though implicit, prerogative to build ever-more power plants at will. And DSM flatly repudiated cultural norms, built up over almost a century of service,

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[12] Windpower research also won support from the California Energy Commission, and investors in wind projects earned state income tax credits (Serchuk, 1995, 193–206 and 241–44).

[13] IRP principles were implemented by the federal government after passage of the Pacific Northwest Electric Power Planning and Conservation Act, Public law 96-501, 1980. State regulatory bodies began adopting IRP soon thereafter, with Nevada being the first to institute it formally after legislative action in 1983 (Wellinghoff and Mitchell 1985, 19).

suggesting that greater power consumption led to higher material standards of living.

Nevertheless, utility managers in some states accepted DSM as a way to mollify interventionist regulators. In the late 1980s, utility managers in New England and California began participating in "collaborative processes" with environmental groups to forge DSM programs offering financial incentives to companies that previously had only disincentives to "un-sell" their product.[14] The transformation emerged as managers realized that regulators would not abate their efforts to push more energy efficiency. Moreover, they recognized that they could gain important benefits by embracing DSM. For example, utilities won positive public opinion for developing popular environmental programs—a form of capital that could be spent in other battles with potentially hostile regulators. Perhaps most importantly, some critics contend that utility managers used DSM programs to limit competition with non-utility generators on the supply-side of their business. Since DSM programs displaced the need for new power capacity, utility executives could argue that regulators should reject applications for non-utility generation projects—whether they be alternative or conventional (Morris 1992, 6–9).

In other words, utility managers may have used DSM to maintain at least some control over their traditional generation business. But they paid a price by submitting to what appeared to be increased regulatory oversight of DSM programs while at the same time elevating the stature of environmental advocates. Previously dismissed by managers as troublemakers, environmental activists became accepted as potent political forces in some regulatory hearing chambers and in the decision-making conference rooms of utility companies.[15] In this fashion, utility managers digested the potentially radical and system-altering innovation of DSM, though they also empowered other elite participants in the system.[16]

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[14] Only in California did utilities in the 1980s have that disincentive removed. The Electric Revenue Adjustment Mechanism (ERAM), instituted in 1982, immunized utilities from the incentive to sell more power as a way to earn more profits. Likewise, it took away the penalties incurred when they pursued energy-efficiency programs.

[15] As an example, Ralph Cavanagh, a lawyer for the Natural Resources Defense Council and a primary actor in establishing the collaborative process in California, frequently joined with Pacific Gas and Electric Company officials to speak about the virtue of the utility's new DSM policies. Moreover, he accepted a position as a member of the Steering Committee, along with long-time energy-efficiency advocates Amory Lovins and Art Rosenfeld, that helped manage a PG&E research and development project (Hirsh and Pruitt 1993).

[16] I am grateful for the assistance of my colleague, Adam H. Serchuk, who helped develop some of the themes and approaches used in this part of the paper. We have explored these themes in greater detail in "Momentum Shifts in the American Electric Utility System: Catastrophic Change or No Change at All?" *Technology and Culture*, vol. 37 (1996), 280–311, April 1996.

RECENT CHALLENGES TO SYSTEM CONTROL

Utility managers may not be so successful in assimilating more recent innovations within the system, however. Unable to control or assimilate the latest technologies, managers may have little say in the industrial organization of the utility system in the future, setting the stage for the competition of novel organizational schemes such as the virtual utility.

The technological threats attack the former industry and market structures of the utility system from several fronts. First, the development of small-scale generating equipment—of which windpower and gas combustion turbines are two examples—continues to erode the utility consensus rationale for natural monopoly (and hence the need for regulation). Challenging the logic that legitimated exclusive retail franchises early in the century, the success of small-scale non-utility generating facilities points to the fallacy of the assumption that only monopolistic utility companies could produce power at the lowest resource costs to society. As recent experience has shown, independent power producers can often generate electricity for considerably less cost and much higher fuel efficiency than utility companies.[17] The new technologies alone, in other words, may justify abolishing the monopoly market structure of the utility industry.

Perhaps more potentially menacing to utility managers' control over the power system are emerging location-specific residential and commercial generation technologies. Extremely small-scale electricity production units, such as proton exchange membrane fuel cells and photovoltaics (Williams 1994, 9–12), have the ability to alter fundamentally the relationship between utility and customer—i.e., the existing market structure. Capable of producing power and selling it to the utility at favorable rates, especially during peak-demand periods, consumers in such a "distributed utility" network may make the traditional one-way production and distribution system obsolete. It may even allow homes and businesses to be disconnected from the grid altogether or connected with neighbors to increase reliability through diversity. Such a scenario becomes more feasible when considering the flourishing of "smart" electronic technologies used for communications, monitoring, energy transfers, and energy efficiency—technologies whose costs are declining exponentially (Newcomb 1994, 36–8). As described by Carl Weinberg, former manager of research and development for Pacific Gas and Electric Company, the era of "constructed energy" coming out of large power plants that took advantage of supposed economies of scale, may be over. The new system may be characterized by "manufactured energy" from technologies exploiting economies of mass production rather than economies of scale. The technologies may continue the trend begun by PURPA producers that makes outmoded the existing (largely) centralized system of electricity generation and distribution. In short, the use of new technologies by recently empowered actors may erode the rationale for the original utility consensus and the control held by utility managers. And as power company executives lose

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[17] Of course, some people rightly argue that to achieve lower costs, the non-utility generators have transferred a good part of the risk in financing plants to utility stockholders and ratepayers.

control, the entrepreneurs who develop these new technologies earn a say in the creation of a new market and industry structure. In other words, they emerge as a new elite group themselves.

On the regulatory front, the existing utility system is further threatened. Hyper-regulation on the state level in the form of mandated DSM programs and set-asides for alternative energy technologies may give way to deregulation. The impulse is spurred by positively viewed efforts to deregulate and de-monopolize other businesses, especially those in the telecommunications industry. Before 1984, for example, American Telephone and Telegraph maintained control over a monopolized market structure in a way similar to that of electric utility companies. Just like power company managers, telephone executives had effectively captured their regulators and had carefully managed conservative inventions so that they could exploit their special market privileges. Rapid and radical technological change altered organizational structure of the industry, however. As microwave and satellite transmission of signals eliminated one rationale for natural monopoly, the business that once enjoyed special status became much more competitive. At the same time, the products or services it sold became less distinguishable in the marketplace, making business success more dependent on how to innovate, manufacture, package, and sell products and services that deliver true value to customers.

As the idea of deregulation continues to become more fashionable, with telecommunications industry restructuring and the fall of centrally-planned Communist economies serving as motivators,[18] advocates of the free market are effectively challenging the notion of regulated monopoly franchises.[19] John Anderson, head of the Electricity Consumers Resources Council (ELCON), an association of large industrial consumers of power, for example, argues persuasively that technological change has eroded the rational for special market arrangements, such as natural monopolies, to allocate society's resources. The free market, he (and others) argue, can do this job better. In California, Michigan, and elsewhere, state commissions have responded to high prices and a general dissatisfaction with the exiting utility system by investigating deregulatory schemes that employ competition (through retail wheeling) to industrial and residential customers. Cherished by utilities because it erected a formidable barrier to entry against competition while also guaranteeing a sound financial foundation (at least until the 1970s), the retail monopoly franchise may be on the verge of disappearing.

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[18] The end of Communism in Eastern-bloc countries appears to have inspired some advocates of deregulation and free market approaches. However, at least one supporter of fundamental regulatory principles, Barbara James, chief counsel to the Electric Division of the Public Service Commission of Wisconsin, observed that "what the failures of Eastern European Communism have to do with the provision of electric service by a productive tension between private investors and government is unclear. Monopoly regulation is unlike any doctrinaire governmental theory, except possibly the Founders' federalist checks and balances (James 1995, 71 note 3)."

[19] Ironically, as some nations move away from state-ownership of electric utilities, they often look to some form of regulation to discipline free market forces and ensure social welfare. And in the United Kingdom, which has privatized its electricity services industry, public disaffection is stimulating efforts to increase regulatory oversight (Pope 1995, A10).

These technological and regulatory innovations are arriving so quickly and have such force, spurred by continuing impact of industry stresses starting in the 1970s, that utility managers are having trouble digesting them. Though most would like to maintain some control over the current system, their chances for success appear poor. In an ironic twist, some environmentalists and advocates of renewable power and energy efficiency have taken relatively conservative positions and have allied themselves with utility managers who oppose the idea of retail wheeling because they worry that a competitive market will neglect environmental protection. After having stimulated so much change themselves, some of these newly empowered activist elites now seek to retain political standing with regulators and legislators so as to achieve their goals. While advocating the use of market forces in a few situations, they argue for retention of some regulatory apparatus to preserve environmental gains that would possibly be lost if free-market principles reigned.[20] Commission-endorsed programs that set aside a certain amount of power capacity for renewable energy technologies and energy-efficiency, for example, provide guarantees (and some would say subsidies ["ESCOs, Environmentalists" 1994, 9]) to advocates of non-traditional resources, and they naturally want to keep those benefits. In a largely free-market environment, however, such guarantees would vanish.

CONCLUSION

By the early 1990s, the utility consensus created early in the century had been effectively shattered. The monopolistic market structure that the consensus established was challenged on several fronts during the 1980s. First, implementation of PURPA opened up the generation business to non-utility generators and therefore ended the special privilege the arrangement gave to utilities as the exclusive supplier of power for a region. At the same time, the development of small-scale power technologies whose costs declined dramatically during the 1980s suggested that perhaps the original rationale for natural monopoly made less sense than it did early in the century. After all, the greater efficiency of a single supplier of power constituted one justification for the existence of natural monopoly. If wind turbines, gas-fired combined cycle turbine-generator sets, and distributed technologies built in tiny increments (compared to the sizes of centralized behemoths) could provide power for less cost, then clearly the rationale for the utility monopolies no longer exists. William W. Berry, President of the Virginia Electric and Power Company,

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[20] Free markets, argue some people, do a poor job in dealing with environmental externalities and equity issues. They also fail to accommodate for situations in which individuals and institutions have perverse incentives to act "irrationally," sometimes because they hold inadequate information. Because of these market deficiencies and market "failures," regulation needs to exist in some form to provide a way for the industry to comprehend public-interest responsibilities. This argument is outlined in Hamrin, Marcus, Weinberg, and Morse 1994.

summarized the situation in 1983. "As in so many other regulated monopolies," he observed, "technological developments have overtaken and destroyed the rationale for regulation. Electricity generation is no longer a natural monopoly (Berry 1983, 3)."

The examples of commercial small-scale successes under PURPA also questioned other arguments for maintaining a consensus that gave utilities natural monopoly privileges. The high capital expenditures needed to offer service to customers constituted a supposed barrier to entry, for example, which helped justify utilities' non-competitive status. But the experience of PURPA demonstrated that such barriers may not be so high after all, at least in the power generation sector. Entrepreneurial companies, such as the scores of cogenerators and small power producers, successfully raised funds and managed financial risks to build their plants. And they did so without relying on an arrangement that promised sufficient profits, under regulation, to guarantee a power company's financial wherewithal (though they benefited from the existence of ironclad agreements with regulated utilities that, under PURPA, shifted some risk to monopoly ratepayers and shareholders). The barrier to entry, therefore, no longer proved to be such an impenetrable barrier after all.

As the utility consensus shattered, so did power company managers' control over the utility system. Regulatory bodies, for example, constituted a newly rejuvenated elite group that always held a modest amount of infrequently-wielded power. But given greater authority and resources by federal and state legislatures beginning in the 1970s, they took on seriously their role as mediators of the existing consensus—somewhat modified by PURPA, of course—partly by adopting values and solutions proposed by environmental groups. A period of hyper-regulation resulted, even at a time when PURPA started the process of deregulating the generation sector of the utility business. Becoming empowered by regulators, these special interest organizations constituted still another elite group that held political and popular support. At times contesting utility managers' previously-held values about growth, the advocates sometimes joined forces with the executives to argue for retention of some form of regulation. After all, the newly forceful regulators now championed the environmental cause (to some degree), and the advocacy groups enjoyed the power they held to alter utility policies.

But while regulators, utility managers, and environmental leaders may have hoped to retain vestiges of the old utility system, with regulators still playing a significant role, other vocal interest groups sought to destroy the utility consensus further. Advocates for complete deregulation and the total employment of free market principles gained status as an elite group by leveraging the changes wrought by PURPA and by riding the wave of deregulation sentiment in other industries. Buttressed by academic supporters (such as MIT's Paul Joskow) these deregulation protagonists hoped to benefit their large industrial clients with surplus power generated outside the traditional service area of regulated utilities.

The disintegration of the utility consensus and the end of control held by power company managers suggests that the traditional model for the industrial and market structure of the utility system cannot survive. With radical technological change eliminating scale economies and advantages of centralization, the late 19th century principle of natural monopoly and the progressive faith in expert regulators no longer retain validity or popular support. Vertically integrated utility companies that operate as monopolies in protected franchise areas simply make little sense in light of the stream of technological innovations that challenge the fundamental assumptions of that earlier model for utility system organization.

Perhaps the elite players in the utility system are beginning to understand the new free-market nature of power generation and marketing. Electricity, which to many consumers for decades was an undifferentiated commodity necessary for business and home use, is now being marketed by some companies in different forms that add special value in certain applications. Power is sold to some customers, for example, with high degrees of reliability and power quality. Some companies offer "standard" reliability but also the information and technical know-how to install energy-efficient equipment that would benefit both the customer and the power supplier. Perhaps more importantly, many companies have begun forming alliances with others to provide these value-added services to customers. Still-regulated utilities serve as brokers to unregulated power suppliers (which include renewable power producers) while working with energy services companies to provide energy efficiency work within customers' businesses and homes. In short, as the perception of electricity as a differentiated product evolves in this new environment, the variety of participants in the utility system may realize that they need to make alliances with others to provide services. As companies make more of these alliances (and as they shift them), the former industry structure of monopolized and vertically integrated utilities falls further into disrepute. Meanwhile, the concept of a virtual utility—one in which partnerships and joint ventures flourish to add value to customers' use of electricity—grows more acceptable.

This new conception of the utility system still has far to go before it becomes universally appealing. Confrontation between elite groups still characterizes the utility system today, with old controllers of power and new ones wrestling for dominance. While some elites, such as utility managers, regulators, and environmental advocates, appear willing to give up extreme positions and negotiate a new consensus, others remain adamantly opposed to creation of any institutional framework that impedes the employment of free market principles.

The power elite framework proposed in this paper may help explain the turmoil in the utility system. First of all, the system currently is populated by a plethora of what can be considered "elite" groups holding various degrees of power. Because of the stresses of the 1970s and 1980s, utility company executives lost their dominance over the system, ceding power to environmental advocates, regulators, state and federal politicians, and leaders of consumer organizations. The day has long past when utility elites could forge a consensus about market and industry structures simply by dealing with just one or two other groups, such as state politicians and civic advocacy organizations. The proliferation of these elite groups makes it hard to arrive at any consensus, especially when each one jockeys for position by trying to influence public policy or regulation. Moreover, even within individual groupings, elite representatives rarely speak with one voice. Early in the century, Samuel Insull could be viewed as the pre-eminent spokesman for utility interests, and he strove to develop the original utility consensus with politicians. But today, some utility executives (especially those with low cost structures) welcome the advent of competition while others shun it. At the same time, even those parties that once supported the former utility consensus have shifted positions. While equipment manufacturers such as General Electric still produce machinery for utilities employing the central station paradigm, they also design and sell small-scale gas turbine-generators and other hardware for the increasingly lucrative and competitive independent power market. Finally, customers who once supported the consensus because of continuously declining rates no longer retain monolithic views. Groups representing large consumers of power lobby for open competition in the retail markets while small-consumer groups worry that their constituents, having little market power, will be stuck being served by high-cost utility companies. In short, the demographics of power within the utility system no longer are as simple as they once were. A profusion of elites fights to gain supremacy in a high-stakes contest. When viewed within this power elite framework, one can understand why no consensus is immediately forthcoming.

To be sure, some order will ultimately result from the confrontation of interests and ideologies. New technological opportunities will certainly play a critical role in realizing that order, just as utility executive elites took advantage of technological options early in the century to advocate a consensus that gave them a monopolistic industry structure. But just because new technologies provide opportunities does not mean that technology will *determine* the outcome of the current system debate. Because of the nature of the power structure within the utility system, the different actors will view technological opportunities differently—either to enhance their positions or to subvert them. Ultimately, through a socio-political process of negotiation, the parties will have to coalesce around one or another means for producing and distributing electricity.

But even this conclusion may be too narrowly constrained. Perhaps the politics of electricity interests will be such that no single consensus results from the current debates. Rather, one can imagine a variety of approaches for producing and using electricity. Some customers may rely on central power stations while others may draw power from local sources or from self-generation. After all, why should there be only one "solution" for everyone? Do all people use the same heating and cooling hardware, computer operating systems, or transportation networks? We have come to believe that everyone requires electricity (as a basic "right" almost). But who is to say that everyone must obtain it through the same means?

In short, this study suggests that the politics of power in the electric utility system has become so complex, due in part to technological problems and opportunities, that a single vision of the future may not be possible. But perhaps, this is where the notion of the virtual utility may fit into the scheme of things. The concept of the virtual utility offers the benefits of increased financial flexibility along with the provision of electricity services without depending on the former paradigm of a centralized management and technological system. As a result, companies employing the virtual utility model (once it is more fully developed) may be able to exploit the new small-scale technologies used in a pluralistic and decentralized marketplace to provide electrical services in a way that yields economic and environmental efficiencies. Time, and the efforts of people at this conference who pursue the virtual utility concept further, will tell whether this vision of the future will replace the consensus that ruled the utility system for so much of the 20th century.

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2

THE VIRTUAL UTILITY

STRATEGIC AND MANAGERIAL PERSPECTIVES:

WELCOMING ADDRESS

Andrew Vesey
Entergy Services, Inc.

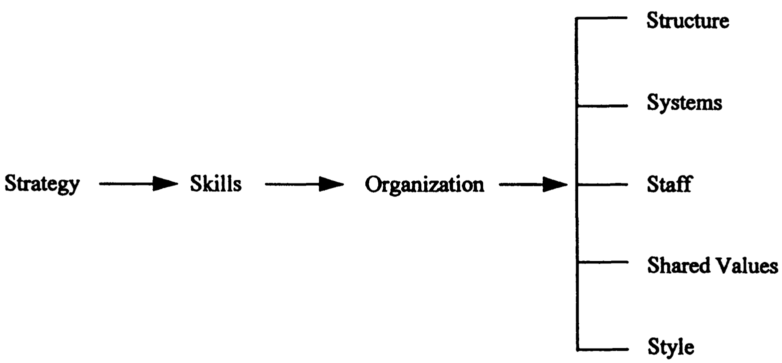
ORGANIZATIONAL LIFE-CYCLES AND CHALLENGES

My presentation attempts to provide a brief overview which is intended to put the issues surrounding this Symposium into an organizational context. Fundamentally, what I would like to say is that organizations exist in a certain environment, and that as these environments change, organizations must change as well. We've been talking about the external forces that shape these environments, technology, regulation, markets, and economics. It has also been suggested that these forces also become the drivers of change. For organizations to continue to be successful, they must continually reform themselves. However, experience shows us that as things change, as the balance of forces change, organizations, unfortunately, do not. It has been said that the one thing bred by success is failure, because as we become good at something we tend to continue doing it, regardless of how the environment has changed. Now I would argue that there are really only two drivers of change: one is technology and the other isn't, and when we discuss the virtual utility concept as a new business concept for the electric utility industry, we are really talking about organizations and organizational change in response to a shift in the dominant technology paradigm.

S. Awerbuch et al. (eds.), *The Virtual Utility*

I would like to use a framework called the *Seven-S* or *the Happy Atom* Framework [** CITE **]; it was presented in *Search for Excellence* [**Peters, Waterman, In Search of Excellence, Harper & Row, 1982 (pgs 9–11) **] as a means of analyzing organizations. The framework reflects the thought that organizations, even though they are depicted in terms of hierarchical charts, etc., are actually collections of *capabilities* or skills which have been created to deliver certain competencies to execute the organizational strategy (Figure 1). In other words, given the Strategy, an organization has to deliver a series of high-level corporate Skills—things it must excel at to be successful. The organization itself is broken into five dimensions or "S's":

Figure 1. Organizational Strategy.



a. Structure—which is what we think about when we talk about the "wiring diagram" of an organization, how individuals and functions relate to each other;

b. Systems—which during this symposium we've collectively coined "processes"; that is the way work is done; and information flows;

c. Staff—those are the skills that individuals in an organization possess;

d. Shared values and style—collectively this is often called the "corporate culture," where shared values are those values which are important in an organization and style is the way management tells its employees what is important.

I would like to talk about some of the changes we are discussing during the symposium—from the traditional utility to the virtual utility—in terms of these dimensions, so we can begin to identify the things—the new competencies and new capabilities—that these new organizations will have to be particularly good at in order to be successful.

MECHANICAL VERSUS COGNITIVE PARADIGMS

I have suggested that the real driver of the changes we are facing is technology, and that the big change is the so-called information technology revolution. I see this as a change from the traditional *mechanical view* of the world in which the value producing processes consisted of the input of raw materials, the performances of mechanics to create end products, to what I call the *cognitive paradigm* (Figure 2). Shimon Awerbuch talked about this—about why accounting is designed to value the output of screw machines but not computers. Traditionally, everything we did was based on a mechanical view of the world, on mechanical processes, but now this is no longer helpful. The power of technology paradigms can be seen in a shift within the mechanical process itself which occurred when the manufacturing industry was first electrified in the late 1880's and early 1890's. Electrification of manufacturing was probably the type of radical architectural innovation being talked about at this symposium [see Awerbuch, et. al. in this volume]; electricity didn't merely enable industries to do the same things faster and more cheaply; instead, for the first time, it allowed them to rearrange their processes, relocate equipment, change the size of factories, develop whole new manufacturing processes, and improve the quality of the product. By electrifying, by moving from water or steam power to electricity, firms were able to fundamentally re-engineer or reinvent the work process. Pretty powerful stuff! This advancement, as significant as it was, took place in the mechanical paradigm of the raw materials—tasks—products cycle which remains the conceptual basis of everything we do today in the way we measure and even the way we talk; indeed our vocabulary in organizations and businesses is based on this mechanical view of the world. For example, we still use "efficiency" as the fundamental figure of merit—how much product we made based upon how much raw material and labor comes in the front door. With all else constant, the more efficient firm wins, so, we design our organizations to be very efficient in that mechanical conversion process. Imagine how powerful, how significant the innovative power of moving from the mechanical to the cognitive world view might be.

We are now in the information age where, as opposed to *automating*, we are *informating*[1]. Instead of mechanical leverage to eliminate human labor we are using information. Products, for example, have increasingly greater information content. Shimon Awerbuch talked about this: by increasing the information content of generated electricity a "smarter" kilowatt-hour may have more information value than energy value—or—the value of a kilowatt hour may be higher in information than in energy. Thinking about this is difficult, because we don't have the right vocabulary; we don't have the right measures. We are operating in the information age with mechanical paradigm tools. This is a totally different world view, and when we think about the virtual utility, we have to think about the *cognitive paradigm.*

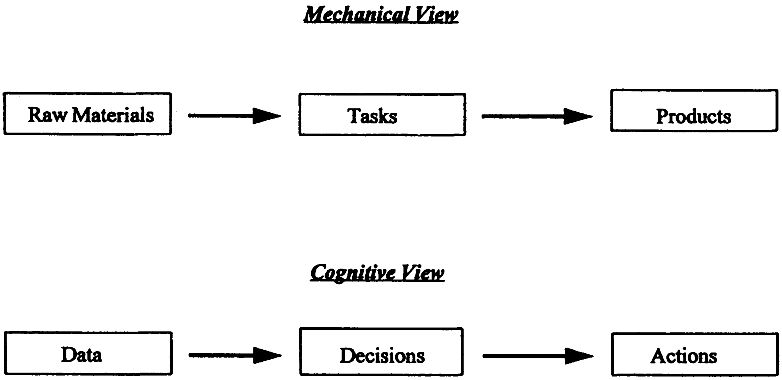
So a good place to start is, what is the appropriate figure of merit, what is it that we design our organizations to be very good at in the information age, within the

[1] See Zuboff, In the Age of the Smart Machine.

cognitive paradigm. I would suggest that we must design for the quality of the decisions made. The firm is now a decision factory, with a process that converts data to decisions to actions (Figure 2) and we want to measure and talk about and design our organizations to make good decisions. Good decisions are a function of two things: the quantity of information we can get our hands on and then the speed at which we process it, i.e.:

$$\text{Decision Quality} = f(\text{Quantity of Data, Speed})$$

Figure 2. Mechanical/Cognitive View



The answer, of course, is that with all else constant, the organization that can gather more information and process it quicker wins.[2]

INFORMATION HIERARCHIES

What is the information that we need, a quantity of what? It comes in four "buckets":

1. *Task*: information around a specific job operation or function;

2. *Interdependencies*: information concerning intra-organizational, inter-departmental or cross-functional activities. Such dependencies between organizations have been essential in process re-engineering.

[2] This idea may not be entirely new. Nathan Bedford Forest, a now notorious calvary General for the confederacy had a military strategy along these lines, which he expressed as "Be the firstust with the mostust." Be the firstust with the mostust: the most information you can get processed the quickest.

3. *Enterprise*: information concerning the goals and objectives of the organization.

4. *World:* information concerning external influences such as competitors, suppliers, technology and customers.

When we speak about the speed of processing, we are talking about how quickly an organization can take data from the four buckets and act on it. Figure 3 illustrates the way information is processed in an organization: the top of the organization has the wisdom; the data is at the bottom. The wisdom in most organizations resides with the senior management. Whenever something happens in the competitive marketplace, information goes all the way up and decisions come all the way down. That is information processing in an organizational context. This takes time, and time is a luxury that competitive firms do not have. As a result the important idea in speeding up organizational information processing deals with "de-layering." De-layering is often taken as a code word for work force reduction; as a means to get people out. However, you eliminate people not just to lower costs, but to speed up information processing. This is not just de-layering but disintermediating. An important implication for the virtual utility, therefore, or for any organization that is going to play in the information age, is to flatten and streamline the organizational structure.

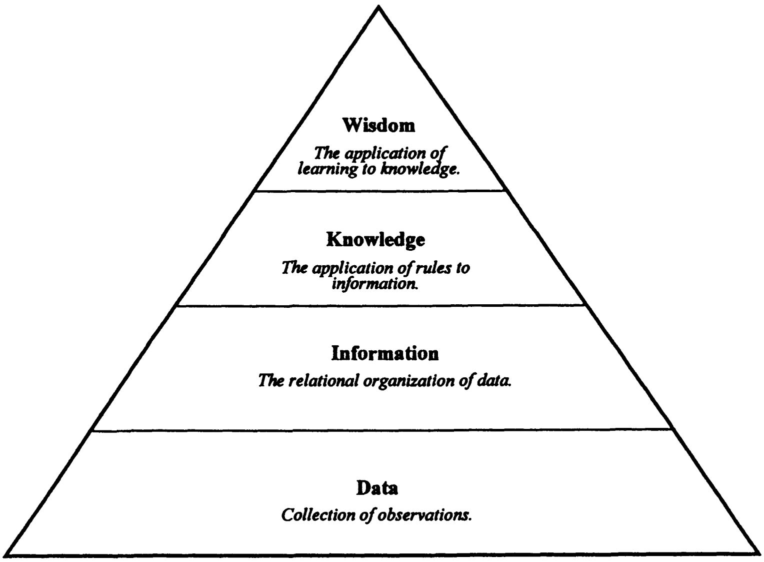
The power of this new organization will stem from having the four buckets of information in the hands of people best able to act on it, and act on it quickly. We hear the term "mass customization:" imagine working on an assembly line and knowing exactly which customer will get a particular product and what that customer will do with it. Imagine that worker knowing what that customer's individual needs were, and being able, on the assembly line, to customize that product to that customer.

The issue then is: where is the needed information within the organization? We use the term "empowerment" frequently; we have all heard it. Many of us are probably in organizations that practice it: that "empower" employees. Why? because those employees have all the task information; increasingly managers say: "They know their job better than I do, so let them make those decisions." Imagine how powerful a competitor your firm would be if your employees had information from all the buckets...not just the task bucket. Empowering employee means driving this information down the firm, which should suggest to us that our new organizations should be structured to get as much information down as far as possible.

ORGANIZATIONAL ATTRIBUTES IN THE MECHANICAL AND COGNITIVE PARADIGMS

We hear about organizations built on convergent knowledge networks. That is what speeding up information processing is all about. This brings us to another one of the "S's" I wanted to talk about: *S*tructure. What are the implications of the changing paradigms of organizational structure and how do they relate to the change from the mechanical-based to the cognitive based process? Figure 4 examines organizational attributes as the firm changes from the mechanical to the cognitive paradigm. Clearly organizations adopted particular attributes to accommodate the mechanical view: to support the processing and conversion of raw materials into products. The attributes are not necessarily bad—they are bureaucratic; they form a cumbersome chain of command, but all of this may have been appropriate for what the organization was trying to do in the environment in which it was operating, and for the environment it was operating in.

Figure 3. Hierarchy of Information: Organization Segmentation



But now we are making a giant leap to the cognitive paradigm, and there are a lot of new words and concepts, although these are already familiar, e.g.: global approach—markets are now global. In a mechanical world they were local because they dealt with local resources. In the information age, they are global. Flexibility and speed, cultural diversity—when a person's contribution to the workplace is information, the diversity of experience and background become critically important, not because it is politically correct, but because it is important to competitiveness.

The culture issues are also indicative of the magnitude of the needed changes. Let's examine the words: learning, collaborative, facilitative management approaches in place of bureaucratic command structures; shared accountability in place of the parental management of the mechanical world. These are the cultural issues surrounding the new information age organization.[3]

Figure 4. Attributes of Organizational Paradigms.

Attribute	*Paradigm*	
	Mechanical	**Cognitive**
Socio-Economic Environment		
Environment	regional	global
Strength	efficiency	flexibility & speed
Demographics	assimilation	*cultural diversity*
Power, Planning & Purpose		
Governance	chain-of-command	*self-management*
Planning	operational	strategic
Power	hierarchical	value added
Organizational Focus	scientific management	competitive advantage
Task Design	simple & sequential	concurrent
Organizational Culture & Leadership		
Culture	bureaucratic	*learning*
Interaction	command roles	*collaborative*
Management Approach	systematic	*facilitative*
Management/Worker Relationship	parental	*shared accountability*

LEVERS FOR PROCESS INNOVATION

Let me now turn to the systems or process aspect of change, an aspect which centers on the concept of "informating." The central issue here is how to use information to improve systems and processes. Figure 5 lists several levers or actions [*Process Innovation—Reengineering Work through Information Technology: Thomas H. Davenport, Harvard Business School Press, Boston, MA,. 1993, Page 51*] to enhance existing processes in the virtual utility or any other new cognitive-view utility com-

[3] Along these lines see the discussion by Awerbuch, et al (in this volume) regarding the importance of learning *around* the new technology.

peting in the information age. The levers (Figure 5) have direct implications for the virtual utility: automational, informational, sequential, tracking, analytical, geographical, integrative, intellectual and disintermediating; we heard about this last one yesterday. Shimon Awerbuch used the term in relation to the introduction of word processing which essentially eliminated the traditional secretarial role and other intermediaries from the written communication process. These levers will be discussed again when we look at the behavioral style or processes that will be needed in a virtual utility system.

Figure 5. Levers for Process Innovation.

Impact	*Explanation*
Automational	Eliminating human labor from a process.
Informational	Capturing process information for purposes of understanding.
Sequential	Changing process sequence, or enabling parallelism.
Tracking	Closely monitoring process status and objects.
Analytical	Improving analysis of information and decision making.
Geographical	Coordinating processes across distances.
Integrative	Coordination between tasks and processes.
Intellectual	Capturing and distributing intellectual assets.
Disintermediating	Eliminating intermediaries from a process.

SKILL SHIFTS

The cognitive paradigm requires us, as individual employees, to undergo what is generally a skill-shift from traditional quantitatively-oriented decision skills to a more qualitative, open ended set of skills suited to the information age. My sense is that employees who will succeed in the organizational environment of the cognitive paradigm we are discussing are going to be skilled at synthesizing, extracting meaning, dealing with open open-end questions and uncertainty of all sorts (Figure 6).

Underlying this skill-set are some important ideas which distinguish the behaviors and style of individuals who succeed in the traditional mechanical-oriented world as compared to those individuals whose skills will be needed for sound decision-making in the cognitive world. For example, using a Meyers-Briggs[4] approach to assessing personality, my experience suggests that most good policy makers and managers in the utility industry today are introverted, sensing, thinking, judgmental types. There are no negative connotations to this; it is merely a classification of preferred behaviors.

Figure 6. Skills Shift.

Quantitative	*Qualitative*
Amount	Essence
Measure	Meaning
Hypothesis	Open-Ended Questions
Eliminate Uncertainty	Welcomes Surprises
Confirms	Explores

Interestingly, one of the four Meyers-Briggs dimensions—the thinking-feeling dimension—has a strong gender bias and feeling aspects, which underlie some of the *qualitative* skills, will be much more important in the new cognitive-based organization. Shimon Awerbuch talked about this issue yesterday, in describing how these new organizations are going to have more of a feminine quality. My point therefore is that cultural diversity and the ability to work in these uncertain, qualitative areas (Figure 6) become important and represent a general skill shift that we are going to have to see in our employees, a shift that enables them to process and internalize less structured data, to synthesize and understand the essence and meaning and to explore open-ended issues in a manner that leads to innovative products and solutions.

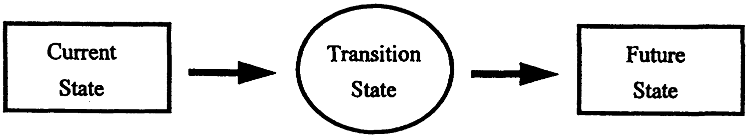
THE "CHANGE" PROCESS

We have been talking about organizations that are changing from the mechanical to the cognitive view; the change process is the transition or dynamic through which firms must pass as they adapt from the current to the future state (Figure 7). The transition state itself is similar to an airplane flight that encounters turbulence: you know you can only get to your destination by flying through it. The transition through the turbulence is necessary, but you want to get through it quickly because it is clearly not comfortable. The transition state (Figure 7) is marked by i) low stability, ii) high emotional stress, iii) high, but often undirected energy, iv) loss of

[4] The Myers-Briggs is a widely used personality/behavior assessment. Gifts Differing, Isabel Briggs-Myers, Consulting Psychologist Press, 1989.

control, v) a return to past patterns of behavior which now become highly valued, vi) anxiety, vii) increased conflict, and, viii) fear; what a wonderful place to be.

Figure 7. The "Change" Process.



Characteristics of the Transition State:

Low stability
High emotional stress
High, often undirected energy
Loss of control
Past patterns of behavior become highly valued
Anxiety
Conflict increases
Fear

Adapted from concepts developed by Kurt Lewin and Richard Beckhard.

While change is discomforting, it is going to continue and most of us are going to spend our careers in large organizations that are in the transition state. Indeed, change will be a characteristic of the cognitive organization, because information changes which affect all aspects of corporate decision making, are so rapid. If firms are going to mass customize with continuous improvement, continuous innovation and continuous leap-frogging over competitors, then they must be constantly re-organizing. Moreover, employees are most likely going to spend the remainder of their career in a continual state of change so that managers of the new organization will have to develop skills that enable them to manage employees in the transition states. These skills (Figure 8), were less valued in the steady state, unchanging mechanical-view organization.

NEW COMPETENCIES

Richard Hirsh [see Hirsh in this volume] suggested that the current utility organization has been essentially unchanged for 50 years or more. By contrast, I will offer the idea that in the future, new utility organizations are going to change on a rapid and regular basis and that this will require a set of skills or competencies which are quite essential, but which do not exist and are not highly valued in today's relatively stable organizations. Figure 9 presents this new set of skills that management must adopt. They represent additional examples of those small "S" skills.

Figure 8. Management Skills Inventory.

Informing	Self-Confidence
Listening	Self-Acceptance
Communications	Personal Adaptability
Conflict Management	Motivating Others
Stress Management	Group Skills
Human Relations Skills	

Staffing, Coaching & Developing

Innovation & Resourcefulness

We have already talked about structure in terms of de-layering systems and informating; we also talked about shared values and style. The new competencies can evolve only from developing those aspects of the organization. An organization cannot simply wish for these new competencies and then build those other skills 'backwards.' The organization comes first; it delivers these things. I would therefore suggest that new utility organizations, whether virtual or just slowly moving toward change, have to acquire the new competencies:[5]

- **Strategic resource allocation:** This is contrast to what we do today, which is budget control. Utilities are very good at budgets and managing to budgets and controlling by budgets. However, what we must excel at is strategic resource allocation—achieving competitive advantage.

- **Market-driven management:** This is a change from the traditional engineering-driven management, as Shimon Awerbuch mentioned yesterday. Firms used to focus on greasing things, tightening things, maintaining things and if there was time left over, they might look at the customer. In the new world, utilities will have to be good at market-driven management—understanding what market wants and needs and delivering it.

- **Portfolio management and asset management:** These competencies replace traditional rate-base management which we used to call "field of dreams" management: build it and they will pay for it. That's what asset management

[5] See work performed by Venture Associates for the Electric Power Research Institute.

Figure 9. New Competencies.

Strategic Resource Allocation:	*Apply capital, O&M, and non-financial resources to achieve competitive advantages consistent with strategic objectives.*
Market-Driven Management:	*Manage operations to develop, market, and deliver products that create customer and shareholder value.*
Portfolio Management:	*Develop and manage a portfolio of owned and non-owned supply and demand resources which achieve market segment, operating, and financial objectives.*
Asset Management:	*Manage individual capital assets to create economic value in excess of the cost of capital employed.*
Process Management:	*Develop and manage business processes linked directly to the utility's outputs to focus resource allocation priorities, improve quality and control costs.*

used to be all about. The new focus must be on asset and portfolio management with the objective of creating wealth. Amazingly, firms still don't use appropriate valuation measures for managing their assets; they still use the weighted average cost of capital (WACC) to value investments and strategies. This is critical and will have to change.

- **Process management:** This is in contrast to functional management, where leverage is gained by understanding the whole process, by acknowledging the interdependencies that exist; efficiencies can be acquired because information flows along process, not functional lines.

- **Management Reporting:** This is very different from the FERC-based accounting and reporting we are all used to as Alistair Preston indicated quite clearly yesterday. Resource allocation involves applying resources to achieve competitive advantages consistent with objectives which is clearly different from budget and control. Traditional managerial reporting has little to do with managing and paying attention to opportunities that create value.

To me, these are the important competencies that new organizations must have. Now we can look at the other "S's" and determine what is needed in terms of structure, systems, and staff in terms of organizational redesign to be effective and deliver the needed competencies. For example, market-driven management aims to develop and deliver products that create value. We have all gotten quite comfortable with these words, yet I would suggest that if we decided to pursue such a capability as a firm, nobody would say: "Okay; now how do we re-organize to accomplish that?' In other words, in formulating new strategies, firms generally forget the organizational changes needed to implement and deliver them. This omission leads to declining, dysfunctional organizations; the harder they try to improve performance, the more they practice their old organization behaviors, the more their actual results deviate from the desired. These firms should be moving their employees away from those old patterns of behavior yet they tend to do the opposite: force employees directly back into those behaviors. The important message here is that making change, whether it is introducing empowerment or customer marketing, requires widespread organizational realignment in order to succeed. Knowing how to reorganize may, in fact, be the most important new skill cognitive organizations need. They are needed to open markets and to develop new products. Now I would also offer that today's utility organizations generally do not have these skills.

So, I think that our challenge here as we move forward is to look at organizations, to look at their competencies and to keep in mind the organizational dynamics of change. In the transition to the virtual utility we are dealing with collections of human capabilities as well as technological capabilities. So I wish us luck as we move forward and hope that this presentation provided a context in which to explore the issues of the virtual utility. Thank you.

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3

BEING VIRTUAL: BEYOND RESTRUCTURING AND HOW WE GET THERE

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INTRODUCTION

The word *virtual* suffers from a recent spate of immense over-use. To add clarity to my own thought, I consulted a dictionary. My old edition, not edited for current usage, says:

> Virtual—existing or resulting in essence or effect though not in actual fact, form or name. From medieval English—virtual—effective, powerful. From Latin—virtus—capacity, virtue. [American Heritage, 1973]

Not much help, perhaps, or maybe lots. In the virtual utility, only the essence remains. The virtual utility should be effective and powerful, should have the capacity of and the virtue of the utility; a utility in everything but fact, form or name. The virtual utility is nimble and fleet of foot, less encumbered with physical assets,

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exploiting its intelligence and capabilities, embracing change and delivering outstanding customer satisfaction. Not a bad place to go.

HOW TO GET THERE

First the mundane. It seems that any agenda to get to the future and past the next ten years of transition will require attention to at least five issues:

i) Allocate Costs—Since by definition there is little we can do to mitigate stranded costs, we must set about the allocation process immediately. In Texas, where investor-owned utilities are committing millions to denying the trends, they have invented a new name for stranded costs—excess costs over market—or ECOM. Mere name changes will not suffice. While we are about it, we need to begin the cost allocation process for fully unbundled utility services.

ii) Restructure Institutions—Our regulatory institutions and the artifacts of their processes will need dramatic changes. From the boring but essential process of culling through mountains of tariff filings, to the critical task of remaking regulators as siting and market power overseers, these tasks, too must be begun immediately.

iii) Address Public Goods—Despite the theoretical and rhetorical wishes of the most fervent free-market talking heads, the public goods aspects of the utility system must be addressed, and in some form preserved. Strandable benefits need not be stranded.

iv) Ensure Technological Progress—Technology drives basic economic form. We instituted the current model of utilities and regulation because of the limits of available technology. Only new and different technologies can enable a different future. Washington, D.C., the states, and the utilities must unfreeze from the headlights, and resume the march forward.

v) Address Market Imperfections—As I already suggested, there are no perfect markets. The subsidies to conventional technologies and fuels ensure that. The perfect need not be the enemy of the good. We can make progress, and must, in improving market efficiency by addressing all true costs associated with production, transmission and consumption of electricity.

There is much detail to be worked out in this or any suggestion. For now, there is value in establishing a context with some framing concepts.

THE BASELINE

We should start with what we have. What we have is a huge pool of physical plant. We have an electron delivery system that has been called a "service" industry. But for most residential and small commercial customers, it is not. The only contact most have with actual people at the "Light Company" is a telephone call to establish connection and a similar call to terminate it when they move. We do not shape the character of our subscription except by the volume of our consumption. We do not try out new "services," or take advantage of "specials" or engage with sales staff in service reviews. We do not hear stories of powerful and creative business leaders emerging from within the industry. We do not seek advertising about product "roll-outs." We do not shop by phone.

We do know that somewhere at the other end of the wire there is a generating plant. We know it is part of the pollution problem, and that it employs some workers that we have never met. We know that on the rare occasion when the power goes out, someone will be at work. We know from the book covers in grade school that electricity is dangerous. We expect to have electricity whenever we want it. And we know that it will be there, at least in varying degrees, for the 60% of the world that has electricity. But for all the success with which electrons are delivered, electricity has not really been a service industry for individual Americans since sometime after the Edison method gave way to the Insull model.

Alternatives to the extant model have been available since the start. The remnants of now unused district heating systems can be found in many of our larger cities. Wind energy provided much of the original electrification of the rural West. Working solar thermal systems have been around for nearly one hundred years. But one by one, these systems and technologies have faded before the relentless economies of scale epitomizing the days when we really did think electricity could become too cheap to meter.

In the last twenty years, however, distributed gas generators, renewable energy and energy efficiency have begun to emerge as technology and service options capable of truly moving the industry toward the service paradigm. The electricity industry has not been very friendly to these alternatives. The exceptions are noteworthy, and their existence reassuring, but of late too many utilities have withdrawn from efficiency and renewable energy, from forward-looking research and development efforts, and from real competition in generation.

The utility industry is now preoccupied with a visage of competition on the horizon. By and large the notion has paralyzed rather than invigorated the electric industry, though the conference industry is doing quite well. One can almost see the utility accounting offices, lit bright with too many incandescent bulbs, with clerks bent stoop-backed over the ledgers, accounting for the pennies of stranded costs and calculating to the mil the rates to be charged and the period of collection necessary to make the company whole. The concern is not a minor issue; industry estimates range around $135 billion for stranded costs—the value of plant and regulatory assets rendered uneconomic by competition. All concern is focused on a promise to allow a reasonable opportunity to earn a reasonable return—arguably meaningless in the competitive paradigm. And amidst this concern over costs that cannot be mitigated, many are forgetting the strandable benefits[1] that need not be stranded.

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[1] Strandable benefits describes the many public goods and private benefits afforded through regulation of utilities. The typical listing includes energy efficiency programs, research and development programs, renewable energy development, low-income programs, and others.

Focusing on stranded costs and positioning for competition are transition tactics. Beyond the transformation lies a future where the electric industry will likely delaminate into a commodity-based electron generation market and a common carrier-like transmission system. At the distribution level, however, the electric industry can undergo its most profound change—from a monopoly-based, central station-connected mechanism for the collection of rents into a vital service industry that rebundles pure electron delivery with value-added options not yet imagined. The distribution sector can drive the growth and change of the entire industry, and operate in a convergence zone where major trends promise to change virtually all the old assumptions about and even the essential character of the industry. Getting there will be one of the most exciting changes to shake the sooty foundations of electricity in quite a long time.

CONVERGING TRENDS

The electricity industry is moving inexorably into a convergence zone where several major trends can and will profoundly shape the industry's future. Growing global demand for energy, deregulation, the information explosion, environmentalism, population, technological innovation and other forces will combine with the trend toward competition to provide new opportunities for value added services and true customer choice. The information content of electricity will increase in importance. The separation between information, matter and energy in electricity will disappear. Though the concern about stranded costs has naturally led to an emphasis on the commodity-based generation sector, the very success of the utility industry in almost universally connecting citizens in this century has laid the foundation for the next major shift—away from the central station model to the high-efficiency, high value of the distributed system. [*See* Linden, et al., 1995].

Environmentalism—Concern about the environment is pervasive, both in this country and throughout the world. In the international community, especially, there is great concern for global issues such as climate change and ozone depletion.[2] As many are pointing out, several of our fiercest economic competitors are positioning

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[2] Environmental activism is, at least partially, a function of the wealth of a society. The richer a society the more of its resources it will be willing to spend on environmental conservation and improvement. This implies that one of the first steps to improving the environmental quality of a society is to increase its wealth, i.e., it is hard for a people in extreme poverty to place a high value on an idea as abstract as environmental quality when their concerns are more immediate and concrete. This appears to be a paradox, as economic development is often associated with environmental degradation. The paradox may in fact be false for at least two reasons. First, continued poverty may well be even more degrading to the environment than development, as the desertification of sub-Sahara Africa shows (the substitution of fossil fuels for firewood for cooking would have a substantial environmental benefit in sub-Saharan Africa). Second, the environmental degradation due to development may be temporary and substantially reversible, as it has been in the OECD countries. But we should always remember that at a basic level, pervasive degradation inhibits growth, and extinct is forever.

their industries for market domination through strong domestic environmental standards. [*See* Moore, 1994] This trend favors technologies that are inherently environmentally sound and will disfavor the costly and efficiency-reducing end-of-pipe controls necessitated for conventional technologies. Even critics of the present approach to dealing with global climate change recognize the importance of alternative generation technologies.[3] All the environmental regulation the most ardent regulator could imagine will, in the end, only control pollution. New generation technologies, efficiency, and other electrotechnologies have the potential to eliminate pollution associated with electricity production entirely—in our lifetimes.

Telecommunications and Computing—As noted in a recent article in *Wired* magazine,

> More Americans build computers than cars, more make semi-conductors than construction machinery, more work in data processing than petroleum refining. Since 1990, US firms have been spending more on computers and communications gear than on all other capital equipment combined. Software is the country's fastest-growing industry. World trade in information-related goods and services is growing five times faster than trade in natural resources. And so on and so forth. [Heilemann, 1996]

Several commentators are beginning to seek lessons from the information revolution that can be applied to an electric utility industry facing increasing competition. [Rábago, 1996] A good place to start is with Marshall McLuhan's oft-quoted first principle—"The Medium is the Message." Let's start with what the message is not.

For all the speed and savings inherent in the new information gathering capabilities of the web, the net, and other aspects of the information revolution, mere efficiency is not the message of the Internet. For all the cultural necessity to "get with it" through a company home page, new billboards is not the message of the Internet. And executive access to documents routinely retrieved by the legal staff is not the message of the Internet.

The message of the information revolution is distribution of intelligence, function, and interactivity. The message of the Internet is transience, choice and acces-

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[3] This view, as reported in *Energy Daily,* Sep. 14, 1995, was summed up as "Current U.S. global climate change policy makes no sense." The participants of a symposium of global climate change on Sep. 13, 1995, sponsored by the American Council for Capital Formation's Center for Policy Research indicated that it was foolish and counterproductive to push for near-term goals of emission reductions. Instead the focus should be on long-term atmospheric concentrations of CO_2. The three major speakers at the symposium were: W. David Montgomery, VP at Charles River Associates; Alan Manne, professor emeritus at Stanford University and Jae Edmonds, technical leader of economic programs at Pacific Northwest Laboratories. The three agreed that new technology is the key to keeping costs down in the long-run when dealing with climate change. Edmonds was quoted as: "The accelerated introduction of advanced energy technologies can so substantially reduce the costs of meeting an atmospheric CO_2 concentration that costs are insignificant until late in the [21st] century." He added: "A clear implication of this result is that measures which accelerate global technology cost reduction, development and deployment have substantial value in achieving [the world's global climate change goals]."

sible technology. It is about a world and a way of thinking that is profoundly at odds with the model dominating our perception of the electric power industry.

The Internet has reached phenomenal use in this country not because it is an information resource, but because the information is now within easy reach of many homes and businesses in this country. On the net, information is no longer limited by its physical location. The Internet does not operate from a single central computer; no central station model of computer intelligence could have created it. The network of networks is an interlaced and interconnected web of distributed computing power connecting millions of sites, each with their own native or potential intelligence. Hypertext links connect the desire for information with its availability at precisely the moment sought by the user and interoperability is the premier protocol.

One message of the new information media is that truly revolutionary growth in the ubiquity and use of information came only with decentralization and nearly unfettered interconnection. If this message has an analogue in the electric utility industry, it is the distributed utility model. The installed base of electric generation connected through the one-way central station-to-transmission-to-distribution model we know today is significantly larger and more pervasive than the mainframe computer systems of a few decades ago. But stranded cost recovery and accelerated depreciation will eventually eliminate this difference. After that, further argument for the central station utility model could sound remarkably resonant of the misguided business strategies of IBM, Wang and other mainframe computer giants.

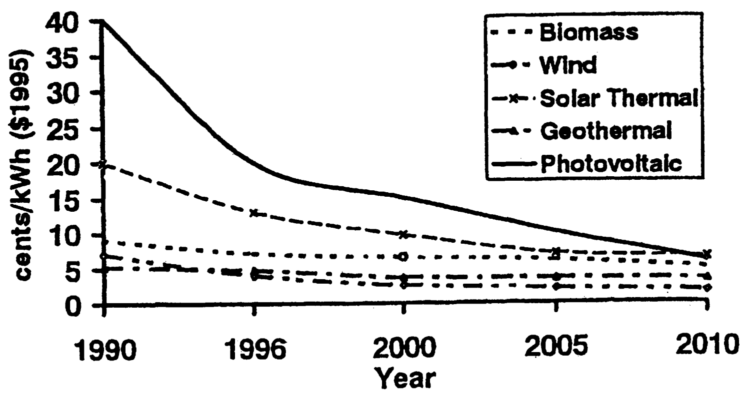
The Internet and World Wide Web have not skyrocketed in the public consciousness because they produce attractive images, because they are "neat," or because they are "high tech." While appearance attracts, content, choice of content, and interoperability rule. Go where you want, stay as long or as little as you like, dig deep or surf, the choice is yours. Through the power of Moore's law[4] and the constant drive for usability, the process is getting easier all the time. Less than ten years ago the only way to interact with a computer was through the arcania of disk operating system commands, painstakingly typed on a keyboard. Less than twenty years ago, one had to use keypunch cards. Technological progress has not only enhanced the range of information and information processing choices one enjoys, but also the ease with which those choices are made. The code behind the program is absolutely irrelevant to the ultimate consumer of computing and information technology. What sells is the ability to be where you want to be, do what you want to do, when you want to do it.

For the electric industry it would be wise to look for the places where the electric equivalent of Moore's law may lie. Examining the efficiency improvement curves of large central scale generation technology suggests that their best days may be gone. The learning curves of renewables, computer-driven energy management technologies, fuel cells and small scale gas turbines offer much greater promise (See Figure

[4] Moore's Law, named for Gordon Moore, Chief Executive Officer of Intel, holds that computer processing power doubles every 18 months and cost reduces by half.

1). With their small size also comes environmental superiority, flexibility, and that most important competitive attribute—adaptability to customer desires. With improvements in small scale generation, from sub-10 MW biomass gasifier/turbine systems to photovoltaic roof shingles, and in storage technologies, from advanced batteries to superconducting flywheels—all managed by an interactive, intelligent interface with the distribution grid—the newer energy technologies offer the greatest range of choice for customers. Because of their small size and their relative independence from much supporting infrastructure, the technologies of the distributed system offer the broadest and most flexible menu of choices for satisfying customers. The companies that become expert providers of that choice will satisfy, at a handsome profit, the needs, wants and desires of future markets.

Figure 1. DOE Cost Projections.



The future will likely include an electric industry strongly influenced by customer choice and an expectation of interactivity, by the computing, telecommunications, and information revolution, and by the progress of innovative technology. The power of the technological innovation does not lie in doing business-as-usual in a different, even more efficient way. The heartbeat message of the future is fundamental change.

As more and more households and businesses expand their use of telecommunications technologies, they will also be installing some of the infrastructure for new energy services.

Many alternative generation technologies, such as photovoltaics, are also well-suited to supplying remote telecommunications requirements; PV is an ideal power supply for the milli-watt microcells of the new personal communications network systems. Intermittent energy sources have more value to users when combined with communications between generator and user. Load control systems and "smart houses" rely on telecommunication for their effectiveness. Two-way telecommunications coupled with two-way energy flow and distributed generation, storage, and management systems could convert every home or office into its own virtual utility. The ability to network users and generators of electricity and to manage energy use interactively offers potential for saving energy that could more than pay for fiber to the curb. Home or building scale systems comprised of generation, management and storage technologies would allow off-peak purchase from the grid and on-peak sale to the grid, all driven by price signals communicated in real-time to the building and managed through a simple computer interface.

Electric systems are essentially geographically based. New geographic information systems (GIS) technologies, involving clipboard computing, digitized mapping and data retrieval systems offer potential for reducing time and labor-intensive costs related to operations and maintenance of the distribution infrastructure. These technological improvements—essentially the digitizing of the distribution system—may also be an important course for ensuring continued reliability in the face of recent industry trends to reduce service staff and close local offices. Developments in information technology already make the deployment of renewable energy generation more practical and less expensive. Computing power increases the value of the information content of electricity.

Knowing where customers are, how they use their electricity, and their collective impacts upon transmission and distribution systems means valuable markets for providers of load-control technology, small-sized supplemental generation systems, and even high-efficiency appliance marketing. Rather than the brute-force solution of adding a new power plant or expensive transmission upgrade, the careful targeting of modular and flexible efficiency or renewable options offers least-cost options to enhance service quality and reliability.

Energy Demand and Population Growth—Global population will probably double by the middle of the next century.[5] Energy demand will nearly quadruple. Population increases directly drive demand for the services provided by energy. Renewable energy, now the marginal energy source, will inevitably provide a greater portion of overall energy demand as depletable resources are depleted and the value of local resources increases. [Lamarre, 1995] In a similar fashion, as demand for services provided by energy increase, the value of energy efficiency also increases.

Population growth, especially in developing countries, means an expanding market for all kinds of energy solutions. Today some two billion people are without electricity. This growing demand will stress the ability and question the desirability of sinking massive levels of scarce capital into traditional energy options. A truly conservative energy policy will likely rely upon the modular, flexible, and scaleable nature of distributed systems, renewable energy and energy efficiency. Even more important in this calculation is the long term trend in fuel supply. Long term solutions must recognize a likely reduction in availability of fossil fuels, due to both limited supplies and growing greenhouse concerns.

Deregulation—The past two decades have seen complete or partial deregulation in many U.S. industries: airlines; trucking; stock exchange brokerage services; rail-

[5] Despite the slowing growth rate, global population will not stabilize until at least 2050, at about the 10-12 billion level, twice the current population. A regional breakdown of current growth rates: Sub-Saharan Africa—2.94%; East & North Africa—2.53%; Asia—1.60%; Latin America & Caribbean—1.69%; North America—1.11%; Europe—0.32%; Former Soviet Union (FSU)—0.56%; and Oceania—1.51%.

roads; buses; cable television; oil and natural gas production; long-distance telephone services; natural gas transmission and distribution; and banking.[6] This trend has reached the electric industry, and is in many respects a global phenomena. In many nations, governments are privatizing formerly state-run electric systems. In some cases, these nations are leap-frogging the U.S. model.

A first and narrow glance at the battles between coal and gas, between utility generation and IPPs, and at the brooding presence of nuclear investments seems to have led conventional thinkers to suggest that competition disfavors distributed resources. These new options have benefited from preferential, though erratic, regulatory treatment, to be sure. But they are not dependent upon that treatment. The modularity of alternative generation resources and the ability to diffuse them throughout the distribution system enables them to provide high value services that offset high prices for delivered electrons. The many currently cost-effective applications identified point the way to even greater opportunities in more open and competitive regimes. A new institutional structure, occasioned by deregulation and competition and centered on the distributed utility model will be facilitated by improvements in telecommunications and information technology, and will exploit the modularity and efficiency inherent in small gas, renewable energy and energy efficiency.

Dematerialization—"Dematerialization" refers to the process of doing more with less material—it is the process of reducing material, labor and energy content while increasing information content to develop a better designed product. Today a single CD-ROM disc can hold tens of thousands of pages of text and graphics. Fiber optics and faster, more powerful chips move and process orders of magnitude more information in fractions of the space used just ten years ago. Today's cars are lighter and use less material than their predecessors. The weight of a 20 HP electric motor has declined from 418 pounds in 1930, to 380 pounds in 1951, and to 190 pounds in 1987. Dematerialization has resulted in smaller production units and often more local production. Already adapted to the idea of mini-mills, the steel industry is now looking at micromills, designed to target markets as small as cities instead of regions.[7]

In the electric utility industry dematerialization can be seen in the economies of manufacturing scale in smaller generation technologies. Dematerialization can also be seen in fuel sources. The original trend toward ever more dense energy sources, epitomized in nuclear power, has carried a significant materials burden in construction materials, fuels and waste disposal. The trend now is toward less dense fuel sources, with natural gas as today's the fuel of choice and hydrogen-powered

[6] Banking deregulation should be a cautionary tale of how *not* to deregulate, as we continue to still pay for the S&L debacle.

[7] Dematerialization appears to follow a curve, with initial trends toward using more material, often in economies of scale, peaking at some point followed by dematerialization, as the attributes that led to concentration either become their own enemy, e.g., environmental impacts of concentrated use, or are not valued by the market. Many industries in the U.S. are clearly on the dematerialization portion of the curve.

fuel cells on the horizon. The ultimate in dematerialization in fuel sources is solar based, such as photovoltaics, solar thermal and wind generation technologies.

Dematerialization is what renewables are about, as abundant, diffuse energy is collected and applied to tasks without matter-intensive conversion intermediaries. As manufactured, rather than constructed technologies, renewables improve efficiency through engineered dematerialization, or what Jun Miyaki of Japan's MITI calls "entropy engineering." Thin film and thinner silicon wafers have improved the cost performance of photovoltaics, membrane heliostats have improved solar thermal costs, and lighter components are key to improved longevity and greater performance of today's and tomorrow's variable speed wind turbines.

To generate electricity from coal, materials are assembled into large machinery to extract solar photons—energy—concentrated from plants into coal in a process taking millions of years. This concentrated energy source is transported using equipment assembled with more materials to a plant in which more materials are assembled in order to construct feeders, boilers, turbines, generators, and waste collection facilities. The heat energy of the coal is released and converted into mechanical energy, which in turn is converted to electric energy. The waste is sent to the land and to the air, almost devoid of the energy quality or any other beneficial quality it contained. Assembling all these materials loads the process with costs and inefficiencies. All this process is designed to reveal and produce an electrical product that in a photovoltaic cell is produced directly from the solar photon. Similar comparisons apply to superconductivity, fuel cells, hydrogen energy systems and energy efficiency.

THE UPSHOT

The relevance of all these converging trends lies in the forces they will exert on the electric industry. The significance lies in the convergence itself. As the components of technology and society converge, they affect each other, just as forces occupying the same field interact. What was once an electricity world neatly divided into its material, energy and information components will be a swirling mass where movement along one vector inspires the movement of another.

In the convergence zone, when electricity service meets telecommunications, electricity will not become "digital," but electricity service can become interactive. In converging with information technology, electricity service can become intelligent, replacing the dumb electron delivery system of the central station model. Fewer, smarter, kilowatt hours will displace the electrons of those old systems. [Awerbuch, 1996] As population and environmentalism converge upon energy we will not need less energy, but more, better, better-timed and better-suited energy sources and services.

Deregulation and increasing reliance upon markets for the allocation of private goods aspects of energy will lead to increasing customer focus. After the dust settles on the stranded cost problem, the key to success will lie in product differentiation around expectations of choice, environmental soundness and technological innovation. The strategic thinking will focus on the forces in the convergence zone. Strategic thinkers will look beyond uneconomic generation and new access rules for transmission systems toward a truly competitive battleground for customer satisfaction. Combining the value-adding attributes of renewable energy and efficiency with electron delivery will offer a ready arsenal of options for keeping and attracting customers focused not just on reliability, but also qualities like environmental soundness, price-stability, modularity, flexibility, intelligence and empowerment through real choice. The future is a convergence zone; those who would be profitable there will exploit every aspect of the new reality. They will be—*effective, powerful, existing or resulting in essence or effect though not in actual fact, form or name*. They will be virtual.

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Part III

The Virtual Utility: Planning and Strategic Investment Analysis

4

THE VIRTUAL UTILITY: SOME INTRODUCTORY THOUGHTS ON ACCOUNTING, LEARNING AND THE VALUATION OF RADICAL INNOVATION

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ABSTRACT

This paper examines the problems associated with the application of traditional capital budgeting practices to the valuation of radically new processes and technologies in an environment of rapid technological change. It focuses on a restructured utility industry, and the possible emergence of the *Virtual Utility*.

Different types of technological innovation are discussed. The paper then illustrates how capital budgeting, by virtue of its accounting orientation, often fails to identify important benefit categories associated with emerging technologies. Finally, the paper offers suggestions for enhancing the capital budgeting process by making

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qualitative assessments to better understand the benefit implications of architectural innovations such as the Virtual Utility.

INTRODUCTION

> "The US electric utility industry is in the midst of a dramatic restructuring. However, it is unclear what kind of industry will emerge. A patchwork of unfolding national and state deregulation has put the restructuring in motion, but there is no defined end-point." (Navarro, 1996: 112).

American electric utilities are undergoing significant regulatory, market and technological changes. In order to rise to the challenges of the new, competitive environment utilities will need to enhance the manner in which capital investment (capital budgeting) decisions have traditionally been made.[1] This paper examines the problems associated with the application of traditional capital budgeting practices to conduct benefit-cost analyses of radically new concepts and technologies in an environment of rapid technological, market, and regulatory change. The paper explores different kinds of technological innovation and illustrates how capital budgeting may fail to identify important benefit categories.

This paper does not propose a new set of algorithms for this changing environment; indeed they may become obsolete before new projects are brought on line. Rather, it examines the potential benefit of revised capital budgeting approaches that are sensitive to the limitations of the underlying accounting information and the positive impact of technological learning in the valuation of new technologies. The paper concludes with some suggestions for improving capital budgeting by making qualitative assessments to better understand the benefit implications of architectural innovations such as the *Virtual Utility* (VU).

Dramatic industry restructuring is not unique to electric utilities. Nearly every institution or major sector of the US economy has, or is currently, undergoing similar dramatic change: manufacturing underwent similar striking changes in the mid 1970s; the financial service industry did likewise in the 1980s; health care, which began its restructuring and, in the late 1980s, continues to undergo changes today. Of course, these are not the only cases; telecommunications, natural gas and even government provide additional examples. The forces driving restructuring differ in each case. In manufacturing, for example, market forces and new process technologies drove change; in health care, the transformation was driven by regulation, which in turn created a radically different market environment for health care organizations. In the case of electric utilities, the forces driving restructuring represent a complex interplay of radical regulatory, market and technological changes.

While differences exist among these industries, there are commonalities as well and utilities stand to learn from the survivors of change in other industries. Indeed,

[1] On this point we generally agree with professor Aggarwal [in this volume].

learning is an underlying theme of this paper and if the experiences of other industries are an indication, utility decision makers (engineers and managers) will need to learn:

1. To re-conceptualize the way in which electricity is generated, transmitted, distributed, marketed, metered, paid for, and conceived as a product;

2. To change the manner in which they conceive and measure performance;

3. Re-conceptualize the way they view their relationship with customers, other utilities, non utility generators and independent power producers, regulators and different components of their own firms (e.g. generation, transmission and distribution) that previously defined them as utilities.

4. To learn new ways to gather and record information, plan and control the use of resources, organize and make decisions.

The scope of these changes is obviously enormous and this paper focuses on two of the aspects: i) the need to learn enhanced capital budgeting (i.e. investment analysis) processes in the forthcoming environment of radical innovation, and ii) the need to learn new ways to monitor and control the costs of generating, transmitting and distributing electricity. Both of these will be needed in the new utility environment.

The structure of this paper is as follows. First we introduce the idea of the "economic engineering mentality," a view that has dominated utility capital budgeting and cost control throughout this century. Second we examine the notion of the *Virtual Utility* (VU), arguing that a new mentality or way of conceptualizing capacity investment and cost control problems are needed. The third section of the paper examines the problems of traditional capital budgeting or benefit-cost procedures as applied to radical new concepts or technologies in an environment of rapid technological, market, and regulatory change. This section explores technological innovation and illustrates how capital budgeting may fail to identify important benefit categories. The final sections discuss the limitations of traditional utility accounting systems and outline a different approach to understanding and controlling maintenance costs for fossil generating stations. The paper concludes with suggestions for improving capital budgeting and cost control processes in utilities.

THE ECONOMIC ENGINEERING MENTALITY

A comparison of manufacturing, health care and electric utilities suggests that in each of these industries a particular type of "expert mentality" rose to dominate the way in which problems were generally conceptualized and solved. For example, in the case of manufacturing, it was the efficiency expert, trained in the F.W. Taylor School of Scientific Management, that emerged as the dominant expert [Loft, 1986]. The "efficiency expert mentality" shows an early preoccupation with cost and capital budgeting which ultimately yielded the most highly evolved system of cost controls (including operations budgeting, standard costing, and financial analysis of capital investment.[2]

In the case of health care, by comparison, the physician emerged as the dominant "mentality" with the view that medical treatment could at any one time justify any cost and investment in new technology. This convincing position swept aside early cost control initiatives in health care and resulted in little concern with capital budgeting [Preston, 1992] so that the dominance of the physician led to a decision-support system removed from cost or profitability considerations. As a result, traditional health care accounting systems evolved into a mere calculus for third party cost reimbursements: instead of cost control systems, hospitals developed "cost finding" and "cost charging" systems. It was not until the 1980s that hospitals began to establish internal cost control and capital budgeting systems. This transformation coincided with the ascendancy of a management mentality in health care that eclipsed the dominant physician.

Finally, in the case of utilities, an "engineering-economics mentality" emerged as the dominant approach to cost. Engineering economics is

> Body of knowledge devoted to the systematic evaluation of the net worth of benefits resulting from proposed engineering and business ventures in relation to the expenditures associated with those undertakings. Accordingly, economic analyses that primarily involve engineering and technical projects commonly are called *engineering economy* studies (DeGarmo, et. al. 1984, 4).

The engineering-economics mentality reveals a decision focus almost exclusively preoccupied with justifying investment in bigger and better central generating stations with the aim of improving the engineering efficiency of the generating process. Hirsh (1989) has demonstrated that every ten years, generating stations increased tenfold in size and became ten times more efficient. What is important is that the decision models for the economic engineering mentality could readily be met with relatively simple benefit/cost measurement and capital budgeting processes (such as the revenue-requirements model). In addition, the argument (and demonstrable proof) that larger, more efficient stations resulted in lower kWh-cost needed only simple, aggregated cost accounting systems: costs could simply be recorded as Fuel costs or Operation & Maintenance (O&M) costs[3] and these could, in turn, be divided by kWh output to yield a simple average cost per kWh. In a regulated environment with low rates of technological change, where costs could be shown to decline by further investment in larger, more efficient central generating stations, there was no need to develop sophisticated cost control systems.

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[2] This long established cost control focus may explain why other industries, including utilities are currently looking to manufacturing to adapt and enhance their own cost control and capital budgeting initiatives.

[3] It was in the area of accounting depreciation that sophisticated techniques were employed but this is another story.

As a result relatively simple capital budgeting and cost control systems proved reasonably adequate for the first three quarters of this century. However, as fossil technology reached *stasis* in the early 1970s (Hirsh, 1989), the relationship between increased size, increased efficiency and lower cost no longer held. As technological stasis emerged so did the specter of deregulation and competition. It was at this point that the economic engineering mentality, the traditional capital budgeting process and the accounting systems which had evolved in their support began to lose explanatory power. The engineering way of thinking became less convincing and useful, thus setting the stage for a shift. The new utility environment, as discussed in the next section, requires new approaches to capital budgeting and accounting in utilities.

THE VIRTUAL UTILITY CONCEPT: RADICAL INNOVATION AND ORGANIZATIONAL LEARNING

The VU can be conceptualized as an entity or model for organizing power generation and distribution by minimizing non-value-adding activities such as excess transactions and excess generation capacity and providing appropriate quality energy on a *just-in-time* basis. The VU could be a virtual organizational entity, which owns few assets, but rather is comprised of an alliance of various power generation and distribution entities (e.g. non-utility generators—NUGs or independent power producers—IPPs) that utilize a variety of supply options including passive, modular power generation and telecommunication technologies.[4] Moreover, the VU can be conceived as a producer of high-value-adding intangibles embodied in fully *mass-customized* electric services.

The VU, with its modular generating technologies, its capabilities to deliver specialized new services and its flexible supply arrangements enabled by new financial instruments such as energy options and futures contracts creates a set of benefits that may differ considerably from the traditional direct benefits usually examined in capital budgeting. For example, while particular generating technologies may or may not demonstrate lower busbar costs,[5] it is the synergism of the VU organizational structure that produces cost reductions in a manner similar to the way flexible process technology reduced total costs in manufacturing, even though direct costs were not always lowered.

Busbar cost comparisons coupled with relatively little attention to cost control may have been satisfactory in a previous technological era, when output was sold to an essentially captive market and utility resource alternatives were technologically

[4] The concepts of passive, capital-intensive, and infinitely durable technologies are explained in a later section.

[5] The "busbar" ($/kWh) cost includes direct *fuel* and *operation and maintenance* (O&M) costs of a plant; it continues to be the predominant cost measure for planning, presumably as a proxy for the true costs of generating power.

homogeneous, consisting largely of fossil fired options which had essentially the same mix of operating, overhead, capital, transmission and distribution costs. The current environment, however, offers both a considerable range of technological options, including capital intensive solar/renewable such as photovoltaics (PV), and Demand Side Management (DSM) alternatives which have fundamentally different overhead, operating, and capital transmission and distribution costs than traditional central generating plants. Given these differences it is no longer sufficient to select resource options on the basis of their busbar or direct costs alone and it will be no longer possible to pass on inefficient resource utilization to customers.

Capital Budgeting and Innovation

The traditional economic engineering mentality is of limited use in conceptualizing the nature of newly emerging technologies in the VU.[6] For example, the absence of a mechanical conversion process in PV-based generation renders the deeply rooted engineering model of electricity production, its related notion of efficiency, and the economic engineering performance measures typically associated with fossil generation (i.e. the busbar cost measure) of limited value.

The task of developing new capital budgeting processes for passive technologies requires more than simply reconfiguring analytical routines; it requires a change from the economic engineering approaches that have held sway in the utility industry for so long. This task is all the more problematic because of the scale and scope of technological change in the VU environment. Electric utilities were accustomed to *incremental innovations* in generating technology for much of this century. These exploited the potential of established designs and improvements in the existing functional capabilities of steam powered technology which yielded relatively small improvements to performance, safety, quality, and cost—the value-adding attributes of central station generating technologies (Betz, 1993: 20–21). Newly emerging generation technologies, however, often represent *radical innovations.* These introduce new concepts that depart significantly from past practices hence creating technologies such as fuel cells and PV which are based on a different set of engineering principles and often open up entirely new markets and potential applications (Betz, 1993: 20). In addition, radical innovation can change the way system components are linked together. These *system or architectural innovations* [Henderson and Clark, 1990] may alter the traditional components used to manufacture electricity thereby altering the nature of the product in a fundamental manner. Although arguably the product still consists of electrons, their *creation, availability, quality and delivery options* are sufficiently altered to produce benefit categories not previously understood or conceptualized. While traditional economic engineering decision

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[6] As discussed subsequently, these are often *passive* rather than active and *capital-* rather than expense-intensive; they tend to be *infinitely durable,* but exhibit rapid technological obsolescence.

tools were useful for valuing incremental innovation in generation, they are not always work well when applied to radical innovation.[7]

Additional architectural innovation might ensue from the realignment between technology and organizational structure in the emerging VU. For example, the traditional technological components of the electricity generation and delivery system include: i) inflexible, central-station generating facilities with non-zero marginal costs, coupled with ii) inflexible distribution systems marked by high sunk costs. Such a system requires significant organizational support and incurs significant overhead and transactions costs (Williamson, 1975). Traditional technology is predicated on hierarchical organizations with broad operational support capabilities and agglomeration (scope/scale) economies. New modular technologies, however, may alter this situation just as technological progress has eliminated agglomeration economies in other technology-based processes including diagnostic imaging and health care delivery. The typical hierarchical structure of an electric utility may dissolve under the VU and re-emerge as a modularized structure operating in a decentralized market economy rather than an agglomeration economy. Traditional capital budgeting techniques which rely exclusively on revenue and expense flows fail to even consider organizational costs let alone the potential organizational synergies of enriching the mix of generating technologies.

Radical and architectural innovations require new sets of organizational skills and knowledge and thus create problems for existing firms: since it is difficult and costly for them to readjust their skills and knowledge base, such firms face distinct disadvantages in the adoption of the new technology (Henderson and Clark, 1990)[8] which partly explains why radical new technologies are often diffused through new ventures or start-ups. Because of this requirement for continual renewal and upgrading of organizational skills and capabilities, organizational (Argyris and Schon 1978; Fiol and Lyles 1985; Senge 1990; Teece 1990; Garvin 1993; Dodgson, 1993) and technological learning (Dodgson, 1991a, 1991b; Carayannis, 1994, 1995a, 1995b, 1996) become important. Further, we argue, resistance to technological innovations may in part be explained by entrenched, dominant "mentalities"—ways of conceptualizing business practices, decisions and strategic options—which have given rise to deeply rooted capital budgeting and other organizational processes. And, while enhanced capital budgeting processes provide the foundation for change, a corresponding change in the entrenched mentality requires organizational learning.

Argyris and Kaplan (1994) note that successful implementation of new processes and technologies requires three interrelated characteristics of learning. First, the "technical theory" supporting change must be demonstrably valid; in particular, its

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[7] Additional discussion can be found in Awerbuch, et al (1996).

[8] Examples: IBM missed early growth in PC markets which was captured by Apple—an upstart; Keuffel and Esser (slide rule manufacturer) virtually disappeared with the diffusion of pocket calculators—a radical innovation; RCA (vacuum tubes, large radio/TV) lost market share to Sony, which capitalized on transistors and miniaturization, an architectural innovation which RCA deemed to be "inferior technology" (Henderson and Clark, 1990: 10). This legacy even follows the digital watch, an architectural innovation that Swiss and American watchmakers also judged to be inferior.

internal consistency and external validity must be established. Second there must be an educational process often characterized by repetition and experimentation through which organizational participants are convinced that the new processes and technologies are valid and useful. Finally, there must be sponsorship of the new technical theory in the organization. Combined, these three characteristics represent the collective process of organizational learning, which, through repetition and experimentation, enables new ideas, opportunities and technologies to be identified and accepted and new decision making processes be performed better and quicker (Teece, 1990). Organizational learning is focused on uprooting established notions about decision models and technological change. It involves the development of insights, knowledge, and associations between past actions, the effectiveness of those actions and future actions (Fiol and Lyles, 1985); it is a process involving the detection and correction of error (Argyris and Schon 1978). Learning is both an individual *and* an organizational process which occurs not only through the imitation and emulation of individuals, (e.g. teacher-student), but also through joint contributions to the understanding of complex problems so that it requires common communication codes and coordinated search procedures (Teece, et al 1990). This paper seeks to demonstrate the validity and stress the necessity of a enhanced approaches to capital budgeting and cost control in electric utilities. It attempts to contribute to the educational process necessary for the introduction of new ways of thinking in organizations.

THE LIMITATIONS OF TRADITIONAL CAPITAL BUDGETING

The Revenue Requirements Method (RRM) and EPRI-TAG concepts used by utilities to evaluate alternative options can be traced back to the beginning of this century, although the procedures did not mature until the post World War II era (Awerbuch et al., 1996). These procedures were conceived in a different technological era, and, as applied, no longer work well. Generally, discounted cash flow procedures (and their utility derivatives—RRM and TAG) were developed for manufacturing and generating technologies with specific characteristics: they were *active*, *expense-intensive* and possessed a *finite durability*. [9] The technologies were *active* in the sense that fuel, labor and overhead inputs were consumed by mechanical processes and converted into measurable outputs. The continual input of resources, as well as the maintenance of the mechanical processes were, from a financial point of view, expense-intensive. The characteristic of finite durability ensured that each day of using machinery required increasing operating/maintenance costs and falling returns thus bringing the ultimate replacement of the complete mechanical process that much closer.

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[9] These attributes, which lend themselves to the characteristics of the economic engineering mentality, were previously discussed in (Awerbuch, et. al., 1996).

In addition, utility generation technologies were marked by relatively low rates of technological progress. This has several implications. First, in such an environment, the useful life of a particular asset can be conceptualized as being driven by the rate at which that asset wears out. Since technology remains essentially constant, an asset with low wear on it will be worth a relatively high proportion of its original value. This does not hold when rates of technological change are high, e.g. computers, where the value of a used asset has more to do with rates of technological change than with how much "wear" it has had (e.g. how many hours it has been used). Moreover, low rates of technological change suggest that a new machine will have only incremental improvements to it. For example, while the traditional "new" milling machine may have had better speed control and somewhat higher slew rates, it was essentially unchanged and therefore did not require major changes in the way the firm produced its product. As a result, overhead and other support costs did not change much from what they were with the previous machine. This illustrates that the replacement decision, and, for utilities, the capacity addition decision, was at one time well supported by the existing accounting. Indeed there was little need for intuition: "intangible" benefits, if any, were small.

The attributes of *activeness*, *expense-intensity* and *finite durability* could be found in most traditional, process-oriented technologies, whether the product was screws, or kilowatt-hours. However, the nature of technology has changed: new process technology, whether CIM (computer-integrated manufacturing) or PV/renewables, is frequently *capital-intensive* which creates important accounting measurement issues since sunk costs are not readily dealt with by the traditional accounting model. In addition, new process technologies are often *passive*, i.e.: there is little distinction between its state of being "in-use" versus its state of being "idle" or "off"; costs are virtually the same, which suggests a marginal cost function radically different from what utility economists and planners are used to seeing,[10] These characteristic also make it harder to allocate costs to output: the personal computer, for example, loses value not in relation to the hours it is used, but as a consequence of technological progress in the industry.[11] Finally, passive technologies possess essentially *infinite durability*—their actual use contributes little to their "wearing out." Indeed, given today's shorter manufacturing life-cycles and high rates of technological change, technology becomes functionally obsolete before

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[10] Stigler (1949) provides some insight into the marginal cost function for a technology with no variable costs: it is a vertical line at its capacity limit, i.e.: short-run marginal costs are essentially zero until the capacity is reached, at which point they are infinite.

[11] Passive, capital-intensive assets do not consume operating costs as do active, expense-intensive ones. The single largest cost for passive assets is depreciation, which is the rate of change in the asset's economic value. Accounting practice cannot estimate this cost reliably. This means that to estimate expected production costs with passive assets requires the accountant to anticipate future technological progress for a particular asset group—a tall order indeed.

Economists view depreciation as a measure of changing economic value, while accountants view depreciation as an allocation of historic (sunk) cost in an "arbitrary but systematic" manner. Sunk cost bears no relevance to actual economic costs of production although the two can be made equivalent through the correct design of accounting depreciation. For discussion see Awerbuch (1992 a, 1992b).

"wearing out" in the traditional sense. Characteristics of passive, capital-intensive technology are not consistent with the ideas underlying the economic engineering mentality which attempts to reconfigure and mold the attributes into a traditional capital budgeting model with the consequence that it fails to appropriately capture the true costs and benefits of passive technology.

The investment decision for passive, capital-intensive technologies is considerably more complicated, and accounting information no longer provides adequate decision support.[12] This affects the valuation of the VU which is based, in part, on passive generating and telecommunications technologies that radically alter the manner in which electricity is produced and delivered.

As suggested at the beginning of the paper, there is much to learn from the experience of other industries that have dealt with the limitations of traditional capital budgeting techniques in response to rapidly changing environments. The following section explores the inherent limitations of traditional capital budgeting and accounting measurement.

THE LIMITATIONS OF TRADITIONAL ACCOUNTING AND CAPITAL BUDGETING

The shortcomings of capital budgeting as applied to the evaluation of CIM and other new passive process technologies have received considerable attention (see for example: Kaplan, 1986). In addition, traditional capital budgeting has been criticized as underlying the myopic investment strategies of American firms during the last two decades (Hayes and Garvin 1982; Hayes and Abernathy 1980). Indeed, it is suggested that traditional capital budgeting techniques have a dismal record in identifying promising new technologies, and have failed to see the important benefits of such major innovations as computers, CIM, computer-aided design (CAD) and robotics (see Awerbuch, 1993a). In a similar vein, we would argue that RRM and EPRI-TAG models have failed to fully recognize the value-adding benefits of passive, distributed generation alternatives because of their myopic focus on direct cost. In this respect, we argue that the benefits of new process technologies in electricity generation can be fully understood only through the use of more robust capital-budgeting techniques based on more powerful accounting vocabularies.

In short, newly emergent technologies have distinctly different benefit/cost attributes which must be captured by enhanced investment decision models. We contend that traditional capital budgeting techniques constitute an impediment to learning. They are rooted in the mechanical concept of production whose attributes

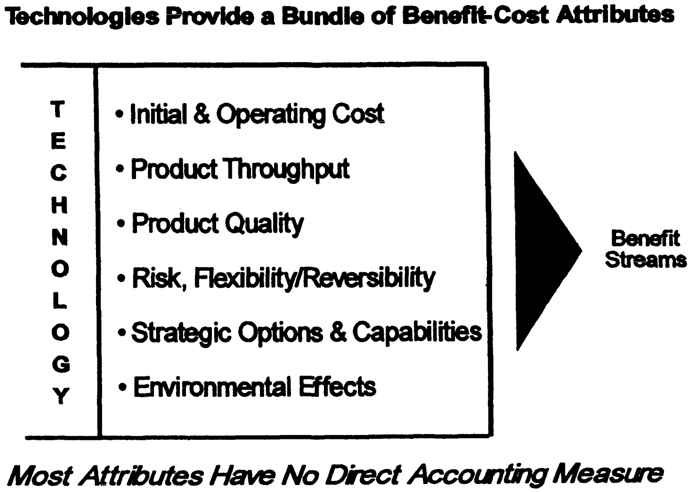
[12] When passive, capital-intensive equipment replace traditional technologies manufacturing processes are usually altered as are throughput, quality and other factors which radically alter the cost picture. When passive technology is replaced with newer vintages the decision is even more complex since judgment must be made regarding capabilities, and regarding the manner in which the new technology affects other aspect of the firms process.

coincide with the deeply entrenched economic engineering mentality of the electric utility industry. New, more robust approaches must recognize, if not quantify, the atypical benefit/cost attributes of new technologies. The next section discusses some of the "atypical" benefit attributes ignored by traditional capital budgeting.

The Attributes of New Process Technologies in Manufacturing

A fundamental capital budgeting lesson to be gained from the experience in manufacturing is that new technologies provide an indivisible bundle of benefit/cost attributes which invariably will differ from those of the conventional technology (Figure 1).

Figure 1. Evaluating New Technology.



This was not generally the case in previous technological eras, where, given low rates of technological progress, a new machine may have differed only incrementally from the previous vintage. Although the differences between new and existing technology choices are generally multidimensional, traditional analyses tend to focus on only one attribute—direct cost—both initial and operating. It is easy to see why this happens. Most of the important attributes of new process technologies have no direct accounting measure and are therefore easy to ignore or to relegate to the "intangibles" category.[13]

[13] For example see the Simmonds-Machine case in Giffi, et al (1990: 170-171).

The traditional focus on cost ignores other important technology attributes such as throughput, and quality which in some cases are the important cost drivers.[14] Other attributes which drive cost relate to the way in which new technologies affect project risk, reversibility and flexibility, all of which have by now been widely recognized.[15] For example, we may be able to estimate a set of expected manufacturing costs for a capital-intensive CIM process and compare them to the expected costs under the current labor-intensive process although the two are not directly comparable: a labor-intensive process is subject to the vagaries of the labor market while the capital-intensive process presents a set of known, up-front outlays coupled with very low annual operating costs. Barring implementation problems, the costs of capital-intensive processes are known with near-certainty.[16]

The flexibility attributes likewise play an important role in electricity generation. Conventional, fuel-intensive technology is inflexible: it requires the firm to commit to the construction of large, irreversible, central-station plants, such as coal, some ten years prior to completion of the plant. The construction period is fraught with uncertainty—environmental and siting permits, various local, state and federal approvals, etc. Assuming the project survives these hurdles, it must operate per the original forecast, by now, easily ten to fifteen years old.

In contrast, a PV project can be more readily moved to meet changing geographic demand; in addition, its scope can be readily altered, or, it can be sold; the modules may not fetch their original cost but will at least fetch some respectable proportion.[17] Hence, under the VU environment a new option set emerges, created by the modular capability of new generating alternatives including small gas turbines, PV and other renewables. This capability can be seen in several different ways. First, it means that these technologies can be installed in small increments as load grows, much the same way the local telephone company installs central-office equipment. It also means that projects can be scaled back or moved geographically, should conditions change. The rapid response to changing load and other conditions

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[14] Product quality and throughput are by now both widely recognized as reducing cost; see, for example, Giffi, et al. (1990).

[15] For example, risk and flexibility attributes are a major factor in producing correct estimates of relative generating costs for renewable- as compared to fossil-based generation.

[16] This has considerable significance for conventional generation where firms will likely have incentives to use various hedging strategies to control fuel price risk. This has not been an issue for most utilities in the past because of the fuel-adjustment clause.

[17] The abandonment of PV installations at Lugo and Carissa Plains (California) illustrate this flexibility. These sites were sold by ARCO to an investor group (See: Strategies Unlimited, *Solar Flare,* 90-1, February 23, 1990, 6-7). The electric output had been sold to Pacific gas and Electric at $.03 per kWh, although the investor group estimated it needed $.10 per kWh to make a profit (Corwin, "Solar Energy Eclipse," *Los Angeles Times*, Volume 110, No. 235, Sec. A, July 26, 1991). The group, therefore, began to sell the panels, expecting to sell the entire supply over a four-year period (Strategies Unlimited 1990: 7). About 20% of the panels were sold in the first year (Corwin, 1991), the remainder were offered in various direct mail catalogues for about $4.00/Watt to $4.80/Watt. The EVA encapsulation of the modules had darkened, which seemed to degrade output by a maximum of 20% (Corwin, 1991), although retailers claim a smaller, 10% degradation (Alternative Energy Sourcebook, *The Real Goods Company*, Uriah, CA, 1992).

reduces uncertainty associated with the long lead-times of traditional, lumpy central-station technologies.[18] It also greatly reduces the enormous overhead costs of planning and implementing lumpy central-station investments.

Flexibility/reversibility therefore means that modular PV installations, though they are highly capital intensive, may actually have lower *sunk costs* and hence can be salvaged at some reasonable fraction of their original cost [e.g. see Hoff in this volume]. This is in comparison to inflexible technology, say a coal plant, where the sunk costs of, for example, engineering design and (literally) bricks and mortar mean that once completed, such plants will generally have a negligible or even negative salvage value. The ability to move or scale-back generating projects reduces risk, and, moreover, enhances the likelihood of demand-supply equilibrium.

Figure 1 showed the set of strategic/capability options provided by new technology. This option-set suggests that by adopting a new process technology, firms may develop certain *capabilities* which Baldwin and Clark (1992), define as "groups of expenditures, which, when taken as a whole, represent an investment for the firm." This suggests that process technology should be adopted under certain situations, even where the present values are relatively low, because the investment is needed to stay on the learning curve, i.e. to create the options for subsequent technology adoption in the future.[19] New technology generally also provides a different set of environmental attributes which are often more benign. Our tools for measuring these benefits are poor. Even poorer is our ability to value the results intertemporally, where theoretical as well as practical impediments exist.[20]

ASSET VALUATION UNDER RAPID TECHNOLOGICAL CHANGE

Valuing electric resource options in an environment of rapid technological change presents special challenges not traditionally faced by utility planners. In such an environment, traditional, relatively static valuation models do not generally allow managers to properly evaluate radical and architectural innovations.

Figure 2 illustrates this problem. It shows the expected output or performance level relative to the required investment for two hypothetical process technologies—an established, dominant technology and a "challenger"—a new innovative process. The established technology, which is depicted as being in the middle range of its S-

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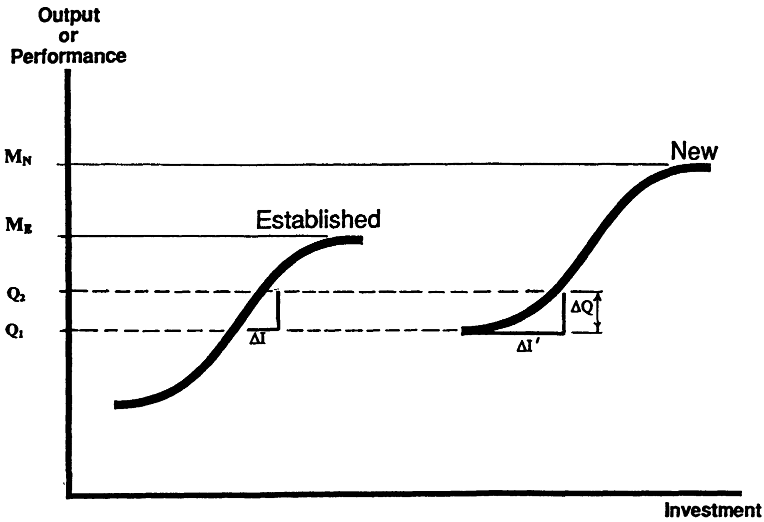
[18] Hoff (in this volume) values some of these flexibility options.

[19] The approach seems to rely less on traditional capital budgeting and more on benchmarking. Carayannis (1996) views benchmarking of best practices as critical in fostering an organizational learning culture that would be the foundation upon which to build a VU.

[20] Awerbuch (1993a) discusses the valuation of environmental externalities using the *social rate of time preference*.

shaped curve,[21] i.e. it has not yet fully matured, is "challenged" by a radical or architectural innovation.[22] We assume that managers have continually improved the established process over time, and, through experience, have found that a $ΔI investment in process improvement raises output from Q1 to Q2, an increase in output of ΔQ. The quantity ΔQ can be thought of as an increased physical quantity produced, a quality improvement, throughput enhancement or cost reduction.

Figure 2. The Capital Budgeting Problem—Cost and Performance: New vs. Established Technology.



Adapted from Richard Foster, Innovation: The Attacker's Advantage.

Let's say that managers are aware of the new process but are reluctant to adopt it because it seems "too risky" relative to a strategy of continued incremental enhancements to the existing process. Kaplan (1986) and others have criticized the managerial tendency to undertake incremental improvements over major, radical ones, but, as Figure 2 illustrates, such a strategy may indeed make good sense from a manager's point of view.

Indeed, the basis for managers' reluctance to adopt radical innovation may be seen quite directly: observe that in order to attain an output level of Q2 with the new process, managers will have to make a much larger initial investment, $ΔI'. Using standard, accounting-based capital budgeting procedures this investment appears

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[21] Logistic (S-shaped) curves are frequently used to describe the emergence and maturation of technologies over their life-cycle. Fisher-Pry is probably the best-known of these models. For additional discussion see Hatten and Piccoli [1993].

[22] The notion of an established process or product being "challenged" as depicted by the S-shaped curves of Figure 2, is taken from Foster (1985).

too risky and the incremental improvement to the established process (represented by $\$\Delta I$) seems a much safer bet.

But this view is static: it ignores efficiency gains likely to be attained by each technology as it progresses along a learning or experience curve (see for example: Utterback and Kim, 1985; Abernathy and Wayne, 1974). While this view is therefore defective as Kaplan (1990) and others have argued, the failure does not necessarily reflect an inherent weakness in the discounted cash flow (DCF) model. Rather, the problem centers on mechanical application of DCF which often omits technological progress and learning considerations that might highlight the ultimate efficiencies of the new process relative to the established one.

And this goes to the heart of the problem described by Kaplan (1990): over time each incremental investment to the established process is made by managers on the basis of the static view since little reliable information exists about the future. Given such information about future performance and price managers would recognize that it is in their interest to adopt the new process early so that they can develop *capabilities* which will better position them to fully exploit the new technology before competitors make their switch.[23]

The manager's problem, of course is that information of the type presented in Figure 2 is not available *ex ante*, but only with hindsight, where it does little to help the decision process. Absent such decision information in real time, it is difficult for managers to know when to adopt the new technology so they wait until it becomes the "least cost" on a static, accounting basis.

With perfect information managers would recognize the future limitations of the established technology, which would suggest that continuing to invest solely in it is wasteful. If they continue to make $\$\ \Delta I$ investments each year they will end up at point M_e, whereas by switching early to the new process they will attain the higher output level M_n. The result is that while each individual $\$\Delta I$ investment appears to be the "least cost" (and lowest risk) at the time, when viewed in total, such "piecemeal" investments in a mature established process only worsen the ultimate outcome: they yield obsolete processes and systems which have been incrementally enhanced over time with no cumulative benefit (Kaplan, 1990).[24]

In valuing the VU and other innovations in electric production and delivery it is important to avoid simplistic, static models to represent more complex dynamic processes. While this suggests the need to devote resources to the measurement of technological progress, in order to develop a set of technology cost/performance expectations over time, it also must serve to underscore the limitations of accounting-based capital budgeting models. While current capital budgeting procedures *project* to the future, they reflect only the past. To make things worse, they are se-

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[23] This is the "*strategic present value*" issue raised by Bierman and Smidt (1988): it is a reason why firms adopt negative net-present-value projects. Another benefit is the information acquired from the project, which cannot be obtained through other means.

[24] There are exceptions of course: Harrigan (1994) discusses various "Endgame" strategies for exploiting mature businesses and processes.

verely hampered by the limitations of the accounting vocabulary they employ. These issues are explored next.

THE NEED FOR A NEW ACCOUNTING VOCABULARY

We have suggested that entrenched mentalities, which are based on the characteristics of traditional, active, expense-intensive technologies, influence the way in which capital budgeting techniques are constructed and applied. In this section we further argue that accounting vocabularies and measurement systems additionally reflect and reinforce entrenched mentalities. In this respect new accounting vocabularies and accounting based information support systems become an important component the educational process of organizational learning. Different accounting vocabularies enable problems to be conceptualized in very different ways and allow entrenched ways of thinking to be challenged.

Utility accounting and reporting systems have evolved little since the early 1930s. They are geared primarily to the regulatory need to precisely determine which costs are to be capitalized and subject to depreciation and which are to be expended in the current period; they are intended to report the utility's financial performance position. Like the financial reports of commercial organizations, utility accounts are of little value for management planning, control and decision making in a rapidly changing regulatory and market environment. And while utility managers are facing increasingly complex pricing decisions and are under pressure from regulators and competitors to monitor and control the costs of generation, transmission and distribution, they posses inadequate cost information for decision support. Accounting systems designed for one purpose, i.e.: reporting to regulators, are inadequate for management planning and control. The FERC chart of accounts [Federal Power Corporation, 1973], though very elaborate in defining assets, categorizes generating costs into only *Fuel, Operation and Maintenance (O&M)* and *Depreciation*, thus representing a huge agglomeration of different cost types whose relationships to output is only poorly understood. While some utilities have begun to disaggregate cost information, these systems typically fail to recognize even the simplest notions of fixed and variable costs making it difficult if not impossible to construct cost models for standard costing, planning, and control. In addition, it is difficult if not impossible to perform incremental analyses or to evaluate alternative technologies. In short, traditional utility accounting systems fail to identify the nature and behavior of individual generating costs. Given the relatively underdeveloped state of utility cost and management accounting, considerable work is needed in order to provide the cost information necessary for the VU.

Activity-Based Costing in Manufacturing

For these accounting issues as well, there are lessons to be learned from other industries such as manufacturing, companies have developed sophisticated cost control techniques in response to competitive pressures. Traditionally, manufacturing costs were separated into their fixed and variable components using statistical analyses that, for much of this century, assumed that output volume—the number of units produced—is the only meaningful cost driver which implies that the manufacturing process generates costs only in direct proportion to the volume of units produced. Managers ignored fixed costs on the assumption that they were not controllable, i.e.: they had to be incurred in order to provide physical plant and facilities for production.[25] As a result of stiff international competition and rapidly changing process technologies in the 1970s, however, US manufacturers found it necessary to develop a better understanding of product costs. The most touted such technique is Activity-Based Costing (ABC), which has spawned a whole new vocabulary for understanding cost behavior in manufacturing which, in turn, has taught manufacturing managers to re-conceptualize not only the manufacturing process but also the nature of their products and their relationship with customers.

Unlike traditional cost techniques which focused upon managing direct costs, principally materials and labor (Awerbuch, et. al. 1996), ABC focuses on the tracing and management of overhead costs which, by the 1970s, had risen considerably relative to direct costs. ABC identifies manufacturing activities (cost drivers) that cause "fixed" costs—those that are not driven by output volume—and charges them to products. Examples of such activities are machine set-ups, quality inspection, product design and the production of waste and defective units. These costs were traditionally largely ignored; managers took them as "givens." Compared to traditional costing systems that assign overhead costs on the basis of arbitrary plant-wide rates such as direct labor hours, ABC has revealed considerable product cross-subsidization in multi-product firms. In particular, ABC suggests that high volume, low complexity products with relatively little waste and few machine set-ups and inspections have traditionally subsidized low volume, high complexity products which require similar amounts of direct labor, but which consume considerably greater amounts of overhead activities. Indeed, understanding the nature of fixed costs—those driven by factors other than output—is important as utilities struggle to remain competitive.

Along these lines, a dimension of ABC that is of particular relevance for utilities is its ability to identify value and non-value-adding activities. The emphasis here is not on product costing, but rather, on improving performance by: i) eliminating or reducing non value-adding costs and ii) increasing the efficiency of value-adding activities. Indeed the control of overhead costs, which was traditionally ignored in manufacturing, has become *the* factor that gives manufacturers an advantage in their increasingly competitive environment. While ABC has become fairly well es-

[25] Additional discussion on the accounting basis for these assumptions is given in Awerbuch, et al., 1996]

tablished in manufacturing, it is yet in its infancy in other industries including health care, financial services and utilities.

The Behavior of Utility O&M Costs

Utilities have made little effort to understand the nature and behavior O&M costs. While small in comparison to fuel outlays, their control nevertheless may yield potentially significant cost savings. Analysis of O&M costs requires two steps. The first conforms with traditional managerial (statistical) cost analysis to identify O&M cost components which are fixed with respect to kilowatt-hour output and those which vary with output. If, as our own preliminary empirical investigations suggest, a considerable proportion of O&M costs are fixed, then ABC or other management accounting techniques are needed to identify activities and drivers that cause fixed O&M costs to be incurred.

Preliminary investigations into the activities and cost drivers of electric utility maintenance costs reveal a number of interesting points. First, fossil fuel plant maintenance is not a single homogeneous activity. Rather, at least five activity centers can be identified:

1. Planned outages and overhauls;

2. Forced outages and repairs;

3. Ongoing maintenance of faults in non critical components;

4. Preventive maintenance

5. Predictive maintenance.

Second there exists a hierarchy of cost drivers that cause these five maintenance activities (and their cost) to be incurred. The hierarchy includes (at least) the following three drivers:

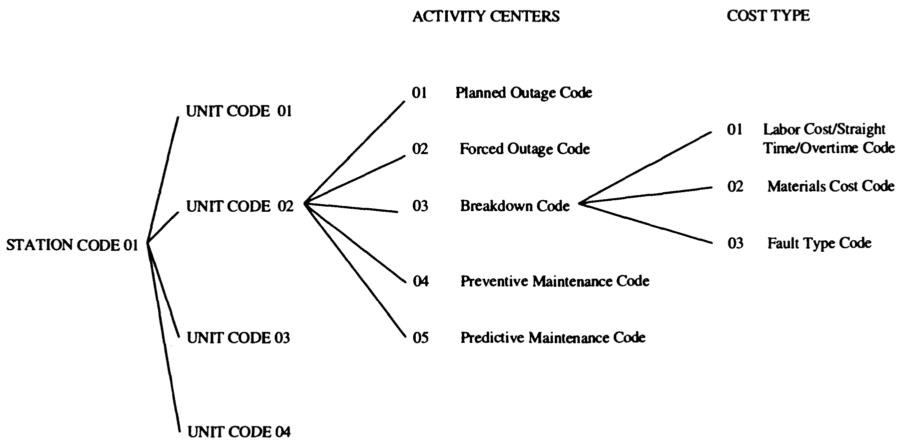
1. *Plant Design:* Particular generating station engineering design and construction creates inherent or "built-in" in maintenance problems; and therefore, drive maintenance costs.

2. *Operating Procedures and Load Type:* The manner in which a generating unit is operated may drive maintenance costs. Such operation can vary with the type of load, e.g. contract power for known, specified periods versus for power generation for dispatch. In addition, deep cycling of baseload plants to meet base, and intermediate as well and peaking demand will drive maintenance costs differently than if the units were run as baseload only.

3. *Maintenance policy:* Maintenance policy itself drives costs in different ways. For example, the typical utility policy of scheduling a standard list of maintenance tasks during a planned outage, whether or not the repairs are necessary, clearly drives maintenance costs up. In contrast, just-in-time maintenance policies, under which repairs are conducted only on those components that need them, drive costs in a very different way.

Designing accounting systems to capture the costs of each of these activities is an important first step to monitoring and then determining whether the various maintenance activities add-value to the generating process. Figure 3 outlines the structure of such an accounting system.

Figure 3. Map of Accounting System.



Utility maintenance policies are undergoing frequent changes and tracing costs to activities becomes an essential element for evaluating such changes. For example, when changing from traditionally scheduled to just-in-time maintenance, it is important to trace costs to activities so the effect of the change can be evaluated. Of particular importance in this situation is the issue of cost *shifting* versus cost *savings* and it may turn out that revised maintenance policies simply shift costs from one maintenance activity to another or from the current to a future period without creating actual cost savings. Indeed, absent adequate cost tracing to activities over time, the value-adding benefits of new maintenance policies are not determinable. For example, a number of utilities are seeking to reduce the cost of planned outages by: i) extending the time between planned outages; ii) deviating from previous scheduled repair/replacement tasks and repairing/replacing only components that are demonstrably faulty, and iii) deferring repair/replacement of partially worn components with the expectation that they will remain functional until the next planned outage.

If we define the value-added attributes of generating station maintenance costs as those which increase the reliability/availability of the unit in the most cost effective manner over time, then clearly fixing components that are *not* broken adds no value. However, if a policy of deferring planned outages (or repairs within a planned outage) increases the number of *forced* outages or the cost of future planned outages, then such a policy, thought it creates short term savings, does not add value. The effects of revised maintenance policies, therefore, cannot be easily determined at present because existing accounting systems fail to track costs to activities.

Cost Conceptualization: Analogies from Other Industries

ABC might also help cost control in transmission, distribution and marketing of electrical services, where a focus on activities and cost drivers might lead to a re-conceptualization of electricity as a diversified set of products. Similar re-conceptualization occurred in health care, where it profoundly affected the delivery of service in the US. In the early 1980s, diagnosis-related groups (DRGs) were introduced as a means of recognizing the different resource consumption patterns associated with different diagnoses and treatment regimes [Smith and Fottler, 1985]. Such a differentiation was not possible previously since hospital costs were simply averaged into a cost per bed-day, as they had been for at least a century. As a result of this re-conceptualization, hospitals evolved into multi-product firms rather than workshops for doctors [Preston, 1992]. Costing systems were transformed from a mere calculus for third party reimbursements into sophisticated budgeting and cost control systems designed to measure the relative profitability of each DRG. DRGs and the accounting vocabulary they spawned have fundamentally affected the provision of medical treatment and made doctors responsible and accountable for the cost of treatment.[26] In this respect, the traditional separation of cost and treatment has collapsed and with it the physician, as the dominant decision making authority.

Similar concepts in electric generation/delivery might be used to cluster customers into service-related groups (SRGs) which consume equivalent or similar amounts of services, or to define utility output in terms of various services, e.g.: energy-related-service groups (ESRGs). SRGs could be differentiated along the lines of population density, distance from the station/substation, time of day, and use and quality of supply. ESRGs could be defined as certain types energy (i.e. quality, time-of-day, type of usage, etc.), as well as particular energy services. This is in contrast to the current conceptualization of all output as a single, generic product consisting of undifferentiated kilowatt-hours. As was the case in health care, a re-conceptualization of the utility product will require specific information on generation and, in particular, on transmission and distribution costs associated with serving each of the SRGs. Clearly, the out-dated busbar cost measure and its underlying cost-accounting vocabulary as constructed the FERC-dictated chart of accounts are inadequate for the decision contexts utilities are beginning to face.

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[26] Starr [1982] would say this is to the detriment of the profession,

The process of evaluating alternative resource technologies in a VU environment highlights the limitations of utility accounting. Traditional capital budgeting techniques focus on direct costs and fail to account for the different indirect and overhead costs of passive generating technologies; activities and cost drivers that cause fixed O&M costs to be incurred are clearly quite different for passive technologies. In this respect, ABC benefit/cost analyses may reveal very different cost savings as well as intangible benefits than the more traditional capital budgeting techniques and measurement systems allow for.

Likewise, re-conceptualization of the utility product will spawn detailed accounting information and will generate insights into how particular customers may be more effectively served by a combination of central and distributed generating technologies such as DSM. Creating a new vocabulary may, as has happened in other industries, result in a new appreciation of the nature and behavior of costs in the various generation technologies and in transmission and distribution systems. This might not only result in improved performance of existing generating technologies but also may encourage new processes of organizational and technological learning to better appreciate the benefits/costs of technological innovation and organizational restructuring.

CONCLUSIONS AND MODEST SUGGESTIONS

Existing utility capital budgeting procedures and cost control are inadequate to properly value new technologies and to improve performance in a VU environment. However, we have probably learned enough from manufacturing so that we might be able to i) develop adequate systems of cost monitoring and control and ii) catalogue or at least identify a potential list of suggested approaches which may help value VU concepts.

The valuation issue cannot be addressed without an adequate accounting system. Of course valuing VU concepts may not be sufficient reason to introduce a new accounting system but as previously discussed, the new environment will require such systems with the following characteristics:

1. They must transition from traditional accounting systems designed for regulatory reporting to ones that can provide cost information in support of management planning, control and decision making.

2. They must identify fixed and variable fuel and O&M costs. Much work is needed to understand the nature and behavior of these cost components.

3. They must be disaggregated costing system capable of tracing costs to those activities and cost drivers which cause particular cost types to be incurred in delivering particular ESRGs.

4. They must support a mode of analysis which evaluates the value-adding attributes of alternative management policies.

5. They must enable methods for tracking costs to bundles of services that will be offered to customers in a VU environment.

While such systems will undoubtedly enhance capital budgeting valuations. it is will probably be useful to make *qualitative* assessments of where the benefits of an architectural innovation such as the VU may lie and what form they will take. This procedure, which is aimed at helping to identify and define potential benefits, consists of evaluating he following issues and threshold questions:

1. Are anticipated benefits largely cash-flow related?

Often they are not, which suggests that DCF type approaches, as traditionally applied, will only capture part of the benefit stream.

2. What are the "non-cash" benefits?

The experience in manufacturing suggests that these will take the form of enhancements in quality, reliability and flexibility. While these ultimately do affect cash flow, it is hard to conceive of them in this fashion. Obviously this question requires some understanding of what the quality-reliability-flexibility concepts mean in the case of electric delivery.

Borrowing from the manufacturing experience, it is safe to suggest that *quality* means the minimization or elimination of non-value adding activities in the electricity generation and delivery process. Additional accounting-based research will likely demonstrate that non-value adding activities include such concepts as reserve capacity requirements, which, like manufacturing inventories, are an outgrowth of an engineering oriented solution conceived for a previous technological era. [27]

Eliminating non-value adding activities probably requires a sweeping re-conceptualization of the manner in which electricity is produced and distributed, just as in manufacturing, the elimination of inventories, product changeover times and similar innovations required a radical reorganization of the production process. The growth of electricity futures trading will likely provide one mechanism for so re-conceptualizing the process. Such options not only enable a firm to acquire needed reserves in an instantaneous, frictionless manner, but they also blur the distinction between energy and capacity—a distinction that is a central part of the current delivery system.[28]

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[27] *Flexibility* undoubtedly means the ability to rapidly shift supply sources and capabilities to meet unanticipated market demand; Retailers, from *The GAP* to *Levi's* have learned to maintain such flexibility with inventory systems that respond to real-time point-of-sale information.

[28] See Graves and Read in this volume.

3. Does the new technology enhance capabilities or strategic options for the firm?

This evaluation necessarily entails assessing the VU in terms of its ability to yield new capability and strategic options for the firm to serve new customers and markets. These capability or strategic options may come in the form of increased ability to serve specialized needs or markets, or to provide new products and services that consumers may value. Some of these new customers and markets may simply take the form of new loads—i.e. charging electric vehicles—just as the proliferation of fax machines and on-line services have generated new demands for telephony. Others may emerge out of technologies and demands not currently envisioned.[29] Flexible organizations, using flexible technologies coupled with innovative financial arrangements may be able to better serve emerging customers and market. Part of the valuation of the VU necessarily depends on an assessment of these possibilities.

4. Does the firm really have a choice about adopting new technologies or organizational structures such as VU?

One line of argument suggests that firms do not really have choices regarding the adoption of broadly based innovation when competitors are embracing them. Kaplan (1986) notes that firms which adopted numerically-controlled production machinery in the 1970s developed an added capability which made subsequent adoption of CIM easier. Indeed there are numerous examples of firms in electronics and other industries who did not stay on the "learning curve" and subsequently lost considerable market preeminence. The threshold question is whether failure to adopt VU and related innovations will place the firm at a strategic disadvantage in the future.

5. Does the VU yield complementary overhead and other cost reductions?

Milgrom and Roberts (1990) develop the idea of the *cost complementarity of new technology*, which suggests that some new process technologies, while not yielding direct operating cost reductions, produce complementary benefits elsewhere in the production process. A complementarity of computer-aided-design CAD, for example, is that it enables direct input to computerized production equipment thus reducing the cost of product changes. Considerable analysis, coupled with experience will be required to evaluate the extent to which the VU concept provides such benefits. However, this much is certain: simplistic analyses that compare busbar costs will not capture the needed decision-making information.

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[29] For example, tiny heat pumps could reduce electricity consumption by 50% ("Developments to Watch," *Business Week*, May 30, 1994, page 129) thereby significantly increasing demand for electric space heating in parts of the country.

6. Is the cost-accounting system reliable enough so that we can reasonably estimate the cost of using a new technology over the previous vintage technology?

The general answer to this question is "no." In order to make technology comparisons we must understand not just the busbar or direct costs involved, but also the *total costs* of using a particular technology including:

1. its use of the firm's overhead activities, and

2. its creation of ancillary costs elsewhere in the production function.

It is doubtful whether we even properly understand the cost link between particular generation/delivery options and the various activities and functions they require elsewhere in the process. For example, high-marginal cost generating technologies support pricing structures based on the units of electricity consumed; this requires meter-reading and billing costs which can be relatively high for low-consumption customers. Low marginal cost technologies, by contrast, like wind and PV, are more suited to leasing or fixed price arrangements for a pre-determined quantity of consumption. For example, with a 25% insolation factor, the "busbar" cost of PV-based electricity is essentially unchanged over the range of 0 to 2190 kWh per year for each kilowatt of capacity. This eliminates meter-reading and possibly other billing costs.

7. Do we understand how overheads are consumed by current vintage technology and operations as compared to a new process?

> Given current utility accounting we undoubtedly do not know how particular technologies and the activities they generate consume the firm's overhead resources. For example, we do not explicitly account for lengthy planning and review procedures for the construction of central-station capacity. Without such knowledge it is difficult to value the quality enhancements that may be provided by VU organizations.

The above list of accounting requirements and threshold valuation questions may represent an ambitious and possibly even vague set of assessment criteria although ongoing accounting system development and capital budgeting research will undoubtedly make such assessments more possible and credible in the future. A different approach may involve understanding the benefits of a given technology or operating construct by applying what is known from similar process technologies. In a sense, however, this thinking leads directly back to the above list. Finally, the above list and the discussion in this paper may prove to be more anecdotal than scientific, but, then, the entire process of valuing radical and architectural innovation is still more of an art than a science.

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5

JUSTIFYING CAPITAL INVESTMENTS IN THE EMERGING ELECTRIC UTILITY:

ACCOUNTING FOR AN UNCERTAIN AND CHANGING INDUSTRY STRUCTURE

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ABSTRACT

The electric utility industry faces fundamental and strategic changes in the way electric power is generated, distributed, and sold. Capital budgeting and capital allocation processes in traditional utilities have to be re-organized and changed to move away from an emphasis on asset additions driven by regulatory requirements to reflect opportunities and costs in the uncertain and unstable strategic structure of the new electric utility industry. This paper examines the limitations of traditional capital budgeting practices in justifying capital investments in the emerging electric utility where many of the benefits are strategic, intangible, generally difficult or impossible to assess in terms of cash flows. While there does not seem to be any one

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best universal procedure, this study develops and recommends the use of an augmented adjusted net present value (ANPV) procedure for capital budgeting in the emerging electric utility.

1. INTRODUCTION

The electric utility industry faces significant deregulation and fundamental changes in the way electric power is generated, distributed, and sold. Traditional vertically integrated electric utilities may have to be radically restructured to meet new competition from firms specializing in specific functions such as power generation, distribution, or services for retail and wholesale customers. Accounting and finance functions at traditional utilities are generally still in the process of reorganizing to provide the information necessary to support such radical restructuring. Similarly, capital budgeting and capital allocation processes in traditional utilities are also being re-organized and changed to reflect the new more competitive environment for electric utilities.

While the capital budgeting and allocation processes must change and shift away from a focus on regulatory requirements, they cannot rely just on "seat of the pants" judgments and must reflect opportunities and costs based on the new (but still unclear) strategic structure of the electric utility industry. In view of the significant changes expected in the electric power industry, many electric utilities may not survive. Under these conditions, it is particularly important to make "correct" capital expenditure decisions. Unfortunately, traditional capital budgeting procedures can have very limited capabilities under conditions of strategic uncertainty, and new capital budgeting systems for the evolving electric utility industry must be developed to overcome the limitations of traditional capital budgeting methods.

This paper starts by reviewing briefly the challenges in developing capital budgeting procedures for the restructuring and changing electric utility industry. It examines the problems faced by traditional capital budgeting practices in justifying investments in the new electric utility environment where many of the benefits of the new investments are strategic, intangible, and may include improvements in quality and the creation of new business options and flexible alternatives. While there does not seem to be any one best universal procedure, based on insights developed from the analysis of the nature of the changes facing the electric utility industry and the limitations of traditional capital budgeting procedures, this paper concludes that an augmented adjusted net present value (ANPV) procedure is most likely to be useful for justifying investments in the restructuring electric utility industry.

2. CAPITAL BUDGETING AND THE CHANGING ELECTRIC UTILITY

Traditional procedures for capital budgeting in the electric utility industry must be modified to reflect the changing nature of the electric utility industry. For example, such procedures must move away from traditional goals such as satisfying revenue requirements to market-based approaches (e.g., Bodmer and Waldman, 1995). Traditional approaches to capital budgeting and the changing structure of the electric utility are then reviewed briefly as bases for developing revised capital budgeting procedures for the electric power industry.

1. Capital Budgeting in the Traditional Electric Utility

While a detailed discussion of the possible shape of the future electric utility industry is beyond the scope of this paper, it is clear that the electric utility industry is going through some significant changes but the final shape of the industry or the structure of the optimal electric power company are uncertain at this time. However, firms in the electric utility industry are most likely to face increased domestic and international competition and continuing pressures to reduce costs and become more efficient (e.g., Pechman, 1993). In addition, electric utility capital investment projects in recent years have faced capital rationing with investment budgets generally limited by the availability of internal cash flows as most utilities have not raised external funds for capital projects in recent years. Thus, capital budgeting procedures in the electric utility industry must reflect and, as far as possible, account for these changes and challenges of deregulation, increased competition, and industrial restructuring. Capital budgeting procedures must account for the mix of explicit and implicit incremental cash flows and risks for a wide range of cost reducing, revenue enhancing, and strategic investments in an environment of changing and uncertain industry structure.

A. The NPV Rule and Traditional Capital Budgeting in Electric Utilities

Traditional capital budgeting procedures focus on the positive net present value (NPV) rule, i.e., accept all projects with positive net present values; projects where the present value of future benefits exceeds the present value of the associated costs with the discount rate used reflecting the incremental risks of the project. However, capital budgeting in traditional regulated electric utilities have generally focused on projects that minimized costs/increased the rate base or on other projects that served regulatory requirements and government mandates and, thus, capital budgeting in traditional electric utilities often deviated considerably from the pure NPV rule. For example, many utilities use the "lowest annual levelized cost" or the "present value of revenue requirements" as the primary economic justification criteria for making capital budgeting investment decisions. Electric utilities need to focus on the worth, not costs, of proposed investments (e.g., Makovich, 1995). Indeed, it has been contended that traditional electric utilities have generally not adequately assessed the incremental risks or cash flows associated with non-traditional power sources such as photovoltaics and other peaking and distributed power generating capacity, and capital budgeting in traditional electric utilities may suffer from many such fallacies (e.g., Tardiff and Bidwell, 1990).

B. The Organizational Role of Capital Budgeting

The process of capital budgeting generally covers long-term capital expenditures including investments in machines, buildings, pollution control equipment, advertising campaigns, options to buy or lease real estate, and other expenditures that have benefits extending beyond one time period. Thus, it covers a wide range of business activity and, as capital budgeting is the process of allocating capital for long-term investments, it is a central and critical aspect of implementing business strategies designed to increase the value of a business. Indeed, announcements of capital expenditure decisions by industrial firms has been found to be associated on average with positive abnormal equity market returns (e.g., McConnell and Muscarella, 1985). Capital budgeting is also an important process that certainly influences and perhaps even determines the long-run survival, growth, and value of a business (e.g., Chandler, 1990). Mistakes in capital budgeting can indeed mean business failure and bankruptcy for a business. Inefficiencies in capital budgeting have also been blamed for the competitive decline of the United States (e.g., Hayes and Garvin, 1982; Porter, 1992).

Management of the capital budgeting process in a business is generally a significant and important responsibility of top management. According to the chief executive officer of Emerson Electric, "the job of management is to identify and successfully implement business investment opportunities" (Knight, 1992). However, most proposals for long-term investment are generally initiated by the part of the business that is also likely to implement such a proposal, or is likely to be most affected by or benefit from it. Thus, capital budgeting procedures must account for agency costs and moral hazard concerns, and the organizational structure and reward systems in a business are likely to influence the generation, acceptance, and implementation of capital budgeting proposals. Once a capital project is proposed, it is likely to move up through the corporate hierarchy until it is approved or rejected. For large and critical projects, this decision may be made only at the highest levels in a business organization.

The role of top management in developing and directing capital budgets in electric utilities continues to increase and traditional approaches to capital budgeting are being modified or even abandoned due to changes in the industry environment. For example, due to the uncertain structure of the electric utility industry, capital budgeting procedures must value real options that enhance a utility's adaptability to industry changes. Further, many of the costs and benefits associated with investment proposals may be unusual, intangible, and difficult to value especially as electric utilities restructure and shift to a deregulated environment.

2. Changes in the Electric Utility Industry

Among the many changes facing the electric utility industry, it would be useful to identify those changes that may have a significant impact on capital budgeting practices. These changes include the impacts of deregulation and increased competition in the industry, and the need to reduce costs, increase efficiency, and manage stranded costs. Unfortunately, these activities must be undertaken in an environment of unstable industry equilibrium due to competitor actions made possible by the low variable costs of electric power.

A. Deregulation and Increased Competition

Just ten years ago, the electric utility industry consisted mostly of vertically integrated and regulated monopolies. In return for monopoly powers, not only was the rate of return regulated, but "mandates to serve" and higher taxes were also imposed on utility companies. Driven by changing economic and social values and following the deregulatory path taken by other previously regulated industries like airlines, trucking, banking, telecommunications, and natural gas, it seems that, in most developed countries, the electric utility industry is evolving into a more competitive business.[1] For example, deregulation is expanding competition and technology is expanding the efficiency and capacity of transmission lines and of small and alternative electric generating plants.[2] In addition, because of its lower overall delivered costs, there also seems to be a move to distributed power generating systems in many cases.[3] Traditional electric power companies must also compete with and evaluate new sources of electric power such as photovoltaics, wind power, fuel cells, aero-derivative gas turbines, co-generation, and other non-traditional sources that pose interesting challenges. Such sources may often supplement peaking capacity, avoid transmission and distribution costs, or provide risk reduction or other difficult to value intangible benefits (e.g., Awerbuch, 1996; Flavin and Lenssen, 1994; Hoff et al, 1996).

As in most developed countries, at least large customers in most states in the U.S. may soon (estimated 2–5 years) be likely to have the freedom to buy their electric power from a number of competing suppliers and such freedom for smaller re-

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[1] This revolution in the electric utility industry is also a part of the overall global move to privatization and to market based economic systems. For details regarding deregulation in a network industry like electric power see, for example, Klein [1996].

[2] Additions to generating capacity by U.S. electric utilities peaked in the 1970s; and in the 1990s, independent power producers in the U.S. have accounted for over half the new power generation capacity and now supply about a thirteenth of all electric power in the United States. Thus, we may once again be moving to an industry structure of a hundred years ago when Chicago, for example, was served by four dozen power companies.

[3] As presently conceived, distributed power generating systems often involve a mix of large central (including high efficiency combined cycle and aero-derivative turbines), small (including fuel cells and photovoltaic plants), and peaking (including flywheel and other storage) power sources with distinctive patterns of incremental cash flow and risk characteristics.

tail customers is expected to follow soon thereafter.[4] These resulting increases in the role of competitive forces and the pace of change seems too fast for many existing companies in this industry, but is perhaps not fast enough for other companies or for most utility customers (e.g., Jenkins, 1996; Navarro, 1996; Stephens, 1996). Interestingly, as indicated in Figure 1, the electric utility industries in many other countries such as the U.K. and Australia are further along this evolution to a competitive industry, and the U.S. electric utility industry may be able to benefit from the experience overseas in its evolution to a competitive environment.[5]

Figure 1. Possible Evolution of the U.S. Electric Utility Industry.

Stage	A	B	C	D	E
Example	Spain	U.S.	U.K.	Chile	?
Features	Vertically integrated	Vertically integrated	Independent generation & distribution	Independent generation, distribution, transmission	Independent generation, distribution, & transmission
	No ROR cap	ROR cap based on asset base	ROR cap for distribution & transmission	ROR cap on distribution	No ROR cap
	Monopoly	Wholesale competition	Competition in generation pool pricing	Competition in generation	Competition in generation, transmission, & distribution
Other models are being developed in Australia, Argentina, Scandinavia, & other countries.					

Source: Author analysis of trends and developments.

[4] The U.S. federal government is taking a greater role in this move to increased competition in the electric utility industry with the empowerment of the Federal Electric Regulatory Commission (FERC) to override state regulations in interstate movements of electric power. On April 24, 1996, FERC approved a Mega-NOPR whereby electric utilities must provide wholesale access to transmission facilities, and as one consequence, the derivatives market in electric power has begun to grow explosively.

[5] As an example, in December 1995, the California utility regulators voted for deregulatory procedures that mirror the deregulatory approach adopted by the U.K. in 1990. In California, starting in 1998, large electricity users (and groups of smaller ones) will be able to purchase electricity from the cheapest source with such freedom for individual customers following five years later. As in the U.K., electric utilities in California would sell power into a wholesale pool before being distributed to users and an independent company will run the transmission lines. Other state regulators in the U.S. are also expected to deregulate electric utilities within a similar time frame but, perhaps, using somewhat different deregulatory procedures.

B. Need to Reduce Costs and Increase Efficiency

Increased competition and deregulation mean that many high cost utilities may face extinction and such utilities must become more efficient in order to survive (e.g., Stalon, 1992). The traditional vertically integrated electric utility generally consists of a number of distinct businesses. Typically the three major components of the electric utility business include power generation, its transmission from the power plant to a retail distribution center or a major consumer, and finally the sale and delivery of electric power to customers. In many companies, these three core businesses are supplemented by other related service and non-service businesses.

In becoming more efficient, electric utilities and their regulators must deal with a number of issues regarding operating and capital costs. Currently, electric utilities do not have clear answers about costing and many other questions important in becoming more competitive (e.g., Awerbuch, 1993). Internally, they must develop and implement systems to determine clearly what drives costs, productivity, and customer needs in each of their businesses. Included among the many actions being taken by electric utilities to prepare for competition are restructuring attempts to develop separate companies that focus on each of the three core businesses (generation, transmission, and distribution/delivery) and companies that focus on other related businesses.[6] Such restructuring attempts are generally preceded and followed by additional programs to reduce specific costs and increase efficiency by, for example, reducing the number of employees. In addition, while traditional electric utilities had limited their operations to a single region within a country, many electric utilities are now becoming global businesses with significant overseas investments in many developed and emerging countries (e.g., Cody and Graham, 1995; Woolf, 1994). As the data in Figure 2 illustrate, developed country electric utilities are undergoing unprecedented waves of domestic (mostly contiguous) and cross-border mergers and acquisitions. The motives for such mergers and acquisitions include lower overall tax rates, increased cash levels, and higher debt capacity (e.g., Bergsman, 1996).

C. Management of Stranded Costs

While the electric utility companies are fairly free from regulatory oversight to make decisions about strategic directions and reductions in operating costs, decisions about at least some capital costs must involve regulators especially as they will impact significantly the future structure of the electric utility industry and the surviving companies. One of these issues is what to do about "stranded costs," i.e., the costs of capital investments, such as nuclear and other power plants, that have be-

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[6] This process of developing separate companies may present a number of challenges. For example, in the U.K., 12 vertically integrated electric utilities were broken into three companies each for power generation, transmission, and distribution before privatization in 1990. All of the resultant companies, sold for a total of $5 billion in 1990, were worth $20 billion at the end of 1995. It has been widely contended that this equity value growth (double the average rate in the U.K.) was due to massive undervaluation in 1990 (e.g., Edwards, 1995). For a different perspective based on the Argentine experience see, for example, Friedland and Holden (1996).

come uneconomic under competitive conditions where cheaper electric power can be brought into a region previously isolated (e.g., Dar, 1995; Kahn, 1994). Stranded costs are a major issue in the U.S. electric utility industry as reasonable estimates range between $135 billion by Moody's (WSJ, November 28, 1995, p. A1) and $180 billion by Goldman Sachs (Forbes, June 5, 1995, p. 125) against a total electric utility equity of $160 billion. "Fair" procedures to allocate stranded costs among the various groups must be developed.

Figure 2. Selected Announced Large M&A Transactions in the Electric Utility Industry (1990 and 1995; over $200 Million).

(1990)

Acquiree	Country	Acquiror	Country	Acquiree's Value (US$B)
Iowa Resources Inc. and Midwest Energy Co.	USA	Midwest Resources Inc.	USA	0.48*
Unerg SA	**BEL**	**Electrabel SA**	**BEL**	**1.00**
Kansas Gas and Electric Co.	USA	Western Resources Inc.	USA	1.88*
Electrabel	BEL	Tractebel	BEL	4.51
SCA AB (Bakab Hydroelectric Assets-50%)	SWE	National Pension Ins.Fund Ltd	SWE	1.00
Centel Corp. (Electric Utility Operations)	USA	Utilicorp United Inc.	USA	0.35
Amhem Local Authority (GEWAB)	NET	Provinciale Gelderse Energie Maatschappij	NET	0.16
			Total	9.38

(1995)

Acquiree	Country	Acquiror	Country	Acquiree's Value (US$B)
Bremen Stadtwerke (49.9%)	GFR	Consortium-Veba/Rurhgas/Tractebel	RER	0.49
Wisconsin Energy Corp.	USA	Northern States Power Co.	USA	3.00*
IRI SPA (Ilva Servizi Energie)	ITA	Montedison SPA/Electricite de France	RER	0.89
Manweb PLC	**UKM**	**Scottish Power PLC**	**UKM**	**1.65**
South Western Electricity PLC	**UKM**	**Southern Co.l**	**USA**	**1.70**
Eastern Electricity PLC	**UKM**	**Hanson PLC**	**UKM**	**4.00**
CIPSCO Inc.	USA	Union Electric Corp.	USA	1.20
Southwestern Public Service	USA	Public Service Co. of Colorado	USA	1.81*
Potomac Electric Power Co.	USA	Baltimore Gas & Electric Co.	USA	4.82*
Norweb PLC	**UKM**	**North West Water Group PLC**	**UKM**	**2.88**
Midlands Electricity PLC	**UKA**	**Powergen PLC**	**UKM**	**2.96**
Escelsa	**BRA**	**Consortium of financial institutions**	**BRA**	**0.39**
Khanon Electricity Generating	THA	EGAT	THA	0.69
Washington Energy	**USA**	**Puget Sound P&L**	**USA**	**0.49**
Southern Electricity PLC	**UKM**	**National Power PLC**	**UKM**	**4.38**
Solaris Power Limited	**AUL**	**Australian GL&GP Utilities**	**AUL/USA**	**0.82**
Citipower	**AUL**	**Entergy**	**USA**	**1.19**
Eastern Energy	**AUL**	**Texas Utilities**	**USA**	**1.61**
Powercor	**AUL**	**PacifiCorp**	**USA**	**1.60**
United Energy	**AUL**	**UtiliCorp**	**USA**	**1.20**
Seeboard	**UKM**	**Central & South West Corp.**	**USA**	**2.46**
PowerGen (Generating Assets)	UKM	Eastern Electricity PLC	UKM	0.31
IES Industries Inc.& Interstate Power Co.	USA	WPL Holding Inc.	USA	2.10*
			Total	42.20

Note: **Bold type** indicates a distribution-related transaction.

*Indicates a Merger of Equals transaction with the aggregate value of the deal.

Source: Morgan Stanley, International Investment Research *(December 12, 1995): 4–5.*

The write-down of these uneconomic assets (stranded costs) can be charged to a number of possible groups. For example, these assets can be written-off quickly and charged to the investor/owners of electric utilities. Alternatively, they can be written-off over some period with either future customers required to pay a regulatory determined share or with current customers required to pay an "exit" fee to be free to buy electric power from the cheapest source. Another approach is to require a surcharge on the transmission of power to pay for stranded costs. There can, of course, be additional choices and, for example, it has been suggested that the state (taxpayers) pick up these charges for non-economic electric utility assets. Additional alternatives for dealing with the problem of stranded costs can involve some combination of these choices.

Each alternative for dealing with stranded costs in the electric utility industry will benefit some groups more than others and, thus, each alternative has its own advantages and disadvantages for each of the involved groups. Consequently, over the next few years different regulatory regions or countries can be expected to develop solutions and mixes of alternatives that reflect their particular mix of economic and political pressures impacting the stranded costs problem. For example, while the December 1995 California deregulatory decision allowed the state's electric utilities to recover all of their stranded costs through a surcharge to their basic rates over the next ten years, such procedures may not be followed by other states.

D. Fixed versus Variable Costs and Deregulation

In addition to the problem of stranded costs, deregulated electric utilities also face continuing market uncertainties and unstable market equilibria. Electric power generation is characterized by very high fixed costs and the price of electric power reflects a relatively small variable cost component. This cost structure means that as electric utilities are deregulated, there is great opportunity for predatory pricing as prices need to cover only the relatively low levels of variable costs in the short run, in case of excess generating capacity, or in the case of a utility facing financial distress. Thus, a stable free market equilibrium may be particularly difficult in the market for electric power, and capital budgeting in electric utility firms must be modified for an environment of market uncertainty especially as such uncertainty and market instability may lead to non-optimal decisions regarding capital investments in electric utilities.[7]

3. Capital Budgeting Challenges of Electric Utility Restructuring

As the discussion in the preceding section indicates, the electric power industry faces a period of significant deregulation and change. This section assesses the impact of these changes for capital budgeting practices.

A. Restructuring Challenges in the Electric Power Industry

While it is impossible to forecast accurately the future structure or the time frame for deregulating the electric power industry, given the issues discussed above, it is

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[7] For example, such uncertainty favors short payback periods and disfavors investments in long lived electric generating plants.

clear that the electric power industry will be much more competitive. Deregulation will mean the loss of captive customers and the possibility of predatory pricing, but it will allow freedom in setting prices, making capital investments, and in providing new services.

Residual regulation will most likely continue to oversee anti-trust and transitional issues such as subsidies for rural and poor customers and the rules, standards, and prices for connecting to local distribution systems. The electric power industry is likely to pass through a somewhat unstable transitional phase of gradually decreasing regulation and some politically acceptable solution to the stranded cost problem before arriving at a competitive market driven industry structure.[8] In this transition phase, many firms are likely to face extinction and "correct" capital expenditure analysis will be particularly important as mistakes could be fatal. It seems that in the new deregulated and competitive environment, power generation and transmission will have to account for total delivered costs, and in retail distribution, electric power companies will most likely create barriers to entry through product differentiation, bundled services, and brand management.[9]

B. Capital Budgeting, Deregulation, and Restructuring:

As electric utilities move to a more deregulated environment, capital budgeting practices must change and there should be an increased focus on the correct application of the NPV rule (e.g., Awerbuch et al, 1996). Capital budgeting procedures should move away from being driven by regulatory considerations to being driven by market forces. The present value of the benefits associated with proposed electric utility investments should exceed their costs where the estimates of future benefits account for the impact of market forces and where the discount rates used to calculate present values reflect non-diversifiable risks of such benefits.

However, the effectiveness of the NPV rule in enhancing the value of the firm depends on the degree to which a number of implicit assumptions made by the positive NPV rule hold in practice. As indicated by the brief review of the electric utility industry above, electric utilities face significant technical change, deregulation, and restructuring. As discussed earlier, the low variable costs of electric power can create considerable market instability. Therefore, many of the benefits associated with investment proposals in the deregulated, restructured, and competitive electric utility are likely to be strategic, intangible, and involve new aspects or new businesses (e.g., some benefits may involve improvements in quality or in future

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[8] Electric utility deregulation has been under discussion for some time (e.g., Stevenson, 1982). While deregulation has picked up speed recently, the process is likely to be slowed by anti-trust, stranded cost, and other legal challenges especially if deregulation poses significant risks to the stability and availability of electric power.

[9] The nature of previously regulated industries such as airlines and telecommunications provide some indications of the likely nature of a competitive electric power industry.

capabilities). Such characteristics make investment benefits difficult to assess, quantify, and measure.[10]

Therefore, given this nature of the changes facing the electric utility industry, there are good reasons to believe that some of the implicit assumptions made by the positive NPV rule do not hold for the evolving electric utility industry and, thus, the positive NPV rule, even with improved implementation, may not be adequate as a basis for capital budgeting in the restructuring electric utility firms. Consequently, it is necessary to examine the organizational setting of capital budgeting and the limitations of the traditional positive NPV capital budgeting rule to determine how it may be modified for use in the restructuring electric utility firms.

Thus, it seems that the capital budgeting challenge faced by the restructuring electric power industry involves two distinct steps. First, electric power companies must move away from a focus on satisfying regulatory mandates to the positive NPV rule. Second, such companies must then account for the limitations of the NPV rule associated with restructuring uncertainties and augment the NPV rule with appropriate additional quantitative and qualitative analysis. Figure 3 summarizes this process of developing capital budgeting procedures for a deregulated, restructured, and competitive electric utility.

3. AUGMENTING TRADITIONAL CAPITAL BUDGETING PROCEDURES

The process of generating and evaluating capital budgeting proposals becomes more complex as the size of the business grows (e.g., Pinches, 1982). In a decentralized multidivisional business environment, the capital budgeting process is likely to be impacted by agency costs and moral hazard problems, and involves procedures for evaluating, motivating, and rewarding project managers, as well as procedures used to allocate capital among competing divisions or business units that may often face different competitive dynamics. Further, as projects grow larger and more complex, there can be many reasons why their evaluation also becomes more complex. This is especially true for capital budgeting projects involving long time horizons, new business areas or unproven technology, uncertain competitive reactions, changes in market imperfections that give rise to investment opportunities, and other factors that are difficult to assess and evaluate. As described next, these limitations underlying traditional capital budgeting procedures can be grouped into three categories, i.e.,

1. limitations in estimating project benefits,

[10] Capital budgeting in the new electric utility industry seems to face a situation similar to that facing the justification of investments in flexible manufacturing technology where many benefits are intangible, hard to quantify, and in the form of real options (e.g., Aggarwal, 1993).

2. imperfections in capital markets, and

3. organizational impediments to corporate decision-making.

Figure 3. Developing Capital Budgeting Procedures for Competitive Electric Power Firms.

MOVING FROM REGULATORY MANDATES TO THE NPV RULE

Replace Regulatory Driven Notions of Economic Justification with
The Positive Net Present Value Rule
Where Future Benefits Reflect Impact of Market Forces and
The Discount Rate Reflects the Incremental Risks of These Benefits

PROBLEMS OF RESTRUCTURING UNCERTAINTIES

Deregulation and Restructuring in the Electric Utility Industry
High Fixed Costs and Low Variable Costs of Electric Power
Significant Continuing Market Structure Uncertainties and Risks
Many Benefits Strategic, Intangible, and New (All Hard to Measure)
Violations of Many Implicit Assumptions of the NPV Rule

CAPITAL BUDGETING FOR COMPETITIVE ELECTRIC UTILITIES

Replace the Traditional NPV Rule with the ANPV Procedure
and Augment the ANPV Procedure with
Procedures Designed to Overcome Other NPV Rule Limitations
In the Context of a
Deregulating and Restructuring Electric Utility Industry
with Continuing Uncertainties in Industry Structure
i.e,
Procedures for Augmenting
Limitations of Uncertain and Potentially Unstable Market Equilibrium
Limitations in Estimating Project Benefits and in Assessing Real Options
Imperfections in Capital Markets
Organizational and Psychological Impediments in Decision-Making

1. Limitations in Estimation of Project Benefits

Traditional estimates of project benefits generally fail to recognize adequately the role of industrial structure and the value of embedded options associated with the proposed investment. It is particularly critical that these limitations are overcome in developing new capital budgeting procedures for electric utilities as they change from a regulated (and protected) industrial and economic environment to a competitive and uncertain one.

A. Industrial Structure and Capital Budgeting

The ability of a business to develop capital expenditure projects that result in positive NPVs depends on exploiting some market imperfection based on proprietary patents, on other unique technological or managerial skills, or on the ownership of unique natural resources. More generally, the ability to generate positive NPV projects arises from a firm's managerial resources, capabilities, reputation, market position, and scale, all of which may have been developed over time to act as barriers to market entry or exit.

In this era of rapid and significant deregulation and increased competition, electric utilities need to identify their core competencies and develop a clear understanding of their competitive advantages. For example, with changing technologies, power generation seems mostly like a mature and commodity-like business where low costs are critical. In contrast, transmission and distribution lines may represent unique assets that are difficult or expensive to duplicate. Similarly, supplying electric power to retail customers may allow for opportunities to develop differentiated and branded products and services. Naturally, this type of strategic analysis will depend on an accurate assessment of a utility's strengths and weaknesses in a changed competitive environment and its likely industry structure. Thus, such analysis is likely to be unique to each electric utility.

Capital investment projects undertaken in a perfectly competitive market environment cannot create value, as any benefits in excess of related costs are competed away. Given that capital budgeting projects can create value only if they take advantage of market imperfections, the evaluation of capital expenditure proposals involves (usually implicitly) the assessment of related market imperfections.[11] The ability of a firm to exploit such market imperfections depends on the nature and structure of the project's industry. So, it is important to understand the role of industrial structure in capital budgeting. As this is particularly difficult in the electric utility industry, given the rapid structural changes and the uncertainties about its eventual shape, it is useful to review briefly how industrial structure may influence capital budgeting decisions.

Variations in business profitability have been shown to depend on a firm's market share in an industry and on the nature and structure of the industry, including its capital intensity and growth rate (e.g., Roberts, 1987). The concentration of firms in an industry and the significance of entry and exit barriers are also likely to influence the profitability of capital expenditure proposals in the industry (e.g., Spence, 1983). While entry barriers are likely to increase the attractiveness of such investments, exit barriers may have an opposite effect. As a first approximation, it is

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[11] Market failures are a two-edged sword with regard to capital budgeting. While market failures and externalities in the markets for goods and services, acerbated by ill-defined property rights and 'free rider' problems, often create the very opportunities reflected in capital expenditure proposals, such market failures also mean that many of the resources used and the benefits generated by a project may be priced inappropriately by market mechanisms (Cowen, 1988). Moreover, market failures have also been considered responsible for the failure of traditional capital budgeting procedures in most cases of capital investment for social goals (Quinn and Winginton, 1981). Similarly, market imperfections associated with uncertain regulation can also lead to non-optimal capital expenditure decisions (e.g., Teisberg, 1993).

contended that for an entry decision, product prices must exceed variable costs and the interest cost on the fixed costs of entry; similarly for exit decisions, product prices must go below the variable cost less the interest cost on the fixed costs of exit. However, in the presence of sunk costs such decisions are no longer symmetric and there is hysteresis, i.e., it is not optimal to reverse a decision when prices move back (e.g., Dixit, 1989).

The nature of industry structure is likely to influence some types of investments more than others. For example, investments in other firms in the form of mergers and acquisitions, or in the form of foreign direct investments, are likely to be heavily influenced by expectations of antitrust actions or by other government regulations. Similarly, decisions regarding foreign direct investments are likely to be influenced by industry structure and other aspects of industrial structure in the host country. Capital expenditures in research and development, advertising, and other means for achieving and maintaining product differentiation, are generally influenced by industry structure and, industry growth rates and competitor reactions have been shown to influence capacity expansion decisions and industry concentration in the corn milling industry (Porter and Spence, 1982).

Influence of industry structure on capital budgeting also includes the effects of economies of scale and scope, learning or experience curves, and other forms of increasing returns. Such influences, which frequently take the form of positive feedback loops can greatly affect market shares, industry structures, and the profitability of related capital investments (e.g., Mills, 1988). These dynamic effects can interact with historical accidents, 'selecting' an equilibrium and locking an industry or a firm into an outcome that is not necessarily the best or easily predictable (e.g., Arthur, 1989). A common example used to illustrate these positive feedback effects is the evolution of the VCR market where the VHS system came to dominate the technically superior Beta system (e.g., Anderson et al, 1988). Learning curve and scale effects have also been shown to influence many aspects of corporate strategy, including investment, pricing, and production decisions (e.g., Majd and Pindyck, 1989; Spence, 1981). For effective entry deterrence in such cases, a firm may have to invest in projects having negative NPVs when they are first reviewed if learning curve benefits are not assessed.

B. Valuing Options Embedded in Capital Expenditure Projects

Much literature on strategic analysis has been devoted to the development of 'sustainable strategic advantages.' These competitive advantages may provide valuable options to grow through the undertaking of positive NPV investments. Also, many capital budgeting projects are considered strategic in nature and such projects have embedded options that provide the firm flexibility in responding to changes in the business, regulatory, or competitive environment (e.g., Carlsson, 1989). In this section issues in the application of contingent claims analysis (CCA) and options pricing models (OPMs) to capital budgeting are reviewed.

There is often some flexibility in the start date of a project, projects may have varying degrees of reversibility, and capital budgeting projects may differ with regard to the flexibility with which they can end or abandon a project (e.g., Pindyck, 1991). As an example, firms with urban or agricultural land or offshore oil leases are best valued using an option pricing approach that recognizes that the value of such assets should reflect not only their value based on their best immediate use, but also their value if use is delayed (e.g., Siegel et al, 1987; Bailey, 1991).

Many investments that are critical for developing sustainable strategic advantage involve investing in intangibles like the development of corporate capabilities and flexibilities related to quality, speed, efficiency, responsiveness, and the capacity to cannibalize for radical innovation (e.g., Baldwin and Clark, 1992). The valuation of the intangible and possible future benefits associated with investments in such capabilities presents considerable challenges, and is generally ignored in traditional capital budgeting.

There are many reasons why a project may be irreversible and why flexibility may be especially valuable in the restructuring electric utility industry (e.g., Cater, 1995; Kaslow and Pindyck, 1994). For example, the expenditure may result in capital that is firm or industry specific, such as marketing and advertising expenditures which are particularly firm specific. In addition, there may be a number of implementation or other costs that may reduce the alternative use or liquidation value of project expenditures to less than its original value (and contribute to project irreversibility). Further, the well known 'lemons' problem (e.g., Ackerlof, 1970), severance pay, reclamation costs, and other government regulations may also contribute to irreversibility. As an example, the sunk costs associated with opening and closing a mine combined with the variability of the price of the output, means that mining decisions exhibit some 'hysteresis' and option pricing models can be used to guide such decisions (e.g., Brennan and Schwartz, 1985).

The ability to abandon or shut down a project may, therefore, enhance its attractiveness (e.g., McDonald and Siegel, 1985). Similarly, machinery that has multiple uses in addition to its use in the specific project being considered is likely to be more valuable and present a lower risk of loss if the project fails (Aggarwal and Soenen, 1989). In many cases, project flexibility in a series of projects may influence their optimal sequence (e.g., Kester, 1984). When sequential irreversible investment opportunities arrive at random, and the firm has limited investment funds, the simple NPV rule leads to over-investment (e.g., Baldwin, 1982).

For projects that can be delayed, the decision to invest depends not only on the discount rate but also on its uncertainty, with the uncertainty in discount rates suggesting delaying the investment (e.g., Ingersoll and Ross, 1992). For projects that take time to build, i.e., where there is a maximum rate at which the initial investment can be completed, uncertainty magnifies the effects of irreversibility because the minimum expected value of a project required for it to proceed increases with the time it takes to build (e.g., Majd and Pindyck, 1987). In contrast, for cases where initial investment can provide information that reduces uncertainty in the future value of a project, it may be appropriate to undertake investments that initially have a negative NPV (e.g., Roberts and Weitzman, 1981). For similar reasons, it is contended that traditional capital budgeting procedures may deter investment in innovation (e.g., Baldwin, 1991) and in flexible manufacturing systems (e.g., Milgrom and Roberts, 1990).

As this brief discussion indicates, in general, it is clear that option pricing analysis can be useful in assessing the value of active and continuing management of a capital project where a project may be delayed, accelerated, or changed in response to new developments (e.g., Kensinger, 1987). In such cases, managerial flexibility must be valued (e.g., Trigeorgis and Mason, 1987). For example, investments in flexible production technology must be valued using option pricing models (e.g., Triantis and Hodder, 1990). The decision to invest is, thus, similar to the decision to exercise a call option (e.g., McDonald and Siegel, 1986). However, since an option can be exercised only once, a firm loses the value of the option to make the investment later, once a decision has been made to make an investment (e.g., Demers, 1991). Consequently, it has been recommended "that in many cases capital projects should be undertaken only when their present value is at least double their direct costs" (page 969, Pindyck, 1988).

Thus, the valuation of project flexibility should be a major focus in the capital budgeting process in the restructuring electric utility industry and the use of contingent claims analysis is becoming more widespread in the assessment of investment strategies by electric utilities. Teisberg (1993) uses such analysis to show that under conditions of regulatory uncertainty currently faced by electric utilities, rational electric utilities will invest in smaller, shorter lead time plants than is optimal or will delay such investments. Using similar analysis, it is also shown, contrary to the results of traditional analysis, that higher cost allowances for projects scheduled to be abandoned may not increase the incentives for further investment in such projects. Kaslow and Pindyck (1994) document how investment decisions at New England Power are being changed with the use of contingent claims analysis. As this discussion indicates, capital investment decisions in electric utilities must and can take into account the insights provided by the valuation of real options associated with such decisions.

2. Imperfections in Capital Markets

Traditional electric utility capital budgeting procedures generally assume that imperfections in capital markets are not critical and, for example, capital budgeting and financing decisions can be separated. The use of the NPV rule generally assumes that all positive NPV projects can be funded. Further, it may be assumed that project risk is reflected adequately by the electric utility's average cost of capital. Traditional capital budgeting procedures generally also do not account for the political costs of publicly disclosed financial or accounting information.

A. Capital Rationing

It has been noted that temporal fluctuations in aggregate investment levels in the U.S. economy have been four to five times the fluctuations in output during the post-war period. These variations in U.S. investment/output ratios are also much larger than those observed in other industrial countries (e.g., Greenwald and Stiglitz, 1988). Some economists have contended that cycles in investment/output ratios are associated with capital market imperfections that, among other factors, make internally generated capital cheaper and preferable to externally generated capital (e.g., Fazzari, Hubbard, and Petersen, 1988). In addition, in the U.S. and in most other countries, external equity financing faces tax disadvantages compared to debt financing. As can be expected, these capital market imperfections and transactions costs may lead to under-investment by regulated firms (e.g., Kale and Noe, 1995).

In the presence of excess and free cash flows, it has been contended that managers are likely to over-invest rather than return the excess cash flows to the owners (e.g., Jensen, 1986). This effect has been confirmed empirically for oil exploration and paper industries where investment levels have been related to the level of free cash flows (e.g., Griffin, 1988; and Strong and Meyer, 1990). Firms that face declines in internally generated cash flows reduce the level of their capital investments, i.e., managers of such firms operate in environments characterized to varying degrees by capital rationing.

In addition to differential transactions costs, there are also a number of other reasons why a firm may operate under conditions of capital rationing. Managers may avoid raising external capital to avoid the associated intense monitoring by outside suppliers of capital. Such external scrutiny may reduce the benefits that can be expropriated by managers. In addition, external financing is generally more expensive than internal financing. One reason for the higher cost of external financing, related to the observed differences between the lending and borrowing rates resulting from the cost of financial intermediation, is the additional cost of flotation involved in a new public issue of securities. Further, because external suppliers of finance have less information about business investments than do managers, such suppliers demand a premium (e.g., Greenwald et al, 1984). In such cases, a firm is unlikely to issue new securities and will under-invest compared to what may be optimal (e.g., Myers and Majluf, 1984). To the extent that a firm can use less costly external financing, such as bank loans or debt issues or private placements of its new securities, it can reduce this differential cost advantage of internal financing.

B. Signalling Effects and the Political Costs of Reported Data

Some projects may be adopted or rejected on the basis of their influence on reported earnings or on stock prices regardless of their ability to add to the value of the business. Announcements of new capital investments, corporate financing, earnings and dividends, and other news about a company, generally influence stock prices. Such information is also evaluated for signals about the prospects for the company because of the asymmetry in information sets available to insiders such as managers versus those available to outsiders such as investors in stocks and bonds. Reported accounting data may also influence firm value even though accounting data often do not reflect economic reality. For example, while the time value of money is unevenly or rarely used in the various accounting standards applicable for U.S. companies (e.g., Aggarwal and Gibson, 1989), it has been shown that accounting choices do have economic consequences (e.g., Holthausen and Leftwich, 1983).

There can be a number of reasons for the influence of accounting data on capital budgeting decisions even though such influences seem to imply deviations from economic rationality. First, as discussed above, managerial compensation may reflect reported earnings. Second, loan covenants and other contractual arrangements with outside stakeholders may depend on reported earnings and other accounting data. Third, non-contractual but implicit agreements between the firm and its various stakeholders may be influenced by reported accounting data. Thus, higher reported earnings may have explicit out-of-pocket political costs as they may, for example, lead to demands for higher wages and salaries, lower prices for output, higher prices for inputs, and a higher probability of governmental regulation (e.g., Aggarwal, 1991). Thus, given the traditional focus on non-owner stakeholders such as consumers and communities in electric utilities, it seems clear that capital budgeting decisions in electric utilities is particularly likely to be influenced by the political impacts of publicly disclosed information.

3. Organizational Impediments to Corporate Decision-Making

Capital budgeting procedures for the new electric utility must account for the organizational setting of such decisions. Because of the highly significant nature of forthcoming restructuring and other changes in the electric utility industry, capital budgeting may suffer from a lack of accurate and reliable data on costs and benefits of a proposed investment, the lack of alignment between the goals of various stakeholders, and by the difficulty of assessing risks associated with an investment.

A. Lack and Cost of Accurate Information

Traditional capital budgeting procedures often do not seem to deal adequately with many of the uncertainties inherent in the estimates of future benefits for a proposed capital expenditure. Even for well defined, tangible, and fairly certain benefits, there are a number of sources of estimation and measurement error as cost accounting systems involve many approximations including those in overhead allocation (e.g., Kaplan, 1986, 1990). Further, there are uncertainties in inflation and interest rates and, because of capital market imperfections and changing tax rates, the estimation of an appropriate risk-adjusted discount rate is also difficult and subject to error. Such errors and lack of detailed information are also a significant limitation in developing risk-adjusted discount rates that reflect the additive risks of specific projects.

B. Agency Costs and Asymmetric Information

An agency relationship is established when one party (the principal) engages another party (the agent) to perform services for the former. However, principals and agents may not operate with the same information set and may not have the same utility functions. Thus, rational utility maximization by managers may not be consistent with owner wealth maximization. Nevertheless, in most large businesses and in many small businesses, managerial functions are largely performed by professional non-owner managers. Consequently, managerial compensation schemes have to be designed and implemented to align managerial and owner goals. In such cases, owners must monitor managers for compliance with these compensation contracts and, in equilibrium, optimal monitoring expenditures still leave some residual agency costs that are not eliminated (e.g., Fama, 1980). It should be noted that the principal-agent problem occurs in many areas of a business, as a business firm is considered a nexus of numerous formal and informal contracts between many stakeholders, e.g., owners, bondholders, managers, employees, suppliers, customers, and the communities where the firm operates (e.g., Aggarwal and Chandra, 1990). Transactions costs theories have analyzed various forms of decentralized organizational structures as to their business effectiveness and their ability to reduce these residual agency costs (e.g., Williamson, 1981). It has been shown that the organizational form used by a business influences its investment decisions (e.g., Fama and Jensen, 1985).

Agency considerations also indicate that managers may exhibit higher risk aversion than may be optimal for the owners, because it is usually difficult for managers to diversify their largely firm specific human capital (e.g., Thakor, 1990). In such cases, firm capital investment is likely to reflect this higher than optimal risk aversion (e.g., Holmstrom and Weiss, 1985). In order to protect their reputations and preserve their human capital, managers may also engage in herd behavior, making investment decisions that are non-optimal for the business and ignoring contrary private information (e.g., Scharfstein and Stein, 1990). Managers also may differ greatly in terms of their propensity to take risks depending on their socioeconomic background (e.g., MacCrimmon and Wehrung, 1990).

In a number of cases, the principal-agent problem is accentuated by asymmetric information as managers generally possess greater information about the costs, benefits, and risks of a proposed investment than do the owners or other outside monitors such as bondholders or financial market participants. As an example, such agency costs and asymmetric information can lead to myopia in managerial investment decisions even in efficient capital markets (e.g., Stein, 1989). In addition, capital budgeting procedures must also account for the costs of collecting and processing the information needed to make capital budgeting decisions (e.g., Kaplan, 1990). It has been noted that because of these information costs, managers may be able to appropriate excess or residual corporate slack (e.g., Antle and Eppen, 1985). Managers are also likely to entrench themselves and favor implicit contracts and investments having a higher value under their management (e.g., Shleifer and Vishny, 1989). It has been suggested that appropriate financing policies be used to limit managerial discretion (e.g., Stulz, 1990). In designing contracts for motivating managers, it is important to account for the costs faced by owners in obtaining the superior information about a project possessed by the manager (e.g., Heckerman, 1975).

Agency cost analysis has also been used to analyze conflicts between bondholders and stockholders. It has been shown that equity holders face incentives to undertake risky investments that transfer wealth from bondholders to themselves (e.g., Jensen and Meckling, 1976). It is also now well known that equity holders in a levered firm may forgo positive NPV investments if a sufficient fraction of the project value accrues to debt holders (e.g., Myers, 1977). Thus, conflicts between stock and bond holders that are unmitigated by other mechanisms are likely to lead to underinvestment and investment in risky projects. While these agency and information asymmetry related costs reduce the efficiency of the capital budgeting process in a business, this process is also influenced by imperfections in the ability to assess risky choices.

As this brief discussion indicates, the organizational setting of capital budgeting in electric utilities must account for these issues related to agency cost and asymmetric information. This is likely to be particularly challenging as the electric utility industry is still evolving.

C. Deviations from the Expected Utility Rule for Risky Decisions

Organizations and individuals face a number of challenges in assessing probabilistic events and their consequences accurately (e.g., Arrow, 1982). Decision science research has articulated and documented a number of systematic deviations from "rational behavior" in assessing uncertain outcomes (e.g., Fishburn, 1989). For example, it has been documented that risk aversion is asymmetric, i.e., people tend to pay more to avoid a risk than for the equal possibility of a gain. A related phenomenon is the high value attached to the fear of regret, especially when associated with an investment that has a poor reputation (e.g., Thaler, 1991). While it is commonly believed that decision makers maximize their expected utility, it has been documented that utility functions that are concave at low levels of wealth and convex at high levels of wealth are more consistent with observed behavior (e.g., Friedman and Savage, 1948).

In addition to the changing curvature of the utility function with regard to expected value and wealth, decision analysis is further complicated by violations of linearity in probability (e.g., Machina, 1987). For example, it has been documented that indifference curves related to expected values are not parallel but 'fan out' in what is known as the Allais Paradox (Allais and Hagen, 1979). The Allais Paradox is actually considered to be part of a wider phenomenon known as the 'common consequence effect' where Samuelson's independence axiom is violated. As an example of such a case, winning the top prize in a lottery has been shown to provide more utility than winning the bottom prize of the same value in a different lottery (e.g., Bell, 1985). Decision makers have also been documented to display the 'preference reversal' phenomenon: choices regarding winning or losing a gamble are based primarily on the probability of winning or losing, while buying and selling prices are determined primarily by the dollar amounts involved (e.g., Grether and Plott, 1979). It has been documented that investors are influenced by prior losses and gains when making decisions concerning risky investments (e.g., Thaler and Johnson, 1990). These contentions of the effects of sunk costs and prior losses and gains have been empirically documented for investments in nuclear power plants (e.g., De Bondt and Makhija, 1988).

Similarly, 'framing' also influences decisions. In 'framing', unrelated contextual data or a reference point unduly affects the outcome of a risky choice (e.g., Tversky and Kahneman, 1986). Judgments regarding probabilistic events are also influenced by phenomenon such as 'availability' (easy recallability), 'representativeness' (similarities based on superficial characteristics), and 'anchoring' (relatedness to an initial number). Thus, 'framing' a decision may provide an 'anchor' and elicit responses related to 'availability' and 'representativeness' and may have a great deal of influence on its outcome (e.g., MacCrimmon and Wehrung, 1986). It has been documented that while new information leads to adjustments in the prior 'anchor' in the right direction, such adjustments are generally too small. In addition, investors and managers have been found to be particularly poor judges of the expected value of remote possibilities such as winning a major lottery (e.g., Tversky and Kahneman, 1981). For example, the abandonment decision has been shown to be governed by aspects related to prospect theory as discussed above (e.g., Statman and Caldwell, 1987).

4. CAPITAL BUDGETING PROCEDURES FOR COMPETITIVE ELECTRIC UTILITIES

This brief review of the traditional positive NPV-based capital budgeting procedures indicates that such procedures make many inappropriate implicit and limiting assumptions. While the use of positive NPV-based capital budgeting procedures has been rising (e.g., Dulman, 1989), it would be useful if, for use in the restructuring electric power industry, these traditional procedures could be modified to overcome their limitations. An expanded version of the traditional net present value calculations that overcomes many of these limitations of traditional procedures and based on the adjusted net present value is developed next for use in the emerging electric power firm.

1. The Adjusted Net Present Value Framework

A. Augmenting the NPV Rule

While the adjusted net present value (ANPV) approach described next can mostly accommodate the limitations of traditional positive NPV based capital budgeting procedures related to capital market imperfections and valuation of real options, it is important that the ANPV be supplemented by additional qualitative analysis and assessments to reflect limitations related to corporate decision-making under uncertainty described above. Indeed, the discussion of the limitations of traditional capital budgeting procedures in prior sections is designed to be a useful guide for developing such supplemental assessment procedures. These supplemental procedures would reflect the specific conditions faced by a particular electric power capital investment proposal.

B. The Adjusted Net Present Value Method

Many of the limitations of traditional capital budgeting procedures related to capital market imperfections and valuation of real options can be accommodated by the adjusted net present value method. The adjusted net present value (ANPV) method is useful in valuing any proposed capital expenditure when the investment and financing decisions can not be separated. The ANPV approach differs from the traditional NPV approach in a number of ways. It uses an all-equity discount rate that reflects project specific inflation and interest rates and the systematic business risk of a particular project. In addition, it uses the value-additivity approach so that the ANPV calculation involves adding to the present value of the operating cash flows, the present value of after-tax amounts of any subsidies inherent in project-specific financing, as well as the present value of debt-related tax shields reflecting the capital structure appropriate for the particular project. Consequently, the ANPV approach encourages the decision maker to adjust project cash flows for specific project-related subsidies and, in addition, project risks are accounted for by adjusting cash flows rather than by making adjustments to the discount rate.

This section develops the ANPV procedure for evaluating proposed capital expenditures in the emerging electric utility. The ANPV approach may be particularly suitable for projects in the new electric power firm since traditional approaches to capital budgeting, such as the calculation of net present value using the corporate cost of capital, are likely to be inadequate because of significant variations in capital availability, project specific finance, approaches used for recovery of stranded costs, and in political risks. Further, these variations and risks may be unsystematic in nature so that project systematic risk may not reflect the systematic risk of the company. Since these conditions can be overcome by the adjusted net present value approach, it may indeed be most appropriate for the capital budgeting process in the new electric power company.

As an example, consider the following formulation for the adjusted net present value of a project being considered by an electric utility (based on Aggarwal, 1993):

$$\text{ANPV} = -I_o + \Sigma\,\{CF_i/(1+k_e)^i\} + \Sigma\,\{T_i/(1+k_d)^i\} + \Sigma\,\{S_i/(1+k_d)^i\}$$

$$+\ \Sigma\,\{O_i/(1+k_e)^i\} + TV_n/(1+k_e)^n$$

where

I_o = the initial investment

k_e = the all-equity cost or discount rate reflecting the riskiness and diversification benefits of the project

k_d = the cost of debt

n = the number of periods in the investment horizon

Cf_i = the after-tax net cash inflows for period i

T_i = the tax shield on debt service payments for period i reflecting the capital structure of the affiliate undertaking the project

S_i = the after-tax value of special financial or other subsidies associated with the project for the period i

O_i = the estimated value in period i of any options created by the project, such as the ability to enter a new business

TV_n = the estimated terminal value in period n at the end of the investment horizon. (This could be the estimated negative present value of the costs necessary to de-commission a power plant).

The first term covers the initial investment. The second term reflects the present value of the net after-tax cash inflows the project is expected to generate. It is important that these be incremental cash flows associated with the proposed investment after accounting for any cost complementarities and other cash flow interactions with other operations (e.g., Stirling, 1994). These cash inflows are discounted at the all-equity cost that reflects the incremental systematic business risk associated with the project (again after accounting for any interactions in the form of portfolio effects). The third term reflects the present value of the tax savings associated with use of debt in the capital structure. By explicitly accounting for the tax shields, it is possible to account for any special tax adjustments and for the unique capital structure being used by the affiliate undertaking the project. The fourth term reflects the present value of any financial or other subsidies received by an electric power projects from home or host, national or state, or other governments.[12]

The fifth term reflects the value of any options, such as the ability to enter a new business, whether exercised or not, generated by the project. These values may be very small, at least for the first few years, and may often be difficult to estimate. Nevertheless, the ANPV approach provides an opportunity to value these options. In order to estimate real option values, it is important to note that the values of such options depend positively on the degree of uncertainty in the price of the underlying asset and the maturity (length of time) of the option, and negatively on the applicable time value discount rate and the difference between the exercise price and the price of the underlying asset. In valuing the real options associated with investments in electric utilities, the nature of these options must first be described by defining the underlying asset, estimating its volatility, and estimating the option's time to maturity. This can often be a challenging task for any real option and especially for such options in the evolving electric utility industry. Of course, even rough approximation of the values of real options are better than ignoring them, and fortunately, there has been considerable work and much progress in estimating real option values (e.g., see Trigeorgis, 1996).

The last term reflects the estimated terminal value at the end of the investment horizon. Although there are many ways to estimate the terminal value, one approach commonly used is to set it equal to the present value of all future cash flows, that is, equal to CF/(k - g), where CF are the annual cash flows at the end of the investment horizon, k is the required discount rate, and g is the expected growth rate for these cash flows. Once again, k must reflect incremental systematic risks of

[12] As pointed out by Professor Charles Moyer in private correspondence, under rate base regulation, these benefits will be recaptured for rate payers at the next rate hearing. Thus, such benefits should only be projected out until the next hearing for businesses such as transmission or distribution which remain under rate of return regulation.

these cashflows. In politically unstable environments it may be feasible to allow the terminal value to reflect the expected present value of the possible future liquidation value of a project under such circumstances. Other aspects of economic and political risk such as uncertainties related to new technologies and the costs associated with the decommissioning of a power plant, may also be modeled as additional terms.

In summary, the recommendations in this paper reflect the fact that the electric utility industry faces fundamental and strategic changes in the way electric power is generated, distributed, and sold. Capital budgeting and capital allocation processes in traditional utilities should be re-organized and changed to move away from an emphasis on asset additions to serve regulatory requirements, and must reflect opportunities and costs based on the new and possibly uncertain and unstable strategic structure of the electric utility industry. This paper notes that traditional capital budgeting practices face many problems in justifying electric utility investments where many of the benefits of the new investments are strategic, intangible, generally difficult or impossible to assess in terms of cash flows and, thus, often ignored by traditional capital budgeting techniques. While there do not seem to be any easy answers or universal procedures, this paper concludes that the use of an augmented ANPV procedure is most likely to be useful for capital budgeting in the restructuring electric power industry.

5. CONCLUSIONS

This paper has reviewed briefly the changing nature of the electric utility industry and the need to augment traditional capital budgeting procedures in such firms. Deregulation and the low variable costs of electric power mean that electric utility firms are likely to continue to face uncertain and possibly unstable market structures. In this environment, many electric utilities are unlikely to survive and it is particularly important to make "correct" capital expenditure decisions as mistakes can be fatal.

Unfortunately, traditional capital budgeting procedures do not adequately account for options embedded in capital projects, the interaction between financing and investment decisions, imperfections in the capital markets that limit availability of external capital, the impact of market structure and competitor reactions on project cash flows, agency costs and conflicts between various stakeholders, and deviations from the expected value rule for decisions involving risk. These factors must be taken into account in designing new capital budgeting procedures useful in the evolving electric power industry.

While there does not seem to be any one universal procedure, the adjusted net present value approach was developed in this study and is recommended for overcoming many of these limitations for capital budgeting in the evolving electric utility industry. In addition, it is recommended that this adjusted net present value procedure be supplemented by appropriate qualitative analysis and assessments specific to a particular project.

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DISCUSSION

Aggarwal, *Justifying Capital Investments in the Emerging Electric Utility: Accounting for an Uncertain and Changing Industry Structure*

AND

Awerbuch, Carayannis, and Preston, *The Virtual Utility: Some Introductory Thoughts on Accounting, Technological Learning & the Valuation of Radical Innovation*

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DISCUSSION

Many years ago I assigned to one of my students in Managerial Economics at Dartmouth's Amos Tuck School, the role of "custodian of the conventional wisdom" because he brought to every discussion the discredited ideas of ancient analysts. I am afraid I may be assuming that role myself in commenting on two papers that describe a world I have not yet come to know—the world of the virtual utility.

Let me begin with some initial reactions. My first reaction is nostalgia for the electric utility world I once knew well and that these papers warn me is now passing into history. My second reaction is concern that the authors may be attacking paper tigers and trying to promote specific industry outcomes in doing so. My third reaction is an inkling that these papers give too little credit to the ability of an interactive business and government system to develop a succession of reasonably efficient forms.

My final reaction, however, is a vision of the electric industry that will evolve. I see that industry with a generation sector populated by unregulated rivals; a transmission sector that is privately owned but publicly run; a distribution sector that includes investor-owned, publicly regulated utilities; and a retail sector in which unregulated rivals assemble generation, transmission and distribution inputs, and sell electricity bundled with other related and unrelated goods and services to consumers.

In my vision, there is no virtual utility. There is only an industry that, like others we know, constrained by government and coordinated through markets, does a reasonably efficient job of combining resources to deliver the quantity and quality of services that users of the services are willing to pay for.

THE AGGARWAL PAPER

Raj Aggarwal motivates his discussion of problems and solutions in electric utility capital budgeting by suggesting that industry changes provide the reason that it is now important to recognize problems and seek solutions. I disagree. Facing the problems and seeking solutions is likely even more important for companies if the industry and its regulatory setting were not changing. This is because regulators won't and can't protect the utilities they regulate. Prudent projects that do not succeed are unlikely to get into rate base. Regulatory assets, created with a promise of recovery, are likely to be lost in whole or in part. There is no certainty that investments made to minimize cost to customers or at the behest of regulators will realize a return. It is essential therefore that managers analyze projects considering demand and regulatory constraints, but with the objective of maximizing the wealth of shareholders.

Professor Aggarwal's discussion of problems offers a guide that is needed. It is frontier finance. It should be, because he wrote the book (Aggarwal, 1993). He observes, quite correctly, that the net present value rule has limitations. A projection of cash flow benefits usually ignores the reactions of regulators and rivals. Options opened or closed by undertaking an investment are likewise almost always neglected. Calculations of the effect on shareholders' wealth simply do not consider problems associated with imperfect capital markets—rationing and signaling. In judging information on projects and estimating efficiency in their execution, the rule is to assume away organizational impediments, even though it is apparent that managers often provide information and act in their own interest rather than that of shareholders.

The problems Professor Aggarwal highlights have no complete solution, nor does he claim to have one. What he offers is the best financial economics can provide. It is the adjusted net present value formula:

$$\text{ANPV} = -I_O + CF@k_{EQ} + T@k_D + S@k_D + O@k_{EQ} + TV@k_{EQ},$$

where the impact on shareholders' wealth is calculated as the sum of after-tax net cash flow of the project (CF) discounted at (@) the all-equity rate (k_{EQ}); the tax shield provided by debt (T) and any after-tax subsidies associated with the project (S), both discounted at the debt rate (k_D); the positive or negative value of options won or lost with the project (O) discounted at k_{EQ}; and the project's terminal value (TV) discounted at k_{EQ}.

More important than Professor Aggarwal's formula is that his discussion of problems, as opposed to solutions, cautions that a great deal of qualitative analysis is required for company managers to make the right capital budgeting decisions in yesterday's, today's or tomorrow's electric utility industry.

THE AWERBUCH, CARAYANNIS, AND PRESTON PAPER

Awerbuch, Carayannis and Preston ("ACP") don't use industry change to motivate their discussion of capital budgeting, organizational behavior and accounting problems for the virtual utility. They appear to say there won't be industry change—change that would be for the best—unless firms in the industry alter their capital budgeting, organizational and accounting procedures. Theirs is an indictment of current practice.

I don't agree with them. I think they mistake the factors that effect change within the firm for the factors that effect change for the industry, that they have conjured up straw men in order to knock them down, that they ignore recent history, that they have let religious conviction overwhelm analysis, and that they fail to understand the wisdom of Professor Aggarwal's discussion.

Whether all firms listen to ACP or not, some firms, incumbents or entrants, will change and are changing what they do and how they do it. The changes are in capital budgeting, organization and accounting and, much more important, in how electricity is produced, where it is delivered, what attributes are marketed, whether attributes are bundled and how bundles are priced.

There may be many incumbents and entrants whose capital budgeting, organization and accounting systems, lack of vision, and failure of leadership cause them to miss value-adding opportunities. There may be many others with the right systems, vision and leadership who simply guess wrong. But there will be a few—systems, vision and leadership aside—who guess right, who choose the "radically new processes" that are best, and—in an industry with many players where rivalry has become unavoidable—the rest will be carried forward by the few. ACP are right to urge electric utilities to develop better procedures, but they are wrong if they believe failure to do so will prevent change for the better from coming to the industry.

That ACP have conjured up straw men to be knocked down seems obvious from both the capital budgeting and accounting discussions. The capital budgeting process has its problems, as Professor Aggarwal points out, but it can deal with passive, capital-intensive, infinitely durable, technologically vulnerable alternatives, and it has dealt with them. It has even found a net present social cost advantage for demand side management programs when there was none.

As for restricting the description of current accounting cost information to FERC accounts and revenue requirement applications—that is simply silly. There has been too much work done, at least by companies I am familiar with, on incremental and avoided cost by time and place of use, customer and product contributions and the immediate and long-term changes that follow from the introduction of an optional rate to suggest that "utility accounting systems...fail to identify the nature and behavior of individual generating costs in the sense that they ignore the cost drivers" or that lack of understanding of cost relationships makes it "difficult to if not impossible to perform any incremental analyses or alternative choice decisions involving different technologies."

That ACP are ignoring recent history seems to be reflected in their total neglect of the nuclear experience. Nuclear was a "new emerging technology," which in the 1970s seemed passive, was capital- rather than expense-intensive, was infinitely durable in the sense that "its actual use contributes little to its 'wearing out,'" and was likely to have rapid technological obsolescence. Contrary to ACP, the "old" capital budgeting techniques not only were of "use [to electric utilities] in conceptualizing the nature of [this] newly emerging technology," but also generally caused the utilities to find nuclear to have an NPV or, in Professor Aggarwal's term, ANPV advantage.

That "religious conviction" overwhelms analysis in ACP's discussion is illustrated for me in their Figure 2 and the discussion that builds upon it. I will use numbers rather than a diagram to show how conventional capital budgeting would evaluate the established and the new technology.

Year	0	1	2	3	4
Established	(100)	70	70		
(Replacement)			(100)	60	60
New	(120)	70	70		
(Replacement)			(100)	80	80
Net Cash Flow if New is Chosen	(20)	0	0	20	20

Numbers in parentheses are gross or net investment; other numbers are benefits. A reasonable manager acting for shareholders and assuming cost of capital of no more than 15 percent would find the new the better choice even though it is more costly for years 0–1–2. That is because the learning that occurs in years 0–1–2 with the new technology reduces the investment in and raises the benefits from its replacement by more than enough to offset its 0 year disadvantage.

Professor Aggarwal might say that a reasonable manager might not bother with the explicit cash flows of years 3 and 4, but would or should consider the value of the option to replace the original "new" project with the improved version that learning would provide in year 2. ACP would seem to say go with the new; forget the analysis; it's bound to keep you from making the right choice; it's bound to hold you to the established technology. What they do say is "while current capital budgeting procedures *project* to the future, they reflect only the past." If that were true, then no improvements in capital budgeting will lead to correct decisions on radical innovations, and analysis must give way to religious conviction if progress is to be made.

In implying a conclusion that faith rather than analysis is the key to progress, ACP not only fail to consider the factors that effect change for the industry, as I discussed earlier, but also fail to understand the wisdom of Professor Aggarwal's discussion. What he says is that capital budgeting has problems, that the problems cannot be eliminated, but that they can be recognized and reduced. And, if you value the options that become available with a radical innovation, you will get an ANPV for the radical alternative that reflects something more than the past.

Analysis may not be enough but, carried out as it should be and carried out in an industry setting, analysis promises much more in the way of progress than does religious conviction.

FINAL COMMENT

These are two stimulating papers. I agree with one and disagree with the other. Taken together, however, these papers do just what they should do. They get us all to think and think with some intensity about the virtual utility and the future.

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Part IV

Risk Management, Options and Contracting for a Virtual Utility

6

INTEGRATING FINANCIAL AND PHYSICAL CONTRACTING IN ELECTRIC POWER MARKETS

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Against the background of continuing restructuring of the U. S. electric power market, this paper considers the integration of financial and physical contracting under various models of market structure and transmission pricing. We begin with a delineation of the objectives which we believe, implicitly or explicitly, underlie the move towards restructuring. These include transparent and efficient markets for both long-term and short-term transactions, dynamic efficiency and innovation, customer-focused operations, and system integrity. We use these objectives to derive a number of important policy implications for the restructured power markets including clear ownership boundaries and regulatory incentives for market participants to operate in a commercial manner, and transparent rules and incentives for efficient contracting and pricing. We point out the implications for decreased competition and increased regulatory transactions cost from proposals which do not satisfy the stated requirements for commercial operations (e.g., recent proposals for nodal pricing of transmission service coupled with highly complex settlement and reconciliation procedures among participants). We then describe a general approach which does satisfy the *prima facie* requirements of market transparency and

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economic incentives. This approach is based on zonal and ex ante transmission pricing, regulated for-profit transmission service providers (TSPs), and permissive market intermediation. We indicate for this approach, under various models of the Independent System Operator (ISO), how financial and physical contracting could be integrated and how regulation of TSPs could be accomplished. The required contracting includes financial instruments (spots, forwards, futures, and performance contracts) encompassing long-term and short-term energy contracts, asset-use and resource supply contracts, ancillary service contracts, investments in generation and transmission assets, load-management and demand-side management contracts, and contracting for other market-mediated services required for the efficient configuration and operation of the power market. We conclude the paper with a discussion of some open research questions.

1. INTRODUCTION

This paper analyzes approaches to the integration of financial and physical contracting in electric power markets. This integration is essential to the efficient restructuring of the electricity supply industry to assure the benefits of competition. On the one hand, restructuring has begun to unbundle the prices and other service attributes associated with the stages (from generation to distribution and billing) of electric power supply, making these more open and transparent to the buyer and seller of electricity and supporting services. On the other hand, these services must be coordinated, rebundled and financed to assure that the various stages of supply operate smoothly and efficiently. Since the earliest discussions of competition[1], the associated joint problems of unbundling and (re-)contracting have been recognized as the centerpiece of the debate on competition in electric power in the United States.[2] The reason is clear. Although unbundling is central to achieving the benefits of competition, inefficient unbundling (i.e., unbundling which leaves undue recontracting or regulatory problems in its wake) may impede and dissipate all the expected benefits of competition. Several problems are apparent in this regard. First is the issue of assuring system stability and integrity and the associated issue of reliability. Second is structuring an appropriate solution to the stranded cost recovery problem during the transition. Third, is determining the appropriate structure of ownership, control and regulatory governance of transmission services. The central focus of this paper is the last named issue on structuring transmission services to facilitate competition in generation.

Concerning the appropriate structure of transmission service in the unbundled market, the example of natural gas has underlined the clear benefits of open access and transparency in price and service offerings from a common carrier bulk transport/transmission provider (see. e.g., [Doane & Spulber, 1994]). Indeed, these perceived benefits were motivating forces in drafting the requirements of the Energy

[1] For a discussion of (re-)contracting issues in this context, see [Joskow and Schmalensee, 1984].
[2] For a discussion of the underlying forces of change in the U.S., see [Fernando et al. ,1995].

Power Act (EPAct) of 1992 and the FERC's subsequent actions to implement open access, comparable service and transparent pricing. However, recent proposals for achieving these requirements in transmission service have been highly complex and seem ill-suited for normal commercial activity, let alone as vehicles for promoting transparency and competition in generation and new services, the main sources of benefits from unbundled electric power. Thus, we argue for clear ownership boundaries for transmission service, with transparent and simple pricing structures, and with performance-based regulation on transmission service providers to assure that they face incentives to consider total system operations and efficiency in their long-range and short-range decisions. This leads us to discuss various organizational boundary issues for both transmission asset providers (TAPs) and the system operator(s) (the so-called Independent System Operator or ISO). We argue that regulated, profit-maximizing agents should be given both of these responsibilities, and we discuss various ways in which TAPs and ISOs might contract with one another to assure economic efficiency and breakeven operations.

The leit motif of this paper is that unbundling of the electric power value chain must be followed by contracting and rebundling along the value chain and that efficiency in rebundling will require transparent markets and commercially oriented market participants. As in any other active market, the market for electric services will consist of both the participants on the physical side of the business (providing generation and associated supply-side support, transmission services, and distribution/demand-side management), as well as the financial side (providing brokering and other intermediation such as financial risk management, and generally enhancing the liquidity and efficiency of the markets they support). The key issue we address is how to assure an efficient integration of these two complementary sides of the market.

In the next section, we set out some principles which we believe should guide the design of proposals for restructuring. In section 3, we describe the elements of the unbundled market place, and point to several key issues which we intend to explore. In section 4, we explore the first of these issues, the structure of the Independent System Operator (ISO) and its role in assuring open access, efficient transmission service and in facilitating the market. In section 5, we explore alternative organizational and ownership structures for the ISO and TAPs. In section 6, we consider access and pricing for transmission services. In section 7, we discuss the role of financial instruments and intermediation in the market. Section 8 recapitulates and points to some open research questions.

2. PRINCIPLES OF RESTRUCTURING

When considering proposals for restructuring, most observers have in mind a set of assumptions (often implicit) on the principles and objectives of restructuring. These generally evoke a vision of an end-state which one might summarize as an efficient, dynamic and competitive market for power. While there is general agreement about this end-state, the factors and conditions which may influence achieving it are often either unstated or left as points of contest in the debate. It is useful for our following argument to summarize these underlying factors and conditions explicitly.[3]

Efficient Pricing: Pricing should be based on short-run marginal cost (SRMC), with breakeven prices derived through efficient demand charges or markup procedures based on SRMC.

Efficient Long-term Contracting: Both on the supply and demand side, long-term contracting for power and for support services should enable risk management and longer-term asset commitment.

Efficient Spot Market: To promote efficient matching of residual assets and demands for service, net of longer-term commitments, an efficient and transparent spot market should exist.

Incentives for Efficient Investment and Maintenance of Capital Stock: All service providers should have appropriate incentives to invest in capital and human assets, and to maintain them, in support of the market.

Incentives for Cost Minimization in Operations and System Configuration: In the short run, all market participants should face incentives to minimize total costs of system operations and to make available to the system assets which are needed for this purpose.

Customer-focused Design and Delivery of Services: Where additional value is attached to changes in services (e.g., in billing, in quality, in documentation, in service support of applications, etc.) by any buyer in the electric power supply chain, there should be incentives for sellers of such services to create these value-adding design changes.

Effective, Fair and Efficient Regulation: Where regulation is involved, it should satisfy the usual regulatory performance criteria, including an appropriate regard for minimizing regulatory transactions costs.

Clear and Transferable Property Rights: To assure discipline and information from the capital market and to provide operational meaning to the value of asset and franchise ownership, property rights (including the right to be an ISO or a TSP) should be clear and transferable.

Effective Competition: Whether in generation, between generation, transmission and load management or in service provision (leveraged by intermediation), competition is the main driver of change and benefits. Thus, proposals for individual pieces of unbundling policy (e.g., for transmission access) must be evaluated in terms of their impact on overall competition and not simply as stand-alone proposals.

System Integrity and Stability: In addition to the economic viability of the system, it must also satisfy a host of engineering requirements related to the special nature of electric power requiring instantaneous balancing of supply and demand across the network.

Let us first note some of the tradeoffs and implications implicit in the above principles. First, with regard to pricing, a tradeoff exists between short-run and long-run welfare. In the short-run, maximizing the traditional welfare measure of consumer and producer surplus (possibly subject to breakeven constraints if scale economies are present) gives rise to SRMC-based pricing. On the other hand, longer-term welfare or fairness considerations may require significant departures from SRMC-based pricing, either

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[3] For a discussion and elaboration of efficiency criteria in the context of regulated industries, see [Crew and Kleindorfer, 1986].

to recover stranded investments (e.g., via access charges) or to promote market transparency.

Second, for incentives and for transferable property rights as well as for regulatory reasons, ownership boundaries must be clear. Absent such clarity, the ability to make decisions and to understand the motives of market participants will be impaired. As a case in point, loosely structured Regional Transmission Groups (RTGs) may have significant problems with decisions regarding maintenance and investment decisions in the transmission network unless the RTG itself is imbued with a decision and property rights structure that makes plain what benefits accrue to whom from such decisions. We return to this issue in section 5.

Third, both long- and short-run markets must have the requisite structure and institutional support to assure that they are liquid, transparent and not captured by anyone.[4] Besides the transparency and ease of access implications of this, we also believe that this implies a relatively permissive approach to intermediaries to promote learning and experimentation and to exhaust gains to trade.

Fourth, the above principles should suggest much more to the reader than simply driving electric power supply toward more cost-reflective pricing. At least as important as this is the change in mind set which accompanies the move from monopoly to competitive markets, a change from internally-driven service provision to market-focused provision, from engineering-focused to customer-focused service delivery, and from homogeneous product offerings to segment-specific products and marketing. The key here is that aggregate welfare is driven both by consumers' willingness-to-pay (which can be expected to increase dramatically if service providers become market-focused) as well as by the total cost of providing a given set of products and services. Thus, there are two sets of conditions appropriate to benchmarking market efficiency:

1. The traditional price-cost benchmark that indicates that price should be set to SRMC (which incorporates implicitly the assumption of cost minimization) and capacity set to assure that SRMC and LRMC are equal;

2. The requirement that new services be introduced when the benefits (measured by customer willingness-to-pay, WTP) exceed the cost of such services; with service quality and other service attributes determined, on a market-segment specific basis.

[4] The early history of the British experience on this point is instructive; see [Newbery, 1995].

3. STRUCTURE OF THE UNBUNDLED ELECTRIC POWER SECTOR AND KEY ISSUES

The Nature of Unbundling

Unbundling occurring at two physical levels (see Figure 1): (1) between generation, transmission and distribution; and (2) within generation, between the provision of energy and various other ancillary services. In addition there is a separation of physical products and financial services as we discuss below. Unbundling aims to achieve clear pricing and service separability between the separate elements along the value chain. The benefits of unbundling are to clarify for competitive reasons the cost and value of each of these separate elements. The problem created by unbundling is that these separate elements must be rebundled, via contracting or spot markets, in an on-going fashion to (re-)create from these elements desired services and end outputs.

Figure 1. Unbundled Electricity Value Chain.

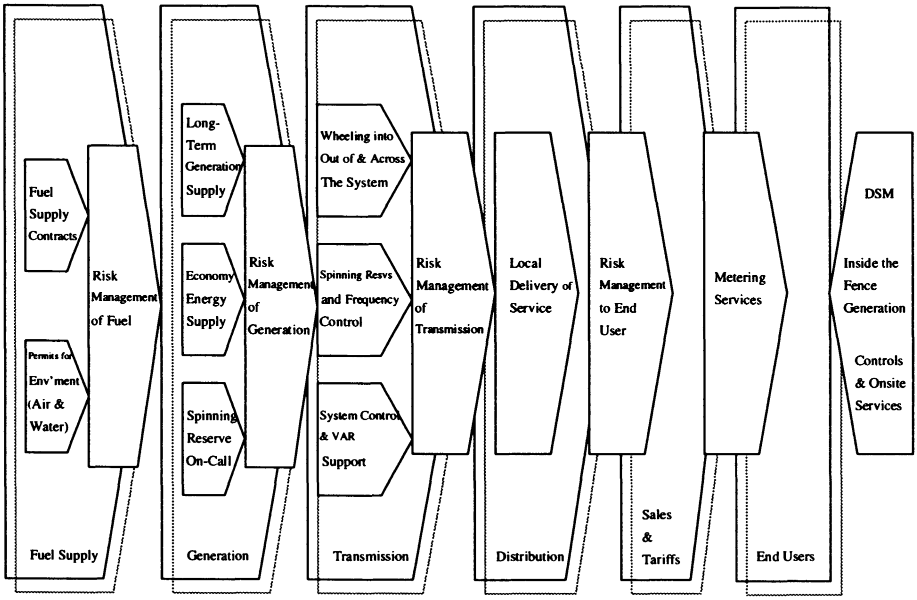
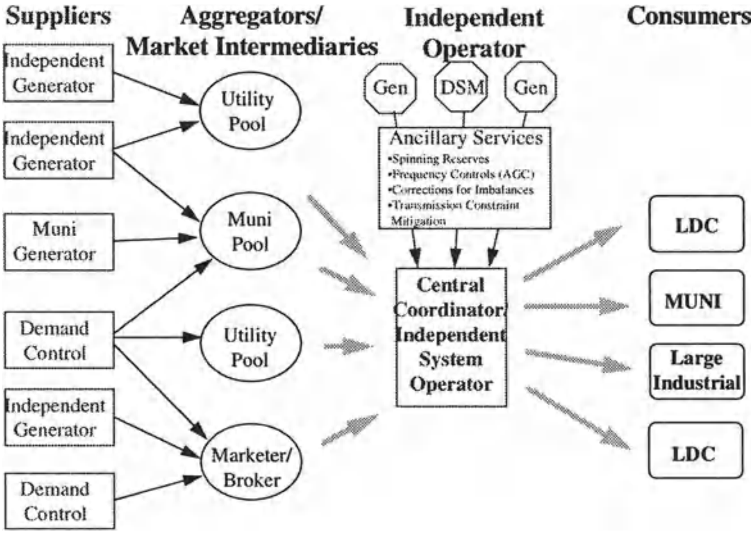


Figure 2 reflects the structure of an industry in which generation, transmission and distribution services are unbundled. Note that the break-up is facilitated actively by power market intermediaries who will also provide or arrange network coordination and other support services. From the standpoint of achieving the efficiency gains which are sought through unbundling, separation of generation, transmission and distribution is clearly the primary goal. Unbundling of generation services (spinning reserves) is also important in order to provide the same competitive and transparency benefits. The latter unbundling could take many forms, but will likely involve contracting for such services in spot and longer-term contract markets by the ISO.

Figure 2. The Unbundled System.



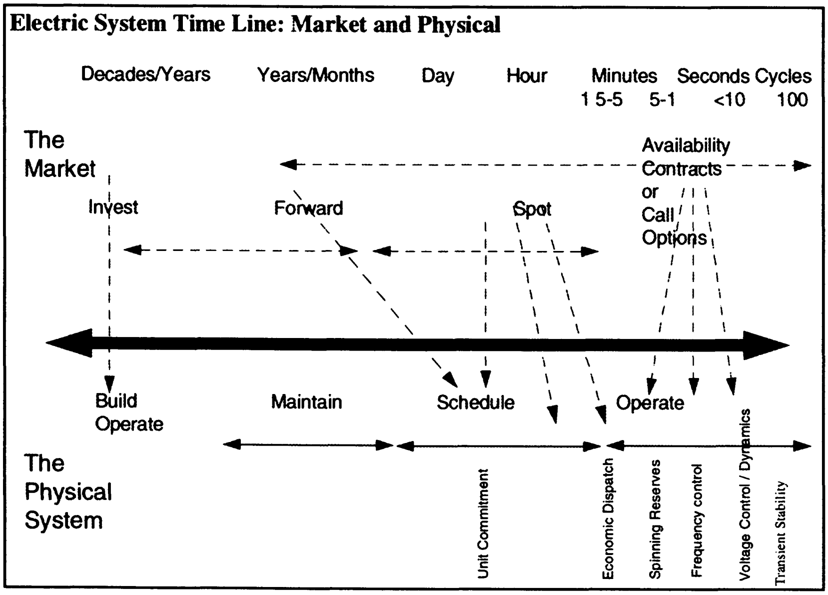
The Role of Intermediaries in an Unbundled Industry

In the old vertically integrated structure of the electric utility industry, there was little scope for intermediation, since all transactions along the value chain were internalized within a single company. However, the trends toward emergence of full-fledged intermediation have been evident for some time, paralleling the trends toward greater competition. Power pooling and exchange arrangements across groups of vertically integrated utilities have been a first step in this direction. Furthermore, facilitated by these power pools and wholesale access, transactions across utility boundaries have expanded rapidly, accompanied by the emergence of NUGs as significant sources of generation. Some of these transactions have been intermediated by power marketers and brokers. In the new industry structure, the role of intermediation should expand rapidly. This is consistent with our view, discussed further in section 7, that intermediation is the "lubricant" of competitive markets.

The Workings of an Unbundled Electric Power Industry

Figure 3 provides a snapshot of the physical functions provided by the electric power system and the financial decisions and instruments which complement and parallel the physical. We structure the physical system functions and the financial market decisions/contracts as they occur in 4 time frames, Long-Term, Medium-Term, Short-Term and Real-Time.

Figure 3: Electric System Time Line: Market and Physical



Long-term Functions and Decisions

Physical: Technology planning and acquisition, human resource planning and development, to build and operate assets to support generation, transmission and distribution (GTD).

Financial: Secure required capital, technology and human resources to accomplish the physical functions.

Medium-term Functions and Decisions

Physical: Schedule and implement system maintenance of GTD assets.

Financial: Forward contracts and bilateral agreements are negotiated for power delivery and contracts for load management, for transmission constraint payments, and for delivery of ancillary generations support are determined.

Short-term Functions and Decisions

Physical: Forecast and schedule near-term power demand. Unit commitment decisions and other set-up decisions to enable economic dispatch are made.

Financial: Execution of medium-term contracts (e.g., forwards); spot markets and economic dispatch provide clearing mechanisms for residual supply and demand.

Real-time Functions and Decisions

Physical: Network coordination occurs to assure system reliability, security and stability. This coordination and balancing occur through spinning reserves and load management, with Automatic Generation Control (AGC) and ancillary generation support providing frequency and voltage support.

Financial: Execution of medium- and short-term contracts for interruptible loads, VAR contracts and other support services.

In terms of organizational boundaries, the natural demarcation is as shown in Figure 3 between the organization(s) controlling long- and medium-term transactions, and those occurring in the short-run or in real-time. The latter transactions are the purview of system operations and organizationally will be the responsibility of the Independent System Operator (the ISO). The longer-term functions and decisions are the responsibility of Generation, Distribution and Transmission Asset Providers (we refer the last-named as TAPs). Concerning transmission service and network coordination, the key is the organization and ownership boundaries of the ISO and the TAPs. We discuss this in the next Section in more detail, but it should be clear right away that two general possibilities exist: either the ISO and the TAPs are brought under the control of one (presumably for-profit, regulated) company, or the ISO and the TAPs remain under separate ownership and control. The former instance is seen in the structure of the UK and New Zealand power markets,[5] in which a single entity owns and controls both transmission assets as well as the ISO. The latter is the model which is being pursued in several ISO proposals under the Regional Transmission Group concept in the US.[6]

In the transition to the unbundled electric power industry, the short-term functions and decisions (those that occur in the time frame of a day down to an hour or possibly to 15 minutes) require the greatest evolution from today's utility operations. Development of a spot market for electricity is the major change in the short term domain. How much change does this actually entail? Looking to other commodities (e.g., natural gas), spot markets develop both rapidly and efficiently. The functions of the pool operator (i.e., the Independent System Operator or ISO) will include responsibility for least cost dispatch for the voluntary pool, together with the real-time functions of reliability, system security and stability for all transactions. The nomination and/or posting of transactions will occur *ex ante* such that the

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[5] For a description of the U.K. transmission infrastructure, see [Newbery, 1995]. For a description of the New Zealand infrastructure, see [Ring and Read, 1996].

[6] For example, *Electricity Daily*, February 13, 1996, describes the launch of a "Super-ISO" in which six midwestern investor-owned utilities have announced their agreement to lease their assets to an ISO organization which would then control all transmission assets as system operator, and would pay for the use of these assets under long-term contracts with the respective asset owners.

physical and financial transactions can be verified *ex post* and any over or under delivery/receipt can be identified and dealt with in the balancing costs.

The pool functions and associated financial instruments are well understood by now and include market clearing dispatch and settlement procedures.[7] The physical functions of balancing and coordination can be maintained through a new/modified set of market instruments that can be exercised by the ISO. As an independent, performance-based, regulated entity, the ISO purchases contracts for reserves—call contracts—with specific performance characteristics based on expected needs that provide for MW and MWh. These contracts will include negawatt as well as megawatt resources. Contracts would be called to cover unplanned outages and increased demands. The cost of operation of this aspect of system operations would be covered through *ex ante* contracts with *ex post* verification—plus a management fee—to the responsible participants. Within a prespecified range, hourly costs could be traded off between participants before the actual transactions came due. The result of these *ex post* trades is the creation of a secondary market in capacity and/or energy directly analogous to the market that has emerged in natural gas with a longer clearing time.

The second function to be fulfilled by the ISO, even closer to real-time, is that of maintaining system frequency. In today's system, frequency is maintained by Automatic Generation Control devices that are installed and operating on most generating units. While the physics are more complex, these devices are best thought of as monitors that automatically sense deviations away from nominal 60 Hz frequency. When frequency is low, additional primary energy (steam) is introduced into the unit thus providing more rotating energy in the system. When frequency is high the reverse is true. Both the AGC device and its operation have a cost to the generating unit owner/operator. This function is readily provided through long-term contracting between the unit owner and the ISO, which would provide contractual incentives for system efficiency.[8]

Two final functions must be fulfilled by the ISO for stability and security to be maintained. The first is the requirement for VAR support (seconds to minutes) and the second the need to respond to rapid changes in system configuration that will induce transience—i.e. manage transience such that the system automatically returns to acceptable operating conditions rather than becoming unstable (in a time frame of cycles to seconds). VAR support today is provided by generators capable of "lagging or leading" in phase angle of generation, through capacitor banks or through static VAR compensation or so called "FACTS" devices, (Flexible AC Transmission Systems). This capability provides the trade-off between real and reactive (VAR) generation at any unit. As with AGC, this function has a capacity

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[7] For the UK, see [Newbery, 1995]. See also [Einhorn and Siddiqi, 1996] for a description of pool operations and settlement procedures in other countries.

[8] Starting in October of 1994 the National Grid Company of the UK advertised in the *London Financial Times* (October 13, 1994) for "Frequency Control Services" and "Reserve and Constraint Services" in advertisements headlined "Have you got the power to make money?" Their bid is to purchase on either the supply or the demand side services that will respond rapidly to frequency change or services that can respond to needs for system reserves or constraints. Both services were called to bid by December 2, 1994.

cost—the capability—and an operating cost that needs to be contracted for, usually as a call contract.[9] VAR contracts will be long term with performance based on monitored unit output—parallel to that employed today.

The final issue in the real-time domain is how the services of system operation and network coordination provided by the ISO would be paid for. As discussed under reserves above, some services required by the system are directly attributable to individual participants in the system. This is specifically true of both shortfalls in supply or excesses in demand relative to contracted levels. ISO can attribute and bill for these services given known contracted capabilities. The balancing and bookkeeping can occur *ex post* as part of an established accounting routine as occurs with the "uplift" function of the UK Poolings and Settlements[10]. The other functions to be fulfilled in real-time by the ISO are systems based and not attributable. These functions need be paid for, in essence, by a performance-based contract between the users of the system (end consumers) and the ISO. As a regulated entity, the ISO will perform as close to a competitive entity as possible if its earnings are a function of the difference between a price cap and its costs. This drives its costs of operating the system to a minimum for provision of a predefined and regulated level of service.

The above sketch of how the unbundled electric power industry might function suggest three critical issues which will need to be resolved. In some sense, these all revolve around the area of the Transmission Service Provider (TSP) and the Independent System Operator (ISO). More specifically, the issues we explore below in detail are these:

1. What are the possible structures and roles of the of the ISO? Will the ISO simply be a market facilitator which controls the Network (the real-time functions above) and the voluntary pool(s), while contracting for assets and support services with other market participants? Or will the ISO be a commercial entity with assets (e.g., wires or generation plant) of its own?

2. How will transmission access, pricing, investment, contracting for services and regulation be accomplished for each of the feasible alternatives identified in (1)?

3. What should be the role of financial instruments and intermediation in the market?

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[9] It should be noted that contracting for VARs was one of the earliest modifications introduced into the UK Pooling system.

[10] Note that the *ex post* balancing function in the UK does not differentiate between sources of problems and spreads these costs evenly to all consumers.

4. ROLE AND STRUCTURE OF THE ISO

This section briefly discusses several approaches to organizing and regulating the ISO and Transmission Service Providers (TSPs) and their relationship to facilitating long-term markets (between Gencos and Discos) and short-term markets between all participants via the Pool. This is one of the central questions which will drive the efficiency and operation of the reorganized industry. A variety of ISO models are technically possible, differentiated in broad terms by the following (inter-linked) factors:

1. involvement of the ISO in the energy market;

2. the scope of business activities undertaken by the ISO, including the extent of support functions bundled within the ISO;

3. ownership and/or control of assets by the ISO.

We will first describe three benchmark ISO models—CoorCo, GridCo and PoolCo—which are broadly differentiated along these lines, and discuss their potential for meeting the criteria set out above. Thereafter, we consider hybrid versions which combine features of the above models.

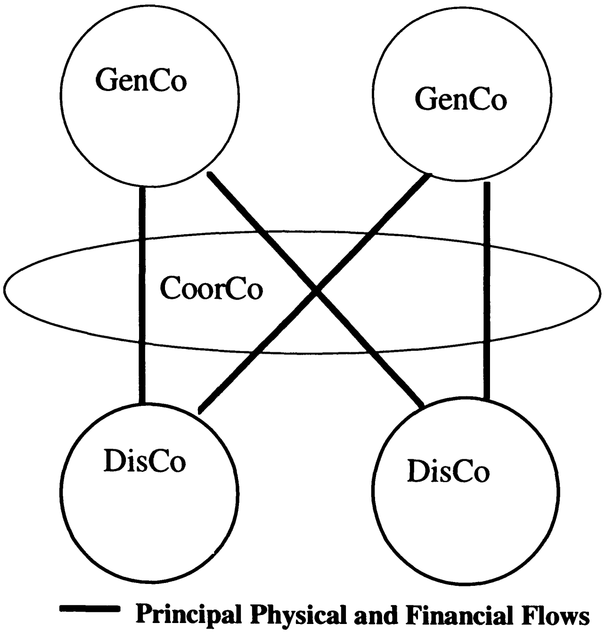
CoorCo—Coordination Service

The CoorCo model of an ISO has some similarities to the various coordination operations that have existed in the U.S. to interconnect transmission lines and pool generation belonging to vertically integrated electric utilities in various parts of the country. Historically, these arrangements were driven mainly by system security considerations, with very little commercial activity taking place across utilities relative to transactions internal to their vertically integrated structures.

An example of a CoorCo-type scheme is the Regional Transmission Group (RTG). RTGs have been proposed to coordinate the transmission resources of different utilities, taking on the coordination of operations, planning and investments, and dispatch and settlement duties on behalf of its members. A prominent example is the Western Regional Transmission Association (WRTA) in the United States which encompasses a large segment of the Western U.S.

Figure 4 illustrates the concept of the CoorCo model. In a strict CoorCo-type ISO model, energy transactions occur only through bilateral transactions between generators and consumers. The ISO is informed of the power flows that would be associated with these bilateral contracts, so that it could make necessary arrangements to accommodate these power flows while maintaining system reliability. There is no "financial" pooling in the energy market—all settlements are undertaken bilaterally between buyers and sellers—and physical flows relating to particular transactions are assumed to follow "contract paths".[11] Buyers and sellers would arrange with the ISO for meeting the cost of losses and system support services that are associated with individual bilateral transactions. Emergency conditions will, on occasion, occur through severe weather or other extremes. Under these conditions, the CoorCo could call on individual generators to supply emergency power or energy.

Figure 4. CoorCo Model of the ISO.



In this bilateral model of energy transactions, individual generators and consumers will receive and pay different prices. Competition will occur through buyers seeking out least-cost sellers leveraging upon the transmission network. The ISO plays no market-making role nor implements economic dispatch to facilitate competition and least cost generation usage.

A CoorCo-ISO is not required to own any generation or transmission assets, only to have control over the operation of sufficient assets to carry out its coordination function properly. The extent of control required by the CoorCo would clearly be system-specific, but is likely to include a significant portion of the transmission network together with generation plant that are necessary for back-up reserves, frequency, VAR support, etc. Owners of transmission assets would sell the right to the use of the capacity of these assets to power marketers and principals striking power contracts. They could also sell transmission capacity to the CoorCo who would acquire this capacity for the purpose of fulfilling its responsibilities. Buyers and sellers would be free to transact in transmission

[11] Even though actual flows will follow the laws of physics and may be quite different.

capacity. These transactions could occur on both a firm or non-firm basis, in both the primary market for transmission capacity sales and in secondary markets. "Firm" in this context implies that owners of firm capacity would have first priority in its use.

Transmission investment is undertaken by third-party transmission providers or by the CoorCo itself. The CoorCo can assist in system planning and by being a central information source for potential investors, thereby ensuring that the most profitable (and hence value-creating) investment opportunities are identified, while simultaneously avoiding excess capacity build-up. For such a decentralized scheme of investment to be effective, investors in transmission would need to receive the full value provided by their investment through an appropriate scheme of pricing (see below).

A key question underlying the CoorCo model is how its operations will be financed and regulated, and what impact this would have on CoorCo's incentives to fulfill the desired objectives. It has been suggested by some that the CoorCo fits the mold of a non-profit or even public enterprise since (a) the value created by CoorCo is largely reflected in quality and reliability terms, both of which are already very high especially in industrialized countries; (b) due to the significant externalities associated with electricity service, it would be difficult to price-differentiate CoorCo's services based on value; and (c) CoorCo may be able to perform its service without significant asset ownership. In the RTG model of the U.S., the ISO is owned by member utilities but operates independently on a non-profit basis. One potential approach is to hold CoorCo to a performance standard and set its revenue based on a "cost-plus" approach. From an efficiency standpoint, this will result in excess conservatism and lack of attention to costs. In particular, CoorCo would not have any incentive to apply pressure on third-party suppliers of transmission services to provide their services at least-cost.

The multiplier effects of a CoorCo which has no strong economic incentive to hold down its own costs could increase costs quite substantially for other industry participants. This could occur through increased costs of losses and system support borne by downstream users, due to "risk averse" system operation. Resolving this problem using a price cap or other scheme of incentive regulation could create new problems, especially if the ISO is a non-profit organization. The basis selected for setting the price cap (such as Rate of Return) could potentially cause new incentive problems, including conflicts of interest between CoorCo and third-party transmission suppliers, generators and customers, thereby jeopardizing its independence and objectivity. On balance, there appear to be very significant incentive and control problems with the CoorCo model of the ISO.

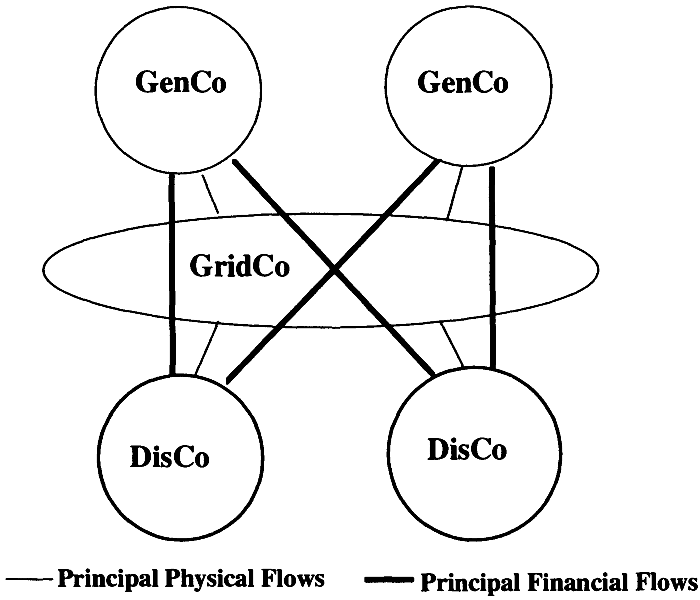
GridCo—Integrated Transmission Grid

The GridCo model expands the role of the ISO by enlarging the scope of its shorter term activities relative to CoorCo and also by taking on the longer term functions associated with the efficient operation, planning and investment of the transmission grid. The purpose of integrating these functions within the ISO is to achieve the economic efficiencies associated with the operation, planning and investment of the transmission grid that are less explicit in the CoorCo model.

Whereas the CoorCo model was based on the concept of competing providers of transmission services, in the GridCo model all transmission services are brought under the umbrella of a single transmission provider—GridCo. This explicitly reduces the reliance on competition to provide efficient transmission operation, although the GridCo should seek to outsource as many of its service requirements as possible. Unlike the "multi-provider" CoorCo model, all power flows associated with bilateral power contracts would use GridCo's lines and transmission services.

Figure 5 illustrates the concept of the GridCo model. As in the CoorCo model, energy transactions will occur through bilateral transactions between generators and consumers. The transmission services associated with these transactions would need to be arranged through the GridCo, including access to the grid and its use. The GridCo would be responsible for operating the system at specified levels of reliability in least cost fashion.

Figure 5. GridCo Model of an ISO.



As in the previous CoorCo model, the GridCo ISO plays no direct market-making role nor does it implement economic dispatch. However, by providing a reliable and efficient grid system, it would facilitate competition in the generation market.

A GridCo will own or contract for the use of (e.g. through leasing or long-term usage contracts) the transmission assets in the network. This would include both wires and associated infrastructure as well as system support services. The system would be "single provider" in the sense that all transmission services would be provided by the ISO. Unlike in the CoorCo model, there would be no market in transmission capacity, primary or secondary. The GridCo would be the sole (regulated monopoly) seller of transmission capacity. This would not preclude the differentiation of transmission service on the basis of firm and non-firm, nor differentiating the pricing of transmission based on space and time (see our discussion below on transmission pricing).

As in CoorCo, transmission investment can be undertaken by third-party transmission investors or by the GridCo itself. In either case, GridCo will act as the clearinghouse for new transmission projects. With an appropriately designed incentive scheme (see below), it would be in GridCo's interest to seek out the cheapest possible solutions to the system's transmission needs.

In contrast with the CoorCo model, GridCo can be set the clear economic objective of minimizing total short run and long run costs of transmission, since all these costs (including system losses) are internalized within GridCo. GridCo would also be held to a quality standard. Revenues to the GridCo would accrue from transmission charges levied on system users. These transmission charges would be designed to recover the capital and operating costs of the system together with an appropriate profit scheme which is designed to sustain incentives for continued cost minimization. A well-designed price cap scheme would provide such incentives.

A significant advantage of GridCo versus the CoorCo model is its reduced complexity. Although a monopoly provider, GridCo will depend on outsourcing for as many services as possible so that the benefits of competition will still accrue to system users without the costs of regulating diverse transmission providers. GridCo would find it in its interest to create competition in the provision of various transmission services, including constrained generation, interruptible load, line maintenance, voltage support, etc. While hold-up problems may be difficult to avoid in the short run (such as plants charging exorbitant amounts for constrained running, or maintenance contractors marking up their prices), GridCo will move actively to eliminate such situations.

The GridCo concept lends itself naturally to systems where transmission assets have been previously owned and operated by a single entity, as in England and Wales. In other situations, as in the U.S. where transmission assets in regional pools have multiple owner/operators, the transition to a single operator has proved to be more difficult, because of the complexities of valuing assets, pricing transmission services to the previous owners and revenue sharing. However, the GridCo concept holds better promise than CoorCo for meeting the objectives of economic efficiency coupled with reliable service that are being sought through the ISO.

PoolCo—Pooling of Energy and Transmission

While there are several variations of the PoolCo concept[12], the core idea of a PoolCo is that of a service which would buy power at generator nodes and sell it at consumer nodes. The PoolCo would be an independent entity which would control the operation of the transmission network within its region and dispatch all generation for energy or system support. Generators would sell power into the pool and consumers would purchase power from the pool at prices that periodically (e.g. each half hour) "clear the market". Market participants would also bear the cost of transmission, which would cause price differentiation by location. The PoolCo would schedule and dispatch generation according to the

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[12] See, e.g., the early work of [Hogan, 1992] and the recent special issue on transmission pricing of the *Journal of Regulatory Economics*, July, 1996.

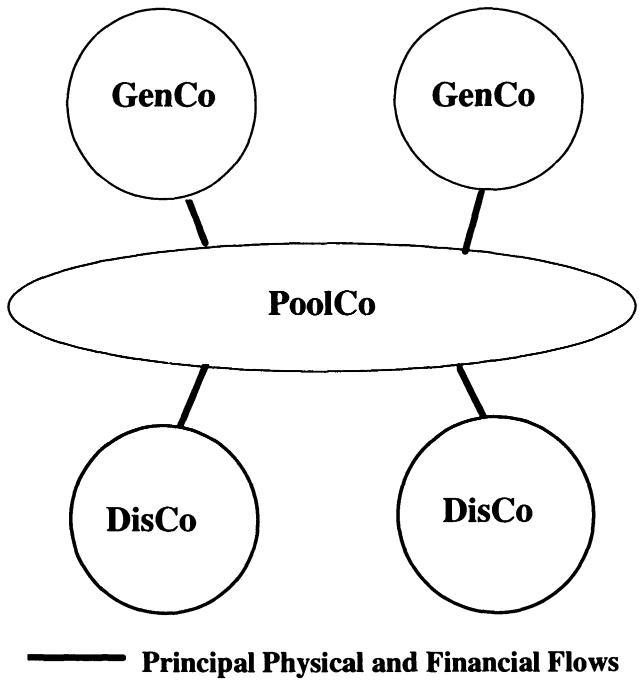
merit-order (where possible) established by the contract prices (bids, costs, or previously agreed on some other basis) of the generators. It would also own or contract for system support capacity necessary for cost minimization and preserving system reliability.

In this ISO model (see Figure 6), the PoolCo would have two basic responsibilities:

1. act as a market clearinghouse, using the transmission facilities at its disposal to link generation and load, thereby "making" the market and preserving its integrity.

2. preserve reliability of service to market participants.

Figure 6. The PoolCo Model of an ISO.



Applied strictly, the PoolCo concept requires mandatory pooling of generation resources, with voluntary (or residual) pools being a variant thereof in which GenCos announce (e.g., on a day ahead basis) which units are to be pool dispatchable. Mandatory pooling is similar to the way the British power pool currently operates and voluntary pooling is similar to the way the Norwegian power pool currently operates.[13] Pooling of both energy and transmission resources in this way is intended to assure equal treatment for all spot market participants in system access, pricing, and revenue allocation. All

[13] The British system is described in [Newbery, 1995]. The Norwegian system is described in [Westre, 1996].

physical flows will enter the spot market, although users may enter into financial contracts ("swap contracts" or "contracts for differences") bilaterally to fix their payments and receipts associated with specific transactions. For the PoolCo to carry out its responsibilities, the only requirement is that it has control over sufficient generation and transmission assets to preserve a competitive market and system reliability. This control can be obtained through ownership of the assets by PoolCo or by contracting for their use.

As in GridCo, the PoolCo would be the sole (regulated monopoly) seller of transmission capacity. This would not preclude the differentiation of transmission service on the basis of firm and non-firm (as in interruptible service), nor differentiating the pricing of transmission based on space and time. As in the previous models, transmission investment can be undertaken by third-party transmission investors or by PoolCo. As before in the case of GridCo, PoolCo will have an incentive to assure transmission investments at least cost. It will facilitate this by long-term planning and publicizing investment needs in the network.

PoolCo goes a step further beyond GridCo by effectively mandating economic dispatch to be carried out by the ISO. This reduces the burden on system users to competitively seek out opportunities for cost reduction. Apart from this, PoolCo's cost and revenue structure, and potential regulatory options, would be very similar to GridCo; since the merit order is quite transparent, PoolCo's economic objective boils down to minimizing the costs of transmission.

As in the case of GridCo, the PoolCo concept has met some opposition in systems which were previously multi-owned and operated, and from those who believe that creation of new monopoly structures is antithetical to the current unbundling initiatives which are aimed at increasing competition. In particular, PoolCo cuts out several intermediation functions which are vital for promoting competition in an unbundled industry. We discuss below some hybrid proposals which have been put forward to overcome such objections.

Hybrid Models: Voluntary or Flexible Pools

An idea which has emerged from experience in several countries (especially Norway and Argentina) and actively supported by several utilities in the California restructuring debate in the U.S. is the concept of a voluntary or *flexible* pool. Under this arrangement, system users (both buyers and sellers) have the choice of either accessing the spot market (created by pooling a segment of generation and load in the system) or transacting bilaterally bypassing the pool altogether. This arrangement is attractive relative to mandated pooling since:

1. it does not preclude the free choice of market participants;
2. it does not inhibit the development of value-creating business opportunities; and

3. it minimizes potential inefficiencies associated with pool rules, letting these evolve over time through experience.

Arrangements similar to flexible pooling exist in markets for all commodities, since these markets consist of both spot and forward contracting arrangements. Some have argued that a flexible pooling scheme is identical to mandated pooling where in the latter case market participants can enter into bilateral side contracts priced off the spot market to fix long-term prices. This remains an open issue but some differences are very clear. In particular, the characteristics of the spot market itself (liquidity, price volatility, etc.) are likely to be quite different in the two cases, since in the latter case spot market participation occurs only by self-selection.

Flexible pooling can co-exist in principle with any of the above models of the ISO. The ISO would provide economic dispatch services to those market participants who opt for it. Given the recontracting and incentive problems with CoorCo noted above, however, we will only consider hybrids of the PoolCo and GridCo in what follows. In the Flexible PoolCo, which is similar to the evolving UK system, most energy is traded through the Pool, with some self-dispatch and intra-zonal bilateral contracting allowed. In the Flexible GridCo, which is similar to the evolving Norwegian system, most energy is traded through bilaterals with residual trades being accomplished through a voluntary pool. In either of these cases, we assume that the ISO is set up as the System Operator responsible for real-time system operations and for short-run operations required to assure timely information on the nature of bilateral transactions is available to assure efficient scheduling and dispatch. We now consider the organization and regulation of this form of ISO and its relationship to Transmission Asset Providers (TAPs).

5. EFFICIENT ORGANIZATION AND REGULATION OF TRANSMISSION

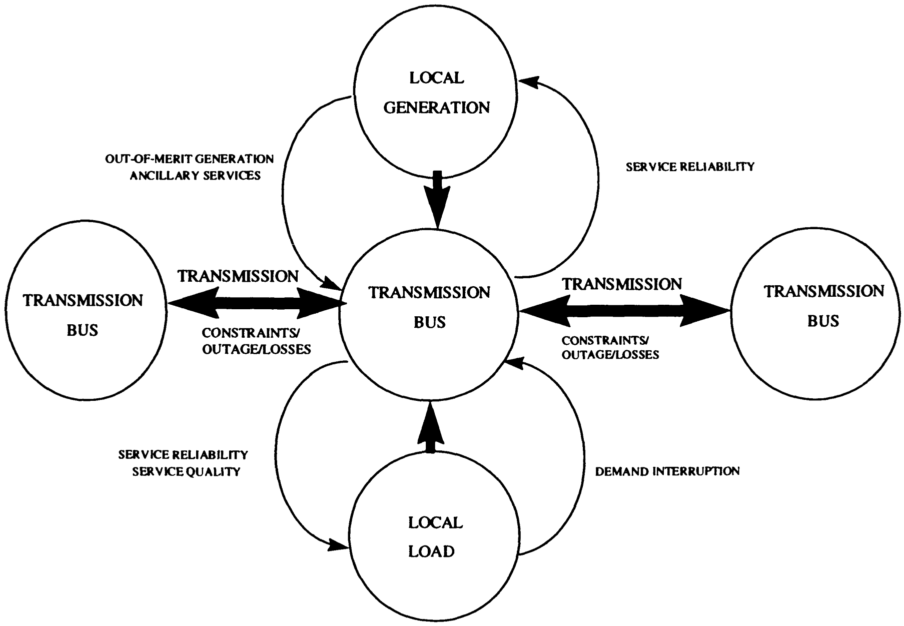
Scope and Organization of Transmission Service

The discussion here is concerned with defining the appropriate scope of transmission service and with the principles underlying the recovery of revenue requirements for transmission assets. Our discussion applies to both single owner (e.g. TransCo) and multi-owner (e.g.) RTG arrangements.

Figure 7 illustrates the components of the transmission service. At a primary level, generators and loads will gain access to the market through a connection to the transmission grid, and their supply and demand gives rise to the electricity marketplace. Bringing generators and wholesale customers could be characterized as the QUANTITY or ENERGY side of the transmission service. The other side of the transmission service is the QUALITY or SYSTEM SUPPORT side, which is concerned with ensuring security of supply, and voltage and frequency standards.

As set out in the framework shown in Figure 7, the quality side of the transmission service would include the procurement of Out-of-Merit (OOM) generation services for constraint control and ancillary services from generators (and other suppliers of these services). The provider of transmission service may also acquire the right to interrupt loads or In-Merit (IM) generation through interruptible service contracts.

Figure 7. Transmission Service.



The other key aspect of the quality side of the transmission service is the security or insurance value of the network. The point here is that all participants in the energy market acquire through their transmission grid connection a valuable option to generate or consume electricity. This option is made valuable by the additional investments (e.g. reserve lines) and operational decisions (e.g. scheduling generation reserve) undertaken by the transmission provider. Hence, the transmission grid is both a medium for transportation/trading, as well as a security network.

It is essential that all these elements on the quality side of the transmission service be internalized within the transmission provider in order for this service to be planned and operated efficiently.

As noted in section 2, the key to successful unbundling is the ability to rebundle without undue transactions costs. In particular, given the importance of centralized operations in accomplishing its real-time functions, it is clear that the ISO must be located within the organizational boundaries of a single economic entity. This leads to one classification of possible ownership structures for transmission: (a) either the same entity which houses the ISO owns and operates other transmission assets, or (b) this entity consists only of the ISO and does not own these assets but leases/contracts for these from other transmission asset owners. Using comparative institutional economics[14], it is not possible to rule either of these approaches out as *prima facie* inefficient. Approach (a), which sets up a single company, the TransCo, would give rise to the usual problems of providing regulatory incentives through performance-based regulation to assure that the TransCo, a regulated monopolist, undertook its responsibilities in a manner which promoted system-wide efficiency. Approach (b), the ISO+TAPs, would yield clearer information on the value of transmission assets and services (the former provided by TAPs and the latter by the ISO), but would lead to transactions costs between the ISO and the TAPs in contracting for and maintaining the transmission assets. A hybrid approach might create a single organizational entity, the TransCo, but require it to have two separate divisions, TransCo-Wires and TransCo-ISO, to create transparency in cashflows and value-added resulting from the asset management and system operation functions of the TransCo. Let us consider these options in more detail.

In the single, unified TransCo option, a regulated monopolist would be given responsibility for universal transmission service. To assure clarity in its motives and some incentives for X-efficiency, this TransCo would have to be a for-profit, regulated monopoly. As noted above, it could be required to keep separate books on its ISO and its TSP operations. The TransCo would then face various forms of profit, price and quality regulation, as discussed below. Revenues for the TransCo would come from:

1. Monopoly or reserved services, such as those associated with running the Pool and system operations.

2. Contestable services, such as connecting new loads or generators to the system, which could be provided by a number of third parties.

Ideally the price and/or revenue for contestable services would not be regulated, but would be determined by an open market in these services. For services of type (a), prices and revenues would be derived from two traditional elements of transmission pricing (see section 6 below for more detail): capacity charges which would depend on the total capacity of generators connected to the grid, and energy charges which would depend on the energy carried by the transmission system. The total of these two charges would cover (for reserved services) asset costs, system operation costs, congestion costs and losses.

Under the ISO+TAPs option, asset providers and transmission service providers would be separated. Here the ISO must deal with the added complication of negotiating with independent asset owners (the TAPs) for continuing use, enhancement and maintenance of their assets. If, as envisioned in several recent RTG proposals, the ISO itself were set up by these TAPs, then additional problems of assuring uniform and fair treatment for all comers (including the TAPs) through a committee

[14] For an introduction to instititional assessment procedures, see [Crew and Kleindorfer, 1986, Chapter 7].

decision-making process involving all the TAPs presents additional opportunities for transactions costs and organizational inertia. Presumably, the same guidelines on reserved and contestable services would hold for the ISO+TAPs approach as for the TransCo approach. However, if the ISO is owned by the TAPs, additional monitoring and oversight will no doubt be called for to assure that the ISO fulfills its market facilitation role in an objective fashion.

Regulation

Appropriate regulatory scenarios will depend on which of the organizational alternatives sketched earlier is chosen. In the event that an asset-thin ISO is set up with no "wires" ownership, the key problem will be to provide incentives to the resulting ISO to properly contract for use of assets, since the cost of such use would be largely outside of the ISO's control. In the event of a TransCo (with, say, an asset-holding division TransCo-Wires and a transmission service division TransCo-ISO, a key regulatory issue will be to assure that the TransCo faces the proper incentives to avoid inefficient strategies such as asset-padding.

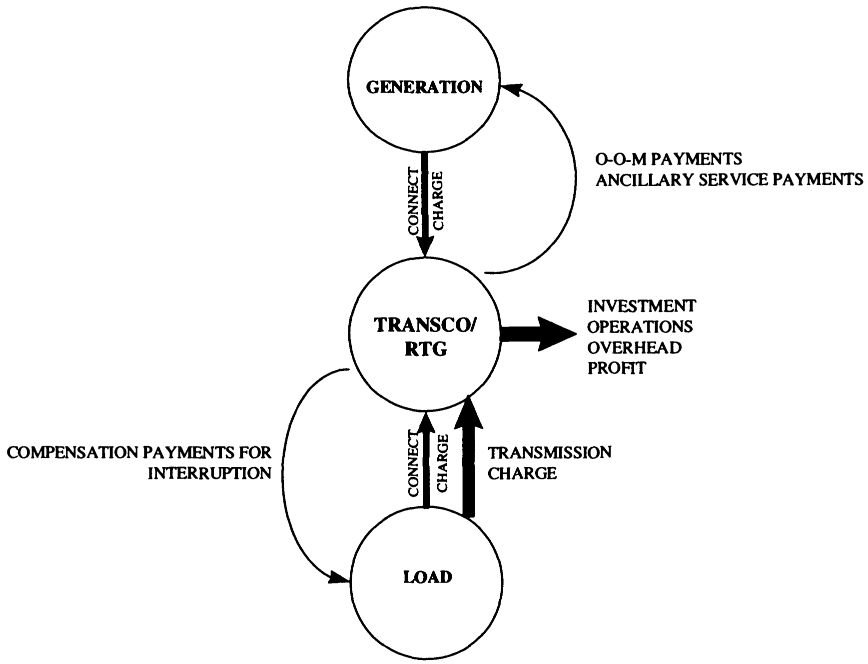
Figure 8 captures the revenue and cost flows associated with transmission service. The transmission charge will be levied on loads (directly in the case of network service, indirectly in the case of point-to-point bilateral contracts), and will cover the cost of both the quantity and quality sides of the transmission service. The transmission provider may also charge both generators and loads for connection to the system (which would reimburse the provider the cost of the connection).

The transmission provider will provide service by building adequate capacity (through investment) and by operating the system reliably and efficiently. In some cases, it may be more efficient for the transmission provider to meet capacity needs by paying generators to operate Out-of-Merit or by paying loads for interruption. In addition, the provider would also be required to meet the cost of system losses and to pay generators for ancillary services such as reserves, frequency control, etc.

The key to effective regulation of transmission is to internalize all the costs that are associated with transmission service within the transmission provider. This will create the correct incentives for optimal investment and operation in the transmission grid. In the longer term planning horizon, the provider will optimally trade off investment decisions against the various operational options (such as Out-of-Merit-Dispatch (OOM) payments or interruptible contracts). In the shorter term operational horizon, the transmission provider will pick among the various short term options which are available to achieve least-cost system operation.

Regulating a TransCo's Revenues—A TransCo's revenue stream could be regulated through cost of service, price caps or various other incentive regulation schemes (see Crew and Kleindorfer [1996]). A pure cost of service scheme is probably not appropriate in a setting where TransCo's cost side is subject to significant uncertainty, especially in the case of constraint control costs. The main point here is that the regulatory scheme should meet two criteria from TransCo's standpoint:

Figure 8. Payment Flows in the Transmission Service.



1. Provide TransCo the correct incentives to invest and operate the transmission system. Thus, a price cap applied on a kWh basis for the energy components of the TransCo's services would be appropriate, and would cause the TransCo to confront the correct incentives for investment and contracting if TransCo is regulated to cover all energy costs (losses and congestion costs) of transmission.

2. Provide TransCo a means of passing through risks that it is not equipped to manage (for example, a substantial change in constraint costs as a result of a change in the relative coal/gas price).

Regulating an ISO+TAPs' Revenues

The same principles as above apply to the determination of the aggregate revenue requirement. In the case of an unbundled TSP with multiple TAPs, revenue allocation mechanisms should provide asset owners proper signals of the value of their existing assets and the incremental value of various options for expanding transmission capacity. This is not as simple as it might seem, since an allocation mechanism based simply on, say, MWh-miles would miss the insurance or quality value of some assets. Thus, a combination of a fixed capacity rental charge per MW-mile per year (set to cover maintenance expenses and depreciation plus a reasonable return on the asset) with a usage-sensitive energy fee would be required.

The issue of multiple TAPs and a correct valuing of their assets for quantity and quality of service remains an open issue. It points to the key difficulty with the ISO+TAPs model, the level of contractual transactions costs with TAPs and the related issue of control of asset quality by ISO. From the TAPs point of view, there are problems of assuring that their assets are valued correctly in contracts with the ISO and that the assets are properly maintained. To the extent that the TAPs jointly own the ISO, there would also be problems of assuring even-handedness in the provision of transmission service to non-TAP users.

6. TRANSMISSION ACCESS, PRICING AND INVESTMENT

Transmission Access

Open access to the electricity transmission networks that criss-cross the country is an essential prerequisite to the operation of a competitive unbundled market in electric power. While the Energy Policy Act of 1992 initiated the opening of access to transmission through wholesale wheeling, several issues surrounding the price regulation of transmission services remain. These need to be resolved before transmission can become fully established as the cornerstone of a competitive electric power market in the US. As we see it, the key issues in transmission pricing to enable effective competition are the following:

- Transparency of prices (unbundled transmission service)
- Non-discriminatory (between native load and third parties)
- Efficiency - cost reflective

The right of access to a utility's transmission network by a third-party generator or distributor provides value in allowing such entitites to sell at a higher price or purchase at a lower price than would otherwise be possible. In an unrestricted marketplace, this value would provide the basis for pricing the service. If the differential between the resulting price and the corresponding cost was excessive, this would normally be eliminated through competition or regulation. Under competition, and assuming that economies of scale are exhausted, prices would be driven down to marginal cost levels. This is a state which regulation would attempt (imperfectly) to emulate. In particular, transmission constraints at certain points in the system will be reflected by higher marginal costs of serving those points. So too will time-of-day differentiation of transmission prices reflect the differing marginal costs of serving particular demand points with transmission services as a function of the pattern of supplies and demands on the system at various points of time. Masking these marginal cost differences by uniform (postage stamp) rates, even if differentiated between firm and non-firm service, will deprive customers of valuable information of the costs they impose on the system with their loads.

In an unbundled industry, we envisage transmission services operating in an increasingly competitive environment. It should first be noted that generation and transmission are themselves substitutes in the sense that the bundled product of non-local generation and transmission can compete with local generation. Thus, with a competitive generation market, the market for transmission services will, if allowed by unbundled pricing, become more competitive over time. In particular, as the large energy price differentials even out throughout the country through competition, the opportunity for transmission service providers to extract monopoly rents will be greatly diminished. For the foreseeable future, however, there will still be a need for regulatory oversight of pricing and access rules for transmission services providers, but competition with generation nonetheless is an important efficiency driver for transmission.

One scenario for emerging competition in transmission services is the following. Transmission companies will sell firm capacity rights at regulated prices, which attempt to mirror location and time-dependent costs. Energy brokers, including generators and transmission companies, would bundle together generation and transmission services on a bilateral basis for wholesale customers. Such bundled services would provide for pricing and billing arrangements, alternative contract lengths and other features which wholesale customers may find useful.

Following our scenario further, interruptible or non-firm service offerings will also be offered competitively, and this from two sources: first through longer-term contractual agreements by companies which have firm transmission and/or generation capacity which they wish to offer on non-firm terms (e.g., by pooling non-coincident demands in an efficient manner); second through medium-term and short-term spot markets which will act further to price the value of interruptible capacity at various points and various times along the transmission grid. In the resulting competitive market among energy brokers, generators and transmission companies, the combination of long-term bilateral contracting markets and shorter term contracting and spot markets will act interdependently to provide appropriate price-cost-value links between suppliers and customers.

The above scenario requires a cooperative organizational compact or regulatory structure (e.g., a Regional Transmission Group) to determine rated system paths and to act as an information or market coordination point for property rights for these paths. For these reason and to assure continuing stable evolution toward a fully competitive market in transmission services, some form of regulation will be required to provide transmission companies with the incentives for efficient operation and investment. In this regard, dictates of low regulatory transactions costs, high transparency of the pricing structures, and flexibility to compete all argue for a regulatory structure which is performance or price-cap based rather than rate-of-return based. Price-cap regulation provides incentives both for operating cost minimization as well as for growing revenues through development of customer-responsive services.

Pricing of Transmission

Unlike generation, transmission and distribution are still perceived as monopolistic, and subject to regulated schemes of pricing, following traditional models. However, even in these areas, innovative approaches are being sought to maximize efficiency. Transmission pricing and regulation must assure that there are proper incentives for investing in the transmission system and for efficiently utilizing existing transmission assets. Any feasible approach must also be transparent and compatible with an unbundled, competitive market for power.

A basic transmission pricing structure will have a combination of three components:

Access Charges:	Customer-specific costs of connecting a generator or load to the existing transmission network
Demand-based Use Charges:	Paid on a per kW basis per annum
Energy-based Use Charges:	Paid on a per kWh basis

Both the demand-based and energy-based charges may (and should) vary by season, by time-of-day and by location. Firm transmission pricing should be structured to assure short-term efficiency and long-term viability/incentives for investment. On both efficiency and viability dimensions, cost-based pricing provides valuable indicators of alignment. The viability implications are clear—failure to recover costs is not sustainable. On efficiency, while cost is not the only determinant, transmission pricing to recover the long-run incremental cost of prudent investments provides important signals to the market on efficient entry. Providing the correct economic signals to consumers and to generators about the short run operating conditions of the grid and providing the owners/operators of the grid with the correct long run economic signals for investment in new capital stock are critical elements in both the operation and the future development of the electricity supply system.

The marginal cost pricing principles that we have discussed above in the context of efficient industry organization also provide the basis for pricing transmission services. The cost of a unit of electrical service to a customer at any point in time and at any location in the system is comprised of:

1. The marginal cost of providing the last unit of energy (system lambda);

   plus

2. the cost of losses (and other variable costs) associated with delivering energy to any point in the system;

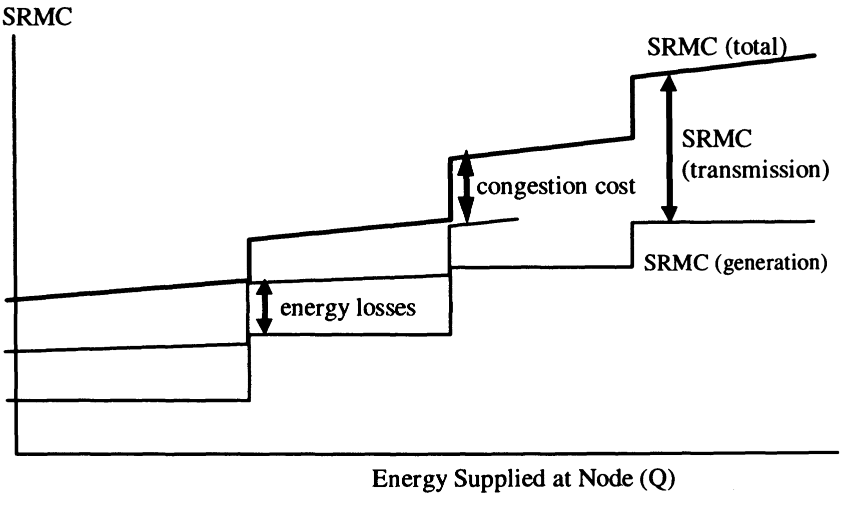
   plus

3. the cost of system reliability—i.e. the cost incurred when strict economic system operation can not meet all of the load. This includes emergency purchases, loading of generators out of the economic merit order to overcome regional genera-

tion/transmission capacity shortages, activation of interruptible load contracts, and load shedding.

This defines what is commonly known as the *short run marginal cost* (SRMC) of electricity service. Strictly speaking, this is the cost per unit supplied at any instant in time, even though in practice, SRMC's are measured over half-hourly or hourly time intervals. Furthermore, SRMC's vary quite significantly over the day, as each of the above components change over time. If a system is correctly designed, SRMC's averaged over the realized states of the world would equal the *long run marginal cost* (LRMC) of meeting an increment of demand at a particular point in the system. This follows from the basic investment criterion of Net Present Value (NPV) $\geq$ 0. In this particular case, what this implies is that investment should be undertaken up to the point when the cost of a new unit of investment and its use should equal the *expected cost* (over the lifetime of the investment) of the SRMC's. These simple principles of marginal cost give a well founded and defensible basis for a transmission pricing scheme. Figure 9 below illustrates the different elements of SRMC for any given bus in the system (assuming all else unchanged).

Figure 9. Elements of SRMC at a Bus in the Transmission Network.



It is important to make the distinction here between setting prices equal to short run marginal costs (which would imply pricing in close to real time) and short run marginal cost *based* pricing. The latter does not require that all participants in the market see and respond to half-hourly or even daily prices, but that the prices charged for the service be aggregated over longer time periods based on what SRMC's are expected to be during that period. In this way SRMC can be, and often is, used as the basis for setting tariffs that hold for time periods ranging from seasons to years. Simple Time Of Use (TOU) or peak / off peak rates are, for instance, aggregations of expected SRMC's.

Based on the above principles, a methodology for transmission pricing consists of the following steps (see the Technical Appendix for details)˙

1. Determine allowed revenue level for the system as a whole or a sub-system

The allowed revenue would be determined for a specific period, e.g. one year, or a three-month season. This could be on the basis of embedded costs as at present, or on the basis of incremental costs or opportunity costs if this is permitted.

2. Determine transmission zones

Based on marginal cost maps developed through various system models (such as "MAPPS") other means, divide the region into zones based on marginal cost. Each zone would cluster contiguous load and generation buses with fairly similar marginal costs. The actual number of zones would depend on the level of aggregation/disaggregation that is required. Even though there are considerable seasonal differences in the system which reverse power flows, the zonal configuration itself will be quite stable, since this is determined by the major system constraints.

3. Develop differentiated transmission charges, using marginal costs as an allocative basis

Having set the total revenue level, what remains is to develop a set of transmission charges that would recover this revenue level in a way that meets the desired criteria for transmission tariffs. In allocating revenue requirements to tariffs, there are basically four dimensions along which differentiation is possible across customers:

a. by location (i.e., transmission zone)

b. by time (e.g., by season or time-of-day)

c. by system usage (e.g., by load factor or peak-coincidence)

d. by reliability (e.g., firm and non-firm).

There are several schemes which may be adopted to allocate charges to different users according to their zonal SRMC's. These should be based on an efficiency rationale such as the following. The basic problem is to recover what, in the short run, are essentially the fixed cost of transmission assets. There is a well-developed literature on alternative methods of allocating such fixed costs which recognizes that various allocation rules have efficiency and sustainability consequences (e.g. [Braeutigam, 1980]). In the present context, these rules would have to be further extended to account for the specific features of transmission assets and usage, including firm and non-firm usage, time-of-use differences in valuation, and assets devoted to system coordination and reliability. We develop in the Technical Appendix one zonal approach in detail, which is quite similar to that currently employed in Norway. The essence of this approach is that it allows ex ante pricing of transmission capacity to all comers on a non-discriminatory basis. It does not reflect the nodal SRMCs since this would overly complicate transmission pricing with very few gains for even abstract efficiency and with considerable loss in transparency in the market. As we argue in the Appendix, the relative magnitude of transmission costs in the electric power value chain are in the range of 10% of total cost. Moreover, only a fraction of this 10% is variable in the short run and therefore includable in the logic of SRMC. Thus, an approximation to SRMC through ex ante zonal pricing with major portions of transmission fixed costs collected through subscription fees sacrifices little if anything on efficiency grounds and gains considerably on market transparency compared to complex approaches to transmission pricing, such as nodal prices with ex post reconciliation procedures.

The approach we recommend in the Appendix is to allocate transmission charges at each bus as a fraction of total revenue requirement (which itself could be zone-specific), with the fraction being determined by an-SRMC based weight at each individual zone. Thus, loads at high SRMC buses would contribute *relatively more* towards revenue requirements than loads at low SRMC buses. In contrast, generators at high SRMC buses would contribute *relatively less* towards revenue requirements than generators at low SRMC buses.

Nodal versus Zonal Pricing of Transmission Services

There is a continuing debate about how precise price signals for transmission services must be in time and space in order to reasonably reflect marginal costs and provide accurate market signals. Perhaps the most pointed form this debate has taken[15] is in the discussion of whether full-scale nodal transmission pricing is desirable or whether zonal pricing is on balance, a better candidate for transmission pricing. As we have discussed above, it should be emphasized that the starting point for **development** of zonal transmission tariffs is, indeed, a one-time computation of node-specific marginal costs under various scenarios. Advocates of zonal pricing, such as the authors of this paper, suggest averaging such node-specific marginal costs across relatively homogeneous transmission zones to obtain an average zonal marginal cost to be used as the basis of transmission rates, which are fixed for a reasonable period of time (e.g. one year). Advocates of nodal transmission pricing (e.g., [Hogan, 1992]), on the other hand, prefer to have prices remain at the level of detail of these node-specific marginal costs, usually in real time with prices adjusting (for example) 48 times in a day. Notwithstanding the apparent efficiency benefits of nodal pricing, There are several reasons why zonal pricing is to be preferred. These include, foremost, the following:

1. *Elasticity Shrinkage*: The cost of transmission is a relatively small (in the order of 10%) component of the total electricity price. Noting that total price

[15] For example, in the restructured U.K. electricity supply industry.

elasticity of electricity demand is low to begin with, the transmission price elasticity of (total) demand is only 10% of (total) price elasticity of demand. In other words, the economic efficiency benefits of fine tuning of transmission pricing signals diminish very rapidly.

2. *Transaction Costs*: Transmission service providers will remain regulated entities for the foreseeable future. The complexities of revenue reconciliation, revenue requirements, comparability reviews and capability assessments are going to be difficult enough in zonal pricing, reset annually or semi-annually. They would appear to be almost impossible under the added complexity of nodal resets. But if transmission prices are to be fixed for a reasonable length of time, it should be clear that the required scenario averaging across time will not benefit much from the added complexity of having to do this averaging at each node. As a further problem in regulatory complexity, if issues of shareholder and customer cross-flows are raised, these will be more difficult to sort out in a nodal pricing environment than under zonal pricing, where zones and recoverable embedded costs can be clearly identified with respect to native customers and ownership boundaries.

3. *Market Transparency*: The most important role that transmission plays in the evolving electricity market is to facilitate an efficient and active energy market, since this is where most of the benefits of competition are going to come from. From the point of view of the energy market place, stability and transparency of transmission prices will be an important driver of efficiency. Thus, given all the other changes taking place in electric power, simple efficient and stable zonal prices can be an important ingredient for both transmission providers as well as GenCos and DisCos attempting to understand the evolving market place, and make appropriate long and short-term contracts for transmission service.

4. *Transmission Cost Structure and Stability of Cashflows*: Given the desirability of reasonable stability of cashflows from transmission services, zonal pricing provides significant advantages. First of all, it is worth noting that the current cost structure of transmission is largely fixed (although this may change as transmission providers substitute generation and load management contracts for new capacity investment to meet network constraints). Furthermore, if stranded investment recovery and asset revaluation are involved, understanding the interaction of market and regulatory constraints (and arguing credibly for acceptable regulatory relief) required to predict transmission cashflows will be quite difficult under a real-time nodal pricing regime. The existence of risk hedging forward arrangements such as contracts for differences will not obviate the need for settlements on a real-time basis, especially since such forward arrangements cannot be mandated on market participants.

In general, the experience to date with zonal pricing (e.g. in the U.K. which rejected real time nodal transmission pricing and opted for a marginal cost based zonal approach) has indicated that rather stable marginal cost patterns emerge at the zonal level. This would indicate that efficiency gains from nodal transmission pricing may be rather small, even if one neglects the very large and evident transactions costs of regulatory and competitive interactions. Thus, it would seem that a rather substantial burden of proof rests in this case with those who would advocate moving beyond zonal pricing to real time nodal transmission pricing.

7. THE ROLE OF FINANCIAL INSTRUMENTS AND INTERMEDIATION

The expansion of market-based activities in the electricity industry has been accompanied by the growth of financial contracting arrangements. These are for both transactional reasons (as the number of players increases rapidly with the vertical unbundling of the industry) and for the purpose of better allocation of risk across different segments of the industry. We will first discuss the emerging and potential role of financial instruments such as forwards, futures, swaps and options in the new industry structure, turning thereafter to a discussion of the critical role of intermediation in promoting the use of these instruments and enhancing overall efficiency and competition.

Whereas the old vertically integrated structure was dominated by long term (forward) contracts and prices fixed over long time intervals, the new industry structure will characterized by a more even balance between spot markets and forward contracting arrangements. In this way, prices will be better reflective of the value of services provided and received, and risk can be borne by those who can do so at the cheapest cost.

The risk associated with electricity supply and consumption can be broadly divided into price (financial) and quantity (physical) risk. Price risk arises because the price of electricity fluctuates quite significantly on a temporal basis, much more than other energy commodities such as natural gas or oil. In the England and Wales spot market, the market "clears" each half-hour and prices can vary by an order of magnitude during the course of each 24 hours.[16] Price risk also arises because of spatial price differences in electricity caused by congestion and losses in the transmission system. In the context of contracting and risk management, the lack of perfect correlation in contemporaneous prices at two different locations is termed basis risk.

Quantity risk depends on the reliability of supply and demand. While the supply of electricity has traditionally been highly reliable in the U.S. and other industrialized countries, in the new market environment consumers will only pay for the reliability they need and suppliers cannot always be assured of take-or-pay contractual

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[16] For example, on Wednesday, Feb 14, 1996, the provisional England and Wales Pool selling price ranged from £8.94 per MWh at 0600 hours to £109.43 per MWh at 1730 hours (Financial Times, Feb 14, 1996).

safeguards when demand fluctuates. Whereas in the old industry structure, interruption options (discounts) may have been used as a cover to subsidize supply to certain demand segments (see [Crew and Fernando, 1994]), they will have a very important role in the new market regime in efficiently allocating resources. This is evident from the rapid growth of load management in the England and Wales electricity system after it was unbundled and privatized.

The need to manage these risks will increase the demand for and hence supply of risk management instruments, closely paralleling the process that evolved following the deregulation of the natural gas industry in the 1980's. The first natural gas futures contract was launched by the New York Mercantile Exchange (Nymex) in April 1990 based on the spot natural gas price at the Henry Hub gas pipeline intersection in Louisiana and rapidly emerged as one of the most successful products launched by Nymex.[17] The launch of this futures contract was followed shortly thereafter by various innovative contracting arrangements introduced by Enron and other market intermediaries, including fixed-for-floating swaps, basis swaps and a variety of financial options based on the Nymex futures contract and Henry Hub spot market.

This process has already begun in electricity. An early form of risk management tool introduced in England and Wales with the privatization of the industry was the "Contract for Difference (CFD)". In its most basic form, a CFD is a swap contract between an electricity generator (producer) and supplier (consumer) in which the price in the electricity pool is swapped for a fixed contract price. Under such a CFD, the supplier would pay the fixed contract price to the generator and the generator would pay the half-hourly pool price to the supplier. Since the generator received this price from the pool for its generation and the supplier paid it to the pool, the net effect was to guarantee a fixed (contract) price to both parties. Figure 10 below illustrates the workings of such a basic fixed-for-floating swap in electricity.

Several variations of the CFD are currently in use in England and Wales (see [Hoare, 1995] for a discussion). These CFDs are typically negotiated bilaterally between large generators and suppliers in the UK. A shorter-term contract known as the Electricity Forward Agreement (EFA) has also been introduced in the UK and is conceptually very similar to the fixed-for-spot swap agreement described above except that contract periods are much shorter (e.g. the same four-hour period for one week). Unlike futures contracts, these EFAs are not exchange traded. Unlike forward contracts, EFAs are brokered transactions, with trades being facilitated by electronic screens. Perhaps due to the domination of the bilaterally agreed CFDs, the EFAs have not become widely used in the UK. This highlights one of the limitations associated with the rigid England and Wales industry structure and monopsonistic power pool—the lack of opportunities for intermediation, traditionally the source of most financial innovations.

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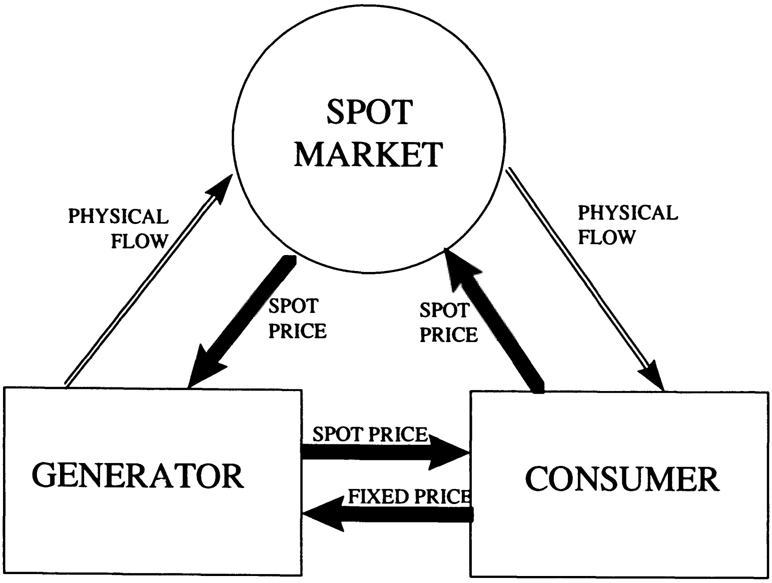
[17] For a discussion, see [Fitzgerald and Pokalsky, 1995].

Figure 10. A Basic Contract for Difference (Fixed-for-Floating Swap).



In the United States, the introduction of the first Nymex electricity futures contract was approved a few weeks ago by the Commodity Futures Trading Commission.[18] This futures contract is based on the spot price at the Palo Verde switchyard in Arizona. A second futures contract has been subsequently approved for trading at the California-Oregon border. Thus, a buyer of such a futures contract would (say three months ahead) effectively fix the price which he pays for electricity at the time the contract comes due. At the time of maturity, the futures price converges to the spot price. Thus, if the spot price is higher than the three-month ahead futures price, he would gain the difference between the two, which would exactly offset the increased price that he would have to pay in the spot market. On the other hand, if the spot price is lower, he would lose the difference. In both cases, his effective price is the futures price transacted three months ahead. A consumer wishing to hedge price risk would buy these futures whereas a generator wishing to hedge price risk would sell futures. Like in other futures markets, this market will also be open to speculators and arbitrageurs who will serve to enhance its liquidity and eliminate market inefficiencies.

Once these futures markets begin to operate actively, other financial innovations are likely to follow shortly thereafter. In addition to the physical options discussed earlier associated with various interruption features, call and put financial options written on electricity futures will take positions on the futures price relative to a specific strike price. Market participants can use these options to place either a cap

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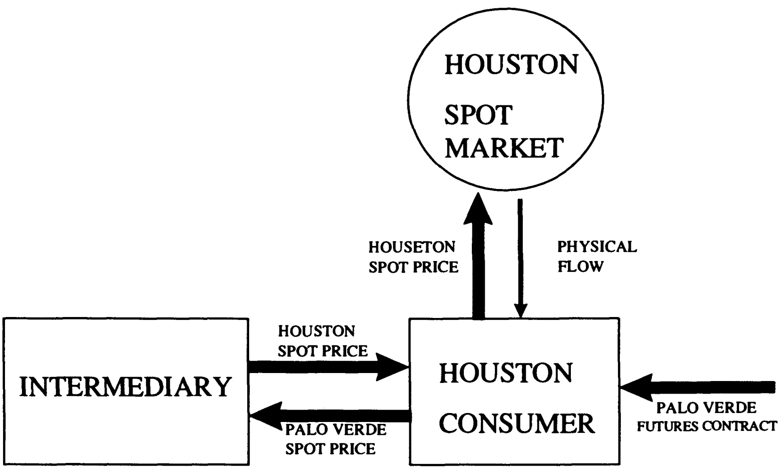
[18] "CFTC OKs First NYMEX Electric Futures Contract", the *Electricity Daily*, Jan. 29, 1996.

or floor on the electricity price. Thus, typically a buyer of electricity would purchase a call option to ensure that his electricity price does not exceed a specific level (the strike price of the option) whereas a seller of electricity could ensure a floor on the electricity price by buying a put option.

Apart from fixed-for-spot swaps as in the UK or in the US natural gas industry, we would also envision the development of basis swaps which would operate in a manner similar to those in the gas industry. A consumer in Houston will not be able to buy Palo Verde futures contracts to perfectly hedge his price risk since the price of electricity in Houston will not be perfectly correlated with the Palo Verde spot price. By undertaking a basis swap with an intermediary such as Enron, this consumer would pay Palo Verde spot and receive Houston spot, thereby completely eliminating his basis risk associated with the spatial price differences between Houston and Palo Verde. Figure 11 illustrates.

Figure 11. A Basis Swap in Electricity.



As seen from the above example, intermediaries are crucial for the structuring and liquid operation of several of the potential markets in electricity. When the scope for intermediation is limited, it is our view that the scope for market competition is also limited. In concluding this section, we briefly review the role of intermediaries in the new unbundled electricity industry.

In the old vertically integrated structure of the electric utility industry, there was little scope for intermediation, since all transactions along the value chain were internalized within a single company. However, the trends toward emergence of full-fledged intermediation have been evident for some time, paralleling the trends toward greater competition. Power pooling and exchange arrangements across groups of vertically integrated utilities have been a first step in this direction. Whereas these arrangements were originally conceived for reliability reasons, to spread the physical risk of supply shortfalls or demand spikes across a wider base, they have more recently become a means of economizing electricity supply sources in a given region. Furthermore, facilitated by these power pools and wholesale access, transactions across utility boundaries have expanded rapidly, accompanied by the emergence of NUG's and IPP's as significant sources of generation. Some of these transactions have been intermediated by power brokers.

In the new industry structure which is envisioned in this paper, the role of intermediation is expected to expand quite rapidly. This is consistent with the view that intermediation is the "lubricant" of competitive markets, of which we would expect to see a proliferation in the new industry structure. Intermediaries will perform the following key roles in this structure:

1. Intermediate physical transactions

Physical transactions could be intermediated either by bringing buyers and sellers together in brokerage-type transactions, or by acting as dealers for the unbundled services which will be provided in the industry. For example, in the latter case intermediaries could deal in location and time-specific generation capacity or energy. Alternatively, intermediaries could rebundle unbundled services into specific forms as demanded by the marketplace.

2. Intermediate financial transactions

- Intermediate fixed-for-spot and basis swap contracts as illustrated above, to facilitate the management of financial risk associated with spot markets in electricity.

- Facilitate the development of more standardized futures-type financial instruments in electricity, based at high volume "hubs" such as Palo Verde and California-Oregon, across the country.

- Intermediate swap-type arrangements where the delivery of electricity at one point in the system or during a specific time interval will be swapped for delivery at another point or over another time interval.

In broad terms, by engaging in these types of transactions, intermediaries will facilitate the emergence of liquid markets and thereby the strengthening of market forces.

8. LOOKING TO THE FUTURE

This paper has focused on the rebundling side of physical and financial transactions in electric power following the unbundling of the basic elements of the electric power value chain to achieve greater transparency and non-discrimination to enable competition. In the process, we have suggested some answers to the key questions of structuring the ISO and pricing transmission services. Our approach is grounded in the realization that transmission services are central to making the market, even though they are not a significant driver of the retail cost of electric power. Thus, the key to a successful transition to an unbundled power market will be to ensure that transmission service is priced in a sufficiently transparent and simple fashion that it facilititates competition in generation and that the ISO is in a position to coordinate bilateral and pool markets in a neutral fashion. In addition, we have discussed various approaches to providing incentives to TAPs and the ISO to invest and to maintain capital stock, to seek out least-cost alternatives for transmission support services and to provide open access to all comers.

A number of open research questions remain, however. These include: models for the efficient integration of long-term (e.g., bilateral energy) and short-term (e.g., spot energy) contracts; models of market intermediation including interface to intermediation for environmental "markets" ; and models for markets involving both firm and non-firm energy use. These models can build on the organizational and ownership principles articulated here.

APPENDIX ON TRANSMISSION PRICING

We develop below a general formula for SRMC-based allocation and analyze the impacts of its use. In this scheme of allocation, transmission charges at each bus are allocated as a fraction of total revenue requirement, with the fraction being determined by the SRMC based weight at each individual zone. Thus, loads at high SRMC buses would contribute *relatively more* towards revenue requirements than loads at low SRMC buses. In contrast, generators at high SRMC buses would contribute *relatively less* towards revenue requirements than generators at low SRMC buses.

There are several analytical approaches to capturing the general flavor of this logic. We follow the standard Ramsey approach in constructing an analytical approach.[19] We consider two cases based on the organization of the network system:

- a multilateral or "network service" arrangement in which power is sold to and bought from a common pool, and

[19] For details on Ramsey pricing, see [Crew and Kleindorfer, 1986]. Note that we are considering multiple owners of transmission assets, and the Ramsey problem here would therefore have a number of breakeven constraints, one for each owner. Rather than pursue this in detail, we separate the problem here into two problems: the first considers efficient pricing to raise sufficient revenues to allow payments to transmission asset owners to allow all transmission losses and costs to be covered. In a second step, we then specify an allocation of these revenues to transmission asset owners which allows each of them to nearly break even, but which also provides some incentives for efficient maintainence and expansion of the transmission network itself.

- a bilateral or "point-to-point" arrangement in which a bilateral contract is used for electric power transactions between a generator and a customer.

In the former case, the SRMC at individual buses is used as described above to allocate revenue requirements and derive transmission charges. In the latter case, we derive efficient contracts based on the specific generation and load zones for the contract, and SRMC *differentials* between these zones.

Efficient Transmission Pricing for Network Service Contracts

We will first consider the case of transmission pricing where all power produced is sold to a common pool from which it is purchased by consumers. It is convenient though not necessary to assume that transmission services are being provided by a single transmission company (GridCo). Energy-related transmission charges (those not collected as connection fees from generators) are borne by consumers and each consumer's cost of transmission is a function of the SRMC at the bus where he is located. Let PT(j) be the transmission price during time-period T per unit of energy delivered at bus j under optimal system dispatch. According to the standard Ramsey formula, the price paid by customers of transmission service should vary inversely proportionally to the demand elasticities of these customers. Given the level of available information and the size of the typical customers, we will make a first-order approximation that these elasticities are equal across customers. In this case, the Ramsey formula reduces to:

$$\frac{P_T(j) - C_T(j)}{P_T(j)} = k$$

where k < 1 is a positive constant and CT(j) is the marginal transmission cost (discussed further below) per unit of energy delivered at bus j. We can rewrite this expression as:

$$P_T(j) = \alpha C_T(j)$$

where " = 1/(1–k) > 1. Given that k is to be set so that transmission costs, including a reasonable return on capital, are exactly recovered, we see that PT(j) must satisfy

$$\sum_j P_T(j)Q_T(j) = \alpha \sum_j C_T(j)Q_T(j) = RR^T$$

where RRT is the total transmission revenue requirement (discussed below) to be recovered in time interval T. From this, we can solve for " to obtain

$$\alpha = \frac{RR^T}{\sum_j C_T(j)Q_T(j)}$$

so that, from above,

$$P_T(j) = \alpha C_T(j) = \frac{C_T(j) RR^T}{\sum_n C_T(n) Q_T(n)}$$

Let us now briefly discuss the definition of CT(j) in more detail. Recall that

CT(j) = Expected value of short-run marginal transmission costs for energy supplied at bus during time interval T. Note that this energy will be supplied from other buses in the network based on its optimal dispatch.

CT(j) would be estimated, using for example the MAPPS model, by taking expected values across reasonable scenarios which might obtain for the time interval in question. Given the complexity of transmission network costing, it is unlikely that an explicit analytical basis for CT(j) can be developed for general networks. Intuitively, however, the form of CT(j) can be written as follows:

$$C_T(j) = L_T(j)\lambda_T + C_{ET}(j)$$

where LT(j) is the expected transmission loss throughout the network per marginal unit of energy extracted at j, λT is the expected marginal cost of generation required to supply the transmission losses LT(j), and CET(j) represent marginal externalities associated with the supply of a marginal unit at j. Such externalities could be positive or negative and result from such issues as congestion costs, out-of-merit-order operation of plants and other transmission externalities. This expression may be thought of as the expected value of such marginal externality costs plus unit transmission losses times unit generation costs when j increases load by one unit. Given this general structure for CT(j), the import of the above uniform-elasticity Ramsey structure is to determine unit energy charges for transmission based on a constant mark-up above short-run marginal transmission costs. The higher the losses in serving a given customer from a given supply bus, and the more inefficient the generation which is called into play to make up these losses, the larger will be the transmission price paid.

While the above approach provides an economically efficient basis for collection of transmission revenues from consumers on a multilateral basis, it does not directly lend itself to pricing transmission along bilateral contract paths. This is important since many wheeling contracts are negotiated on a bilateral basis between generators and consumers. We turn to this issue next.

Efficient Transmission Charges for Point-to-Point Service Contracts

We will consider the case of a bilateral contract between a generator at bus i and a customer at bus j. Let PT(i,j) be the transmission price during time-period T per unit of energy injected at bus i and extracted at bus j under this contract.[20] As in the previous case, we can use the Ramsey formula to obtain a basis for pricing transmission service in this bilateral contract. At the outset, note that given our previous definition of SRMC at a bus j, CT(j), the marginal cost CT(i,j) of a unit of power injected at bus i and extracted at bus j is simply the difference in marginal costs at the two buses. Thus,

$$C_T(i,j) = C_T(j) - C_T(i)$$

Indeed, moving power from low marginal cost to high marginal cost buses is the means by which transmission adds value to the network. Following arguments that parallel the previous multilateral case, we can obtain the following formula for the transmission price PT(i,j) between buses i to j:

$$P_T(i,j) = \frac{C_T(i,j)RR^T}{\sum_m \sum_n C_T(m,n)Q_T(m,n)}$$

A further generalization, which could be explored if desired, is to set Revenue Requirements that are differentiated by zone, so that the above pricing formulae would be determined on the basis of the revenue recoverable within each zone from intra-zonal transmission.

Note in the above that we do not specify which partner (buyer or seller) to the bilateral contract would actually pay the transmission charges. The point here is that these transmission charges are unbundled charges to be paid by the partners to this contract. They represent the marginal costs imposed on the transmission system to serve the contract plus a markup to recover capital costs and possibly other fixed costs, e.g. some portion of stranded investment costs for one or other of the transmission asset owners.

The above discussion has been framed in terms of transmission charges based on per unit energy flows during T. Clearly, this is equivalent to capacity flows as long as customer load represents a 100% load factor. In practice, for both risk management reasons as well as revenue stability, the transmission component of a bilateral contract will take the form of a two-part tariff, covering energy losses as a percentage of total energy demanded plus a subscription fee per MW of required capacity. It is straightforward to translate the above Ramsey logic into this two-part tariff world. One simply deducts the

[20] The somewhat awkward language on injection and extraction is required here since, as in the multilateral case considered above, the actual energy supplied to j may not be that injected at i, but will depend on the entire network geometry and power flows at the time of the transaction.

marginal cost of energy losses from the price implied by the above formulae and the remaining per unit price is to be collected over the time interval T as a subscription fee.

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CAPACITY PRICES IN A COMPETITIVE POWER MARKET

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ABSTRACT

The traditional practice of pricing capacity and energy separately will diminish as a consequence of restructuring the electric power industry. To the extent that capacity continues to be priced explicitly, those prices will be based not on the book value of investments in generating facilities but rather on the market value. We elucidate the determinants of market value by exploiting the observation that rights to capacity are equivalent to holding options on energy. Capacity values depend on the level, volatility, and correlation of energy and fuel prices. They also depend on the type and efficiency of the associated capacity.

INTRODUCTION

The thesis of this paper is that the long-standing practice of pricing capacity and energy separately will diminish as a consequence of restructuring the electric power industry. We anticipate the decline of two-part pricing for several reasons. First, we observe that one-part pricing is pervasive in competitive commodity markets, such

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as those for metals, petroleum, and chemicals. Second, we are extrapolating from the experience of the natural gas industry, which is similar to electric power in a number of important respects and has been a policy model for the Federal Energy Regulatory Commission (FERC) efforts to restructure electric power. Third, we see trends in the industry itself that presage a move to one-part pricing, including the shift to power pool bid prices (rather than variable cost dispatch), so-called "real time pricing" (RTP) experiments, and the privatized power market in the United Kingdom. In the balance of this paper we will review the pricing of electric power under traditional public utility regulation, document the decline of two-part pricing in the natural gas industry, and describe the relationship between the market prices of capacity and energy by exploiting the observation that rights to generating capacity are equivalent to holding options on energy.

POWER PRICES UNDER PUBLIC UTILITY REGULATION

The U.S. electric power industry has long relied on power supply contracts which largely mirror public utility rate making. Typical long-term contracts for purchased power distinguish between capital and operating costs, with a price per unit of capacity (demand charge) based on depreciation, interest, and other capital costs and a price per unit of energy (commodity charge) based on operating costs.

A similar pricing structure was and is used even where utilities have formed power pools to dispatch jointly and thereby share diversity benefits in the form of reduced reserve requirements. Many power pools calculate an "as-if" production cost for each member utility that is based on a hypothetical least-cost use of those portions of plants and contracts that are solely owned by the member. The cost of this stand-alone dispatch is compared with actual plant use under pooled dispatch to determine a share of savings from joint operations. Savings are often allocated on a basis such as the "split savings" formula used by the Pennsylvania-Jersey-Maryland (PJM) power pool, whereby each buyer splits the difference between the average cost of the units it avoided dispatching and the average cost of units that sellers dispatched in excess of their own requirements.

In addition, each member is responsible for providing operating and planning reserves to the pool. The overall capacity requirement is based on generation reliability and transmission security standards developed by the North American Electric Reliability Council (NERC). That is, the requirements are determined administratively, rather than being based on a market demand for a given amount of reliability.[1] If a member is not meeting its capacity obligation, it must pay a penalty to the

[1] Of course, the utilities and NERC have tried to relate reserve targets to market characteristics. For instance, it is typical of utilities and power pools to achieve one-day-in-ten-year loss-of-load probability (LOLP) targets. A "one-in-ten LOLP" means that without regard to duration or extent of outage, generation should prove able to meet demand roughly 99.97% of the time. Equivalently, curtailments due to inadequate available generation should occur only about 2.4 hours per year. This standard is believed to be economic because of the finding that the cost of unserved electric energy can be as high as $5 to $40 per

pool based on the price of a new combustion turbine. These penalty payments are split among members who are providing more capacity than is needed to meet their shares of the joint capacity obligation.[2]

Utilities within a power pool are generally able to enter into long-term supply contracts with each other (or parties outside the pool), or into contracts for just the capacity component of generation. Indeed there are strong incentives to do so, as pool accounting can readily lead to situations where a bilateral contract is more economical for both parties than reliance on the pool's implicit exchange. This opportunity arises because neither the share-the-savings rate for energy nor payments for capacity credits reflect marginal costs. For instance, all of the interchange buyers necessarily have incremental costs above that of the unit that is setting the system "lambda" (marginal cost). Accordingly, the split savings rate collected by a seller whose incremental units are at the top of the dispatch ladder must be above the system lambda. It is equally easy to describe situations where the split savings rate is below the system lambda, or the capacity credit/penalty rate is much different than the market value of capacity.

Traditional power pool cost-sharing rules do not yield a single price. Each member sees a different price which is only coincidentally equal to the system marginal energy cost or to the cost of capacity shares available in the bilateral contract market. Moreover, the calculations involved in power pool cost-sharing require disclosure of details about each utility's costs that would be proprietary in a competitive market. As a result, essentially all power pools are moving towards a bid-pricing system wherein all interchange transactions will clear at the same system price. Central dispatch will still occur, but it will be based on bids rather than variable costs. This arrangement eliminates incentives to "game" the pool as well as the need to reveal cost information. It also provides better price signals to consumers.[3]

Of course in a bidding system suppliers will know when capacity is valuable and when it is not, and they will bid accordingly. It would be surprising indeed if bids did not sometimes exceed the expected marginal cost of generation, because there will be no means of enforcing a cost-based limit.[4] The only constraints will be those

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kilowatt-hour, so a few hours of outage has a cost comparable to the annual carrying cost of a new combustion turbine. In that sense, costs and benefits of reliability are just about balanced. Of course, customers have never had the opportunity to signal their willingness to pay during shortages, so this estimate of the value of lost load (VOLL) may not be confirmed in a competitive market where prices ration capacity.

[2] Responsibilities for capacity reserves are calculated based on stand-alone and pool-wide loss-of-load probability, contribution to system diversity, typical availability of the largest unit in each company's supply portfolio, and other factors.

[3] Indeed, there is no reason in principle not to extend this system to include demand-side bidding as well, so that buyers and sellers interests clear simultaneously.

[4] Market power is a potential obstacle to a well functioning generation market. The thoroughly documented anti-competitive behavior in the U.K. power pool has shown that concerns about market power are not without foundation, and certain regions of the U.S. that might operate as a pool have similarly high concentration of generation ownership, as well as periodic transmission constraints that temporarily isolate submarkets. However, we believe that some combination of pricing restrictions, capabilities of the transmission grid operator (sometimes called the Independent System Operator or ISO), and divestiture of generation (if necessary) could solve these problems.

presented by competitors and customers' willingness to pay—as in other competitive markets. Bidding for supply will also allow the price of power to rise (as demand grows and capacity is retired) to a level sufficient to induce capacity expansion—high enough, that is, to justify the cost and risk of investments in new capacity.

THE NATURAL GAS INDUSTRY

Prior to 1978 the wellhead price of natural gas was subject to ceilings imposed by the Federal Power Commission. Nearly all supply contracts between producers and gas pipelines were long-term, typically covering the entire life of a well or, if an explicit fixed life was used, twenty years. Almost every contract specified a commodity price plus a "take-or-pay" clause. The take-or-pay clause was equivalent to a demand charge, in that it guaranteed a minimum payment in each year of the contract.

The Natural Gas Policy Act of 1978 initiated a sequence of dramatic wellhead price increases for new gas. These price allowances succeeded in stimulating exploration and production that eventually more than solved the supply shortage that had motivated the Act. In addition, the high energy prices of the late 1970s and early 1980s triggered more energy conservation and efficiency improvements than had been anticipated. Finally, the U.S. economy went into a deep recession in 1980 to 1982, and the world price of oil collapsed in 1982–86, together resulting in a significant excess supply of gas. This "supply bubble" induced new federal regulations (FERC Orders 380 and 436) giving customers more flexibility to shop for gas directly at the wellhead (by taking transportation services only from the pipelines, rather than bundled gas and transportation), and producers competed for market share by offering spot gas at prices far below the regulated prices of the NGPA. By the mid-1980s a spot market for gas was thriving.

In fact, the spot price of gas was so much less than the average embedded cost of gas in pipeline supply contracts that a succession of additional regulatory policies were promulgated to "unbundle" gas pipeline services to wholesale customers (mostly distribution companies and some large industrials) and to deregulate wellhead production (by 1989).[5] These rules eventually forced the pipelines to become

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[5] These regulations include FERC Orders 500, 451, 497, and 636. Order 500 was designed in large part to cope with some of the transition costs of restructuring. The pipelines were generally unable to honor many of their take-or-pay contracts, creating a financial crisis for the industry very much analogous to "stranded investment" exposure that the electric industry now faces from its out-of-market contracts and base-load generation capacity.

Changes in the natural gas and electric power markets should not be attributed solely to the "invisible hand" of the market working its magic. The gas supply "bubble" was a consequence of incentives for development created by regulation. The current surfeit of electric generating capacity is likewise a consequence of regulation, such as incentives under the Public Utility Regulatory Policy Act (PURPA) to develop non-utility generators (NUGs).

common carriers, with no obligation to provide gas procurement services (though many pipelines have marketing affiliates who still perform such functions). Today, we have complete open-access at the wholesale level, with distribution companies fully responsible for their gas procurement and pipeline transportation scheduling on behalf of end-users.

The New York Mercantile Exchange introduced a futures contract for natural gas in 1990. Since then the vast majority of gas supply contracts have been tied either to the futures price or a "spot" price index at one of several major market centers ("hubs"). Now most long-term contracts are really agreements to agree rather than commitments to purchase fixed quantities of gas at predetermined prices. Moreover, one month is too long a term for many transactions. Daily and even partial-day contracting is now common, especially for backup service. The industry seems to be performing well despite having almost fully abandoned long-term contracts with two-part pricing.

The initial change to short-term contracts for natural gas was due chiefly to the excess supply of gas and the emergence of a spot market. However, once an active well-functioning spot market was in existence, the rationale for long-term supply contracts was undermined. Indeed, long-term fixed-price contracts entailed a drawback *vis à vis* short-term contracts in that they exposed buyer and seller to substantial credit risk.

It also became possible to trade transportation rights over pipeline bulletin boards, although doing so was not particularly easy. A distribution company in New England might need transportation contracts on two or three pipelines in order to move gas supplies from the Gulf Coast up to market. Assuring that all the links in the upstream supply chain would coincide (as to timing and quantity of flow) was difficult, since the final demand was uncertain and the multiple bulletin boards involved were not linked in any way. The solution required standard contract terms and conditions. Standardization also promoted liquidity, so that a third party could trade a contract or capacity right if it did not turn out to be useful to its original holder. Only short-duration contracts could satisfy this constraint, so a one-month contract horizon became standard.

By 1995, even a one-month duration seemed like an unduly long contract period to certain gas users. For instance, customers with a substitute fuel (typically residual fuel oil) may want to shift to and from natural gas in mid-month, whenever relative prices favor switching fuels. A gas-fired electric power plant may cycle throughout the month, week, or even day, hence need gas on comparably flexible and short terms. Finally, within-month spot price movement (especially in the early spring and late fall) can sometimes be so great that a one-month fixed price contract involves too much price risk for some parties. Thus despite the shrinkage in contract time horizons, producers have been willing to expand gas reserves.

THE MARKET PRICE OF ENERGY

One of the salient features of competitive commodity markets is that prices are volatile. In the absence of regulatory or other institutional constraints, prices rather than quantities are the principal locus of risk bearing. This is clearly illustrated by the experience of the natural gas industry. We anticipate that experience will be repeated in electric power.

One piece of evidence for how commodity prices for power might behave in the future comes from the real time pricing experiments of Georgia Power, Niagara Mohawk, and others. The pricing formulae used in these programs add a scarcity rent surcharge to the marginal energy cost in each hour that is based on the prevailing loss-of-load probability (LOLP) times an estimated cost of unserved energy, sometimes called "value of lost load" (VOLL). VOLL values are estimated to be a few dollars per kilowatt-hour, with the result that on-peak energy prices can sometimes be an order of magnitude larger than marginal generation costs. Because this premium is extremely sensitive to short-run changes in operating reserve margins, the real time price is also more volatile than system marginal energy costs.

RTP programs are intriguing, but thus far they are limited experiments. VOLLs have been derived from "over-under" studies that are also the basis for the current industry standard 15 to 20 percent reserve margin targets. Many industry observers suspect that such margins are higher than will be needed in large regional power pools where market prices, rather than administrative rules, are used to determine service priority and reliability needs. On the other hand, only a small number of self-selected customers, presumably those with high demand elasticities, currently participate in RTP programs. Comprehensive RTP services would include more reliability-sensitive consumers. Market prices for energy might be more or less volatile than RTP prices, since scarcity rents might be paid not on a prospective basis but only in the event of curtailments.[6]

One problem with all of the available data—whether from RTP experiments or bulk power transactions—is that prices reflect the existing quantity and mix of generating capacity. That supply mix is itself the result of the traditional public utility structure of the industry. In the future, the amount and mix of capacity will reflect a different market structure and incentives. We anticipate that there will be relatively more peak-load and less base-load capacity as the market evolves.

As another example, the U.K. electric power pool also is priced on a bid lambda plus VOLL times LOLP basis.[7] This market has been plagued by anti-competitive price manipulations, attributable largely to the fact that the generation market is

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[6] Note that having an LOLP-driven scarcity term allows the market to anticipate shortages. This has the virtue of avoiding the need for very fast, price-based service rationing in the few minutes (or less) when satisfying all loads becomes impossible.

[7] In addition, the U.K. buyers' price includes a term called "uplift" which covers the average half-hourly cost of what are often referred to as "ancillary services" in the United States. These are the costs of reserves, generation for line losses, voltage control, and out-of-merit dispatch to avoid transmission-destabilizing contingencies. They are recovered in an energy surcharge that is typically a few percent of the total price.

heavily concentrated in two large players.[8] Nevertheless, it provides evidence that this form of pricing is workable, and its spot price patterns are roughly consistent with what we would expect. In particular, like RTP prices, the U.K. half-hourly pool price is quite volatile. The system lambda component by itself is already inherently volatile, being subject to demand, fuel price, and plant availability, among other random factors. A commodity price that also includes the scarcity value of capacity will be even more volatile. If capacity is abundant, then the scarcity term is close to zero over a wide range of demands. On the other hand, the scarcity term acts as a multiplier of production costs whenever demand approaches available capacity.

For the same reason, we expect the volatility of peak-load prices to be greater than the volatility of base-load prices. Peakers operate on the portion of the load curve where production costs rise sharply and where the scarcity rent term becomes important. Conversely, base-load service is relatively predictable as to both demand and supply (marginal cost).[9]

Finally, it is very unlikely that there will be a single price for electric service of any kind that applies over a wide area. This is because power produced in one region of the country is not a perfect substitute for power produced in another region due to transmission costs and transmission constraints.[10] Indeed, engineering limitations on power flow can arise over seemingly quite short distances and time frames, for example when increased line loading could create conditions that might destabilize the entire grid. The adjustments to accommodate or avoid such circumstances will create power prices that vary by location. Regional price differentials are observed in the natural gas industry too, where it is not unusual to observe spot prices that differ by a factor of two or more at different hubs. Thus transmission constraints may add to the volatility of energy prices.

THE MARKET VALUE OF CAPACITY

In an active well-functioning electric power market the value of generating capacity will be nothing more nor less than the present value of the electric energy it is expected to produce net of the cost of producing it. This should come as no surprise. Capacity has value only because it can be used to produce a commodity that has or may have value.

In fact, from a purely financial perspective generating capacity is a *derivative* asset—an asset the payoffs to which are determined by the prices of one or more

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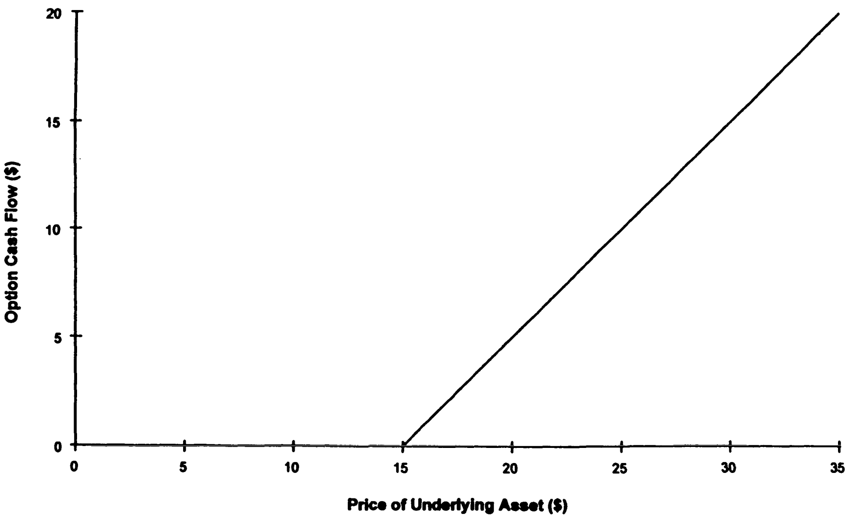
[8] See, for example, Office of Electricity Regulation (1995).

[9] It is possible for the marginal cost of power to go to zero or even below when demand is very low. In other words, there are circumstances in which system costs would fall if demand were to increase, because it would avoid, for example, the cost of cycling a base-load unit with high shut-down and start-up costs. Zero prices have been observed in the U.K. power pool.

[10] This concern is the basis for several restructuring proposals. See, for instance, the numerous articles and public comments before the FERC by William Hogan proposing nodal pricing, or by Marija Ilic on the design and pricing of transmission support services and access charges.

"underlying" assets. To be more specific, ownership of generating capacity is equivalent to holding a portfolio of call options on energy.[11] An elementary call option is a contract that gives the holder the right to buy a specified asset for a fixed cash price on a predetermined date. The fixed cash price is referred to as the "strike" or "exercise" price and the contract date is the "expiration" date. The salient feature of an option is that it is a right, not an obligation, so the holder will exercise an option only if it is profitable to do so. For example, the holder will exercise a call option only if the price of the underlying asset exceeds the strike price. Figure 1 depicts the cash flow profile of a call option with a strike price of $15.

Figure 1. Cash Flow Profile of Call Option.



This financial equivalence of generating capacity and call options on energy is perhaps easiest to see in the case of a dispatchable generating unit. Under traditional rate of return regulation the manager of a dispatchable power plant will run the plant to meet load if its avoidable cost is less than the avoidable costs of other available units.[12] In a competitive market the owner would operate the plant if the avoidable cost of the unit is less than the market price of energy. Thus the generating unit entitles the owner to obtain electric energy in exchange for fuel and other production costs. In this analogy electric energy is the "underlying asset" and the avoidable cost of the plant is the "strike price" of the option. Thus the value of capacity will fluctuate over time as expectations of energy prices evolve.

The portfolio that is equivalent to a unit of generating capacity consists of a bundle of call options with serial exercise dates. Consider, for example, the rights to a

[11] For an exposition of derivative asset valuation techniques in the context of electric power, see Incentives Research Incorporated (1995).

[12] Note that only avoidable costs are germane to decisions about whether to run the plant. Sunk costs are irrelevant.

hypothetical unit of capacity beginning today and extending for a period of one year. Note that we could partition the one-year time horizon into twelve time periods each of one month duration. We could approximate the value of this capacity by a portfolio that consists of twelve call options, one with one month to expiration, another with two months to expiration, and so on. The value of the capacity is just the sum of the values of the options in the portfolio.

Once we recognize the analogy between electric generating capacity and call options on energy, three characteristics of elementary option prices are noteworthy:

- The higher the price of the underlying asset, the higher the value of a call option, other things being equal.

- The higher the strike price of the option, the lower the value of a call option, other things being equal.

- The higher the volatility of the price of the underlying asset, the greater the value of an option, other things being equal.[13]

The first two properties follow from the fact that the payoff to a call increases with the price of the underlying asset and decreases with the strike price of the option. The third property—option prices are non-decreasing in the volatility of the underlying asset—is not so obvious. It is due to the fact that the holder need not exercise an option. In contrast to the risk exposure of the underlying asset, where up-side risk is balanced by down-side risk, the risk exposure of an option is one-sided. Thus more volatility is always better than less (or at least no worse) from the perspective of an option holder.

A salient feature of the call options embedded in generating capacity is that not only is the price of energy volatile but so is the operating cost of the plant. The "strike prices," in other words, are random. The impact of strike price volatility on the value of an option depends on the correlation between the strike price and the price of the other underlying asset. To see this, contrast the values of two options, one with a fixed strike price and another, otherwise identical option with a random strike price. If the strike price and the price of the underlying asset are uncorrelated, then the payoff to the option with the random strike price is more volatile than the payoff to the option with a fixed strike price, and hence the former has a greater value than the latter. If the prices are positively correlated (that is, if the two prices tend to move together), on the other hand, then the payoff to the option with the random strike price is less volatile than the payoff to the option with the fixed strike price, and hence the former has a lower value than the latter.

Fuel is the largest component of avoidable costs for a conventional generating unit. It is also the most volatile component. In the balance of this paper, therefore,

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[13] It is common practice in the theory and practice of derivatives pricing to use the standard deviation of returns as a measure of volatility.

we will explore the relationship between capacity values and fuel prices even though, strictly speaking, there are non-fuel components to avoidable costs as well.

The properties of elementary option prices enumerated above suggest that the market value of electric generating capacity will have the following characteristics:

- The value of capacity will increase when prices for future delivery of energy increase;

- The value of capacity will decrease when prices for future delivery of fuel increase;

- The value of capacity will increase when the volatilities of prices for future delivery of energy or fuel increase; and

- The value of capacity will decrease when the correlation of energy and fuel prices increases.

This suggests that it is not meaningful to talk about "the" value of capacity. Capacity values will vary depending on the specific delivery period and the time remaining until delivery. In fact, there will be a schedule of capacity values for each delivery period, with distinct values corresponding to each type of fuel and heat rate.[14]

At this point we should emphasize that the relevant prices for the underlying assets are *forward* values, not *spot* values. A forward price is the price established in advance for delivery of a commodity on a specified future date whereas the spot price is the price for immediate delivery. Since generating capacity conveys the right to produce energy in the future, the forward prices, forward price volatilities, and forward price correlations are germane to the pricing of capacity.

To illustrate these ideas we have computed the market value of a hypothetical block of generating capacity based on a range of prices and price volatilities for energy and fuel. We assume that a unit (e.g., kilowatt) of capacity returns cash flows (C_t) at a rate equal to either the difference between the price of energy and the cost of fuel (when that difference is positive) or zero (otherwise):

$$C_t = \text{Max}(0,(P_t^E - h\,P_t^F))$$

The symbols P^E and P^F in this expression denote the spot prices of energy and fuel, respectively. The symbol h denotes the heat rate of the generating capacity, which we assume to be constant. In other words, the capacity is either operating or idle, and the decision to operate depends solely on the relationship between the prices of energy and fuel.

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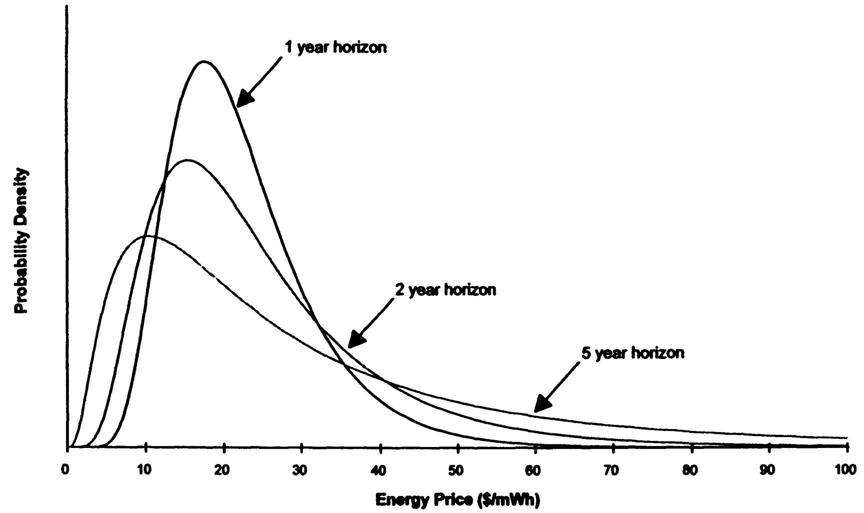
[14] Of course, this logic can be taken further, to differentiate capacity values by other characteristics, such as plant availability, ramp rates, and so forth.

We made very simple (and in some cases unrealistic) assumptions about the behavior of energy and fuel prices to derive our numerical results:

- the underlying commodity prices can be described as log-normal random walks with constant trend and volatility parameters;
- forward prices for delivery of energy and fuel at the relevant future dates are equal to current spot prices (i.e., the forward curves are "flat");
- spot prices and forward prices for all relevant delivery dates are perfectly correlated; and
- the term structure of interest rates is flat.

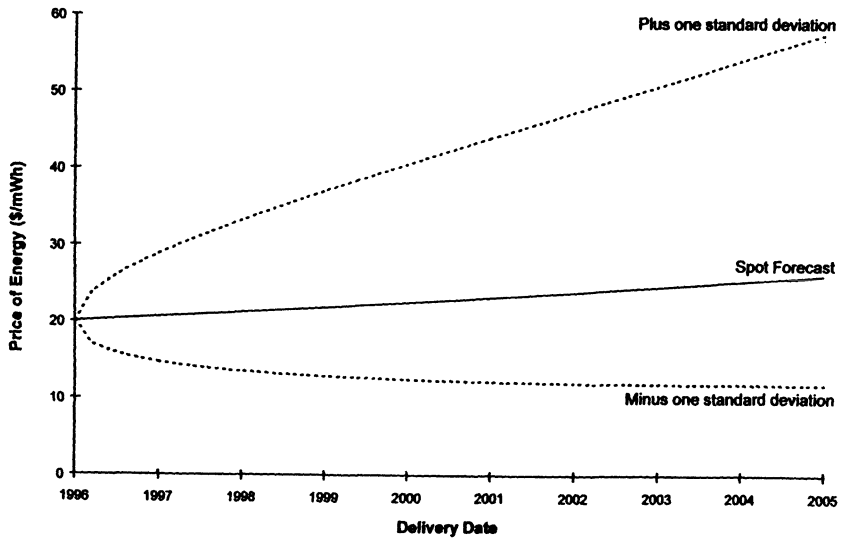
The most important implications of the assumption that prices can be described as log-normal random walks are that 1) prices cannot be less than zero, 2) price changes are proportional (i.e., the odds that prices will double are about the same as the odds that prices will halve), and 3) uncertainty about prices increases with the length of the time horizon. Figure 2 shows the probability distribution of a log-normal price process with constant trend and volatility rates at successively longer time horizons. (The trend is 3 percent per annum and the volatility is 40 percent per annum.) Figure 3 shows the expected value plus a one standard deviation confidence interval for the same price process over a nine-year time horizon.

Figure 2. Price Distributions for One, Two, and Five Year Horizons.



Probability distributions reflect a 3 percent per annum trend and a 40 percent per annum volatility.

Figure 3. A Hypothetical Price Forecast.



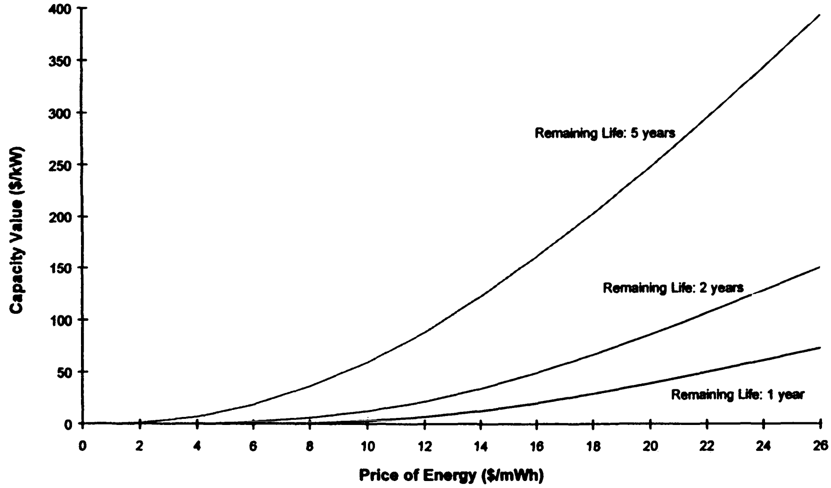
Forecast reflects a 3 percent per annum trend and a 40 percent per annum volatility.

This hypothetical block of capacity is a derivative asset, which is to say that the cash flows can be replicated by a (continuously rebalanced) portfolio consisting of the underlying assets. The virtue of the foregoing assumptions is that they permit us to apply the well-known Black-Scholes option pricing model (as extended by Black (1976) and Margrabe (1978)) to compute capacity values. While in reality the behavior of energy and fuel prices is considerably more complex—we have completely ignored seasonality, for example—these simplifying assumptions will suffice to illustrate the most important features of the relationship between capacity values and the underlying commodity prices, namely that the market value of capacity will depend on the level, volatility, and correlation of the underlying forward commodity prices. Our goal, in other words, is to illustrate qualitative rather than quantitative results.

In the following examples we price a unit of capacity based on the assumption that it will be available 75 percent of the time. (If the price of energy always exceeded the price of fuel, in other words, a kilowatt of capacity would produce 6,570 kilowatt-hours of energy in the course of a year.) Our results are obtained by treating capacity as if it were a portfolio of call options, with serial expiration dates that differ by two tenths of a year. Thus the value of one year of capacity rights is found by pricing five call options (one that expires in two tenths of a year, another that expires in four tenths of a year, and so on) and then adding them up. Other assumptions will be identified as we go.

Figure 4 depicts the value of capacity as a function of the price of energy and the duration of the delivery period when the price of fuel is $15/mWh. (We report the price of fuel in terms of megawatt-hour equivalents.) It shows that capacity values are an increasing function of the price of energy and of the length of the delivery period. Note that capacity has value even when the price of energy is less than the cost of fuel. This is true because the capacity holder has a right to produce energy, not an obligation. So long as there is some chance that the price of energy will exceed the cost of fuel during the remaining life of the capacity, this right (i.e., option) has value. Note too that the relationship between capacity value and energy price is not linear. This reflects the uncertainty about future prices and the concomitant uncertainty about whether the embedded options will be exercised. Capacity prices increase with the length of the delivery period in our examples chiefly because the cumulative energy output of a block of capacity increases with the delivery period.

Figure 4. Capacity Value Versus Remaining Life.



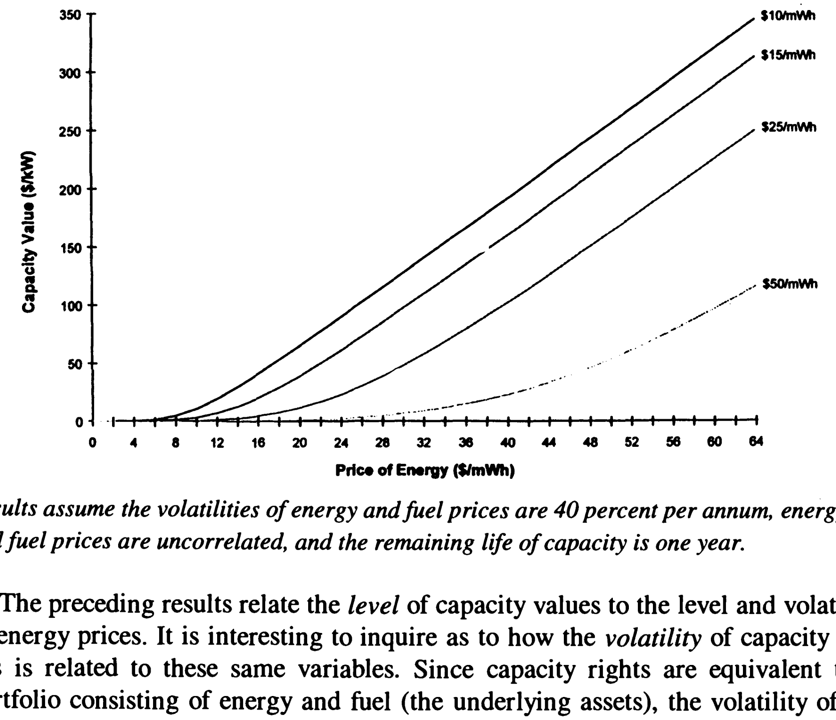
Results assume the price of fuel is $15/mWh, the volatilities of energy and fuel prices are 40 percent per annum, and energy and fuel prices are uncorrelated.

Figure 5 depicts the value of capacity with a remaining life of one year as a function of the price of energy and several alternative fuel prices. Clearly, the higher the price of fuel, the lower the value of the capacity. This reinforces our earlier observation that it is important to relate capacity values to specific types of capacity. The value of a unit of generating capacity that burns natural gas will not be the same as the value of a unit that burns coal, for example. And the values of two gas-fired generating units with different heat rates will differ. Note again that capacity has value even when the cost of fuel exceeds the price of energy due to the fact that the capacity represents a right to produce energy rather than an obligation.

Figures 6 and 7 demonstrate that the value of capacity is an increasing function of the volatility of both energy prices and fuel prices. The higher the volatilities, the higher the value of capacity. The impact of volatility on capacity values is least significant when the price of energy is far in excess of the price of fuel. This is due to the fact that there is essentially no doubt in such circumstances that the capacity will in fact be used to generate energy.

Figure 8 shows that the correlation of energy and fuel prices has an important bearing on the value of capacity. The higher the correlation, the lower the value of capacity, other things being equal. When energy and fuel prices are correlated, it means that changes in the energy prices tend to be accompanied by offsetting changes in fuel prices, thus reducing the impact of price volatility on capacity values.

Figure 5. Capacity Value Versus Fuel Price.

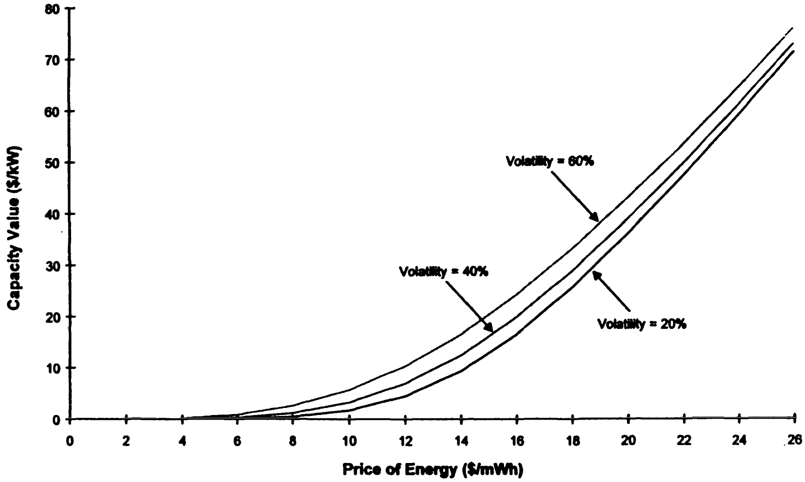


Results assume the volatilities of energy and fuel prices are 40 percent per annum, energy and fuel prices are uncorrelated, and the remaining life of capacity is one year.

The preceding results relate the *level* of capacity values to the level and volatility of energy prices. It is interesting to inquire as to how the *volatility* of capacity values is related to these same variables. Since capacity rights are equivalent to a portfolio consisting of energy and fuel (the underlying assets), the volatility of capacity values will be related to the volatilities and correlation of energy and fuel prices and the amounts of energy and fuel in the equivalent portfolio. All of these factors are either inputs to or outputs of the valuation model used to derive the preceding numerical results, so we can use them again to investigate the volatility of capacity values.

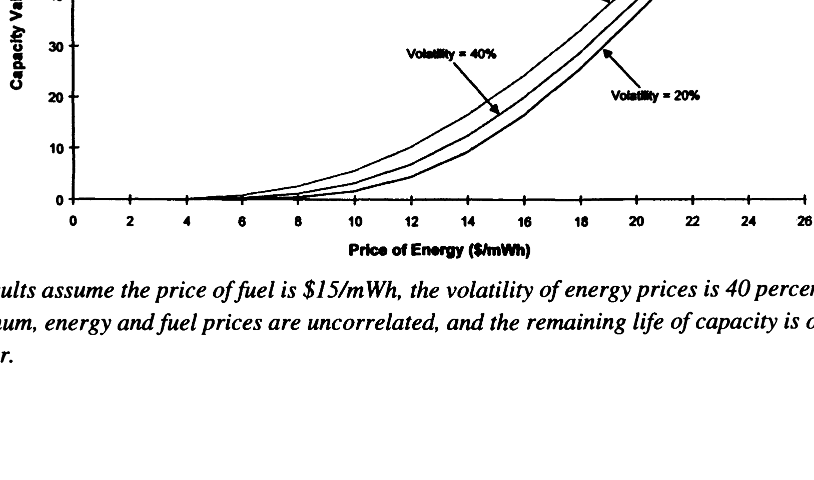
Figure 9 reports the volatility of capacity values as a function of the price of energy. We assume for purposes of illustration that energy and fuel prices both have volatilities of 40 percent per annum and a correlation coefficient of 0.5. Clearly, the volatility of capacity values is greater than the volatility of the underlying energy and fuel prices. Moreover, the volatility of capacity values is much greater when energy prices are low than when energy prices are high. (Another interpretation of the same results is that the volatility of capacity with high generating costs is greater than the volatility of capacity with low generating costs, other things being equal.) Therefore, just as one should not speak of "the" value of capacity, one should not speak of "the" volatility of capacity values, since both parameters depend on the characteristics of a specific block of capacity.

Figure 6. Capacity Value Versus Energy Price Volatility.



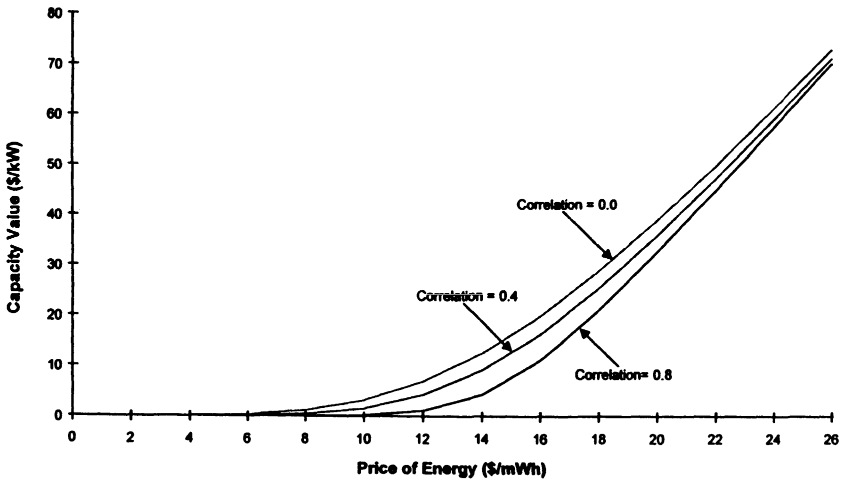
Results assume the price of fuel is $15/mWh, the volatility of fuel prices is 40 percent per annum, energy and fuel prices are uncorrelated, and the remaining life of capacity is one year.

Figure 7. Capacity Value Versus Fuel Price Volatility



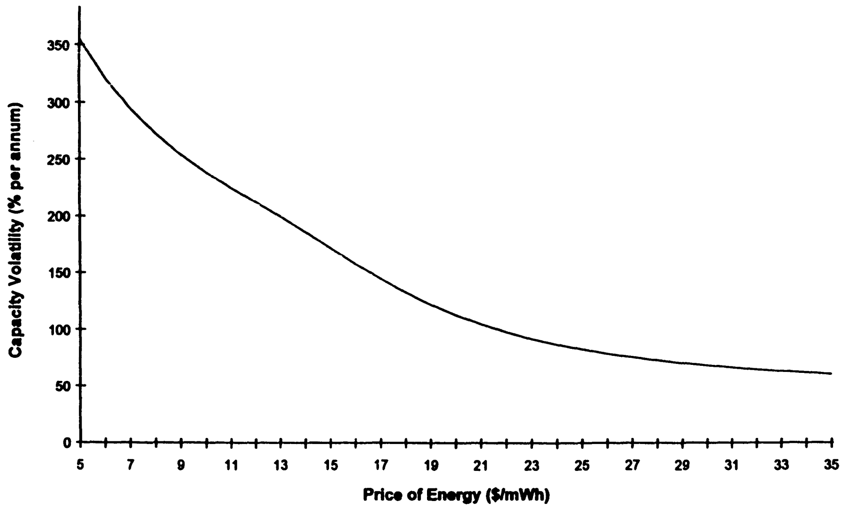
Results assume the price of fuel is $15/mWh, the volatility of energy prices is 40 percent per annum, energy and fuel prices are uncorrelated, and the remaining life of capacity is one year.

Figure 8. Capacity Value Versus Correlation of Energy and Fuel Prices.



Results assume the price of fuel is $15/mWh, the volatilities of energy and fuel prices are 40 percent per annum, and the remaining life of capacity is one year.

Figure 9. Volatility of Capacity Values.



Results assume the price of fuel is $15/mWh, the volatilities of energy and fuel prices are 40 percent per annum, the correlation between energy and fuel prices is 0.5, and the remaining life of capacity is one year.

CONCLUSION

Under the traditional public utility model of the electric power industry capacity has value apart from its potential to generate energy. These capacity values are determined administratively, through rules established by regulators and power pools. Some experts believe that capacity will continue to have value apart from energy even after industry restructuring. This view appears to be based on expectations that there will be some circumstances under which it will not be possible to buy energy at any price—that is, there is some probability that loads will go unserved. Our view, on the other hand, is that the potential for such events is itself due largely to public utility regulation. Specifically, utilities have had insufficient incentives to unbundle services and price reliability explicitly. With the advent of effective competition, firms will have incentives to redesign energy services, with the result that it will be possible to guarantee delivery of energy or equivalent financial compensation.

We surmise that another reason some experts believe capacity will have value apart from energy is that they have failed to distinguish between spot and forward energy prices. As we pointed out earlier in this paper, capacity values depend on forward energy prices, not spot prices. In contrast to one of the simplifying assumptions used to develop the numerical examples presented in this paper, spot and forward energy values are not perfectly correlated—far from it, in fact. This means that spot capacity values and spot energy prices can change independently. There is nothing inconsistent with this observation and the proposition that capacity values will be a function of energy prices.

To sum up, our view is that two-part pricing is to a large extent an artifact of regulation rather than an intrinsic feature of power supply technology and economics. Given that view, what role if any will capacity prices play in a competitive market? There will always be consumers of electric power who wish to manage their risk exposure. Consumers with firm loads can manage risk by entering into forward contracts at fixed or indexed prices. In these cases, however, the distinction between capacity and energy is irrelevant. A two-part price accomplishes nothing more than a one-part price. Consumers with random loads, on the other hand, can manage their risk by acquiring options on energy. This is precisely how we have characterized capacity rights. Capacity prices, in other words, will be the premiums that customers pay to acquire options on energy. Thus, although we anticipate that the prevalence of two-part pricing will diminish in the electric power industry, capacity pricing is unlikely to vanish altogether.

ACKNOWLEDGMENTS

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8

MANAGING RISK USING RENEWABLE ENERGY TECHNOLOGIES

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Cristy Herig
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ABSTRACT

This paper investigates the potential of owning renewable energy technologies to mitigate risk faced by the electric utility industry. It considers the effect of market structure on the plant ownership decision and how the attributes of renewable energy technologies can help to manage risk. Explicit consideration is given to the renewable energy technology's attributes of fuel costs, environmental costs, modularity, lead time, location flexibility, availability, initial capital costs, and investment reversibility. It concludes that renewable energy technologies, particularly the modular technologies such as photovoltaics and wind, have the potential to provide decision makers with physical risk-management investments.

1. INTRODUCTION

Regulatory and technical forces are causing electric utilities to move from a natural monopoly to a more competitive environment. Associated with this movement is an increasing concern about how to manage the risks associated with the electric sup-

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ply business. There are several approaches to managing these risks. One approach is to purchase financial instruments such as options and futures contracts. Another approach is to own physical assets that have low risk attributes or characteristics (Hoff, 1997). This research investigates the potential of mitigating risk by owning renewable energy technologies.

Two groups that would consider owning renewable power plants for risk-management purposes are power consumers and power generators. Power consumers need power to operate their businesses or residences and power generators operate their businesses to make power. Power generators include investor-owned utilities (IOUs), municipal utilities, independent power producers (IPPs), and other market segments that can use generation to satisfy multiple requirements such as within a distributed generation configuration.

The decision to own a renewable power plant is influenced by a number of economic issues. Some of these issues depend on market structure while others depend on the technology's attributes. The second section of the paper considers the effect of market structure on the plant ownership decision. The third section discusses how the attributes of renewable energy technologies can help to manage risk from various ownership perspectives. Explicit consideration is given to the attributes of fuel costs, environmental costs, modularity, lead time, location flexibility, availability, initial capital costs, and investment reversibility.

The research concludes that renewable energy technologies, particularly the modular technologies such as photovoltaics and wind, have the potential to provide decision makers with physical risk-management investments. The use of these investments and their risk-mitigation value depend upon the ownership perspective.

2. MARKET STRUCTURE

This section considers some of the issues affecting the plant ownership decision associated with market structure. Two issues upon which market structure has a dominant influence are to whom the plant owners are allowed to sell their output and the contractual relationships between plant owners and output purchasers.

2.1. Output Sales

One issue of concern to plant owners is to whom they can sell their output, an issue that is affected by the structure of the electric utility market. The current market structure is composed of a group of integrated utilities and IPPs as shown in Figure 1.[1] The thick lines correspond to the transmission system and the thin lines correspond to the distribution system.

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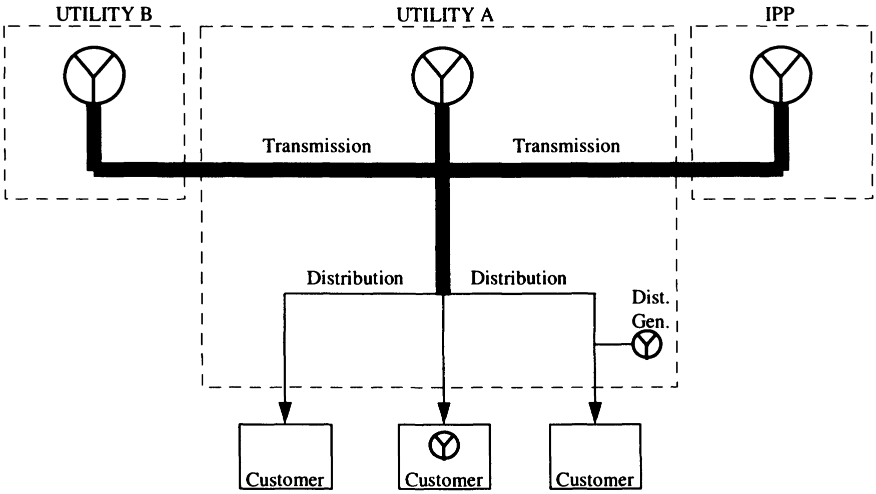
[1] The following three figures are based on Hyman (1994).

Figure 1. The Current System.

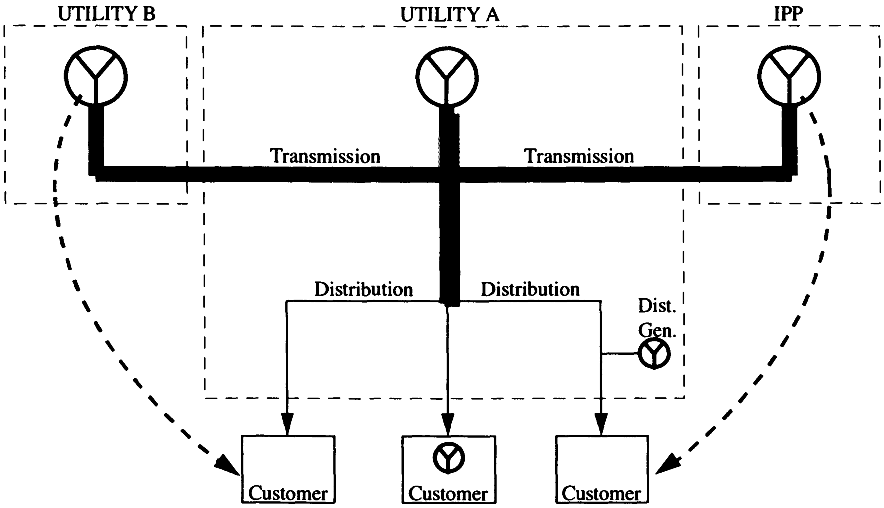


Under this structure, renewable power plants can be owned by IPPs, by IOUs and municipal utilities (either as central station or distributed generation), and by power consumers. IPPs are limited under this structure to selling their output to the utilities who supply power to power consumers, while the latter are limited in their ability to own plants depending upon whether or not the plants can be physically located on their premises.

Although the electric utility industry is becoming more competitive, there is likely to be a transition period as this occurs. Figure 2 suggests that this transition will provide greater contractual freedom between generators and consumers. While the physical characteristics of the electric supply system may not change, the dashed lines with arrows in the figure indicate that IPPs can sell their output directly to power consumers in addition to selling to utilities. The power flows through the same electrical wires but the payment flows directly from the consumer to the generator with some charge going to the utility that manages the transmission and distribution system. This opens up an additional market for renewable technologies that are not physically located on customer premises.

Full-scale competition is likely to result in structural change in the industry. In particular, the generation market will probably become fully competitive and separate transmission and distribution utilities will distribute the power. As shown in Figure 3, it is likely that generation will not be owned by the same companies that operate the transmission and distribution systems to avoid conflicts of interest. Power generators might sell their output to a transmission utility or power pool, to local distribution utilities, or directly to consumers.

Figure 2. The Transitional System.

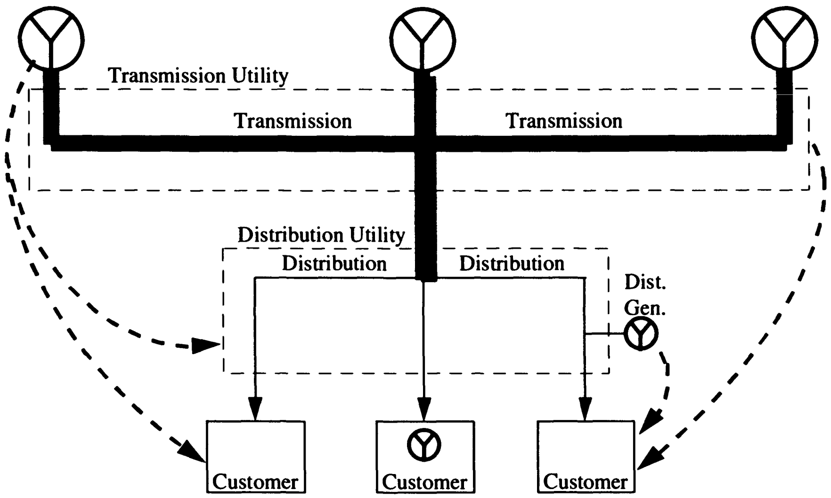


In addition to this increased access, greater competition is likely to encourage the market for distributed generation IPPs. First, IPPs could serve a group of consumers but use only a portion of the distribution system. This reduces the IPPs' costs associated with using the transmission and distribution system (if the IPP is central generation) and the transaction costs associated with siting many small plants on customers' premises. Second, the IPPs could sell their output to the high value consumers at the times when they are consuming power and then have access to the transmission and distribution system to sell their excess output when the consumers do not need the output.

Power marketers are potentially very important and can serve as an intermediary between the plant owner and the output purchaser in each of the three scenarios described above. Hamrin and Rader (1994) suggest that a specific type of power marketer may be a renewable power marketing authority (also called renewable aggregator). Such a power marketer aggregates, firms, and transmits renewable resources and then sells the power. Hamrin and Rader suggest that this is necessary to enable renewables to participate in a wholesale commodities market because it allows intermittent renewable resources to be mixed together and then be packaged as a commodity and marketed in sizes that reduce transactional costs. That is, renewable aggregators would help to solve the intermittent output and marketing problems associated with renewable technologies.

Another possible type or role of a renewable aggregator might be to obtain more attractive financing for renewable power plants. A renewable aggregator might be able to attract the financial capital from individual investors who are interested in promoting the use of renewable energy by investing their funds in such plants. A renewable aggregator would aggregate demand for capital from renewable project developers rather than demand for electricity from power consumers.

Figure 3. The Competitive System.



2.2. Sales Contracts

A second issue of concern to power plant owners is the contractual relationship between the renewable plant owner and the customer to whom the output is sold. There is no need for a contract if the renewable plant owner consumes the output itself. The terms and conditions of the contract (if one exists) become very important, however, when the plant owner and the output consumer are not the same party.

Utilities have historically operated as if they had long-term sales contracts with their customers even though no contracts existed. Utilities set their rates with the oversight of public utility commissions and the customers' only options were to pay the rates or to leave the system. This structure has not offered much choice to customers with regard to contractual relationships for future power needs.

This structure has, however, been the basis for the long-term power purchase agreements that utilities have offered IPPs, agreements that have been essential to the development of the IPP market, particularly for capital-intensive renewable energy technologies. According to the wind-generating manufacturer Kenetech Corporation (1994), for example, sales of wind turbines fall into the general categories of power purchase agreements, direct sale to a utility, and equipment sales. Under the power purchase agreements category, Kenetech arranges for third-party financing based on the value of the particular power contract. Fully three-quarters of Kenetech's installed base, three-fifths of Kenetech's 1,114 MW of wind plants currently under construction or in the contracting process, and all of the 945 MW of wind plants that were proposed in the California Biennial Resource Planning Update are in the power purchase agreements category.

The changing electricity supply environment is affecting long-term contracts in several ways. First, public utility commissions are moving away from traditional rate making to performance based rate making.[2] This encourages utilities to be more cost conscious and to exercise great care about the contracts that they sign. For example, many utilities are currently financially exposed due to long-term power purchase contracts. Southern California Edison Company (1994, pp. 1, 9) and Pacific Gas and Electric Company (1994, p. 40), for example paid an average of $0.080/kWh and Niagara Mohawk Power Corporation (1994, p. 23) paid an average of $0.065/kWh for purchased power in 1994. The two west coast utilities estimate that the market price of electricity at the generation level in a competitive environment would be closer to half of what they paid in 1994.

Second, utilities also recognize that there are no guarantees that customers will remain in the system. Hyman (1994) suggests that this may result in the situation where utilities need more protection from customers rather than vice versa. In the future, utilities may have to move toward a system of commercial contracts with large customers to protect themselves.

These and other changes make it unclear what the future will hold in terms of the types of contracts that will exist between generators (IPPs and utilities) and consumers. This is of concern to those interested in the development of renewable energy because a key to the success of the renewable power industry has been the ability to obtain long-term contracts.

While IOUs may be shying away from long-term power purchase contracts, there is no reason to believe that all parties in the market will do likewise. As stated earlier, the current electric utility structure does not offer most customers choice with regard to the type and duration of contracts that they enter into. In a more competitive market, it is likely that some customers will be willing to enter into long-term contracts. This desire may be further increased if a competitive market results in highly volatile electricity prices. Other commodity markets, for example, abound with risk-management tools such as forward and futures contracts (i.e., agreements between two parties to buy or sell an asset at a certain time in the future for a certain price), and swaps (i.e., the exchange of a fixed income stream for a variable income stream; swaps can be regarded as portfolios of forward contracts).

Moreover, other competitive industries commit to long-term capital improvements instead of continuing to manage short-term variable costs. Consider, for example, the manufacturing sector and automated machines versus labor intensive machines. Renewable energy technologies are comparable to automated machines and fossil-based technologies are comparable to labor intensive machines. Specifically, renewable energy technologies have high up front costs but require no fuel (automated machines have high up front costs but require little labor) while fossil-based technologies have lower up front costs but require fuel (labor-intensive machines have lower up front costs but require more labor). Substantial investments

[2] Under traditional rate making, revenue equals cost (as calculated by the utility) plus profit (as determined by the public utility commission). Under performance based rate making, profit equals revenue (as determined by the public utility commission) minus cost (based on the utility's performance).

have been made in automated machines to replace labor-intensive machines in competitive manufacturing industries. This is a source of strategic competitive advantage for some firms.

The question is who wants to purchase electricity under long-term contracts and how long is long-term? A possible role for renewable aggregators in markets where generators have direct access to consumers is that of negotiating long-term contracts between consumers and renewable power producers. A renewable aggregator would make sense in this situation if it could more successfully lower transaction costs or secure contracts to sell renewable power than a single producer.

3. RENEWABLE ENERGY TECHNOLOGY ATTRIBUTES

The previous section discussed some of the important issues associated with market structure from a plant owner's perspective. This section describes the particular attributes of renewables that can be used to mitigate risks and ownership scenarios that benefit from these attributes. The attributes considered include: fuel costs, environmental costs, modularity, lead time, location flexibility, availability, initial capital costs, and investment reversibility.

3.1. Fuel Costs

One of the most often stated positive attributes of renewable technologies is that they have no fuel costs. As a result, there is no uncertainty associated with the future fuel costs to operate a renewable power plant. All ownership scenarios mentioned earlier can benefit from this attribute. Different ownership scenarios, however, will benefit to a different degree with those experiencing the most uncertainty realizing the greatest benefit. Currently, this includes IPPs and power consumers because fluctuations in fuel costs (or electricity prices) directly affect the profit of IPPs, the profit of commercial and industrial users of electricity, and the well being of residential consumers who use power for their residential needs. IOUs and municipal utilities that generate power realize less of a benefit from a reduction in fuel cost variability because they currently pass this uncertainty on to customers through fuel adjustment clauses. In a more competitive environment, however, it is unlikely that this practice will continue.

When comparing renewable to fossil-based plants, the absence of fuel cost uncertainty must be added as a benefit of the renewable plant or counted as a cost of the fossil-based plant. Cost analysis for fossil-based plants typically projects a stream of expected fuel costs, discounts the results, and considers the present value cost as part of the cost of the plant. This analytical approach, however, improperly converts the uncertain stream of future fuel costs into a stream of certain costs without accounting for uncertainty.

One way to account for this uncertainty is to determine the cost of entering into a long-term, fixed price fuel contract, such as a natural gas contract (e.g., Awerbuch, 1995). Entering into such a contract is comparable to taking out a loan and should, as such, be considered a form of debt financing. Taking this approach has a direct cost and an indirect cost. The direct cost equals the present value cost of the fuel contract discounted at the firm's cost of debt. The indirect cost equals the increased cost of future investments due to the fact that entering into the contract changes the firm's capital structure.

3.2. Environmental Costs

Another attraction of renewables is that they produce low or no environmental emissions. Quantifying the value of this benefit, however, is controversial. A good part of the debate stems from the fact that the various participants in the process may have vastly different valuations.

The perspective taken in this paper is that of the plant owner, including investors in IPPs, utilities, or power customers. Plant owners can incur two types of costs associated with emissions. First, there is the additional cost of building the plant to comply with current environmental standards. This cost, which is minimal when environmental standards are low, is usually included in evaluating all types of plants, both fossil-based and renewable.

Second, there is the cost associated with future environmental standards that have not yet been established. As Swezey and Wan (1995) point out, "prospective environmental cleanup costs of fossil-fuel-based plants are never considered upfront when generation investment decisions are made." These future costs have the potential to be quite high. Pacific Gas and Electric Company (1994, p. 20), for example, estimates that compliance with NOx emissions rules for its existing power plants could require capital expenditures of up to $355 million over the next ten years. It is likely that these costs were not anticipated by Pacific Gas and Electric Company when the plants were initially constructed. Power plants that are considered to be very clean according today's standards (e.g., natural gas based generation) may fare very poorly in five years.

A conceptual framework that can be used to view this future cost is that the decision to build any polluting generation source includes the plant owner's decision to give a valuable option to the government. The option gives the government the right (but not the obligation) to change emissions standards or impose externality costs (i.e., environmental taxes) associated with environmental damages at any time and require that all generators meet the standards. The result of this is that there is a positive probability that the plant owner will incur costs in the future. The cost of this option must be accounted for when comparing fossil-based to renewable plants. Either fossil-based plant owners require compensation for the option that is given to the government or renewable plant owners need to be given a credit. The benefit of low or zero future environmental costs depends upon who owns the plant, since some owners are more likely to incur environmental costs. For example, utilities and IPPs are likely to experience more stringent regulation than power consumers that own plants.[3]

This idea is similar to stock options that are given to company executives as part of their compensation; while there are no costs associated with the options when they are given, the cost will be incurred at some future time if the option is exercised, thus diluting the stock's value. This represents a cost to stockholders and a value to the executives to whom the compensation is given.

3.3. Lead Time

IOUs and municipal utilities are still considered to be regulated natural monopolies, which requires them to serve all customers regardless of whether or not it is profitable to do so. The interaction between demand uncertainty, plant lead time, and capacity additions is of concern to these utilities. The smaller the utility is in size, the greater the concern. For this reason, municipal utilities might be particularly concerned about demand uncertainty at the generation system level.

The following example illustrates the interaction between demand uncertainty, lead time, and capacity additions. Figure 4 presents capacity and demand for a hypothetical utility generation system. The heavy lines correspond to historical data and the light lines to projected data. The current year is 1995. Actual peak demand (heavy solid line) increased in 1992, remained constant in 1993 and 1994, and increased in 1995. System capacity (heavy dashed line) remained constant during this period.

A typical approach to incorporating demand uncertainty is to project high, average, and low demand scenarios (e.g., Price, Clauhs, and Bustard 1995). The average projected demand is depicted in Figure 4 by the light solid line and the high and low projected demands by the light dashed lines.

The utility is faced with the decision to invest in either one of two plants. The plants are identical except for their lead time and capital cost: one plant requires a one year lead time and costs C^1 (it is assumed that the full cost is incurred when construction begins) and the other requires no lead time and costs C^0. The utility must decide whether to choose the plant with a one year lead time or the plant with no lead time. The real discount rate is r.

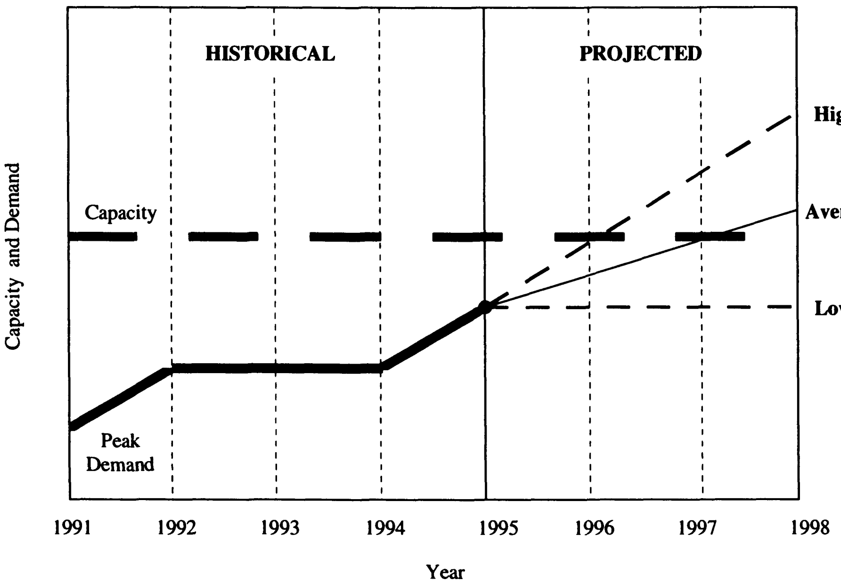
One solution to this problem is to assume that the utility must satisfy average projected demand (i.e., the light solid line in Figure 4), calculate the discounted cost of each alternative, and compare the results.[4] This approach suggests that the plant with a one year lead time be built in 1996 at a present value cost of $C^1/(1+r)$ and the plant with no lead time be built in 1997 at a present value cost of $C^0/(1+r)^2$. The

[3] This does not imply that consumers do not place a high value on the absence of emissions as illustrated by the success of green pricing. Rather, it is that consumers are less likely to be required by the government to clean up a generation source than an entity whose primary business is power generation.

[4] Relative plant costs are unchanged if it is assumed that the utility must satisfy the high projected demand rather than the average projected demand.

utility is economically indifferent between the two alternatives if $C^0/(1+r)^2$ equals $C^1/(1+r)$, which reduces to C^0 equal to $C^1(1+r)$.

Figure 4. Demand Growth and System Capacity (High, Average, and Low Scenarios).



This approach to incorporating demand uncertainty, however, does not capture the dynamic nature of demand growth. Demand growth can change over time so that demand can grow or not grow at each point in time as represented by the small solid circles in Figure 5. For example, peak demand might increase in 1996 (point B) and then not increase in 1997 (point D) and 1998 (point F).

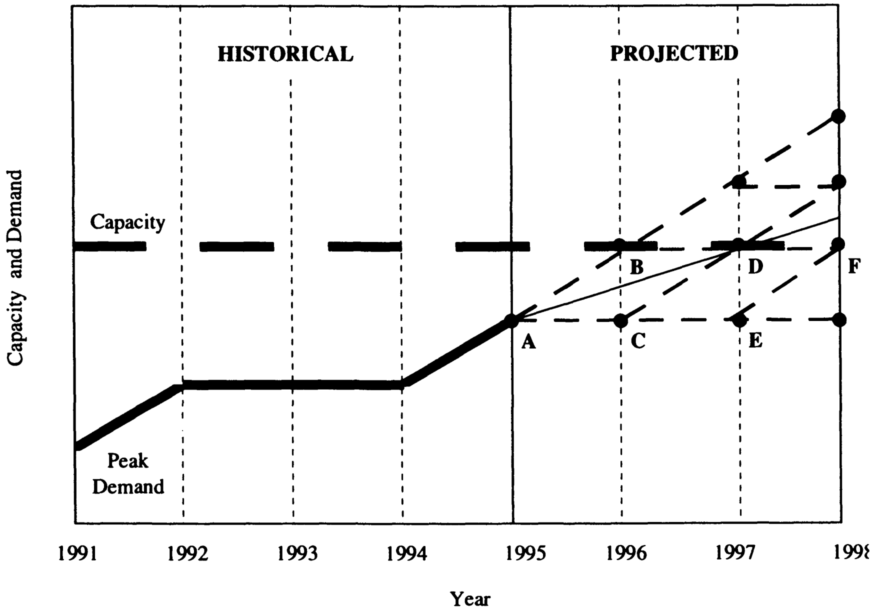
The utility has the obligation to have sufficient capacity to satisfy peak demand the first time it occurs. Figure 5 suggests that construction of the plant with a one year lead time must begin in 1995 (point A) because there is a 50 percent probability that additional capacity will be needed in 1996 and it takes one year to build the plant.[5] Construction of the plant with no lead time, by comparison, can be postponed until at least 1996. The plant will be built in 1996 if demand increases (point B), otherwise construction will be postponed if demand does not increase (point C); it will be built in 1997 if demand increases (point D), otherwise construction will be postponed if demand does not increase (point E), etc.

The present value cost of the plant with a one year lead time is C^1 because the cost is incurred in 1995. The expected present value cost of the plant with no lead time equals the probability that the plant will be needed (i.e., the first time demand

[5] The possible projected demands are based on the historical observation that system peak demand has a 50 percent probability of increasing and a 50 percent probability of staying at its current level in any given year.

reaches capacity, or points B, D, and F) times the discounted cost of the plant. This equals $C^0/(1+2r)$.[6] The utility is economically indifferent between the two alternatives if $C^0/(1+2r)$ equals C^1, which reduces to C^0 equal to $C^1(1+2r)$.

Figure 5. Demand Growth and System Capacity (Dynamic Evaluation).



[6] The expected cost is calculated by determining the probability of the cost occurring and multiplying this by the discounted cost. Figure 5 indicates there is a $(1/2)$ probability that the plant will be built in the first year at a discounted cost of $C^0/(1+r)$, a $(1/2)^2$ probability that the plant will be built in the second year at a discounted cost of $C^0/(1+r)^2$, etc. The expected cost of the expenditure equals

$\sum_{t=1}^{\infty}\left(\frac{1}{2}\right)^t \frac{C^0}{(1+r)^t}$, which simplifies by reducing the infinite series to an expected cost of $C^0/(1+2r)$.

In general, the expected present value cost of the plant with no lead time equals the probability of needing the plant at time $k+L$ times the discounted cost summed over all time periods. That is,

$E[Cost]=\sum_{k=0}^{\infty}\left[\binom{k+L-1}{L-1}(p)^L(1-p)^k\right]\left[\frac{C^0}{(1+r)^{k+L}}\right]$ where k is the number of years, L is the number of years of lead time associated with the alternative (L must be a positive integer), $\binom{k+L-1}{L-1}$ is the number of possible combinations of $(k+L-1)$ objects taken $(L-1)$ at a time, p is the probability that demand will increase, r is the real discount rate, and C^0 is the current cost of the plant with no lead time. This expected cost simplifies to $E[Cost]=C^0\left(\frac{1}{1+r/p}\right)^L$

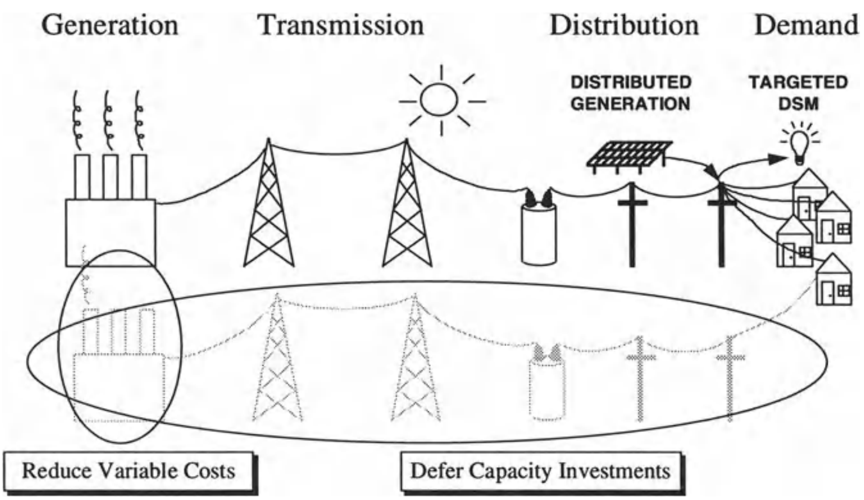
While the first approach indicates that the plant with no lead time can cost a factor of r more than the plant with a one year lead time, the dynamic approach indicates that the plant with no lead time can cost a factor of $2r$ more than the plant with a one year lead time. Suppose, for example, that the plant with a one year lead time costs $1,000,000 and the discount rate is 10 percent. The plant with no lead time can cost $100,000 more using the first approach and $200,000 more using the dynamic approach.

3.4. Location Flexibility

IOUs and municipal utilities have historically satisfied customer demand by generating electricity centrally and distributing it through an extensive transmission and distribution network. As demand increases, the utility generates more electricity. The capacity of the generation, transmission, and distribution systems can become constrained once demand increases beyond a certain level. The traditional utility response to these constraints is to build new facilities.

Utilities, however, are beginning to consider alternative approaches to dealing with transmission and distribution capacity constraints (Weinberg, Iannucci, and Reading 1991), such as using photovoltaic and other distributed generation technologies or reducing demand through targeted demand side management programs (Orans, et. al. 1992). These investments can reduce a utility's variable costs and defer capacity investments as illustrated in Figure 6.

Figure 6. The Benefits of Distributed Generation to the Utility System.



A special case of the value of modularity and short lead time occurs within this distributed generation setting due to the location flexibility associated with the modular generation technologies. The analysis from the previous subsection can be applied to the transmission and distribution system in addition to the generation system in the case of distributed generation. That is, rather than determining the value of short lead time for the generation system, the value of short lead time is determined for the transmission and distribution system.

The value of short lead time when combined with location in a distributed generation setting is probably of greater value to IOUs than to municipal utilities. The reason for this is that municipal utility systems tend to be highly concentrated in urban areas (and thus are highly interconnected) while IOUs have systems that are more spread out.[7]

3.5. *Availability*

Plant modularity also affects plant availability, which is of interest under all ownership scenarios. Modular plants are likely to begin producing power (and thus revenue for utilities and IPPs or cost-savings for power consumers) earlier than non-modular plants. In addition, modular plants have less variance in their equipment availability than non-modular plants.

3.5.1. Earlier plant operation

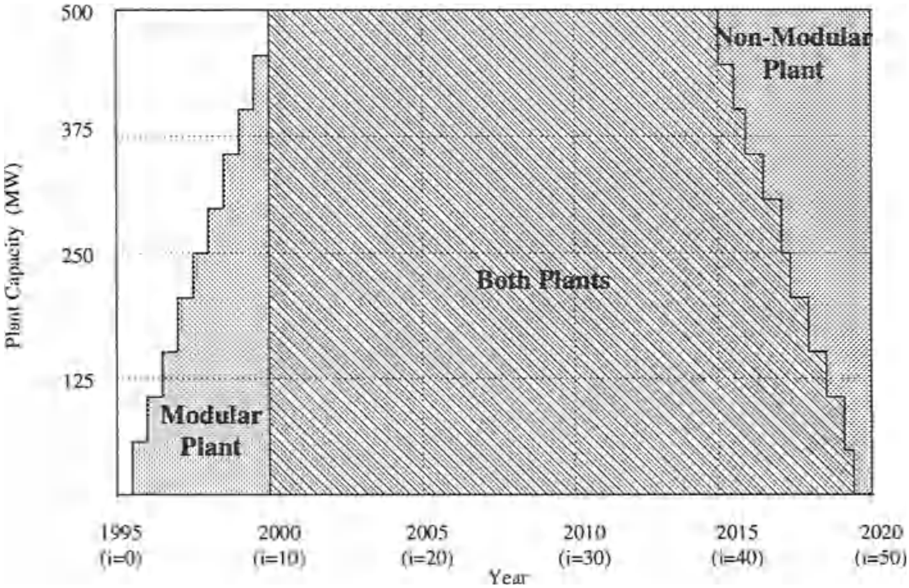
A modular plant can begin operation as each segment of the plant is completed. This availability means that a modular plant will begin to produce revenue earlier than a plant that is not modular or is lumpy. Using a hypothetical example, suppose that a utility wants to build a 500 MW facility. A modular alternative can be constructed in 50 MW increments with each increment having a 6 month lead time (i.e., it takes 5 years to complete the plant). A 500 MW non-modular plant, by contrast, is built in one segment and has a five year lead time. If it is assumed that each plant or portion of the plant has a 20 year life beginning at the point when the equipment starts operating (i.e., one horse shay depreciation) then the modular plant begins earning revenue six months after the start of construction while the non-modular plant produces no revenues until the fifth year. As illustrated in Figure 7, the plants have identical capacities between 2000 and 2015 while the modular plant has higher capacity between 1995 and 2000 and the non-modular plant has higher capacity between 2015 and 2020.

Assume that revenues (R) for the full plants are constant in real terms over the life of the plants and that they are proportional to plant capacity (e.g., a plant with 10 percent of its capacity on-line receives 10 percent of R). The present value of the revenues from the modular plant equals $\sum_{i=1}^{10}\frac{(i/10)R}{(1+r)^{i/2}}+\sum_{i=11}^{40}\frac{R}{(1+r)^{i/2}}+\sum_{i=41}^{50}\frac{[(50-i)/10]R}{(1+r)^{i/2}}$

[7] Location is also very important to power consumers who own their own generation facilities. This is not for reasons of risk and uncertainty but because, under the current market structure, the generation facility must be physically located on the customer's premises in order to self-generate. This restriction will become less important as the access to the T&D system becomes more open.

and the present value of the revenues from the non-modular plant equals $\sum_{i=11}^{50} \frac{R}{(1+r)^{i/2}}$; r is the real discount rate and i corresponds to six-month time periods. If it is assumed that a 500 MW plant has revenues of \$50,000,000 every six months and the discount rate is 10 percent, the present value revenues of the modular plant are \$710,000,000 while the present value revenues of the non-modular plant are \$540,000,000.

Figure 7. Modular Plant Produces Revenue Sooner than Non-Modular Plant.



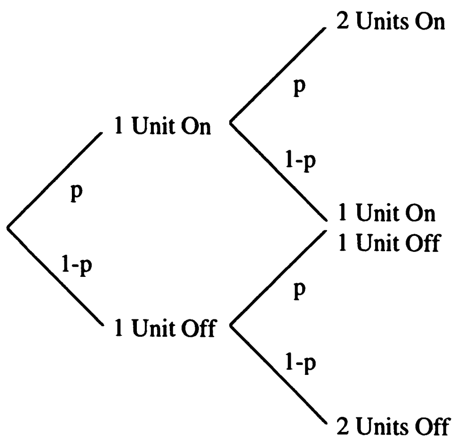
An interesting extension occurs when the modular plant is infinitely divisible (i.e., the steps in Figure 7 turn into straight lines). Let L be the number of years to complete the full plant, T the life of each part of the plant once completed, and r the continuous time real discount rate. Analogous to the discrete time case, the present value of the revenues from the modular plant equals (for $T > L$; and for T, L, and $r > 0$) $\int_0^L (x/L)(R)\exp(-rx)dx + \int_L^T (R)\exp(-rx)dx + \int_T^{T+L} [(T+L-x)/L](R)\exp(-rx)dx$; this simplifies to $[R]\left[\frac{1-\exp(-Tr)}{r}\right]\left[\frac{1-\exp(-Lr)}{Lr}\right]$. The present value of the revenues from the non-modular plant equals $\int_L^{T+L} (R)\exp(-rx)dx$; this simplifies to $[R]\left[\frac{1-\exp(-Tr)}{r}\right][\exp(-Lr)]$.

The ratio of the revenues from the modular plant to the non-modular plant is $\left[\frac{\exp(Lr)-1}{Lr}\right]$. Notice that the only variables in this equation are the real discount rate and the number of years it takes to complete the plant; that is, the life of the plant is not relevant.

3.5.2. *Reduced variance of equipment availability*

Modular plants have less variance in their equipment availability than non-modular plants when equipment failures in the modular plant are independently distributed. A non-modular plant can be considered to be either operating or not operating. If its forced outage rate is $(1-p)$, it has full availability with probability p and is unavailable with a probability of $(1-p)$. Modular plants, by contrast, can have partial availability. For example, a modular plant with two identical segments has three possible levels of availability as depicted by the probability tree in Figure 8: the plant is 100 percent available if both segments are functional; it is 50 percent available if either the first or the second segment is functional (thus the 2 in the probability distribution in Figure 8); and is unavailable if both segments are non-functional.

Figure 8. Distribution of Plant Availability for Modular Plant.



Availability	Probability
100%	p^2
50%	$2p(1-p)$
0%	$(1-p)^2$

The mean or expected availability of a plant regardless of the number of segments is one minus its forced outage rate. Since the forced outage rate is $(1-p)$, the mean availability is p. Variance for a non-modular plant is $\left[p(1-p)^2+(1-p)(0-p)^2\right]$, which simplifies to $p(1-p)$.[8] Variance for a modular plant with two segments equals $\left[p^2(1-p)^2+2p(1-p)(\frac{1}{2}-p)^2+(1-p)^2(0-p)^2\right]$, which simplifies to $p(1-p)/2$. In general, it can be shown by using either an iterative repetition of the variance calculation above or by an application of the Central Limit Theorem (Ross 1988) that the variance for a plant with n independent identical segments equals $p(1-p)/n$. That is, variance decreases as the number of segments increases.

Consider a specific example where the non-modular plant and the segments of the modular plant have a 10 percent forced outage rate and the modular plant has 10 segments. The variance for the non-modular plant is 9 percent (standard deviation equals 30 percent) but the variance for the modular plant is much smaller: less than 1 percent (standard deviation equals 10 percent). This indicates that the plant's availability is more predictable.

3.6. *Initial Capital Costs*

Projects with short lead times tend to have greater certainty associated with their installed cost due to fewer cost overruns and less lost revenue due to plant delays. This is of interest to any party that is responsible for plant construction, although it is most significant for IPPs since utilities and power consumers frequently install generation facilities through a contracting procedure, thus shifting the construction risk away from themselves to the contractor. Two other benefits associated with modular technologies are that modular plants tie up fewer capital resources during construction and that modular plants have off-ramps so that stopping the project is not a total loss

3.6.1. Fewer capital resources are tied up during construction

A modular plant ties up fewer capital resources during the construction of the total plant. The project developer only needs enough working capital to finance one segment at a time. Once the first segment is completed, the unit can be fully financed, and the proceeds used to finance the next segment.

Figure 9 presents the unrecovered capital costs for both the non-modular and the modular plants based on the example in the previous subsection assuming a linear investment rate. The developer building the modular plant requires at most one-tenth of the total project cost at any one time. This could translate to a lower risk of

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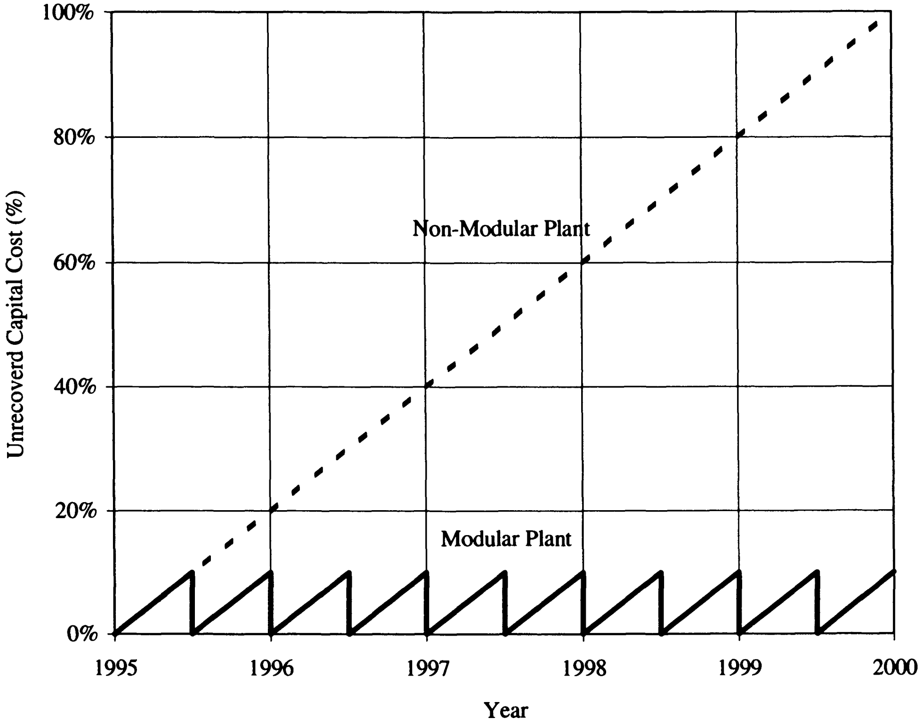
[8] The variance of a random variable X is $Var(X)=E\left[(X-\mu)^2\right]$, where E is the expectation and μ is the mean.

default and thus, more attractive financing. This benefit is likely to be of particular interest to companies with limited financial resources, such as IPPs.

Figure 9. Unrecovered capital costs of modular and non-modular plants.

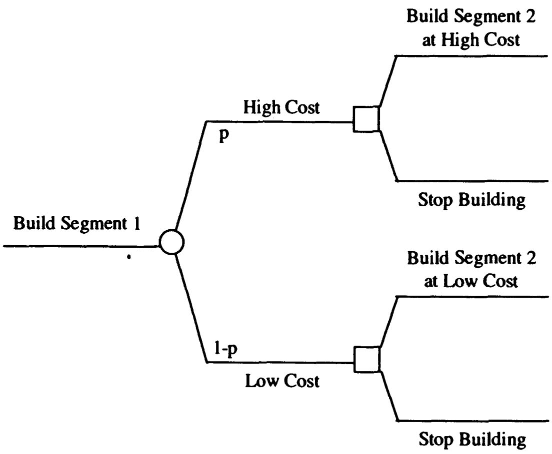


This benefit is similar to the benefit realized by a developer that chooses to build single-family dwellings rather than an apartment building. The full financial resources are tied up in the apartment building before it is sold while the single family dwellings can be sold as they are completed, thus requiring less working capital.

3.6.2. Project off-ramps

Modular plants have off-ramps so that stopping the project is not a total loss. Figure 10 presents a simple example for a plant that is composed of two identical segments. It is assumed that there is no market for the uncertainty associated with capital costs. The squares and circles in the figure correspond to decisions and uncertainties, respectively. The only uncertainty is what the cost of construction will be for each segment. This uncertainty is resolved after the first segment is completed and before the decision to build the second segment is made. If construction cost is high for the first segment it will be high for the second segment as well. Likewise, if construction cost is low for the first segment it will be low for the second segment as well. Cost will be high with a probability p and low with a probability $(1-p)$.

Figure 10. Modular Plants Can be Halted without a Total Loss.



Net Benefits

Modular Plant	Non-Mod. Plant
$V\text{-}C_H$	$V\text{-}C_H$
$0.5*(V\text{-}C_H)$	$-0.5*C_H$
$V\text{-}C_L$	$V\text{-}C_L$
$0.5*(V\text{-}C_L)$	$-0.5*C_L$

The figure presents the net benefits associated with the completed plant for a modular and a non-modular plant after all decisions are made and cost uncertainty is resolved. It is assumed that the costs are proportional to the completed project for both plants. The difference between the modular and non-modular plants is that the modular plant has value after the first segment is completed while the non-modular plant has value only after both segments are built. That is, half of the value minus cost is obtained for the modular plant if only one segment is completed while there is only a cost for the non-modular plant if only one segment is completed. It is assumed that the plants have no salvage value.

To illustrate the difference in net benefits between the modular and non-modular plants, consider the following example. Suppose that the value of the completed plant is $1,000,000, high cost is $1,500,000, low cost is $500,000, and the probability of high cost, p, is 0.5. It can be shown by working backwards through the tree in Figure 10 that both segments will be built whether the cost is low or high for the non-modular plant while only one segment will be built if costs turn out to be high for the modular plant. The expected net benefit for the non-modular plant is $0 while the expected net benefit for the modular plant is $125,000. Thus, while modularity provides value to utilities who want to control demand uncertainty, it is also of value to investors who are funding an IPP and are unsatisfied with the project's progress.

3.7. Investment Reversibility

Investment reversibility is the degree to which an investment is reversible once it is completed. This is of interest because a plant owner has the right (but not the obligation) to salvage a plant should its value become low in the particular application. Modular plants are likely to have a higher salvage value than non-modular plants because it is more feasible to move modular plants to areas of higher value or even for use in other applications. The degree of reversibility is a function of the difficulty and cost in moving the technology to another location and the feasibility of using it in different applications. Given that the uncertainty associated with the plant's future value is spanned by market traded assets, the value of this option is similar to an American put option on a dividend paying stock. Details of the evaluation approach can be found in Hoff (1997).

To illustrate this concept, suppose that a utility is accepting bids for a 50 MW battery facility. Two IPPs submit bids with identical prices proposing two technologies with identical efficiencies, lifetimes, and maintenance requirements. The only difference is that one plant is a single, 50 MW battery while the other plant is 50,000 automobile batteries (rated at 12 volts and 83.3 amp-hours).

Now suppose that in the future, due to technological breakthroughs in Superconducting Magnetic Energy Storage or other storage technologies the battery plant may become obsolete. The automobile battery plant could be salvaged for use in cars, while the 50 MW battery would have few other uses and may have to be sold as scrap. This makes the modular plant superior to the non-modular plant because the plant has a higher salvage value under an assumption of technological progress.

This value is not merely hypothetical. Consider, for example, the 6 MW Carrisa Plains photovoltaic plant facility in California, whose original owner, Arco Solar, sold the plant for strategic reasons to another company. This company dismantled the plant and the modules were resold at a retail price of $4,000 to $5,000 per kilowatt at a time when new modules were selling for $6,500 to $7,000 per kilowatt (Real Goods, 1993). That is, the investment was reversible, partially due to the modularity of the plant.

4. CONCLUSIONS

Regulatory and technical forces are causing electric utilities to move from a natural monopoly to a more competitive environment. Associated with this movement is an increasing concern about how to manage the risks associated with the electric supply business. This paper investigated the risk-mitigation potential of renewable energy technologies from several ownership perspectives. Specific attention was given to the effects of market structure and to the attributes of fuel costs, environmental costs, modularity, lead time, location flexibility, availability, initial capital costs, and investment reversibility.

Table 1 summarizes the ownership scenarios that benefit from the attributes of renewable energy technologies; X denotes some benefit and XX denotes much benefit. The conclusion of this research is that renewable energy technologies, particularly the modular technologies such as wind and photovoltaics, have attributes that may be attractive to a variety of decision makers depending upon the uncertainties that are of greatest concern to them.

Table 1. Important attributes under various ownership scenarios.

	Consumers	IOUs	Municipals	IPPs
Fuel Costs	XX	XX	XX	XX
Environmental Costs	X	XX	XX	XX
Lead Time		X	XX	
Location Flexibility		XX	X	
Availability	X	X	X	X
Initial Capital Costs				XX
Reversibility	X	X	X	XX

The next step of this research is to develop a set of representative case studies for each of the types of decision makers in table 1 and to numerically quantify the economic risk-mitigation value of the various attributes described in this paper. Analytical approaches to be used in the analysis include risk-adjusted discount rates within a dynamic discounted cash flow framework, option valuation, decision analysis, and future/forward contract comparisons. The analytical approaches will be selected based on the available information and how well they demonstrate the value of the various attributes of the renewable energy technology given the specific requirements of the decision maker making the investment decision.

5. ACKNOWLEDGMENTS

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DISCUSSION

Hoff and Herig, *Managing Risk Using Renewable Energy Techologies,*

AND

Graves and Read, *Capacity Prices in a Competitive Power Market,*

AND

Fernando and Kleindorfer, *Integrating Financial and Physical Contracting in Electric Power Markets*

Mark Reeder
New York State Public Service Commission

DISCUSSION

I have been asked to comment on the preceding three papers.

The Hoff and Herig paper does a nice job of displaying the characteristics of renewable energy technologies and showing the ways in which they differ from traditional large, central generation plants. My primary concern with the paper is that it appears to have a bias toward characterizing differences as advantages. While in most instances the difference that is discussed is in fact an advantage, this is not always, nor obviously, the case. Furthermore, I would suggest that the authors update the paper with an eye toward the competitive electric industry that is expected to exist in the near future. It appears to me that the paper is written from a foundation of traditional regulated provision of generation, rather than the more market-driven decision making that lies ahead.

One point that I found particularly valid is the advantage that lies with generators, such as renewables, whose lead time is short. In the volatile world of energy markets, the ability to defer decision on building a new plant until the last possible moment carries a significant benefit. This characteristic of renewables dovetails nicely with the Graves and Read paper (which I discuss further below) in which the similarities between installed generation capacity and options in financial markets are described. That paper points out that the value of an option increases: (1) as the volatility in the market price of the underlying good increases, and (2) as the time between the purchase of the option and the date in which it can be exercised increases. The Graves and Read paper points out that options theory can be used to put a price on the value of generating capacity. That same analytical approach could be used to place a value on the benefit of short lead time. Hoff and Herig could make use of this and produce estimates of the benefit of short lead time.

The paper appears to assume that, from a buyer's point of view, fixed price energy is preferable to energy whose future prices are uncertain. Keeping in mind that electricity tends to be an input into the production process of other goods, it is important to recognize that obtaining fixed prices for inputs is not always beneficial to the buyer. Finance theory focuses on the benefit of reduced uncertainty in the profit stream of a producer. Profits equal the difference between the revenue obtained for the product and the costs incurred in producing it. Fixing the price of a key input does not necessarily assist in reducing the uncertainty of profits. This is especially true where the price of the firm's output may be correlated with the price it pays for a key input. For example, consider a gasoline station that is offered a ten-year contract to buy wholesale gasoline at a fixed price of $1.10 per gallon. Accepting such an offer would be extremely risky from the gas station's point of view. Because the price it sells its gas for will go up or down over the ten years, fixing the price it pays for wholesale gas ensures that its profit stream will be highly uncertain. This is not desirable. The gas station producer would prefer to let the price it pays for gas float with the market, since doing so creates a strong correlation between the output price and the input price, thereby keeping the uncertainty of the profits to a minimum.

In the past decade, several electric utilities have been hurt when they obtained fixed-price electricity supplies only to find that a subsequent drop in world energy prices made it very difficult for them to sell that power to retail customers at remunerative prices. In the coming competitive market, generation producers will sell to middlemen and directly to customers. This should allow fixed-price generation to find buyers that prefer fixed prices and variable-priced generation to find buyers that prefer variable prices. It is not yet clear what portfolio of fixed and variable priced generation will be demanded by the market. This makes it difficult to predict the advantage, if there is one, of fixed cost electric production facilities such as hydroelectric.

One of the advantages of renewables highlighted in the paper is their small size, which makes a whole bank of small generators more reliable, in total, than a single large generator. The analysis shows that the much more uncertain revenue stream of the large generator creates additional risks when compared to the bank of smaller generators. While the point about uncertain revenues is clearly valid, I am not convinced that there is a significant financial cost associated with the perceived increased risk of a large plant. So long as one accepts that the outages of generating plants are independent events, it would appear that this risk is a completely diversifiable one. For example, investors could invest in mutual funds that contain scores of electric generating companies. The investor in the mutual funds has diversified the risk of generating outages just as effectively as occurs for the investor in small renewable generators.

An additional advantage that I believe is overstated is the assertion of the modularity of renewable plants. It is pointed out that there is an advantage of adding supply in small megawatt increments when compared to the 500 megawatt increment associated with a large central generating station. This is an example where a look to the future market-oriented electric industry is instructive. In the traditional regulated world where each utility had its own reserve requirements, a 500 megawatt increment of supply could create havoc for a utility whose total supplies were only 2,000 or 3,000 megawatts. In a competitive market, however, the bump up in an increment of supply is relevant only to the extent it would significantly impact the market price. Markets for electric power, however, will generally be quite large—the New York market alone is in the 30,000 megawatt range—so that any increment in supply associated with a single plant will be an insignificant part of the total market and have a negligible effect on the market price. In such an environment, the difference between a plant that is a 10 megawatt increment and one that is a 500 megawatt increment appears to be, in most instances, unimportant. This difference does become relevant in small markets such as may exist in transmission constrained load pockets (e.g., Long Island).

My final comment on the Hoff and Herig paper goes to the point that is made in the paper about the benefit of distributed generation. Small generators located within the distribution system can alleviate the need to spend money reinforcing transmission lines that otherwise would bring power from outside the area into the system. The traditional analysis would show that if the cost of the additional generation is less than the cost of reinforcing the transmission lines, the distributed generation should be pursued. While this is quite true from a straightforward benefit cost analysis, when one looks at the situation from the perspective of a competitive generation market, the conclusion becomes more clouded. The scenario in which distributed generation passes a benefit cost test is exactly the same one that has been labelled a "load pocket" problem from the perspective of establishing competitive generation markets.

In a load pocket situation, the amount of load within the pocket exceeds the amount of power than can be brought into the pocket from outside via transmission lines. In such a situation, the consumers within the pocket cannot rely completely on competition among the providers outside the pocket to set the market price. This conclusion follows from the fact that, even if the outside power is cheap, the transmission lines will fill up with that power prior to meeting the full load within the pocket. The marginal supply of power to meet the marginal demand must come from within the pocket. In such a situation, the spot market price for power in the load pocket is determined solely through competition among the generators inside the pocket. If there are insufficient generators inside the pocket to provide effective competition, the few generators that are located there are perfectly poised to exercise market power. What is needed for effective competition is either a large number of generators located inside the pocket or strong transmission ties that allow consumers to buy from the larger, outside competitive generation market to meet their marginal electricity demands. In such a situation, if the cost/benefit analysis yields a close call between adding an additional distributed generator and reinforcing the line, the option of reinforcing the line should receive a preference due to its advantage in facilitating effective competition.

There is another side to this story, however. If the distributed generation is of a scale as small as the demands of individual consumers, then deployment of numerous such units can significantly help with the potential market power problem of load pockets. Extremely small units would be seen by the market as a reduction in demand and could help eliminate the load pocket by lowering the pocket's demand to a level below its import capability from outside power markets.

Turning to the Graves and Read paper, I believe this paper has provided a significant contribution in pointing out, in a clear and easily readable way, the relationship between electric generation capacity and the financial concept of an option. The authors clearly point out that owning generation capacity is identical, in its financial characteristics, to owning an option to purchase electricity. The descriptions of the characteristics of option prices were similarly clear and quite valuable. The paper is self-contained, and needs nothing further. I found myself, however, reading the paper and continuously thinking about how to apply the insights of the paper to the developing competitive electricity market. The use of options will be prevalent in the marketplace, and I would encourage the authors to investigate more deeply the role of options in the market. Whether this research is done or not, the market itself will define the roles of various financial instruments as it evolves.

As for the value of an option contract, one only needs to look at the past decade of power purchase contracts between utilities and independent power producers (IPP) to see why a value exists and why it is especially high when the market price is volatile. Many utilities, including some in New York State, in which I am a regulator, signed contracts with independent power producers that were the mirror image of options. In financial terms, they would be called "puts." A put is an instrument in which the owner of the put obtains the right to sell a good at a prespecified price per unit. This is, in effect, what power purchase contracts were; they gave an IPP the right to build a generator and sell its output at a pre-specified price. The IPP did not have the obligation to do so, which meant that it was at the IPP's option whether or not to supply the power at the specified price. The mistake made by policy makers and utilities was that IPPs were given these "puts" for free. As the Graves and Read paper makes clear, such an option always has a positive value, and as the paper also makes clear, the value is highest when the volatility of the underlying market price of the good—in this case electricity—is high. So, what some of us did in the 1980s was give, for free, highly valuable puts to developers of IPPs, and history shows that the IPPs, or at least many of them, cashed in on this free good.

One particular use for the call option in the emerging competitive market is as a potential tool that can be used to mitigate market power in load pockets. This concept has not yet been fully developed, but, in its simplest form, it is as follows. A small number of generators may exist within the load pocket, and those generators may have market power during peak times when the demand within the load pocket exceeds the amount of power that can be brought in to it via transmission lines. Electric markets, and especially small ones, in transmission constrained areas (a.k.a. load pockets), are especially vulnerable to market power at peak times when the full utilization of supplies causes the price elasticity of supply to be small. The generators could, as a condition for being given freedom to charge market prices, be required to sell call options that cover a significant portion of their generating capacity. The options would be callable by the buyer only during a fairly small number of hours associated with peak demand periods. The consumers inside the load pocket would purchase the options. In this way, a purchaser of the option would be protected against high spot prices that could result from an attempt to exert market power. From the generators' point of view, the call options would greatly reduce the profitably of a strategy designed to artificially increase spot prices during peak periods. Furthermore, as long as the number of call options issued is less than the amount of generation required from within the load pocket, the spot price may still properly reflect the short-run market clearing price that would be appropriate for the load pocket. This is important since it is desirable for the consumers within the pocket to face prices during shortage periods that reflect the true resource costs even where the price lies above the strike price in the call option. The ideal is to have the price rise high enough to perform its proper rationing function during shortage periods, but not rise as high as the artificial price that might be obtained by a generator exerting market power.

In contrast to the other two papers in this session, which focused in on narrow aspects of the electric industry, the Fernando/Kleindorfer paper is quite broad in scope. It discusses numerous issues associated with the institution of a competitive framework for the bulk power system. I will limit my comments to a couple of key areas.

One issue that the paper addresses in some detail is the need for an incentive system for the independent system operator (ISO) and the transmission asset provider (TAP). The authors highlight the important point that the incentives should go beyond simply motivating cost reductions in the ISO's personnel, computers, etc., but should also provide incentives for quality of service dimensions. The authors correctly point out the critical importance of reliability. The authors appear to overlook one key quality dimension of the ISO's performance. Poorly designed ISO rules could create significant indirect costs that get imposed on the participants in the electric market. Another way of putting this is that the ISO is charged with creating an efficient platform for commercial transactions. If the ISO's rules do a good job of maintaining reliability, but do so via overly burdensome restrictions on the flexibility of the traders, significant costs could be unnecessarily created and imposed on ratepayers.

One possible incentive mechanism could be a reward or penalty for the ISO based on the extent to which electricity cost per kilowatt hour for the entire region is minimized. This could produce some perversities tied to a tradeoff between expensive but valuable on-peak power and less expensive off-peak power. Additional study is needed on such an approach as well as on other approaches that could motivate the ISO to excel in providing an efficient platform for commercial transactions.

The authors point out that the "key to effective regulation of transmission is to internalize all the costs that are associated with transmission service within the transmission provider." (Page 26) While this is a valid recommendation, the authors do not make clear just how these costs could be internalized.

One point made in the paper that appears to be minor, but it is in fact an important one, is the conclusion that an ISO overseen by a multiplicity of transmission providers, or other market players, presents real difficulties in efficiently coming to decisions on key questions. The paper notes that if a committee decision-making process is used, there is a significant threat of organizational inertia. (Page 25) While multi-party oversight and a committee decision-making process may be advantageous from some perspectives, policy makers should be aware of the disadvantages, one of which is inertia.

My final comment relates to the paper's discussion of transmission pricing. In a discussion of the relative merits of zonal pricing versus nodal pricing, the authors note that the less exact prices of the zonal approach are acceptable, in part, because the cost of transmission is a relatively small (10 to 20 percent) component of the total electric price. In this regard, the paper is correct that the consumption decisions of a consumer of electricity, such as an industrial customer or residential customer, will be minimally affected by inexact pricing of the transmission component of the final delivered price. The paper does not address, however, the important role of transmission prices as a rationing device during times when the demand for congested transmission interfaces exceeds their capability to move power from one location to another. A key benefit of short-run marginal cost-based prices that vary hourly and contain detailed differentiation by location, is the economically efficient, rationing function that such prices provide in the allocation of transmission use over constrained interfaces. The paper would be improved if its discussion of transmission pricing considered this aspect more fully.

Part V

Industrial Organization, Technological Change and Strategic Response to Deregulation

9

MONOPOLY AND ANTITRUST POLICIES IN NETWORK-BASED MARKETS SUCH AS ELECTRICITY

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ABSTRACT

Deregulation requires a shift entirely from regulatory economics to industrial-organization economics. Effective competition requires parity among competitors and an avoidance of cooperation. The specific criteria for effective competition include (in most cases) at least 5 reasonably comparable rivals, no single-firm dominance, and reasonably free entry. Premature deregulation, before those conditions are reached, is a cardinal error and is usually irreversible.

Important electricity markets may never reach those conditions, and so special caution is needed in removing regulatory protections. Current antitrust policies and resources tend to be weak, which accentuates the need for FERC to apply strict antitrust criteria about mergers and strategic price discrimination.

Key words: effective competition, deregulation, mergers, strategic price discrimination

Although this meeting is mainly about the electricity industry, my paper covers broader issues which also arise in the telecommunications sector. Both sectors share common economic issues, and both are in the midst of big changes of policy and structure. They are regulated industries which are switching to an entirely different

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context: the economics of competition and monopoly, sometimes called "antitrust economics."

That shift is a more radical one than many industry people seem to realize, and so my task is to pose the new competitive issues directly, perhaps even bluntly. Getting to effective competition is actually a sophisticated, complicated and probably lengthy task. My job here is to review the criteria for effective competition and how to get there.

I'll leave sector details to the many capable others at this conference and simply review the main "mainstream Industrial Organization" guidelines for promoting competition in formerly-regulated sectors. There'll be a little of the positive: e.g., the rich yields of good performance, and the meaning of effective competition. A little negative: e.g., criticism of some theory and antitrust fads. A little of the old, including Henry Simons, the great original Chicago-School leader, who may loathe much of what has been happening in these two sectors.[1] A few funny things, including a little corporate and ideological fibbing. And some sad things: e.g., don't lean heavily on antitrust, because it's now a bent reed, maybe even a broken reed for coming decades.

This is an unusual time, of course: just as the ICC has been abolished, telecommunications has been pushed into a period of perhaps chaotic "reform." Both electricity and telecommunications are in flux, and their FCC and FERC regulators are trying to wind down. The ICC's fade-out is a reminder that sectors really do trace out the life cycle that I portrayed in 1972 (Shepherd, 1973).

The current experience also fits my 1973 warning that deregulation is complicated, intricate and often lengthy. The main danger is that deregulation will veer into a market-dominance trap, rather than march cheerfully on to effective competition. Intellectually, it is all-important for officials and experts to replace regulatory economics (controls to get "efficient" outcomes even under monopoly) with industrial-organization economics (about real competitive processes, with dynamic impacts). Only if that happens will there be a good chance for the budding competition to become really effective.

So we need a strong grasp of mainstream Industrial-Organization concepts, instead of a quick-fix jump to the current antitrust mind-set and devices, or instead to patching up the old regulatory treatments of mergers and strategic pricing. The antitrust fashions *du jour* are not necessarily reliable; indeed, they are pretty dubious. For example, merger-policy errors permitted "abominable" (Alfred Kahn's word) airline mergers during 1985–88; the current antitrust agencies are obviously weak, not merely "more rigorous and theoretically valid;" current merger guidelines are usually impractical and vague; and the U.S. judiciary contains a majority of Rea-

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[1] Henry C. Simons (1948); Simons, Frank H. Knight and Jacob Viner were the original Chicagoans, who in the 1930s-1940s applied deep intellectual power to competition-monopoly issues. They opposed monopoly, which they saw as endemic and harmful.

After the 1950s, the School was captured and reversed to shallow optimism under George J. Stigler, claiming that monopoly has no practical importance. But that perfect-markets optimism has nothing to do with the original Chicago thinking.

gan/Bush-appointed judges, many of whom are likely to rebuff some genuinely pro-competitive policies. I'll explain all these points and more in what follows.

I pose two main questions:

First: How do you define truly effective competition, and how do you get from ineffective competition under dominance and tight oligopoly to effective competition?

Second: What are antitrust's actual weaknesses and strengths? How can deregulators avoid naively relying on antitrust to do things that it really can't, such as to control dominance or reduce it?

My specific lessons in the paper are (each is discussed in a separate section below):

1. The economic goals are multiple and complex, and "static efficiency" is just one of them. Innovation, fairness and diversity may be the most important ones.

2. Effective competition usually requires at least 5 comparable competitors, a lack of dominance, and reasonably easy entry.

3. Single-firm dominance and tight oligopoly do not usually provide effective competition.

4. Single-firm dominance and tight oligopoly usually fade slowly rather than rapidly, at perhaps 1 market-share point a year.

5. Dominant firms in particular exploit their wide control of the market to apply selective, strategic pricing devices, in ways which tend to quell their little rivals and prevent effective competition.

6. Entry barriers are often high, especially from hard-to-assess endogenous conditions such as the incumbent's discretionary actions.

7. Rather than being clear and well-defined, markets are often segmented and complex, and adjacent markets are often linked by having the same competitors in them.

8. U.S. antitrust policies have become a weak cure, both for dominance and tight oligopoly, and also for complex mergers of the types now arising in electricity and telecommunications.

9. In these two sectors, these economic criteria call for much deeper changes to promote competition than now seem to be in prospect.

10. Instead, premature deregulation may entrench dominance further, blocking the chances for genuinely effective competition.

11. Moreover, even after deregulation may have occurred and succeeded, strong protections will still be needed against backsliding caused by mergers and anti-competitive actions.

I will then finish by outlining the main practical lessons for electricity (and telecommunications).[2]

We need to grasp the core ideas and the wide lessons of the last century's business experience across all sectors. That's hard enough to do, and it may be particularly hard for specialists whose training and experience are in one traditional utility sector like electricity, under traditional regulation. It's even harder for any of us to foresee and encourage a sequence of policy moves **that will remove regulation only after competition has become strong enough.**

Also, you have to make a disorienting Looking-Glass shift in economic ideas, from regulation to competition. A prime example of this: price discrimination or "Ramsey pricing" (an inverse-elasticity rule for efficient static pricing) **changes from a possible regulatory GOOD into a competition-policy BAD** (a robust set of pricing weapons for blocking competition). Another example: the more that regulators withdraw their constraints, so as to permit free-entry "open access," the more freely may the dominant firm take complex actions to block the entry.

Moreover, telecommunications has since the 1950s been something of a strange cuckoo-land, full of illusions and pie-in-the-sky hype; and electricity now seems to be catching that disease, too. Beware loose talk and smooth assurances. If you just open up dominated markets and "let 'er rip," the ripping may just hit consumers and small rivals.

In reviewing these basics, I risk boring you by repeating long-established ideas. But these patterns—like gravity or the color wheel—do exist, even if some people don't recognize them or prefer to deny them. And my discussion is not just "structuralist." It combines structural and strategic-action points and sequences, to clarify the intricate statecraft that is needed to point these complex sectors toward genuine competition.

1. MANY ECONOMIC GOALS

Performance criteria have to be reviewed, because a narrow focus just on static economic efficiency can mislead policy judgments. The major economic goals go well beyond static efficiency, as summarized in Table 1.[3] Innovation is particularly im-

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[2] In fact, many of the lessons also reflect the experience of other formerly-regulated industries in replacing regulation with competition. They include banking, stock-brokerage and broadcasting, as well as many parts of the transportation sector: airlines, railroads, trucking, and intercity buses.

[3] This truth has been well recognized for over a century, ever since modern research began and antitrust and regulatory policies started to take form. For recent surveys, see Scherer and Ross (1991) and Shepherd (1991).

For new-Chicago-School claims that only static efficiency and maximizing producer-and-consumer portant; in U.S. industrial history, technological improvements and new products have been the main engine of progress, easily swamping the marginal gains from static efficiency.[4] Fairness and freedom of choice are also other major goals, which are vital to the U.S. economy and American society.

Table 1. Goals for Industry Performance.

1. Efficiency
   - A. Cost efficiency
   - B. Allocative efficiency (price equals marginal cost; consumer surplus is maximized)
2. Technological Progress
   - A. Invention of new methods and products
   - B. Innovation of these into real markets
3. Fairness in Distribution, involving
   - A. Wealth
   - B. Income
   - C. Opportunity
4. Other Wider Goals, including
   - A. Freedom of choice
   - B. Security from severe job or financial losses
   - C. Diversity of alternatives

This point is especially germane to mergers, because merger partners often claim that their merger must be approved immediately so that it can deliver large efficiency gains in the future. But those claims are often marred by exaggeration and speculation, as has always been true in antitrust experience. I will discuss that below, in a little more detail.

But first, there is a deeper problem that is posed by the multiple goals. A competitive firm's performance along this whole set of goals is virtually impossible to assess and predict in advance. **Even if a monopoly-raising merger delivers all of the static-efficiency gains that the partners claim for it, those static gains may be entirely nullified by sacrificing much larger benefits of innovation, fairness, freedom of choice, and other dimensions.**

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surplus matter, see Bork (1978) and McChesney and Shughart (1995). The latter is a particularly useful source, presenting comprehensively the Chicago attack on U.S. antitrust policies for being harmful to efficiency.

[4] Not only Joseph A. Schumpeter (1942) but also the content of modern analysis attests the primacy of innovation. See especially Scherer and Ross (1991).

That is a main reason why wise antitrust officials have usually refused to be boxed into the guesswork of assessing possible future benefits and costs, as they assess mergers.[5] Over and over again, both the benefits and the costs have been too complex and uncertain to permit any adequate, prudent judgments.

Instead, U.S. antitrust laws and policies have wisely focused on the impact on competition as the determinant of decisions.[6] If a merger reduces competition substantially, it is usually best—and legal—to prevent it, despite self-interested rhetoric or numbers about the claimed possible gains. Those gains can usually be obtained in other ways which don't harm competition, as I'll note below.

2. EFFECTIVE COMPETITION

The requisites of effective competition derive from mainstream research and industrial experience. The post-1970 theorizing—of Chicago school, game theory, and contestability genres—doesn't supplant them.[7]

The bedrock need is for ***competitive parity*** **among** ***enough reasonably comparable rivals*** **to prevent collusion,** with free entry to reinforce the pressure. Decades of extensive economic research into industrial organization—using theoretical analysis, large-scale econometrics, scores of case studies, and other methods—have clarified the conditions that are required for competition to be effective. They include three main elements, as a minimum:

- **at least 5 reasonably-comparable competitors.** That provides for unremitting mutual pressure for efficiency and innovation, as well as to avoid any sustained coordination and collusion among competitors,[8]

- **an absence of single-firm dominance.** That prevents strong unilateral market control over much or most of the market, which could exploit and/or create imperfections in the market,[9] and

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[5] That was true when I helped in drafting the original Antitrust Division Merger Guidelines in 1968. Though the post- 1980 Guidelines have included efficiencies as a matter of principle, in practice the agencies have had little success in evaluating them, and the recent 1992 Guidelines tend to demote them. See Areeda and Turner (1978), Fox and Sullivan (1989), and Scherer and Ross (1991).

On recent merger policies, including the 1992 Merger Guidelines issued by the federal antitrust agencies, see the "Special Issue on Merger Guidelines" (1993).

[6] Leading surveys of U.S. antitrust policies include Areeda and Turner (1978), Fox and Sullivan (1989), and First, Fox and Pitofsky (1991).

[7] For a review of those schools, see Shepherd (1990), especially chapter 1.

[8] The number 5 is a general consensus number, approximately indicating that 3 or 4 are almost always too few to avoid repeated cooperation and that 5 to 8 may be necessary to have confidence that collusion will not usually occur.

The earlier mainstream literature used to require 10 or more comparable firms, so as to make collusion really unlikely. Under Chicago-School pressure, the mainstream now has retreated to specifying only 5 competitors, as an absolute minimum.

- **reasonably free entry** into and among all segments of the market, so that numerous new firms can enter, survive, and acquire significant market shares.

3. DOMINANCE AND TIGHT OLIGOPOLY AREN'T EFFECTIVE COMPETITION

Dominance exists when the leading firm's market share is in or above the 40–50 percent range, and there is no close rival and only a fringe of small competitors.[10] The key failure of dominance is that **competition usually lacks parity among a substantial number of rivals,** so there is a lack of strong mutual pressure. All of the firms are likely to perform poorly: the dominant firm has an easy time of it and is not pressed to perform well. It can resort to a variety of strategic and selective tactics to quell any aggressive small rivals. Those little firms, on their part, face excessively high risks and pressures; the dominant firm can, after all, eliminate any one or all of them if it really tries to do so. They exist only at the mercy of the dominant firm.

If dominance fades, tight oligopoly is the next stage: it exists when 4 firms hold over some 60 percent of the market.[11] Coordination and collusion are likely to occur for significant periods. In both situations, there may be intervals of sharp competition; but joint market control and poor performance are likely to occur much or most of the time.

In certain pure theoretical cases (perfect "Chicago-world" conditions, contestability, etc.), dominance and tight-oligopoly controls over the market might be weak, according to abstract (and little-tested) theory. But policy officials represent real citizens, not academic ciphers; they can't prudently rely on mere theorizing. Seminar "insights" are simply not good enough for real-world problems. A big irony since 1980 has been the rush of supposedly "business-oriented" regulatory officials to take radical deregulatory actions on the basis of mere academic theories.[12]

Real dominance in real markets—from Standard Oil and American Tobacco on to United Shoe Machinery, ALCOA, Eastman Kodak, General Motors, IBM and Xerox, among others—has normally applied lasting controls over the market. That is mainly because dominance can often exploit, and even create, a variety of market

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[9] Although merger policies have recently been vague and shifting, they usually prohibit gaining (roughly) 40 percent of the market by merger, because that will permit unilateral controls. The same logic applies to dominance itself.

[10] This range reflects the research consensus in the field; see Scherer and Ross (1991) and Shepherd (1990).

[11] Or when the HHI is over some 2,000 to 2,500. The Hirschman-Herfindahl Index (HHI) has replaced the 4-firm concentration ratio in most U.S. antitrust merger calculations, though it is a flawed measure. On its definition and uses, see Scherer and Ross (1991) and Shepherd (1990).

[12] Major examples include the Department of Transportation approving clearly-anti-competitive mergers during 1985-88, and the FCC and state commissions rushing to deregulate long-distance telephone service. FERC and electricity mergers are the next possible example.

imperfections. Those imperfections have been a central topic of the field for many decades, and they are known to come in many types. Table 2 summarizes some 19 of the main categories.

Table 2. Eighteen Categories of Market Imperfections.

1. Pecuniary Gains May Be Obtained by Some Firms. They occur when a firm is able to buy its inputs at lower prices than its competitors can. These pecuniary gains let the firm obtain excess profits even when the firm is not really more efficient. In telecommunications and electricity, a retailer might get service at lower prices, giving it an advantage as a competitor.

2. Consumers May Exhibit Irrational Behavior. Some buyers may have preferences that are poorly formed or unstable. They may be deeply loyal to a supplier, even without any basis other than habit. In telecommunications and electricity, many smaller customers may be reluctant to consider new suppliers; they would become "captive" customers. The loyalties may be created or intensified by advertising designed to steer the choices by consumers. The loyalties may permit the charging of supra-normal prices, not based on efficiency; or instead, other customers may irrationally dislike the long-time local monopoly firm.

3. Producers May Exhibit Irrational Behavior.

4. There May Be Large Uncertainties, Which Interfere with Rational and Consistent Decisions by Consumers and/or Producers. Main elements of decision situations may be unkown, or may be known to change unpredictably so that consumers or producers cannot make accurately-based decisions. In telecommunications and electricity, especially, small customers may be ill-informed and excessively fearful of trying new suppliers.

5. Lags May Occur in the Decisions and/or Actions of Consumers or Producers. Actions may not be prompt, letting other firms take strategic actions which prevent competition. Consumers and r8ivals may be sluggish.

6. Some Firm Managers May Also Hold Non-rational Loyalties.

7. The Segmenting of Markets May Be Accentuated and Exploited. If producers can segregate customers on the basis of their demand attributes, then the producers may be able to use price discrimination strategically so as to extend and sustain monopoly power. Segmenting also permits a maximizing of the monopoly profits, and they can be used in later strategic efforts. The segmenting violates the single-good, single-price assumptions of the simple pure-market case. It can prevent effective competition by rivals and entrants throughout the whole of the market. In telecommunications and electricity, the long-standing price discrimination among customer groups may be made even sharper. The dominant Baby Bells and local electric firms can develop extreme price discounting so as to repel competition.

8. Differences in Access to Information, Including Secrecy. If some firms have superior knowledge compared to their rivals and/or consumers, then these firms may gain excess profits without having higher efficiency. The patterns of innovation may also be distorted. Dominant firms may be particularly able to accentuate the unevenness in access to information, to the point of complete secrecy about crucial information.

Table 2. Eighteen Categories of Market Imperfections *(continued).*

9. Controls over Key Inputs and Technology. Firms may obtain specific controls over crucial inputs, such as superior ores, favorable geographic or urban locations, access to markets, and patents or other access to critical technology. These controls may permit exclusion of competitors and an exploiting of consumers. In telecommunications, access to the local-exchange system has long been a critical issue, not yet resolved. In electricity, the obvious danger is for controls over access to local markets, either by technical controls or by pricing.

10. Barriers Against New Competition. New entry may be blocked or hampered by a variety of conditions which raise entry barriers. Some economic causes of barriers may be "exogenous," that is, basic to the market. Other barriers may be "endogenous," created deliberately by voluntary actions of the incumbent firms. The barriers may occur both at the outside edges of the market and among segments of the market.

11. Risk Aversion. Some consumers and/or producers may be strongly risk averse. That may inhibit their ability to try new alternatives.

12. Transactions Costs and Excess Capacity May Be Significant.

13. Firms May Have Sunk Costs, Including Excess Capacity and Switching Costs that Arise from Past Commitments. These sunk costs may prevent the firms from making free adjustments. They may also curtail or prevent new competition. In railroads, roadbed and trackage are obvious large sunk costs. In electricity, the leading instance is "stranded costs," which may distort future competition.

14. Because of Principal-Agent Problems, Firms May Deviate from Profit-Maximizing.

15. Internal Distortions in Information, Decision-making, and Incentives May Cause X-Inefficiency and Distorted Decisions.

16. Shareholder and Other Financial Owners of the Firm's Securities May Be Unable to Coordinate Their Interests and Actions Perfectly.

17. In International Markets, There May Be Artificial Exclusionary Conditions, Including Barriers at Borders.

18. In International Markets Firms May Often Have Differences in Information About Languages and Cross-Cultural Variations.

Despite rhetoric to the contrary, some—perhaps many—of the imperfections are found in telecommunications and electricity markets, in close correlation with monopoly, dominant-firm and tight-oligopoly situations. They reinforce the dominance, make it more profitable, and entrench it against competition. Any claims that these markets are close to perfect conditions are not in close touch with reality. Such claims bear the burden of proof, to show that the many perfect-market conditions do in fact exist.

4. DOMINANCE AND TIGHT OLIGOPOLY USUALLY FADE SLOWLY, IF AT ALL

Research has shown has that dominance usually recedes slowly, even when entry and other conditions favor a rapid decline.[13] Normally a market share over 50 percent seems to decline on average only about 1 point per year; thus, an 80 percent share would usually take 20 years to recede to 60 percent (which will still give clear single-firm dominance for many years more). Table 3 illustrates this fact, by listing a few prominent U.S. dominant firms which have held clear dominance for over 40 years, even though in most cases they soon became modest or inferior in their performance. They are a few among many exceptions to the "efficient-structure hypothesis."

Table 3. Long-Lasting Dominance in Selected U.S. Industries (Other than in Franchised Utility Sectors).

Name of Dominant Firm	Years of Dominance (Approximate)	Length of Dominance (Approximate)
Eastman Kodak	1900 – continuing	95+ years
IBM	1950s – 1990 (continuing?)	40 years
General Motors	1930 – 1985	55 years
Alcoa	1900 – 1950	50 years
Campbell Soup	1920s – continuing	70+ years
Proctor & Gamble	1920s – continuing	70+ years
Kellogg	1920s – 1980	60+ years
Gillette	1910 – continuing	85 + years

Another prominent example is AT&T in long-distance markets. During 1984–89 its market share receded rapidly at some 4 points per year, down toward a 60 percent share. That rapid decline partly reflected the beneficial working of the FCC's continuing constraints on AT&T, against the much smaller newcomers MCI, Sprint and others. But then the FCC effectively removed its constraints in 1989, and AT&T's share suddenly stopped declining, for at least 5 years. Only now may it be receding again, but now apparently at only about the typical 1–point-per-year rate of decline.

Moreover, the industry may be stuck in a dominance/tight-oligopoly trap. The business press recognizes that AT&T, MCI and Sprint are mostly doing rather soft competition, avoiding sharp price competition. Letting in the local Bells may be the only real cure; but that too is a gamble, with other side effects.

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[13] See especially Paul Geroski's survey chapter on that topic in Hay and Vickers (1987). I happen to have done some of this research; see Shepherd (1976).

The clear lesson: hopes that monopoly and dominance will quickly disappear are contrary to industrial experience. Worse, these old utility firms have about a century of experience in controlling and resisting policy officials, as well as in averting competition.

5. DOMINANT FIRMS COMMONLY EXPLOIT AND CREATE IMPERFECTIONS BY USING SELECTIVE DEVICES

Dominant firms have always deployed selective and strategic devices to quell competition. Price discrimination is a particularly effective technique, in which the firm cuts special deals with the customers it most wants to keep.

In a regulated-monopoly situation, price discrimination has a different role. It gives a set of prices which vary by the "inverse elasticity" rule, with the possible effect of maximizing total output. Therefore it is often defended as being pro-efficient, on a static basis. In recent years it has been renamed as "Ramsey" prices.[14] But whatever virtues such pricing may have for static allocation under regulated monopoly, they become irrelevant once the monopoly is deregulated and becomes a dominant firm under competitive attack. Then the dynamic, strategic effects of discriminatory pricing come to the fore.[15]

Here is a crystal-clear case of a Looking-Glass effect: you must shift your thinking away from static-efficiency theorizing in order to see the dynamic dominance-preserving impacts. **As soon as competition begins, price discrimination becomes the powerful strategic tool of selective price discounting.** If competition were fully effective already, then the selective pricing by anybody and everybody would be pro-competitive. But when a dominant firm does it, it is anti-competitive. The dominant firm deploys the selective pricing as sharp-shooting, to quell competition precisely where it arises. At the same time, it maintains the profitable yields from sheltered or captive customers in its core customer base.

Virtually all important dominant firms in U.S. business history have done these actions aggressively, playing upon the market segments like a pipe organ; from Standard Oil, American Tobacco and National Cash Register, on to ALCOA, IBM, General Motors, Xerox, newspapers, airlines, and now even Microsoft. AT&T has been doing it, as also have the local Bells.

And now some electric firms are doing it too. They are locking up some of their largest and best customers with multi-year cut-rate contracts, even before competition is opened up to other firms. It is a smart strategic move, which looks good because they are cutting prices. It also is politically astute because it seems to entice the large firm from moving away from the area. But it does lock out new competition before it has a chance.

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[14] See Baumol, Panzar and Willig (1982) and Baumol and Sidak (1994).

[15] See, for example, Scherer and Ross (1991), Shepherd (1992), and Shepherd (1995).

Strategic actions of this sort are key sources of "endogenous" entry barriers, as listed in Table 4. Dominance not only correlates with entry barriers; it can actively create them.

Table 4. 22 Common Causes of Entry Barriers.

* Indicates special relevance to network-based markets.

I. Exogenous Causes: Basic Sources of Barriers

***1. Capital Requirements:** Related to large sizes of plants and firms, to capital intensity, and to capital-market imperfections.

***2. Economics of Scale:** Both technical and pecuniary, which require large-scale entry, with greater costs, risks, and intensity of retaliation.

***3. Absolute Costs Advantages:** Many possible causes, including lower wage rates and lower-cost technology.

4. Product Differentiation: May be extensive.

***5. Sunk Costs:** Any cost incurred by a new entrant which cannot be recovered if the firm leaves the market.

6. Research & Development Intensity: Requires entrants to spend heavily on new technology and products.

***7. High Durability of Firm-specific Capital (Asset Specificity):** Imposes costs for creating narrow-use assets for entry, and losses if entry fails.

8. Vertical Integration: May require entry at two or more stages of production, for survival; raises costs and risks.

9. Diversification by Incumbents: Massed resources redeployed among diverse branches may defeat entrants.

10. Switching Costs: Complex systems may entail costs of commitment and training, which impede switching to other systems.

***11. Special Risks and Uncertainties of Entry:** Entrants' higher risks may deter them and/or raise their costs of capital.

***12. Gaps and Asymmetries of Information:** The incumbents' superior information (about technology, marketing, customers' conditions, etc.) may help them to bar entrants.

13. Formal, Official Barriers Set by Government Agencies or Industry-Wide Groups: Examples are utility franchises, bank-entry limits, and foreign trade duties and barriers.

II. Endogenous Causes: Voluntary and Strategic Sources of Barriers

***1. Preemptive and Retaliatory Actions by Incumbents:** Including selective price discounts to deter or punish entry.

***2. Excess Capacity:** The incumbent's excess capacity lets it retaliate sharply and threaten retaliation forcefully.

Table 4. 22 Common Causes of Entry Barriers *(continued).*

***3. Selling Expenses, Including Advertising:** They increase the degree of product differentiation, and make it harder for entrants to attract customers.

***4. Segmenting of the Market:** It segregates customer groups by demand elasticities and makes broad entry more difficult.

5. Patents: May provide exclusive control over critical or lower-cost technology and products.

***6. Exclusive Controls or Influences over Other Strategic Resources:** Such as the electricity distribution network, superior ores, favorable locations, and unique talents of personnel.

7. Raising Rivals' Costs: And actions which require entrants to incur extra costs.

8. "Packing the Product Space": May occur in industries with high product differentiation.

9. Secrecy About Crucial Competitive Conditions: Specific actions by incumbents may create secrecy about the key conditions.

So there is a particular danger that old regulated industries will slide into a kind of **market-dominance trap,** where much of the industry comes to be inhabited by dominant firms that are invulnerable to effective competition.

It is important to deter the strategies in these formerly regulated industries, because many of the firms still contain inefficiencies from past times. Also, the regulatory setting may be especially open to manipulation by these regulation-experienced monopolies.

In short, these are particularly eligible candidates for standard, strict, mainstream types of antitrust criteria and treatments. FERC's benefit-cost and related merger criteria are, by comparison, likely to be harmful. Strict antitrust criteria toward both industries need to be developed and applied without delay.

Can the small, hard-pressed antitrust agencies somehow take over immediately these major new monopoly problems, in a brisk and tight manner—especially under the current kinds of flux and merger booms? I doubt it, but it is important that they try. Granted, both sectors may involve two unusual conditions: 1. vertical integration, and 2. economies of scale and scope, and some network effects. But these future conditions are uncertain and would only be matters of degree, which many mainstream industries also contain. They can be readily incorporated in antitrust decisions.

6. BARRIERS ARE OFTEN HIGHER THAN CLAIMED, PARTLY BECAUSE OF THE DOMINANT FIRMS' USE OF DISCRETIONARY ACTIONS

New entry has been a popular icon which, it is often said, will quickly cure any monopoly problems. But that again is merely theory, not established fact. New entry is actually a complicated process, and it is rarely a strong force in mainstream markets, able to discipline incumbent dominant firms.[16] That is probably true also for firms in these two industries, with their long-established previously-franchised monopoly positions. AT&T has proven it conclusively, by holding its dominance so tenaciously in long-distance markets. Even if electrical firms recede to dominant positions (from 100 percent market shares down to holding, say, "only" 60 to 90 percent of their markets), free entry will often still be only a weak constraint on them. That reflects their entrenchment and solid customer base, as well as their ability to create barriers in advance. Also, the new entities trying to come into these complex markets will usually be weaker and vulnerable to high risks.

For both industries, a reliance on "open access" to enforce competitive results may be naive. Truly open access may occasionally apply some limits on dominant-firm choices. But the effects will normally be weakest precisely against those highly dominant firms where powerful potential competition is most urgently needed.

The two industries contain many of the entry problems common in other sectors, as noted in Table 3. Perhaps most important are endogenous, discretionary actions by the incumbents, using strategies with prices and other elements in ways which retard or block new competition. Although monopolists often portray their own established situations as transparent and fragile, the opposite is often true. AT&T has demonstrated that, and it seems likely to be true in electricity. These firms are using many of the tactics which have been honed by dominant firms during decades of experience across all manner of other U.S. industries.[17] They include price discrimination, erecting technical barriers, patents, etc..

Entrants and little rivals face difficulties in attracting customers, even when formal regulatory barriers are removed. Even when markets are formally opened, competition may arrive slowly. It will naturally try first to enter the creamy markets where profits might be largest. But the incumbent firms fend that off by locking up the biggest customers ahead of time.

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[16] On one variant of this issue—the role of "perfectly contestable markets"—see Baumol, Panzar and Willig (1982); for a critique, see Shepherd (1984) and Shepherd (1995).

[17] See Scherer and Ross (1991), Areeda and Turner (1978), and Fox and Sullivan (1989), among many others.

7. WHEN MARKETS ARE SEGMENTED AND LINKED

Here as in many earlier industrial markets, the really difficult questions arise in: 1. defining such segmented markets, some of which are still monopolized while others are becoming competitive, and 2. setting a consistent policy which includes these varying segments. Telecommunications has many such parts: local POTS service to disparate customer groups, cable TV service, cellular service, and others. Electricity is almost equally thoroughly subdivided, into residential, small business, large industrial users and other customer groups, with still more special conditions involving interruptible service, etc..

Research and antitrust agencies have not solved this problem, of adjacent markets which contain the same rivals/potential- entrants but seem to have differing degrees of competition. The segments may seem to be separate markets, but the players may just treat them as tactical areas within larger strategies. No easy solutions exist.

It is tempting, in frustration, simply to declare these markets to be formally open to new competition and then announce Victory and Effective Competition. But virtually all prior industrial experience counsels against that quick fix. Premature deregulation is probably irreversible, because it would permit dominance to become entrenched under ineffective antitrust. **The regulatory haven for franchised monopolies would be replaced by an antitrust haven for stable market dominance.**

8. ANTITRUST WEAKNESSES AND LIMITS, TOWARD MERGERS AND DOMINANT-FIRM TACTICS

The antitrust agencies, regrettably, can't be relied on to foresee and avoid the dangers. They are thinly staffed, lacking in telecommunications and electricity expertise, and often over-matched (both technically and in the political arenas) by legions of seasoned industry-employed specialists.[18] Also, antitrust is itself not a precise, powerful policy mechanism, unfortunately. Instead it is a fallible, human activity, which often makes mistakes or follows unbalanced policies.[19] Currently the agencies are often overwhelmed and scantily budgeted, trying only to apply mild policies

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[18] For example, the Antitrust Division has only about 350 lawyers and 60 economists for the entire U.S. economy (and relevant foreign firms). That provides only a few staff members even for major industries.

Moreover, the deregulation since 1975 of financial markets, airlines, railroads, trucking, buses, and telecommunications (broadcasting, telephone service, cable TV) has already unloaded large added burdens on these agencies. Further, the agencies must operate with difficult tasks of gathering information. Often they can get evidence only by persuading a judge to require the company under a civil investigative demand. Regulation, in contrast, usually obtains full information.

[19] In addition, federal antitrust is still weak, with only a modest recovery from the minimalist Reagan-years policies. Its staffs of economists include a large number of new-Chicago-School-minded employees hired in the 1980s, who regard monopoly as only a minor and transient problem. The doctrines include the Bork-Baumol belief that antitrust is usually harmful, and therefore it should be minimized. See Bork (1978), Baumol and Ordover (1985), and McChesney and Shughart (1995).

rather than strict ones. Even so, of course, they are still attacked by defendants and ideologues for being too severe.

On top of all that, antitrust must operate through the federal courts, seeking to win cases.[20] During 1981–93, Reagan and Bush officials placed on the U.S. federal courts a large majority of all of the 900 or so sitting federal judges. These officials openly selected conservative judges (many of them with minimalist views of antitrust), who generally accept Chicago-School views.[21] One key Chicago-School tenet—the so-called "efficient structure hypothesis"—is that dominant firms are positively beneficial; they embody superior performance and economies of scale and scope, which wholly offset any weak monopoly effects.[22]

This judicial staffing has shifted the odds against antitrust cases which seek to constrain mergers or to prevent pricing actions which intensify market dominance. Even though dominance is usually a bar to effective competition, any possible stronger attempts against it by antitrust officials—or by private plaintiffs—will face Chicago-minded judges, probably for several decades. That dim prospect chokes off antitrust efforts at the source.

In any event, **antitrust has always been at its least effective in treating market dominance,** or in trying to avert the creation of new dominance. It has to rely on the lumbering Sherman Act Section 2 case, and its methods for assessing and deterring the standard forms of dominant-firm strategic pricing are weak and primitive. The dominant firm itself usually has substantial economic and political power, and it makes grand claims that it is superbly innovative and is achieving economies of scale and scope. For over 5 decades, antitrust has been so baffled by dominance that the agencies have virtually given up all attempts to treat dominance.[23]

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[20] The Antitrust Division can only operate by filing cases in federal courts. The FTC holds its own administrative proceedings, reaching its own decisions. But virtually all of its substantial decisions are appealed to the federal courts and so the FTC must, like the Antitrust Division, direct its crucial efforts through those same courts.

[21] That leaning is reinforced by Henry Manne's ongoing "economics-education" program for judges, which continues after more than 15 years, now operating at George Mason University. With its long list of large-corporate sponsors, it has now provided intensive Chicago-School-sympathetic schooling for a majority of the judiciary.

[22] See Bork (1978), Posner (1976), McChesney and Shughart (1995), and Shepherd (1988).

[23] The AT&T case, with its 1984 divestiture, was an outstanding exception, of course. But notice: it highlights the dangers of dominance in both telecommunications and electricity markets. AT&T was an urgent target even of Chicago-School-minded officials like William Baxter, the Reagan Antitrust Chief, because AT&T had been a regulated monopoly (just as the private electric firms have been).

If electricity mergers and anti-competitive actions are allowed to proliferate now, it may soon become necessary to launch an even more drastic attempt to obtain horizontal divestiture by scores of electric companies. That may, in fact, be impossible. And that irreversibility makes it particularly important to set strict policies now, without delay.

Toward Mergers

The overriding antitrust objective is the protection of effective competition: any merger is prohibited if its effect "...may be substantially to lessen competition, or tend to create a monopoly," in the words of the amended Section 7 of the Clayton Act (38 Stat. 731, 1950). Any weighing of the merging partners' claims about future gains in efficiency is to be considered only as a side exception to the competitive impact.

The antitrust approach recognizes that benefits and costs are ultimately at stake. But it sensibly accepts that judging future competitive impacts—including innovations, unpredictable human actions, and the net gains compared to alternative actions—is simply too difficult and easily bamboozled. Regulators may think they know the industry so well that they can make these benefit-cost adjustments. But competition changes all that, creating inherent uncertainty about all elements of performance (remember, efficiency is just one element, perhaps a minor one). The judgments have to be made in haste amidst severe interest-group pressures, manipulative actions, and ample exaggerations. That is clear not only from the majority of hundreds of past antitrust cases; it is also evident from poor regulatory experience in all sectors from airlines and electricity to railroads.

Avoiding a Benefit-Cost Approach

Regulators are often tempted instead to make a detailed attempt to weigh the benefits and costs for each merger. But that is not a correct framework, for three main reasons.

First, it invites pie-in-the-sky **exaggerations and endless contests and confusions** among self-interested assertions and "experts."[24]

Second, it is only the **net benefits** of the merger that matter, **after** deducting all gains that can be obtained by other methods that don't reduce competition. Long-term contracts, alliances, and other devices are often fully available to give the benefits, so that net merger benefits are small or nil. To sacrifice competition in order to obtain benefits which are available from non-merger methods is bad economics and bad antitrust. Antitrust policy has firmly insisted on considering net benefits only. That principle is clear, but it also can add to the practical difficulties of guessing future outcomes.

Third, each merger decision may have **precedential effects** on other mergers and other competitive practices in other markets. Example: permitting Merger A (which raises monopoly in, say, New England, because it may yield efficiencies) will set precedents which let Mergers B through T occur elsewhere in the country (even though their monopoly harms have no offsetting benefits).

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[24] In virtually all past antitrust cases, the claims for gains have been inflated, sometimes disastrously so. From the chaotic Penn-Central merger in 1969 to the Republic-LTV steel merger in 1984 and others since then, the claims have ranged from speculative, at the least, to absurd and catastrophically wrong, at the upper end.

Recognizing the Antitrust Agencies' Limitations

The antitrust laws and criteria are the correct basis, and the agencies' current approaches are a useful start. But the Antitrust Division's and FTC's specific current methods toward mergers also are themselves imperfect, most particularly in being impractical, vague and lenient. So the regulators' task is to replace their own past methods toward mergers with a genuinely antitrust-based approach, **and** to improve on the antitrust criteria and methods.[25]

The specific antitrust treatment for each merger involves these steps:

1. Defining the relevant markets. The relevant markets need to be defined with caution, using comprehensive information. The **product-type** and **geographic** dimensions have to be decided, using complex information and judgment, as summarized in Table 5. The agencies' "SSNIP" method is usually too hypothetical to be much practical use.[26] Where markets are segmented and linked, the task is even harder.

Table 5. Specific Conditions Defining the Market.

The General Criterion Is Substitutability, As It May Be Shown by
Cross-elasticity of demand
The general character and uses of the goods
Judgments of knowledgeable participants
Product Dimensions
Distinct groups of buyers and sellers
Price gaps among buyers
Independence of the good's price moves over time
Geographical Area (Local, Regional, National, International)
The area within which buyers choose
Actual buying patterns
The area within which sellers ship
Actual shipping costs relative to production costs
Actual distances that products are normally shipped
Ratios of good shipped into and out of actual areas

[25] For a related, perceptive discussion on market definition, degrees of monopoly, and antitrust criteria in electricity, see Frankena and Owen (1994).

[26] The method assumes that the established sellers adopt a "small but significant non-transitive increase in price," and it considers whether the response by outside suppliers makes that price rise unprofitable. The method is, unfortunately, largely hypothetical and therefore impractical in many cases.

Yet some speculation cannot be avoided, because the relevant markets are those that will exist after the regulators remove their controls and protections. Such future unfettered markets will allow firms to take competition-affecting actions which are currently not permitted.

2. Is market power already substantial? The degree of competition in the market depends on the basic economic conditions, including imperfections in the market. Effective competition requires: competitive parity, strong mutual pressure, and a low the likelihood that competitors can coordinate their actions. That is assessed mainly by considering the market's structure: the market shares of firms, the numbers of substantial competitors, and the ease of entry. An HHI measure is only part of the relevant evidence, and it must be embedded in a full set of facts.

In addition, one must consider the core customer base of the dominant firm, because that base may contain the most loyal customers, which rivals will be unable to attract. Fringe entry may occur but be blocked from competing for the core customers.

One must also assess the many elements of entry conditions, both exogenous and endogenous. In that context, the possibility of "open access" is usually a secondary and minor element, relating to potential competition rather than real, direct competition.

In addition, there may be vertical linkages, adjacent markets, or other specific conditions which reduce competition, either now or probably in the future situation. Those specific conditions must also be included in the judgment.

Trends must also be considered. The merging partners will stress a rising trend of competition, but that may be untrue or easily reversed. Competition will often be a recent, brief development, or it may be entirely a matter of possible future entry.

3. Will the merger reduce competition substantially? That too involves the three elements: market shares, numbers of substantial competitors, and entry conditions. An increase in the HHI can be suggestive, but it is often only a minor element.

4. Possible Net Benefits of the Merger. Recall the reasons for discounting heavily the claims of merger benefits. Abuses and doubts of these sorts rule out all but the best-proven and largest net gains, since there will be extensive other harms (to innovation, fairness, freedom of choice, etc.) from any rise in monopoly power that is allowed.

9. THE ELECTRICITY AND TELECOMMUNICATIONS INDUSTRIES MUST UNDERGO DEEPER CHANGES, IF COMPETITION IS TO BECOME EFFECTIVE

Despite a lot of enthusiastic press speculation, most parts of these two sectors are not yet even remotely close to having effective competition; and the future trends are deeply in doubt, for the reasons I've reviewed. Nothing that regulatory or antitrust officials can do can be relied on to prevent the industrial and political moves to entrench the existing monopolies.

Of course competition may instead spread like wildfire, but that cheery possibility is stressed mainly by self-interested advocates and Chicago-School optimists.

10. AVOIDING PREMATURE DEREGULATION, DESPITE PRESSURE

The main cautionary lesson is that premature deregulation is a real danger now and in coming years. There are high risks that wrong policy steps now will create weak semblances of competition, which will block off the chances for genuinely effective competition.

During the complicated transition to effective competition, the FCC and FERC need to retain significant constraints on the old monopoly suppliers. Only when enough comparable competitors have become established can they prudently remove their protections. Any premature deregulation can irreversibly fix dominance in place.

These companies' advocates are likely to claim instead—with no little condescension—that the constraints are misguided, obsolete, and based on "out-of-date economics." There will continue to be an understating of the extent of monopoly and an overstating of the power of entry. The FCC and FERC must recognize that some overlap between 1. their continuing regulatory constraints on dominance and 2. the expanding antitrust treatments, cannot prudently be avoided. That is why a firm, skeptical grasp of antitrust is so crucial.

An instructive example is AT&T in long-distance markets. AT&T began demanding deregulation even when it held over 80 percent of the market. Its market share declined at a significant rate only during 1984–89, while the FCC retained some constraints on it. Even so, the gradual rise of MCI and Sprint discredited the "contestability" claims that entry was easy and complete, and that dominance no longer held any market power. Instead, MCI and Sprint have taken nearly 10 years to become reasonably strong and profitable rivals: AT&T's operations are extremely profitable despite any competitive pressure; and there are still only three major competitors. Competition is not in fact effective yet, more than a decade after it began.

Once the FCC withdrew in 1989, the onset of competition was stalled, at least for several years. That is one reason for letting the local Bells in, to provide effective competition at long last. But the same pattern has been played out in "open access" to local telephone markets. And if FERC is equally incautious toward electric monopolies, it may expect the same rigidity of dominance in many scores of relevant local electricity markets.

Like AT&T, established private electric firms demand a premature removal of the constraints, so as to get what they claim to be "a level playing field." But that mis-states the situation. **The playing field is inherently tilted already in favor of**

the established monopoly, and it will stay tilted during the dominance and tight-oligopoly conditions. Only well-designed regulatory constraints on the dominant firm can offset that tilt, leveling the field enough to let competition grow toward being genuinely effective.[27]

11. AFTER DEREGULATION: MERGERS AND ANTI-COMPETITIVE ACTIONS

Even after the regulators withdraw, the game is not over. If deregulation has been premature, then particular efforts are needed to avert mergers and strategic actions which will strengthen the dominance. Even if competition is close to being effective, the universal pressure for horizontal mergers will occur. More likely, many of the mergers will occur ahead of the full competition, as in electricity and telecommunications now.

Usually, these stampedes overwhelm the antitrust agencies, both technically (because of their scant staffing and expertise in the newly-deregulated sectors) and by sheer political muscle. So deregulation is often thwarted afterward, even where it has somehow approached success.

12. FIVE PRACTICAL PROBLEMS FOR ELECTRICITY COMPETITION[28]

The omens are not favorable in electricity. It will probably take FERC at least many months more to develop a sound economics-antitrust basis for the future, in assessing mergers and dominant-firm actions. That delay will reward electricity firms for

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[27] Sport analogies can be helpful on this point. All leagues apply extremely complex and sensitive rules to seek comparability among competitors, so that competition is meaningful and effective. If rivals are mismatched, there is no meaningful competition and mutual pressure for excellence. It is **pro-competitive** to arrange level competition during the transition from monopoly to competition. The advocates of the dominant firms will of course deny or ignore this fact.

[28] Telecommunications points are similar to those for electricity. The reform bill just hammered out in Congress did not come from Adam Smith or anyone wanting a true Invisible Hand. Instead, it was a complex deal brokered among special interests. Any resulting effective competition—in **any** significant market—will be an accidental side effect of the grinding of these great political gears.

At best, there may be some mutual invasions by a few big players such as AT&T and the local Bells (some of whom may try to merge to form even larger units). Even after a several-year period of getting competition established, competition will not be effective in most markets. They will still not have 5 strong, comparable rivals, nor an absence of dominance or tight oligopoly, nor reasonably free entry. Henry Simons' ghost—and we on earth—will still see the power-bloc syndicalism that he despised, rather than effective competition.

Of course competition will probably "heat up," amid publicists' assertions about a "New Era of Competition." But amid the circus, don't forget the technical criteria for effective competition.

forestalling competition by: 1. locking in big customers now with specially tailored cut-price long-term deals, and 2. making important mergers.

When FERC does assess mergers and actions, there will be special difficulties:

1. Market Definition

The crucial electricity markets for long-run full-requirements wholesale power are complex, rather than simple. The packages of services that are sold in wholesale markets arecomplicated, and they are usually subject to a variety of specialized controls and conditions. The primal fears of blackouts, which the retail suppliers and the ultimate consumers of electricity naturally have, can be decisive in restricint their choices to "safe" suppliers and contract terms. And the segmenting of these markets (among customer types and sizes) is often deep, so that dominant firms can use price discrimination to isolate and squeeze their lesser competitors.

2. Monopoly Power

Structure in the key electricity markets contains dominance and tight oligopoly, reinforced by imperfections. That is a central fact of the industry at this point.

3. Entry Is Not Easy

That is particularly true for each established supplier's core customer base. Various exogenous (basic and natural) and endogenous (discretionary and strategic) factors impede entry into most electricity markets.

4. Vertical Integration

The three levels have of course been anciently linked by integration. Perhaps, as some observers now say confidently, these close vertical ties could easily be dissolved, or otherwise ignored or made transparent in order to encourage open competition. But such a glib possibility seems facile rather than reassuring. The economic basis for such a big, complicated step is debatable. It may be that vertical economies are large, as John Kwoka has recently reported (Kwoka 1995). Or the economies may exist only between two layers, not among all three.

Indeed, it may soon come to be agreed that an entirely separate power grid is the most efficient form for the industry, to take the place of vertical integration and other alternative pooling arrangements. Any prudent FERC or antitrust merger decisions must allow now for the uncertainty about these possibilities.

If vertical ties are cut, there may still be many complex vertical restrictions in place or quick to emerge. It is not wise to assume that there will be a clean choice between vertical integration and complete independence of the stages.

5. The Net Benefits of Mergers are Often Hard to Measure

Merging partners routinely offer promises of very high benefits. But those are routinely overstated in the heat of the moment, and they always ignore other ways to obtain many or most of the same benefits, such as by contracts, alliances, coordination, etc.. FERC will need to develop ways to estimate these net benefits reliably.

13. WHAT FERC MAY NEED TO DO

FERC's general responsibility is to **avoid premature deregulation**; to deregulate **after** competition is as effective as possible. Currently, FERC has two main tasks: to absorb the knowledge about effective competition, and then to develop sophisticated pro-competitive rules, without delay. The two main problems facing FERC are **mergers** and **strategic pricing** using price discrimination. Until FERC has learned fully the competitive impacts and the economic criteria for reducing them, **FERC would be wise to freeze all merger proposals and selective pricing deals involving individual large customers.**

If instead FERC lets the mergers and selective pricing go ahead without applying full assessments and constraints to them, then FERC and the nation may soon find that the chances for effective competition in much of this industry have shrunk to zero, permanently. Such a retention of monopoly is surely the rational goal of the existing regulated, about-to-face-competition electricity monopolies.

Unless FERC freezes mergers until it can apply a full review, the current mergers will establish a lax precedent for later ones. Delaying these mergers may seem awkward ("standing in the way of efficient progress"), but it is better than triggering a wave of competition-stifling mergers.

Fully effective competition as I've summarized it—with at least 5 comparable rivals, no dominance, and reasonably easy entry—may simply be impossible to reach in much of this industry. Dominance may be perpetual, and most markets may have to make do with 2, 3 or 4 substantial rivals; and entry may remain difficult in most markets within the industry.

If so, then FERC needs to be all the more cautious about in deregulating pricing and in permitting mergers. If competition is likely to have no more than 3 or 4 main rivals, one of them dominant, then letting any merger (especially by the dominant firm) swallow up one of those scarce rivals will clearly reduce competition sharply. All the happy rhetoric about "fierce competition" among the remaining 2 or 3 won't change that fact. And if the dominant firm is allowed to use strategic price discrimination, that will reduce the competition and deter entry even further.

13.1. Mergers

Market definition is the key step for FERC. Until competition is fully effective, most electricity markets are in fact tightly limited in both product and geographic space, and they are also subject to special bottleneck controls. The market definitions offered by the incumbent firms will usually grossly overstate the true scope of markets and the degree of competition already occurring.

FERC needs to stick mainly to the possible monopoly-increasing effects of mergers, in deciding its actions. The temptation instead is to be dazzled by the companies' claims of the future economies that the merger will guarantee. Those benefits always sound solid, exact and large, easily offsetting any fuzzy doubts based on uncertain future rises in the degree of monopoly.

But the benefits are the really fuzzy matter. They are future, often merely speculative, and not guaranteed. And the **net benefits** are even less sure. Usually the net benefits will be much smaller, especially when the full costs of monopoly (in all the dimensions of performance, including innovation, fairness, etc.) are figured in.

FERC will also have to deal with segmented markets, which are only partly competitive. If FERC deregulates the whole market, that may then allow a retention of monopoly in some parts. Their excess profits may then be used (by the old chestnut of cross-subsidizing) to subvert competition in the other segments. Here, too, FERC needs to apply strict standards, so as to avoid permitting irreversible monopoly after deregulating.

13.2. Strategic Pricing

I've reluctantly come to the conclusion that **FERC needs to prevent all monopoly firms, in all areas, from cutting special deals with favored customers.** That seems to be the only way that this entrenching price activity will be averted. Otherwise, light-footed large firms will demand special deals and get them, using threats of leaving so as to play off local suppliers against each other. Or alternatively, the utility firms will do the pricing at their own initiative, so as to bar new competitors.

14. CAN FERC EVER SAFELY DEREGULATE?

These lessons seem to imply that FERC should never fully deregulate, because the industry will never reach fully effective competition in many or most of its parts. That's conceivable. But it doesn't mean that FERC must retain old-style regulation forever.

Rather, **FERC can simply adopt strict antitrust criteria** toward mergers and pricing. Though current antitrust policies are generally weak and sometimes capricious, they do purport to prevent large mergers when the HHI is over about 2,000 and entry is difficult. That would actually be reasonably close to the criteria based on effective competition. Also, antitrust often tries to prevent deep selective pricing by dominant firms, aimed at little rivals.

So FERC can indeed expect eventually to remove most of its old-style regulation, **if it will adopt strong antitrust criteria in its place.** There will naturally be complaints by the dominant firms that the policies are unrealistic and too strict, but rhetoric of that sort is part of the antitrust process. FERC should get used to it and install valid criteria without any further delay.

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10

SERVICES IN AN UNBUNDLED AND OPEN ELECTRIC SERVICES MARKETPLACE

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ABSTRACT

Unbundling in the electric services industry (ESI) will result in greater diversity in customer services and service providers. Unbundling raises interesting questions for business and public policy-makers because it is neither a benign activity from the stand-point of efficiency or equity, nor, in certain circumstances, a desireable policy due to economic and technical constraints. This paper provides an overview of unbundling objectives and principles, and identifies key questions decision-makers should address in developing unbundling policies. A numerical example illustrates that value can be created when customers have hetereogenous needs for electric service attributes.

S. Awerbuch et al. (eds.), *The Virtual Utility*

1. INTRODUCTION

The emerging vision of the electric services industry of the future is one of great diversity in customer services and in service providers. The achievement of this diversity is based on the unbundling of services traditionally supplied by a vertically integrated utility. The results of this unbundling are the provision of opportunities for new entry, for new rivalry among existing suppliers, and for new services for customers. Thus, from a market structure stand-point, unbundling of electric services has been identified as a condition for the attainment of a more open marketplace for suppliers and customers. In the transportation, telecommunications and natural gas industries, unbundling has played an important role in the evolution of their market structures. From a welfare point of view, unbundling can provide welfare improvements by allowing customers to better align their preferences with available service options.

Unbundling options raise interesting questions for business and public policy-makers. Unbundling is neither a benign activity from the stand-point of efficiency or equity, nor, in certain circumstances, an achievable objective due to economic and technical constraints. Although unbundling can benefit the evolution of the electric services industry toward a more competitive structure, it may also raise concerns. Under what conditions would unbundling produce undesirable outcomes such as facilitating the exercise of market power or increasing the cost of service? What are the objectives for unbundling and what are the conditions for effective unbundling? Should limits be placed on the extent and manner of unbundling in order to achieve broader public objectives? What should government's role be in industry's unbundling practices? These are important questions to be addressed in determining policies and strategies for the evolving electricity services industry

This paper provides an overview of unbundling issues from business and public policy standpoints. It begins with an overview of the characteristics of unbundled services, differentiating between end-use services and supply services. Next, we demonstrate how unbundling and differentiation in end-use services can enhance social welfare, and discuss limits to the effectiveness of unbundling in reaching business and public policy objectives. Finally, we examine objectives for unbundling, and issues associated with meeting those objectives given the unique technological and economic characteristics of the industry. We conclude with a discussion of key questions about business and public policies toward unbundling.

2. UNBUNDLING AND VISIONS OF THE ELECTRIC SERVICES MARKETPLACE OF THE FUTURE

2.1. Overview

The electric services industry (ESI) worldwide is undergoing restructuring on a scale unparalleled in history. Government-owned systems in countries other than the US are being corporatized (that is, transformed into business enterprises), and, in some cases, privatized in order to facilitate commercialization into highly efficient and productive businesses (International Energy Agency, 1994). Fundamental change is also occurring in policies toward competition in a traditionally monopolized industry. Restructuring to achieve a more open marketplace is promoting entry of new generators and retailers of electric energy to customers, thus breaking-down the traditional vertically integrated nature of the industry.

Future restructuring of the ESI will likely result in the traditional electric utility no longer being a monopoly merchant of electricity services to a given set of customers. In this vision of the ESI, energy services could be separated from delivery services. Customers may buy their electricity from one of a number of retailers that have been licensed to provide electric services, or, should they so choose, they may go out into the market and procure energy directly. The retailers could purchase electricity through intermediaries, energy merchants, who would act as supply aggregators. The retailers could also go directly to the market to purchase electricity from a number of generators. Gas and electric energy services could be supplied by the same retailers and merchants. There could also be an open market for energy efficiency services, some of which could be provided by retailers or distributors, but most of which could originate from private businesses that may not be affiliated with the retailers or distributors (such as mechanical contractors or equipment distributors).

There would need to be an infrastructure in-place in order to make the market work according to this vision. Delivery of purchased energy could be through transmission and distribution businesses that could be monopoly businesses regulated through self-governing schemes (such as regional transmission groups) or through government agencies (such as the Federal Energy Regulatory Commission or state agencies). Market transactions involving buyers and sellers of electricity could be handled by power exchanges, by independent brokers and marketers or through directly negotiated transactions. The system could be coordinated by an independent system operator who would take on responsibilities for the reliability and system integrity functions needed to assure system operability.

This characterization of the industry is not complete without including the financial marketplace where buyers and sellers of electricity could engage in financial contracting to achieve price risk management objectives using futures contracts and hedging instruments such as the well-known "contracts for differences" observed in the restructured UK power market. The financial contracts are important in this marketplace because they can produce similar economic and financial results as physical contracts. They also provide a mechanism for raising capacity expansion capital, replacing the role of traditional long term contracts such as independent power producer (IPP) supply contracts (with utilities). However, they cannot perfectly replace physical contracts because of the difficulty in fully hedging electricity purchases with uncertain demand.

In general, the ESI market of the future is believed to be one in which end-use customers can tailor their service purchases to their service needs, and except for the transmission and distribution services, can choose the sellers that are best able to provide those services. The intermediate services market is similarly diverse with retailers, merchants, financial service providers, and generating companies engaging in transactions designed to be efficient and profitable.

In comparing this stereotypical paradigm of the future ESI to that of the traditional ESI structure, it is possible to see that service unbundling is essential. Bundled services constitute two or more services that are offered simultaneously. Historically, electric services to end-users have been bundled and supplied by the local utility. Customers connected to the system received electricity service based on engineering standards for reliability and quality, standards that may have been set by a state regulatory agency. Intermediate services (such as transmission and coordination) were delivered according to operating policies determined by the National Electric Reliability Council, governmental agencies, power pools, or others.

Although unbundling is commonly identified as a key element of competitive policies (Maize, 1995; and Smith, 1994), it need not be strictly limited to that end. In this context, unbundling is frequently taken to mean the provision of services by many suppliers. Similarly, bundled service is interpreted as being a sole supplier service. From a more classical perspective, unbundling does not mean deregulating or competitive service provision. Unbundling simply means giving customers the right to assemble their own service bundles. Those services that go into the bundle could still come from one service provider. Separating structural issues involving who provides the services from service selection issues is important because, as will be discussed later, unbundling can be justified whether or not it is accompanied by the introduction of competitive alternatives.

2.2. *Dimensions of Unbundled Services*

A precise discussion of unbundling requires an understanding of the various dimensions of the services that are bundled. These dimensions include definition of the service, identification of the buyers and seller(s) of the service and of the benefactors of the service, and specification of whether the service is a final (consumption) service or an intermediate (network or supply) service. In terms of end-use services, customers are looking for service that provide important attributes such as:

- Energy: the consumption of kilowatt-hours of electricity for the purpose of doing useful work in the provision of light, heat, and mechanical services;

- Capacity: the rate of energy consumption, matched at each point in time with supply;

- Reliability: the probability that energy and capacity service needs will not be met;

- Voltage level and stability: the delivered voltage and its stability over time;

- Power quality: the characteristics of the delivered waveform, such as related to the existence of frequencies other than 60 hertz; and

- Price risk: the predictability of the price of the service.

This is a list of service attributes, not services themselves. Of course, the service attributes define the characteristics of the service provided, but do not define the source of the service. For example, there are alternative ways of obtaining reliability. A customer could add back-up power facilities on site. With service bundling, customers are given a bundled service with a fixed set of attributes. If the attributes constitute more than what is needed, then the customer is paying for unwanted service features. If the attributes constitute less than what is needed, then the customer will have to supplement the delivered service, such as by purchasing on-site power line filtering equipment to meet power quality needs. This list is not an all-encompassing list; it leaves out attributes such as time to service restoration after outages, quality of customer billing information, etc.

There are also intermediate supply or network services necessary for the provision of the end-use services. Kirby, et al (1995) provide a comprehensive and detailed description of these services. Broadly speaking, the services can be characterized as follows:

- Load balancing: the rate of supply of energy so as to equal the rate of energy use under stochastic demand conditions, to maintain system frequency (and time accuracy), etc.;

- Power delivery: transmission and distribution services needed to meet demand under specified voltage conditions;

- Reliability and system integrity: the services such as operating reserves, voltage support, and analysis and resource management needed to insure that the system can withstand outages in time-frames perhaps lower than one cycle (or 17 milliseconds);

- Voltage stability: services using equipment that supply reactive power and transform voltage levels in order to maintain voltage within specified tolerances;

- Economic control: real-time management services to facilitate economical use of facilities; and

- Metering: data acquisition of supply, network conditions, and consumption.

This list could be extended to services that are of a long time-frame such as transmission planning.

Intermediate services are often for the benefit of the system rather than specific buyers and sellers.[1] The provision of operating reserves, for example, is an important source of system support; insufficient generating capability can result in no customer being served. This is in contrast with the case of storable services that can be provided even when the current rate of consumption exceeds the current rate of production. Voltage support through the supply of reactive power can avoid islanding in a power system where areas of low voltage after a contingency are "blacked-out" due to low voltage conditions. Such system-support characteristics of intermediate services gives those services a public good dimension, thus making it difficult to attribute costs to particular buyers and seller transactions. Intermediate and end-use services are complementary; if they are separated by a retail or wholesale customer, they must be rebundled in order to meet service requirements.

2.3. Historical Perspective

Unbundling has been occurring in the ESI even before the current wave of restructuring. Industrial customers have traditionally had a choice of voltage level, and many industrial and residential customers have had choices of interruptible load programs (such as central air conditioning load management programs or interruptible contracts for industrial customers). Moreover, the advent of time-of-use pricing brought with it the realization that the cost of electrical service varied over seasons and times of day.

Customer integration into upstream supply services has also resulted in service unbundling. Distributed generation systems such as on-site cogeneration or use of renewable energy sources has meant that customer have had to obtain different services from their local utility, services that emphasized back-up power for their customer-owned generation facilities.

The structural unbundling of the services from vertically integrated utilities has resulted from several well-known factors. Governmental policies (such as the Public Utility Regulatory Policy Act of 1978 and the Energy Policy Act of 1992, and state policies supporting competitive resource bidding) have facilitated entry at the generation level. The structural unbundling in telecommunications and natural gas industries has raised questions (although somewhat tenuous in nature due to the different physical and economic characteristics of the industries) as to why such unbundling should not occur in the ESI. The Federal Energy Regulatory Commission's current Mega-NOPR that includes functional unbundling of transmission services with comparability service requirements, and decisions in California and Wisconsin requiring restructuring of the provision of intermediate services are recent examples of structural unbundling activities.[2]

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[1] See the paper by Fernando Alvarado in this volume.

[2] Notice of Proposed Rulemaking, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities," Docket No. RM95-8-000, Federal Energy Regulatory Commission.

3. ECONOMIC PERSPECTIVES ON UNBUNDLING AND BUNDLING

Unbundling and bundling have not just been of interest in regulatory economics. Various dimensions of bundling have been analyzed in the economics, marketing science, and industrial organization literature. In this section we review fundamental insights gained from this literature and relate those to current questions in electricity service unbundling.

3.1. Bundling Policies and Customer Preferences

Bundling is the practice of offering two or more commodities as a combined product. One motivation for such practice is "tie-in sales," the practice of using market power with one commodity to facilitate sales of the other commodity or to leverage market power into the other commodity's market such as to limit entry. A classic example of tie-in sales (which is now considered illegal in the US) is the infamous practice by IBM of forcing its computer customers to buy IBM punch cards.

The profit potential of bundling monopoly products when leverage would not be advantageous was demonstrated by Stigler (1963). In a seminal note which commented on a court decision, Stigler showed how a bundling strategy could increase profits by taking advantage of customer preference heterogeneity. Stigler makes the following argument referring to the practice of block booking a superior movie with an inferior movie. Consider two customer types A and B with the following willingness to pay for two products X and Y.

	Willingness-to-Pay of A	Willingness-to-Pay of B	Monopoly Price	Profit
Product X	\$8.00	\$7.00	\$7.00	\$14.00
Product Y	\$2.50	\$3.00	\$2.50	\$5.00
Bundle X+Y	\$10.50	\$10.00	\$10.00	\$20.00

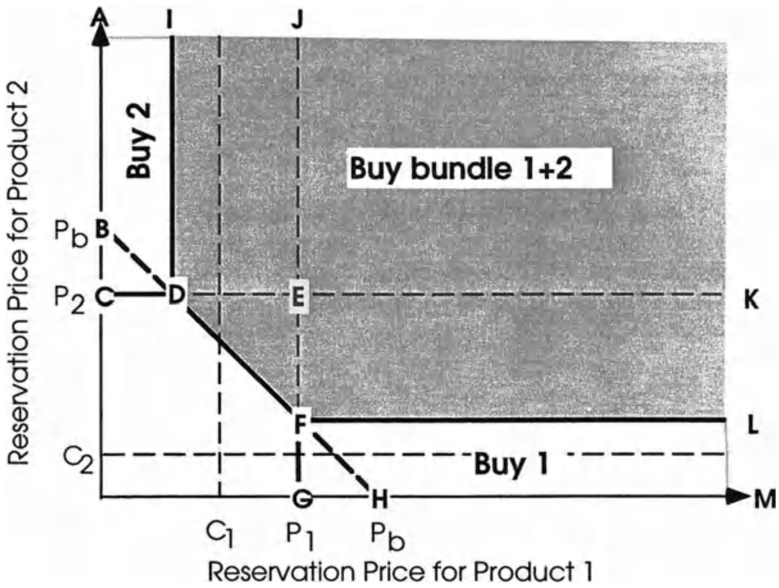
From a leverage point of view, there is no advantage to bundling the products since the monopolist could exercise monopoly power to maximize revenues from each of the products separately. Yet bundling could increase total revenue by taking advantage of customers' preference diversity. Assuming zero marginal cost of both products and no first degree discrimination where each customer could be charged a separate price, a profit-maximizing monopolist will price product X at \$7 and product Y at \$2.5 yielding a total profit of \$19. However, if the two products are bundled and sold as a package, the monopolist could price the package at \$10 and increase its profit to \$20.

In this example, bundling would not affect economic efficiency since under either strategy both customers purchase the two movies, but the profit increase comes at the expense of consumer surplus. In general, however, depending on production costs and the value customers place on the product (as revealed by their reservation prices), bundling could increase or decrease profits and social welfare by comparison to the provision of unbundled service from a monopoly supplier.

On the cost side, there are several circumstances in which unbundled supply could be disadvantageous. High fixed or "start-up" costs or production and delivery economies associated with unbundling could harm profits and social welfare. An example would be metering costs for the separate unbundled goods. In Stigler's example, if there were homogeneous preferences resulting in only one type of customer, profits would be unaffected by the bundling or unbundling decision; however, if there were higher costs for unbundled supply, obviously bundling would be more attractive.

Stigler's analysis was extended in the classic work of Adams and Yellen (1976) who introduce the distinction between "pure" bundling when only the bundle is being offered and "mixed" bundling when the bundle as well as its individual components are being sold. In the case of two components, these alternatives can be analyzed using Figure 1. Customers are characterized in terms of their reservation prices (on the two axes of the diagram) for the two component products. It is assumed that these reservation prices are additive.[3] P_1, P_2 and P_b represent the corresponding prices for Product 1, Product 2, and the bundle of both products respectively while C_1 and C_2 are the production costs of the two products.

Figure 1. Illustration of Customer Choice under Mixed Bundling.



[3] This assumption has been relaxed in more recent work.

When only the two component products are offered, customers whose reservation prices fall in region MGEK (excluding the line EK) will only purchase Product 1 (since their willingness to pay for product 2 is below its price). Likewise, customers in region ACEJ (excluding the line EJ) will only purchase Product 2 and customers in the region JEK will purchase both Products 1 and 2. The line BH represents the set of reservation prices whose sum equals the price of the bundle; these customers are indifferent toward buying the bundle because to them its value equals the bundled price. With pure bundling, customers in the region ABHM will purchase the bundle while other will be excluded.

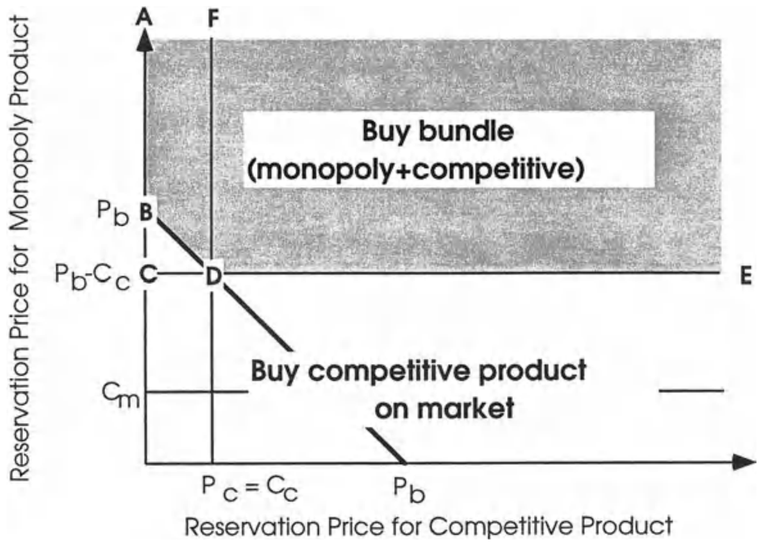
The shading in Figure 1 delineates the grouping of customer choices under mixed bundling. Customers in region MGFL will purchase only Product 1 since their reservation price for Product 2 is lower than the incremental price of the bundle over the price of Product 1 alone. Likewise, customers in region ACDI will purchase only Product 2, and customers in the region IDFL will purchase both products (that is, the bundle). This illustrates how bundling can increase market penetration by inducing more customers to purchase both products. Customers in the region IDEJ were induced to buy the bundle rather than just Product 2, customers in the region KEFL were induced to buy the bundle rather than just Product 1 and customers in the triangle DEF who would not buy any of the products separately, are also induced to purchase the bundle.

An important question, however, centers on the profitability and economic efficiency of bundling. Since mixed bundling includes as special cases pure bundling and pure component sales, with optimal price setting by a monopolist, a mixed bundle will be at least as profitable as the pure alternatives. As to the social efficiency, however, it can improve or worsen depending on the customer preference distribution. As demonstrated by Adams and Yellen (1976), social surplus loss could result from oversupply of a good as part of a bundle (that is, supplying it to customers who value it less than its cost). Referring again to Figure 1, we notice that the added buyers of Product 2 due to bundling have reservation prices for Product 2 that exceed its production cost and hence selling them the bundle increases social surplus. On the other hand, some of the buyers of the bundle have reservation prices for Product 1 below its production cost (that is, the customers to the left of the vertical line at C_1) and hence selling Product 1 to these customers as part of the bundle results in loss of social surplus. From the monopolist's perspective, since $P_b > C_1 + C_2$, the bundle is sold at a profit to all the bundle buyers. Pure bundling may not always increase profits, however, it is profitable when customers' reservation prices for the component products is negatively correlated (as shown in the example provided by Stigler). But again the economic efficiency of such a policy can go either way depending on the specific distribution of customer preferences.

3.2. Bundling Policies with Mixed Competitive and Monopolistic Product Markets

The profitability of pure and mixed bundling by a single product monopolist who bundles the monopoly-supply product with a competitively-supplied product was first examined by Schmalensee (1982). The analysis of the pure bundling option illustrated in Figure 2 below reveals that a monopolist cannot improve its profits by bundling its product with a competitively-supplied product and sell it as a pure bundle. As was pointed by Schmalensee, if the bundle price is P_b, the market price of the competitive product is C_c, and the production cost of the monopoly product is C_m, then the bundle will be purchased by all customers in the region ABDE; the monopoly profit is $P_b - C_c - C_m$ per customer. However, if the monopoly was offering its product alone at price $P_b - C_c$, it would be purchased by all customers in the region ACE (including triangle BCD) yielding the same profit per customer over more customers.

Figure 2. Customer Choice under Pure Bundling with a Competitive Product.



Social surplus will also decrease under the pure bundling policy since the monopoly good is supplied to fewer customers whose reservation price for the product exceeds its cost, while the competitive good is oversupplied to the customers in the region ABDF whose reservation price for that product is below its production cost. On the other hand, mixed bundling of a monopoly good with a competitive product serves as a price discrimination mechanism and it will generally increase the monopolist's profits. However, the effect of such a policy on social surplus is undetermined and depends on the customer preference distribution.

A direct implication of the above analysis is that a monopoly should always seek the opportunity to unbundle component services or products (that can be viewed as pure bundles) by divesting product components that can be offered competitively. Furthermore, the above analysis suggests that if the monopoly does not find it profitable to unbundle a potentially competitive component it is because of strategic reasons such as tie-in leverage where the monopoly is exploiting its monopoly position to profit from a potentially competitive component.

3.3. Unbundling, Product Differentiation and Pareto Efficiency

An important motive for unbundling and differentiation of service attributes is the use of customer heterogeneity and emulation of profitable trades among willing customers to improve economic efficiency. Different customers may have different trade-offs between a certain quality attribute of a service and other attributes resulting in a varying willingness to pay for different levels of that attribute. Unbundling such a quality attribute and providing it at different levels provides customers with a choice by offering a variety of products instead of one.[4] Figure 3 illustrates the concept of expanding a single offering in a price-quality space into an array of options by unbundling and differentiating a service attribute. Customers having different price-quality tradeoffs will exercise their choice by selecting different levels of service that match their individual tradeoffs.

Unbundling and differentiation of service reliability is a classic example of such practices and, in the context of the ESI, it has been implemented in the form of interruptible service or other form of priority service contracts.[5] In this section we present a simple, stylized example that illustrates how unbundling of service reliability, when accompanied by proper differentiation and pricing, will benefit both consumers and suppliers.[6]

The basic idea in unbundling reliability in electricity service is to recognize that traditional electricity service bundles energy and reliability, thus offering uniform reliability to all its customers. However, customers may differ in their willingness to pay for reliability so, given the opportunity, some customers may opt for cheaper and less reliable service. Furthermore, modern metering and control technologies allow customers to segregate their loads and select different reliability levels for portions of their load. In the following example we will assume a system supply capacity of 2400 MW that serves a total load of the same magnitude (that is, no

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[4] Differentiation of reliability levels may not strictly fit the definition of unbundling because reliability is an attribute of electricity service. However, one multiproduct context in which the same result can be attained is one in which a customer self-generates such as with renewable technologies or cogeneration, and achieves the desired reliability level by obtaining backup power over the transmission system.

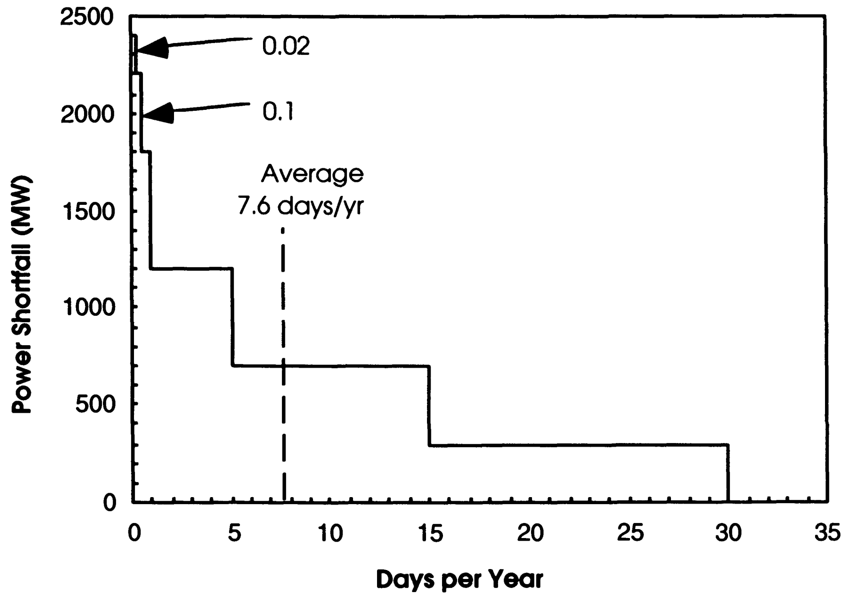
[5] The methodological foundation of priority service and efficient rationing is described in several articles by Chao and Wilson (1987), Wilson (1989) and by Chao, Oren, Smith and Wilson (1986).

[6] The following illustrative example was developed as part of joint work by Shmuel Oren with Dr. Hung Po Chao of EPRI, Professor Stephen Smith of Santa Clara University and Professor Robert Wilson of Stanford University.

reserve margin on the supply side). Figure 4 illustrates the frequency of power shortfall of various magnitudes (number of days with corresponding shortage level). Shortages are assumed to last a full day. Thus a shortage of 2400 MW will occur once in 50 years, 2200 MW once in 10 years, 1800 MW once in a year and so forth.

Figure 3. Customer Choice of Unbundled Service Quality.

Figure 4. Power Shortfall vs. Cumulative Number of Days per Year.



Under uniform service with rotating outages, customers will experience an average of 7.6 outage days per year (clearly unacceptable reliability by today's standards.) The traditional (and costly) engineering response to such a situation has been to beef up the system with enough reserve capacity so as to reduce the expected outages to a selected acceptable level (one day in ten years). Our objective is to demonstrate, however, that with unbundling, and proper price incentives it may be possible to enlist voluntary curtailment by customers (that could be viewed as providing the equivalent of spinning reserves, but with demand-side resources) so that the system will provide an adequate level of service reliability. We will further show that such a scheme can make each customer better off while the supplier collects the same revenue.

On the demand side, we will assume that there are eight types of customers or market segments and six load types that are characterized in terms of shortage cost per unserved kW day. For simplicity, we will assume that each market segment has the same total load of 300 MW that is distributed equally among three load categories. The distribution of load types varies by market segment as described in Table 1. Note for example that Type 1 customers present three sets of demands: 100 MW with a shortage cost of $200 per unserved kW day, 100 MW with a shortage cost of $10 per unserved kW day and 100 MW with a shortage cost of $0.5 per kW day.

Table 2 displays the menu of service options offered in terms of the probability of curtailment and the annual demand charge per kW for that level of service reliability. When faced with such a menu, a cost-minimizing customer will select a price and reliability for each kW of load that minimizes total expected cost, that is, the charge plus expected shortage cost. The menu was designed to induce customers' selections that match exactly the shortfall distribution. In other words, we created an incentive scheme that induces customers to accept just enough voluntary curtailments to cover the shortfalls.

Table 3 describes customers' self-selection of service reliability. For each unit of demand a customer calculates the annual cost (including demand charge and shortage cost) under each service option in the menu. The shortage cost on the left identifies the type of load, while the rest of the numbers in each row give the total expected cost for a unit of the corresponding type under the alternative service options identified on the top row. For example, a kW with a curtailment cost of $200, if assigned to the first menu option, would experience an expected annual shortage cost of (0.02)($200)=$4/year. Adding to it the annual charge of $84 results in a total expected cost of $88 per year. By repeating this computation for each of the other options, we see that the first menu option is the least costly for that type of load. Similarly, the second option is best for the second type of load and so on. The figures on the diagonal of Table 3 represent the least cost for each of the corresponding load types.

Based on the above calculation and with proper metering and control, each customer type will divide its load among the various service options, according to the shortage cost of each demand unit. The resulting distribution of service selections and the corresponding cumulative number of megawatts of power that may be curtailed with the corresponding frequency given in Table 4. Note that the distribution of megawatts available for curtailment shown in the last row of Table 4 matches exactly the shortfall distribution shown in figure 4. Thus, all the supply shortfalls can be covered in this example by contracted curtailments.

Table 1. Profile of Demands (MW) and Shortage Costs.

	Customer Type 1	2	3	4	5	6	7	8	Total MW	Shortage Cost per kW day
MW of Demand	100	—	—	100	—	—	—	—	200	$200
	—	—	100	100	100	100	—	—	400	$50
	100	100	100	—	—	100	100	100	600	$10
	—	100	—	100	100	—	100	100	500	$3
	—	100	100	—	—	100	—	100	400	$1
	100	—	—	—	100	—	100	—	300	$0.50

Table 2. Menu of Service Options.

	Average Number of Interrupted Days per Year					
	0.02	0.1	1	5	15	30
Demand Charge per kW/yr	$84	$72	$48	$30	$12	$0

Table 3. Basis for Selecting Preferred Service Option. Minimize (service charge + expected shortage cost)/kW

Load Type: (categorized by cost per unserved kw day)	Alternative Service Options (categorized by average number of interrupted days per year)					
	0.02	0.1	1	5	15	30
$200	**$88**	$92	$248	$1,030	$3,012	$6,000
$50	$85	**$77**	$98	$280	$762	$1,500
$10	$84.20	$73	**$58**	$98	$162	$300
$3	$84.10	$72.30	$51	**$45**	$57	$90
$1	$84	$72.10	$49	$35	**$27**	$30
$0.50	$84	$72.05	$48.50	$32.50	$19.50	**$15**

Table 4. Basis for Selecting Preferred Service Option. Minimize (service charge + expected shortage cost)/kW

	Load Type (categorized by shortage cost per unserved kW day)					
	$200	$50	$10	$3	$1	$0.50
Interruptions per year selected	0.02	0.1	1	5	15	30
Total MW selecting that level	200	400	600	500	400	300
Interruptible MW at that frequency	2,400	2,200	1,800	1,200	700	300

We will compare now the costs borne by each market segment under the service options menu as compared to a uniform service at a single price.

The top half of Table 5, corresponding to the price menu, gives the total expected cost for each market segment broken down into the expected shortage cost and payment to the supplier. For customers of Type 1, the total charge per year is the sum of the charges for all the demand units in that market segment based on the assignment specified in Table 4 and the demand charges specified in Table 2. Thus,

Table 5. Comparing Total Customer Costs with and without Reliability Unbundling.

With Alternative Service Options ($ millions)								
	Customer Type							
	1	2	3	4	5	6	7	8
Charge/yr	13.2	9	13.2	18.6	10.2	13.2	7.8	9
Shortage cost/yr	2.9	4	3	2.4	3.5	3	4	4
Total cost/yr	16.1	13	16.2	21	13.7	16.2	11.8	13
With Random Outages ($ millions)								
	Customer Type							
	1	2	3	4	5	6	7	8
Charge/yr	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Shortage cost/yr	160	10.6	46.4	192.3	40.7	46.4	10.3	10.6
Total cost/yr	171.8	22.4	58.1	204.1	52.4	58.1	22	22.4

Type 1 customers assign 100 MW to the one day in fifty year interruption at a cost of \$84/kW/yr, 100 MW to the one day per year interruption at a cost of \$48/kW/yr and 100 MW to the 30 days per year interruption at zero demand charge. The total charge to Type 1 customers 1 will therefore be:

(100 MW)(\$84/kW)+(100 MW)(\$48/kW)+(100 MW)(\$0/kW)=13.2 Million.

Similarly the expected annual shortage cost in that segment is computed based on the selected reliability and the corresponding shortage costs as:

(100 MW)(\$200/kW)(0.02)+(100 MW)(\$10/kW)(1)+
(100 MW)(\$0.5/kW)=2.9 Million.

This gives a total annual cost of \$16.1 Million.

For comparison we present on the bottom half of Table 5 the corresponding costs for the case where the shortfalls are covered by random curtailments and a single uniform price is being charged for all demand units. In this case all load types, regardless of their shortage cost, experience the average number of outages which is 7.6 days per year. Hence, the expected shortage cost for customers of Type 1 is computed as:

[(100 MW)(\$200/kW)+(100 MW)(\$10/kW)+
(100 MW)(\$0.5/kW)][7.6]=\$160 Million.

The uniform price has been computed so as to produce the same total revenue for the supplier so that each market segment bears the same share of the total revenue which amounts to \$11.8 Million.

We note, that while some market segments may be charged more when service priorities are differentiated, the increase is more than offset by the reduction in their curtailment losses and, on the whole, every customer type is better off while the supplier collects the same revenues. Obviously, the increased benefits to the customers create the opportunity for raising prices and profits.

The key element in the above example is the price menu specified in Table 2, that must be carefully designed to induce the desired customer selections. However, designing such a price structure only requires an estimate of the aggregate load type distribution rather than the distribution in each market segment that would be more difficult to obtain.

4. DEVELOPING UNBUNDLING POLICIES IN THE ELECTRIC SERVICES INDUSTRY

Business and public policy-makers are vitally interested in unbundling issues. Functional unbundling, which focuses on giving end-use customers information about and choice of service attributes, affects pricing and service policies. Structural unbundling, which adds customers choice of suppliers to the results of functional unbundling, affects the emergence of competitive pressures in the ESI. Each form of unbundling has efficiency and distributional implications.[7] As a result, each has implications for social welfare, financial objectives of energy suppliers, and attainment of social objectives such as toward the environment, energy efficiency, and low-income households. In addition, functional unbundling may be needed for structural unbundling when existing sellers of bundled services continue to be providers of all components of the bundle. This section of the paper provides a discussion of the objectives for unbundling, identifies ESI service and system characteristics that will affect unbundling policies to reach those objectives, and provides a list of important questions that should be addressed in developing those policies.

4.1. Objectives for Unbundling

There are many reasons why business and public policy-makers may favor unbundling of electricity services. Some of the reasons are for the public interest, and others are for private interest. Whichever case holds, it is important to understand unbundling objectives (and their bundling policy counterparts) because the design and evaluation of unbundling policies will be based on the objectives being sought.

1. Improve Economic Welfare

As demonstrated above, unbundling can be used for welfare improvement in the consumption of end-use services. A primary concern with bundled services is that they do not allow customers to receive and pay for the particular service attributes that they desire. Welfare can be enhanced when the under-supply or over-supply of particular service attributes is corrected and the appropriate prices are attached to the purchased services. This emulates efficient trades in a secondary market that allow customers to purchase services that meet desired attribute levels.

2. Reduce Price Discrimination

Unbundling can be sought to overcome welfare losses due to strategic behavior by utilities. One such objective is price discrimination. Stigler (1963) demonstrated how bundling could be used by producers to segment the market in order to achieve higher profitability by capturing more of the consumer surplus. This can have a welfare benefit, however, by making the product available to a larger customer base than would than would have occurred otherwise. On the other hand, as discussed in the previous section, Adams and Yellen (1976) demonstrate how bundling can be

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[7] Structural unbundling could include the divestiture of services and assets associated with the provision of those services.

used as a form of price discrimination to enhance profitability, but potentially reducing welfare by inefficient supply.

As a means of price discrimination, bundling can be used to charge high use customers more than low use customers with one of the bundled goods serving as a metering mechanism. The use of punch cards as a metering mechanism for IBM computers is a classic example. Cassady (1946a and 1946b) provides a general discussion of motivations and methods of price discrimination.

Unbundling can facilitate the discovery of the incidence of price discrimination by motivating more detailed, service-specific cost analyses. Frequently the cost of component services in a bundles of utility services have not separately determined. Traditional cost-tracking systems often do not break-out costs by component services. Thus, unbundling will encourage the development of new cost accounting systems and practices.

3. Constrain Market Power Arising from Tie-in Sales

Bundling can also be used to increase profitability and to exert market power through tie-in sales.[8] Tie-in sales can be used to raise entry barriers by reducing customer choice and the potential market share for entrants. Tying can also raise entry barriers by forcing new entrants to offer similar bundles. Of course, as mentioned previously, tie-in sales can be found illegal if the result is to "substantially lessen competition."[9] However, it is often a matter of debate as to the motivation for bundling goods. For example, one legitimate justification for bundling is to require that maintenance of purchased equipment be done by the equipment's distributor. Such a policy may assure that additional sales of the equipment are not harmed by poor performance resulting from improper maintenance performed by others. In a similar fashion, the need to maintain electric power system reliability and integrity may dictate the need to bundle selected system services.

If bundling can be used to extend market power, then unbundling may prevent the leverage of market power from one market to another so as to facilitate growth of competitive pressures within the industry. An example of this is the structural unbundling of the merchant services provided by pipeline companies, giving end-use customers the opportunity to purchase gas directly from producers.

Lewbel (1985) and Braden (1993) argue that it makes little sense from a profitability standpoint for a monopolist to bundle a monopolized good with a good that can be sold competitively. The monopolist may continue to bundle due to some degree of bounded rationality (since doing should not improve profitability) or due to a strategic leverage motive. An example of the latter could be the desire for a vertically-integrated utility to maintain bundled transmission and generation services in order to prevent competition for emerging generation services.

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[8] Burstein (1960) provides a general discussion of the economics of tie-in sales. Shepherd (1991) discusses the use of tie-in sales as a means of extending market power, particularly by dominant firms.

[9] Sheperd (1991), p. 287.

4. Increase Supply Choices

If unbundling facilitates effective competition in one or more of the previously bundled product markets by giving new service options to customers and intermediate service suppliers, then unbundling could provide a positive contribution to welfare improvement. By giving customers choice, they could put pressure on the market for least cost supply and the creation of new services. By giving intermediate service suppliers options, pressure is again put on the market for innovation and efficiency. Obviously, it is critical that effective competition emerge. If the services of vertically integrated utilities are structurally unbundled (such as through the creation of separate companies in a holding company), and entry does not occur, then unbundling has made no effective organizational change; basically the same organization is providing the service, but under new terms and conditions lacking the same regulatory safeguards that existed in the provision of the bundled regulated service.

5. Facilitate Informed Decision-Making

There can be other positive results from quantifying and revealing the costs of the component services. Such information can enhance customer loyalty (or understanding) by revealing the costs and can develop mutual trust between buyers and sellers, particularly when the supplier may have regulated and unregulated businesses. Such revelation may allay fears of cross-subsidization between products. Service cost accounting may also contribute to good business practices by identifying areas of business efficiency improvement.

Revelation can also facilitate yardstick competition and provide customers information that can be used to identify opportunities for lower cost provision of services. By knowing the cost of service elements, it becomes possible for customers to evaluate alternatives to traditional supply bundles and for alternative suppliers to identify opportunities for entry. For example, the merits of distributed utility investments rest on knowledge of transmission costs. Transparency of costs also lowers information costs for buyers and sellers in the marketplace.

6. Improve Efficiency of Regulatory Practices

If the component products in the bundle are subject to monopolization, then it can be argued that continued regulation of the bundled goods provided can be appropriate on market failure grounds. In addition, Gilbert and Riordan (1992) show that when goods are complements, the information costs required for regulation can be reduced if the bundled good is regulated rather than its separate components. Knowledge of service costs will help regulators to be better monitor and assess the distribution the benefits and costs arising from structural change in the ESI.

4.2. Service and Supply System Characteristics: Implications for Effective Unbundling

Effective unbundling of electricity services to achieve stated public and business policy objectives requires that technical and economic characteristics of the services and supply system be considered. Service and supply system characteristics can pose significant constraints on unbundling policies. Understanding these characteristics provides insights into whether or not to unbundle, and, if unbundling occurs, then how to do it successfully. In this section, we discuss the following list of service and supply system characteristics that have important effects on electricity service unbundling.

1. Measurability of Component Services

To achieve efficient supply of an unbundled service requires the ability to meter production and usage, and to vary the production level. Without metering capability, it is impossible (1) to assure that the efficient level of production and usage is obtained, (2) to enforce payment for services received, and (3) to accurately estimate consumption costs. Supply costs are time-dependent, so costs dependent upon load shapes. If a retailer wanted to give an accurate estimate of the cost of service for a particular customer, absent metering, the retailer would be required to estimate that cost based on surrogate consumption measures (such as use by similar customers or by the average customer within a customer class). This raises the issue of transferrability discussed below. Besides efficient pricing, metering to obtain accurate cost estimates is the only way to meaningfully communicate costs to customers in real-time and to provide the most reliable and trustworthy cost estimates for the customer.

The expansion of metering in the transmission and distribution system is already occurring, but is not yet at a scale required for implementation of customer choice and real-time pricing on a broad scale. End-use metering on a real-time basis is only available on a limited basis, principally in the industrial class and among high consumption customers. A majority of residential and commercial customers do not yet have real-time meters. Additional metering capabilities will be required for power quality monitoring.

There are certain services that may be inherently unmeterable or that require self-reporting of supply. For example, system management (that is, ancillary) services such as for system control. Maintaining bundles of such services may reduce information, monitoring and enforcement costs, and sustain efficiency of supply.

The measureability problem also includes capability. One example is network capacity. Network capacity is particularly difficult to quantify because this capacity is contingent upon the entire condition of the power system (as specified by the load and generation distribution, transmission facilities in-service, etc,). As a result, estimates of future network capacity are dependent upon assumptions about the system condition.

2. Production Externalities

The ability of electricity suppliers to vary production levels can be constrained by power system technology with inherent production externalities. The interconnected nature of the system means that individual actions (such as unexpected actions to change a generation availability or to change demand) can have adverse system-wide reliability effects. In addition, individual company operating practices can impose costs on others, such as through the redistribution of system losses.

3. Joint and Common Costs

Several of the objectives for unbundling requires unambiguous cost determination. An example of these objectives is making costs transparent to enable informed decision-making by buyers and sellers. If costs are ambiguous, then the method for determination becomes questionable, underlying objectives (such as to cross-subsidize) become a concern, and the chosen method of cost determination becomes suspect. A particular example of this issue is unbundling of generation and transmission services, and the subsequent deregulation of generation. The existence of common costs (or shared costs) involving generation and transmission provide the opportunity for cross-subsidization of generation by allocation to the regulated transmission sector.

Joint production occurs when two or more products are simultaneously produced in a technologically-determined proportion. As a an example, the movement of electrical energy through alternating current transmission system is significantly governed by technological factors (that is, Kirchoff's Laws) thus making the "routing" of transmission flows essentially impossible to achieve. This particular problem may be lessened in the future due to technological change. New technologies using power electronics (that is, flexible alternating current systems such as phase shifters) will give system operators more control over transmission flows in the future than has existed in the past. Electrical capacity costs are also joint in time; that is, capacity that stands ready to serve at one hour of the day is generally ready to serve at another hour of the day. These factors make it difficult to unbundle of service costs (such as transmission investment costs) using cost allocation techniques.

Joint production constrain the supply of component services. For example, electric power systems cannot differentiate generation reliability levels for an individual customer without means of actually physically disconnecting that customer's loads or without that customer agreeing to curtail service under certain system operating conditions.

4. Public Good Characteristics

It can also be difficult to vary the supply level for a particular customer when services have public good characteristics. As mentioned before, spinning reserves provide real-time load balancing services for the entire system. This is not to say that spinning reserves could not be obtained competitively; it is to say that achieving the optimal reserve level based on willingness to pay is complicated by the inability to exclude consumption of the service by particular customers who may be free riders. Transmission capacity additions suffer from the same problem in that an investment in a new transmission line or in reinforcement of an existing line can benefit or harm customers throughout the system. Costs for contingency analyses (an ancillary service needed to test the security of current or future operating states) are difficult to unbundle from a set of system administration services designed to insure system integrity and reliabilty.

5. *Tranferability Limits*

As noted above, unbundling can be used to meet several objectives. These objectives require knowledge of a customer's use, value, characteristics (such as income level or appliance stock), or preferences. In many cases, there is a lack of perfect knowledge of these data so surrogates must be used. The surrogates are either customer characteristics or consumption characteristics (for example, industrial customer vs. load factor typical to industrial customers). Such surrogates should be non-transferable; that is, a customer should not be able to misrepresent the service characteristics that are needed to determine the cost and terms of service.

An example of the transferability issue could be the characterization of a particular customer by the characteristics of the typical industrial customer: high load factor and a willingness to pursue competing options for elecrrical energy, and thus having a low value of service and high price elasticity. Given these assumptions, it could be argued that an industrial customer should receive price discounts for reliability because of favorable load pattern and low value of service. Such an unbundling scheme could produce substantial price distortions for customers who do not fit that load and value of service pattern. If the assumption about industrial customers is true, then that surrogate measure of load shape and value would be non-transferable and the unbundling objective could be effectively reached.

4.3. *Key Questions in Evaluating Unbundling Policies*

What then can be said about the evaluation of unbundling policies in the ESI? The evaluation of the policies can be done using different frameworks that assess static and dynamic efficiency (in a welfare context), and distributional equity with respect to all stakeholders. No matter which evaluative framework is used, there are several key questions that should be addressed.

In our discussion we do not specifically identify questions relating to structural unbundling to encourage entry and more competitive interplay in the ESI. The nature of such questions leads to arguments for and against competition in the industry rather than unbundling itself – a discussion which has been more than amply covered elsewhere. Unbundling to achieve a competitive marketplace assumes that effective competition will result. If it is unlikely that the benefits of competitive pressures will attain, then successful structural unbundling is questionable. Even though we do not explore structural change questions, we do point out questions that will influence the nature of the unbundling to achieve structural reform objectives.

Based on our previous review of the literature, of objectives for unbundling, and of the salient characteristics of electricity services and the suppy systems, we believe that the following questions provide key considerations in devising unbundling policies.

1. What is the objective of the unbundling policy (such as increased customer value and societal welfare, better customer or intermediate services provider information, and structural reform)?

Unbundling analyses should consider the value improvements that might be achieved. Improved customer value may be possible if there is a demand for service diversity in end-use services. Examples of different end-use attributes were given above. With price revelation (or transparency), end-use customers and users of intermediate services will be able to make more informed decisions. With better information, trade-offs between suppliers and technological options (such as distributed technologies) becomes easier to assess. Finally, with structural unbundling, customers and users of intermediate services may have access to new resources.

2. Is there a demand for the unbundled services that would suggest a potential for welfare improvements?

Services should not be unbundled if there in no demand for the unbundled services. A motivator for increased demand could be lower cost because of the customer's ability to rebundle the components into a more cost effective service bundle. Gains from unbundling services to customers could result from their being able to rebundle the complementary services to better achieve the desired service attributes, thus increasing the value of the rebundles service. An example could be increased value by customers being able to choose more environmentally-preferred generation sources.

Unbundling into component services produces a form of service modularity. This service modularity is likely to be most sought by more sophisticated cusomers who are capable of understanding the technological and economic dimensions of service provision (Wilson et al, 1988). Modularity can come at a loss of system integration valued by customers who prefer "one-stop shopping."[10] The emergence of new system integrators such as energy marketers could reduce concerns about loss of system integration; however, the choice between alternative system integrators still results in some increase transaction costs for customers. As a result, whether the unbundling produces greater customer value will depend upon whether there is increased

[10] Independent system operators and power exchanges may be used to maintain the value of integration for identified system services.

value resulting from the customer's ability to choose individual component services net of any loss in value from the lack of system integration.

3. What effects will unbundling have on transactions costs, and start-up costs associated with implementing an unbundling policy?

There could be changes in the nature and level of transactions costs if unbundling is associated with greater choices for customers and intermediate service providers. There may also be significant start-up costs to consider. Metering changes may be needed such as to achieve real-time pricing and balancing of supply with customer demand. Retooling and retraining the work force and customers to be efficient in supplying and purchasing unbundled products will result in added costs.

4. What will be the effects of unbundling on supply efficiency?

Unbundling could result in efficiency losses such as those arising from economies of scale and scope, and of coordination within the interconnected network. There are likely to be such economies in some system management and control functions for economy, reliability and system integrity. The generally accepted view that economies of scale exist in transmission and that economies of density occur in distribution suggest limits to the extent of unbundling that should occur in those segments of the ESI. Independent system operators may be used to insure that inefficiencies arising from excessive unbundling of system management functions do not occur.

5. What new risks and risk allocations will occur?

Unbundling also introduces new risk levels and allocations. Many of these risks arise from structural reform. Deregulated generation companies would face greater profit risk than existed under ratebase regulation. Customers would face new risks whether or not they played in the spot power market simply because the change in supply risks for retailers and in the manner and pricing of supply, such as through real-time pricing rather than a regulated tariff. The existence of these new risks will result in changes in information costs as customers and intermediate service users seek ways to reduce risk through better information. Stockholders will face new risks with structural unbundling. The new incidence and allocation of risk will pose an opportunity for the development of a financial market for price risk managment, but will impose new transaction and information costs on users of that market.

6. Does the unbundling policy address the unique technological and economic characteristics of electricity services and the supply system?

This list of characteristics identified previously in this section can pose various problems such as in identifying costs, in addressing network externalities, and in determining optimal supply levels (due to the public good dimensions of some electricity services). Explicit linking of the unbundling policy with those characteristics will be needed to insure the efficiency of that policy.

7. How will the unbundling affect regulatory practices and costs?

Public policy-makers will also face important issues in unbundling. They will undoubtedly be concerned about the price and service patterns that emerge after unbundling. Cross-subsidization issues will not go away, particularly in the presence of common costs. Issues raised by the supply and customer characteristics listed in the previous section will need attention, particularly those evolving some degree of market failure. Fairness issues in the manner in which unbundling occurs will continue to be raised not only by customers but also by competitors.

5. CONCLUSION

The extent of unbundling in the future of ESI is likely to be substantial. We have identified potential gains and losses from such unbundling, and have suggested key issues and questions that should be considered in business and public policy-making toward service unbundling. We are not arguing against unbundling in principle; in fact, we have given examples of unbundling that produce welfare-improvements. However, this overview of unbundling showed that thoughtful examination and discussion of unbundling issues is needed to improve the likelihood that chosen unbundling policies successfully meet the objectives being sought, and recognize the unique economic, technical, and market structure characteristics of the ESI.

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TECHNOLOGICAL CHANGE AND THE ELECTRIC POWER INDUSTRY:

INSIGHTS FROM TELECOMMUNICATIONS

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ABSTRACT

This paper examines key parallels and differences between the electric utility and telecommunications industries with respect to the role played by new technology, and the particular prospects for electric power distributed resources (DR) in the electric utility industry. Technological change influences industry structure and affects regulatory policy. The paper explores how these dynamics play out in the transition from an industry characterized by vertical integration, natural monopoly, and cost-of-service regulation, to one exhibiting rapidly increasing product/service differentiation, market entry, as well as competition, new technology, and the evaporation of traditional economies of scale. The paper draws from the literature on technological innovation and industry structure, and builds on the premise that the competitive structure and dynamics of an industry reflect underlying product and process technologies.

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1. INTRODUCTION

A rich body of literature and theoretical modeling has emerged during more than a decade of experience with deregulation, vertical de-integration, and the introduction of new technology in the telecommunications sector. There have also been sweeping changes in the players, the relations between them, the services offered, and the rules regulating the industry. In this paper, we examine the broad parallels between telecommunications and electricity as new technologies are introduced in the face of changing markets and changing regulation, with a particular eye toward a diverse group of electric power technologies referred to as *distributed resources.* We will argue that the competitive structure and dynamics of the electric power industry will—as in telecommunications—reflect the rapidly changing technologies on which the industry is based.

We start by examining key similarities and differences between the two industries. We then take a closer look at telecommunications developments over the last decade, focusing on technological change, the introduction of substitutes and complementary services, access pricing, and regulatory issues such as treatment of depreciation and stranded investment. We also describe emerging synergies between telecommunications and electric power, as well as some of the partnerships and joint ventures that have emerged to exploit such synergies. With this background, we then turn to the implications of these issues for business strategy and regulatory policy in the electricity sector. This is broad territory. Since in-depth treatment of the involved theoretical and policy issues is not feasible here, we concentrate on the parallels between the two industries and possible outcomes. Finally, we also suggest possibilities for further inquiry relevant to the diverse array of stakeholders with an interest in today's rapidly evolving electric power industry.

The term *distributed resources* (DR) is relatively new to the electric power industry, although many of the concepts and particular technologies coming under its rubric have existed for two decades or more. The term has emerged in response to a variety of recent trends, including:

- The introduction of new technologies that tend to eliminate the scale economies that have characterized centralized electric power generation throughout most of the twentieth century;
- Continued technological and commercial development of generation, distribution, and demand-side management (DSM) technologies;
- The advent of substantial competition in markets for wholesale electric power generation;
- The potential for *retail* competition in the provision of electricity and electrical end-use services;

- Competition-related motivations to promote functional and/or financial vertical de-integration;

- Recognition that the historical industrial structure and regulatory apparatus have created perverse incentives and accounting artifacts at odds with economic efficiency; and

- Concern for environmental externalities associated with traditional central station generation and hopes that technological alternatives can mitigate such externalities.

Technologies included in the emerging literature on DR include small-scale generation and cogeneration (for example, residential-scale fossil-fired cogenerators that simultaneously produce space and water heat), photovoltaics, fuel cells, storage devices such as flywheels and advanced battery systems, direct control of end-use appliances for the purposes of minimizing coincident peak demands, real-time pricing, and efficiency-oriented end-use DSM targeted toward service areas experiencing rapid growth or otherwise requiring expansion and/or transmission and distribution system reinforcement.

2. PARALLELS BETWEEN TELECOMMUNICATIONS AND THE ELECTRIC POWER INDUSTRY

While the technologies comprising the telecommunications industry are quite different from electric power, both industries exhibit network characteristics where economies of scale and scope combined with interconnection requirements and the need for coordination among firms and/or customers create unique pricing considerations and regulatory implications (see, for example, Katz and Shapiro 1986). Technological change has had a substantial effect on the nature of telecommunications networks; similar dynamics appear to be emerging in electric power. The effects and implications of new decentralized technologies such as cellular phones and packet-based data communications on telecommunications are likely to have instructive parallels with emerging decentralized electric power technologies. Such parallels have implications for industry structure, pricing strategies, and antitrust and regulatory issues. Both industries have been long dominated by a single, interrelated set of technologies. Both industries also present challenging issues relating to interconnection and network access pricing; and both involve bottleneck issues related to "essential facilities" (Laffont and Tirole 1994).

Given the nature of these issues, it is also distinctly possible that individual decisions in electricity and telecommunications markets will lead to suboptimal industry outcomes, since individual consumers make decisions without regard for network effects. For example, some in telecommunications fear that the simultaneous introduction of two-way broadband technologies based on cable, fiber optic, and "wireless cable" technologies will result in none of the individual technologies capturing markets sufficiently large to support their widespread development. Similarly, electric power markets in recent years have been characterized by an increased prevalence of industrial customers investing in on-site generation to meet all or part of their electricity needs. Such decisions may adversely affect the remaining customers of the electric utility because of the capital intensity of the industry and associated fixed costs, and may also affect the economics of supplying electricity at the margin.

2.1. Technological Change

Arguably the most important reason for those with an interest in electric power to examine the recent telecommunications experience stems from the role that technological change has played in each industry. To understand how technology shapes these industries, one should first consider some of the fundamental economic properties that come into play. Technological change can be continuous or discontinuous, patentable or non-patentable. It can induce cost reductions and introduce entirely new products. It can be embodied in particular inputs, or can affect the productivity of all inputs. In practice, any new technological development is likely to involve a blend of these features. Technological change and regulatory innovation can be seen as the drivers of competition in telecommunications markets (Vogelsang and Mitchell 1997).

Successful exploitation of new telecommunications technologies has created a need for new investment criteria, pricing strategies, and regulatory mechanisms in that industry, and many observers believe that similar needs are now beginning to develop in the electric power industry. In both cases, successful firms will be those capable of innovation (Tushman and Anderson 1986), effective pricing strategies, and (as changes in regulation and the entry of new participants in the marketplace result in functional and/or financial unbundling and vertical de-integration) "maintaining control over the value chain" (Florida and Kenney 1990). Electric utilities, like the regional Bell operating companies (RBOCs) of ten years ago, have not typically been organized to provide their employees with the incentives to develop process or product innovations. To successfully compete with new entrants in the marketplace, today's electric utilities will likely need to make radical changes in corporate organization and culture.

2.2. Production Functions and the Economics of Scale

Technological change alters the parameters of the firm's production function. Four characteristics that can change are 1) elasticity of substitution among inputs, 2) input intensity, 3) returns to scale, and 4) efficiency. At the simplest level, changes in the relative ease of input substitution can save resources, as has occurred in telecommunications when fiber optic transmission allows switching to be located remotely. Technological advances can also change the relationships between variable and fixed factor costs, as gas-fired combustion turbines with their lower capital costs have done in an electric power industry long dominated (at least for baseload power generation) by coal, oil, and nuclear technologies.[1] For a given input price ratio, the optimal capital-labor ratio can change. Thus, recent advances in power generation control technologies (digital control systems, real-time data acquisition, artificial intelligence-based controllers, and so on), have significantly reduced the number of personnel required to effectively operate utility-scale fossil fuel generation plants. New technology can also affect returns to scale, with associated changes in output for a given input combination.[2] Technological change can alter any of these parameters for any one firm and change the structure of the industry in which such firms operate (Berg and Tschirhart 1988).

Demand elasticity also comes into play. A relatively elastic market demand implies higher social returns to the price cut that accompanies a cost-reducing innovation. Some technological advances may create entirely new products and/or services. When substitute products and/or services alter demand elasticities, they limit the market power of entities formerly functioning as "natural" monopolies and reduce the historical justification for regulation.

Also, new production technologies may reduce scale economies, making entry feasible. As new markets are developed, more firms of minimum efficient scale can be sustained, limiting the market power of existing firms. The disruptive nature of innovation accordingly complicates the task of regulators, creating new possibilities for competition in what were formerly natural monopoly sectors. Substitutes for the products and services traditionally provided by regulated natural monopolies can now be supplied by entities not exhibiting sub-additive cost structures characteristic of natural monopoly. Such developments, as noted in the DR literature, may well change the shape of the underlying supply curve for meeting a given demand for end-use electricity services.

2.3. *Network Characteristics*

Most of the relevant similarities between telecommunications and electricity stem from the fact that both industries supply services through networks, which by their nature require coordination between and among both firms and consumers. Expectations, coordination, and compatibility exert complex influences on capital investment, technology adoption, and product selection. Issues relating to network access pricing, vertical integration and/or restraints, economies of scale, and transaction costs are important to policy determinations in both industries. The presence of network externalities (that is, benefits accruing to producers and consumers beyond

[1] The regulatory distortions associated with the Fuel Use Act of 1978, motivated by concerns about limits in the future supply of natural gas, may also have contributed to this outcome.

[2] The exhaustion of economies of scale for central station electric power generation is fundamental to the entrance of independent power producers (IPPs) using relatively small (50–300 MW) gas-fired technologies into wholesale generation markets and to recently recognized prospects for DR.

those responsible for developing the involved technologies) means that market mechanisms alone are unlikely to produce outcomes that would be optimal from a social perspective.

Both electricity and telecommunications networks also include resources that are, as *essential facilities*, bottlenecks in access to networks that make the exercise of market power possible because of large economies of scale or technological superiority. Important policy issues arise concerning the best means of inducing an efficient resource allocation with respect to how network access is accorded to potential service providers. Policies aimed at inducing efficient network access need to create proper conditions for entry into the competitive segment, while at the same time avoiding 1) unnecessary or counterproductive litigation; 2) the discouragement of potentially efficient future investments in the monopoly segment; and 3) inefficient bypass (Berg and Tschirhart 1988).

In telecommunications, it rapidly became evident that interconnection charges would play a crucial role in governing access, promoting efficiency, and preserving positive network externalities as competition developed in the local segment of the network. The same situation seems likely to develop for electricity. For example, one of the biggest issues underlying the current "PoolCo vs. bilateral" debate focuses on the need to ensure that network access provisions appropriately account for technical issues such as "loop flow," while at the same time promote the provision of electricity by the most efficient combination of existing and new power suppliers.

3. DIFFERENCES BETWEEN THE INDUSTRIES

There are, of course, also important differences between telecommunications and the electric utility industry.[3] These include diversity of products, rates of technological change, geographic boundaries, capital intensity, and externalities, as summarized in the table below.

Consider as an example the issue of "stranded investment." While the issue of existing plants and how they are affected by changes in technology and the structure of markets arises in both industries, it will likely loom larger for electric power than telecommunications. The rapid rate of technological development and cost declines in telecommunications have caused regulators to permit existing telecommunications assets to be depreciated more quickly than is the case with today's electric power technology. It should be noted, however, that AT&T only shifted to depreciation practices reflecting current technology and market conditions after deregulation, a move which contributed to write-offs of more than two billion dollars in 1985.

[3] These differences are important at this time, but several of them, such as product diversity and rates of change, are already beginning to narrow with the development of new technologies.

Distinguishing Characteristic	Telecommunications	Electric Power
Diversity of products and services	Intrinsically high. Delivery mode easily separated from content.	Traditionally low. Network only delivers homogenous kW and kWh. DSM broadens scope, but is currently limited to energy services. Information technologies will likely broaden scope substantially over time.
Rates of technological change	Rapid. Initially spawned by fiber optics/digital switching; now by new wireless technologies.	Limited to technologies and services required to meet energy service needs, but potentially accelerating with advent of distributed services.
Geographic barriers	Satellite and terrestrial wireless transmission has reduced barriers, but barriers remain for other modes.	Current industry still constrained by transmission capacity and losses. Distributed Resources (DR) may change this, but at slower pace.
Entry costs	Low for content. Relatively high for distribution (except for capacity resale) but potentially declining rapidly with advent of broadband wireless technology.	High for central station generation, with the exception of brokering/power marketing. High (if not prohibited) for T&D. Distribution entry costs could change substantially with DR.
Capital intensity	Capital costs increasingly scaled to size of potential market.	T&D costs currently dependent on assumptions that imply natural monopoly conditions. DR may reduce capital intensity and increase scalability to the extent that service needs and reliability concerns can be met on stand-alone basis, and increase labor-intensity.
Externalities	Mostly positive, associated with increased services available more broadly.	Significant negative externalities (mostly environmental) associated with existing generation technologies.

Electric power and telecommunications have differing requirements for capital intensity. To the extent that an electrical grid is still required for most customers, large-scale capital investments and complex arrangements for access, operations, and maintenance are necessary, even in an industry characterized by extensive functional or financial de-integration. Telecommunications, on the other hand, is moving to a point where the capital investments required to provide new services can in many cases be scaled to the size of the market targeted for such services, as evidenced by the current state of cellular telephony markets.

Externalities also constitute an important difference. The negative environmental externalities associated with current power generation technologies have served as a powerful impetus for regulatory intervention in decisions (often referred to as integrated resource planning) undertaken by electric utilities. Such considerations also are prominent in current discussions about electric power restructuring. In contrast, telecommunications externalities are more often positive in nature, leading to policies to subsidize consumer access in low-income and high-cost segments of the market.[4]

4. TECHNOLOGY AND THE TELECOMMUNICATIONS INDUSTRY: A CLOSER LOOK

4.1. Access Pricing

As telecommunications deregulation in the United States and the United Kingdom began to play out, it became increasingly clear that pricing for interconnection would play a fundamental role in determining the new structure of the industry. Competition in the local segments was introduced by cable companies and mobile operators who needed access to the dominant providers' local and long distance services. Determining how to charge for use of a network (access pricing), however, represents a set of difficult issues. For example, it is likely that a marginal cost-based pricing system for telecommunications access would prevent the dominant telephone operator from recovering the fixed costs of the network, as well as many of the costs that stem from meeting universal service objectives.

4.1.1. Market-Determined Access Pricing

One approach to access pricing, of course, is "leaving it to the marketplace." In other words, firms are allowed to negotiate privately but the threat of *ex post* anti-trust litigation is relied upon to prevent inappropriate pricing or access restrictions, an approach taken to telecommunications in New Zealand. The extent to which telecommunications services are considered to exhibit characteristics of public goods, however, has prompted some form of price regulation for access for tele-communications in most countries. For electricity, the public interest considerations are arguably even stronger.

4.1.2. Mandatory Divestiture

At the other regulatory extreme, access prices have been established following a mandated vertical divestiture, such as the one applied by the US Department of Jus-tice in the breakup of AT&T. While this access pricing approach may promote competition by helping establish symmetry among competitors, it may also cause a significant loss in economies of scope. This view is held by many, including some regulators and policy-makers in the electric power industry. Such a drastic approach may also fail to respond to technologically determined changes in the location or nature of network bottlenecks. Moreover, as experience in telecommunications

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[4] A notable exception is current concerns about Internet access to pornographic materials and the resulting tension between regulation of content and constitutional rights under the Fourth Amendment.

demonstrates, vertical divestiture of one carrier does not entirely solve problems with market power, since local exchange carriers supply access to the local loop to interexchange carriers with whom they will eventually compete.

4.1.3. Cost-Plus "Markup"

Outside of the United States, a third approach to access pricing in telecommunications has been to preserve the dominant, vertically integrated firm, while regulating access prices to create a level playing field and promote competition. Regulators may then establish guidelines for pricing access on the basis of long-run incremental cost plus a markup. This markup is designed to allow the dominant provider the ability to cover the "access deficits" (revenue erosion that makes it impossible to cover fixed costs associated with the existing network) that result from the market entry of new participants. In both telecommunications and electricity, total network capacity costs often change non-proportionately as the size of the network expands; this change is caused in large part by increasing returns to scale. The effect can present particularly serious problems when—as was the case in telecommunications and as now appears likely as a major issue in electric power—there are large fixed (and sunk) costs associated with historical investments.[5]

4.1.4. Broad-Based Price Caps

Another approach is the use of a "broad price cap," which sets an upper limit on the average of both access charges and final goods prices. By decentralizing price decisions, including those relative to access, such an approach allows firms (presumably with better knowledge than regulators about demand and cost structures) to implement second-best efficient (Ramsey) pricing structures, under which prices are inversely proportional to the price elasticity of demand for customers or classes of customers. Although the principles involved in price cap regulation are relatively straightforward, their application to interconnection pricing is complicated and does not lend itself easily to regulatory pricing prescription. In addition, the lack of explicit treatment for final prices raises equity concerns in situations (as is the case in electricity and telecommunications) where the economics of providing service differ significantly across customers.

Both the broad-based price cap approach and other methods (such as ECPR) are amenable to relatively rigorous theoretical modeling. These and other alternatives, however, will depend on 1) the type and intensity of competition between the former monopoly provider and new entrants requiring interconnection (that is, access); 2) the relative sizes of the firms; 3) differences in costs associated with supplying

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[5] What should comprise the markup is subject to considerable debate. The Efficient Component Pricing Rule (ECPR) would mark up incremental costs to recover the revenues foregone by the incumbent supplier (Baumol & Sidak, 1994). For the ECPR to encourage economic efficiency the incumbent's retail tariffs must be efficient. Because this condition is generally not satisfied in local telecommunications markets, a minimum proportional markup to recover common costs can increase efficiency (Mitchell & Vogelsang, 1997).

final output; 4) the strength of applicable budget constraints; and 5) the actual costs of interconnection (Mitchell et al. 1995).[6]

4.2. Auction Mechanisms

An alternative to explicit pricing as a means for allocating network access is the use of auctions. While not employed thus far for this purpose, auctions have been applied with great success for allocating portions of the frequency spectrum for commercial uses, namely communications services such as wireless telephony, data communications, and pagers. These auctions not only generated unprecedented revenues for the licensing of public assets; they also allocated resources efficiently with the rights to use portions of the frequency spectrum accorded to the firms that valued them most.

Since auctions are essentially games with specific, well-defined rules, they are amenable to rigorous quantitative analysis based on game theory (Milgrom 1996). The frequency spectrum auctions in the United States were developed on the basis of extensive theoretical analysis and mathematical simulations undertaken by expert game theoretic economists. Other frequency spectrum auctions conducted without the benefit of *ex ante* analysis, such as those in New Zealand and Australia, produced serious unintended consequences and results that were clearly suboptimal (Milgrom 1996). Thus, while auctions serve as a potentially powerful tool for allocating resources in an industry involving public goods, they must be carefully designed to avoid unintended adverse outcomes.

Auctions have been increasingly used during recent years by electric utilities for the purposes of acquiring new power supply from other producers. These auctions, known in the industry as "competitive bidding," were developed to inject a degree of competition into what was formerly an administratively determined approach to setting prices for power purchases by electric utilities from Qualifying Facilities (QFs), as mandated by the Public Utilities Regulatory Policy Act (PURPA). Subsequently, the use of the mechanism has been broadened to cover non-QF independent power suppliers (many of them utility affiliates) and vertically integrated utilities with excess capacity.

While these auctions represent an improvement over the administratively determined "avoided cost" pricing first employed for PURPA compliance, their design has not typically been based on any rigorous theory or *ex ante* simulations. As one might expect, these auctions have not infrequently been marred by gaming

[6] Hybrid approaches are also available, which combine aspects of both price cap regulation and cost-based approaches. An example would be a "banded" approach where the regulated firm is given the flexibility to price between a lower bound for access charges defined by long-run marginal costs of expanding the network and an upper bound of long-run incremental costs plus the markup that makes the incumbent financially indifferent to entry. As technology and markets evolve to become more competitive, regulatory intervention can then be gradually reduced by relaxing the bands or lengthening the time between cost-based "true-ups."

(inefficient outcomes resulting from strategic behavior on the part of bidders exploiting artifacts in the auction process) and other unintended outcomes.

Many of the "restructuring scenarios" being debated for the electricity sector involve some type of auction mechanism for buying and selling electricity and at least implicitly address network access pricing. The application of game theoretic economics and auction theory to electric power in this context has significant potential value, and in fact will be required if some of the difficulties associated with gaming and allegedly supranormal profits experienced in the UK electric power system are to be avoided.

4.3. Complementary and Value-Added Services

Changing technology requires us to examine and distinguish between those products that complement one another and those that serve as substitutes. In telecommunications there has been an enormous proliferation of *value-added services,* which often complement existing telecommunications services. This phenomenon introduces new complexities in analyzing markets where competitors' new services initially provide simple substitutes for existing telephone service. As an example, the number of cellular phones in use increased by more than 50 percent in 1994, while the number of pagers rose by almost 24 percent, despite the fact that both technologies enable mobile communications and are mostly used by the same individuals (King 1995). A simple view that widespread paging is a competitive substitute for cellular (or vice versa) would ignore the fact that (with current technology) the two products can complement one another. The same is true of long distance telephone service and the Internet. While e-mail may substitute for long distance telephone calls in certain markets, in others the need for Internet access, whether demanded by final consumers or Internet access providers, may actually increase the demand for long distance telephony. Current attempts at reforming electricity regulation must be carefully designed to acknowledge the competitive implications of substitutes but at the same time provide incentives for economically efficient complementary services.

The introduction of new technologies—wireless (including cellular), cable TV, and new types of Internet access (such as the World Wide Web)—have also led both to spin-offs from traditionally vertically integrated firms (AT&T is a recent example) and to a plethora of new joint ventures involving the integration of newer technologies with traditional telephone services, such as those between telephone companies and cable companies or between cable companies and wireless services providers. The introduction of new technology can change both the nature of the players and the structure of the industry itself, and makes considerations about both regulatory policy and business strategy considerably more complex.

Similar developments are occurring in electric power. What began with substitutes (PURPA QFs, and customer-owned generation) for vertically integrated monopoly provider services is now evolving into a broader set of complementary services involving aspects of demand-side management, real time pricing, distributed resources, and improved control over end-use electrical equipment. Like telecommunications, the electric power industry will create opportunities, risks, and new regulatory issues. The entities most likely to prosper in this environment will anticipate emerging technologies, supplement existing business expertise with partnerships and joint ventures, and formulate marketing and pricing strategies responsive to rapidly changing consumer preferences.

4.4. Competition and Vertical Restraints

Despite technological change, competition will not work equally well in all market segments of the telecommunications and electric power industries. For example, conflicts over universal service and inter-class cross-subsidization delayed passage of telecommunications reform efforts in Congress, and are likely to the largest stumbling blocks to the development of acceptable retail electricity wheeling schemes that overcome conflicts between economic efficiency and political acceptability.

Telecommunications appears well ahead of electricity with respect to the relative maturity of alternatives to price-regulated local telephone service, including cellular communication, private e-mail, personal information management (PIM) devices, and various Internet-based communications modes. In addition, competition among long distance providers, combined with the successful resolution of most network access and pricing issues pertaining to vertical transactions, has bolstered confidence in the workability of the competitive model. The increasingly competitive industry structure includes deregulated long distance services, entry of long-distance providers into local markets, and giving RBOCs the opportunity to offer long distance services when their local markets are determined to be open to competition.

Similar developments—many referred to today as distributed resources—could have powerful influences on the structure and regulatory implications for the electric power industry. The advent of relatively small-scale fuel cells or gas-fired commercial or even residential cogeneration technologies, for example, all have substantial implications for the role played by existing electric power distribution companies.

4.5. Regulatory Accounting Practices

Regulatory depreciation practices emerged as an important issue in the transformation to a competitive telecommunications industry, both in terms of recovery associated with technologically and/or economically obsolete investments, and looking forward, in terms of how such practices are likely to influence the adoption of new technologies embodied in capital equipment. Depreciation can be viewed as an intertemporal capacity cost allocation issue. Typical pricing patterns in cost-regulated industries recover investment uniformly over a prescribed asset life for the equipment. However, sometimes a shorter economic life or accelerated depreciation more nearly reflects the changing economic value of assets than historical, regulation-oriented accounting practices. Entry by firms using new technologies can drive down service prices, and the average total cost with a new technology can be less than the average variable cost of using the current equipment. Both the firm and regulator face a dilemma in this situation. With a shortened economic life, the current price is too low to allow full capital recovery; so either the price must increase to provide the cash flow (depreciation) to maintain the financial viability of the firm or the asset must be written down and the loss absorbed by shareholders.

Regulated telephone companies found themselves in this situation with customer-premises equipment whose rate-base value was greater than its economic or replacement cost value because of dramatic technological changes combined with free entry into customer terminal equipment markets. Ultimately, firms had to write off equipment that had been under-depreciated. A very similar set of circumstances is now arising in efforts to restructure the electric power industry, where stranded investments in existing generation plants loom as the largest and most contentious issue.

5. IMPLICATIONS OF TECHNOLOGICAL CHANGES FOR ELECTRIC POWER BUSINESS STRATEGIES

5.1. Pricing and Service

In the presence of technological change and impending industry restructuring it will be imperative for electric utilities to develop differentiated pricing structures and tailored, complementary service packages. In telecommunications such strategies have been central to a firm's success and indeed survival. They will be similarly important for electric utilities. Such developments, of course, give rise to the same difficult issues relating to the accounting and/or structural separation, interconnection, and cross-subsidy issues discussed elsewhere in this paper.

There is already considerable evidence of such activities in the electric power industry, including 1) new service offerings to an electric utility's currently franchised customers; and 2) the emergence of energy service companies (ESCOs). ESCOs, interestingly, are mostly owned by existing electric utility and natural-gas-related holding companies, which are trying to establish an early foothold in new markets in the United States and abroad. Such service offerings are likely to increase dramatically with the advent of widespread retail competition, which most observers view to be imminent. As an example of such activities, consider the following promotion excerpted from UtiliCorp's Energy One World Wide Web home page:[7]

> EnergyOne (SM) is a powerful portfolio of high-quality energy products and services from UtiliCorp United, a company that has been in the energy business since 1917. With Ener-

[7] The EnergyOne worldwide web site is *http://www.UtiliCorp.com/aboute1.htm*

gyOne, UtiliCorp United has become the single source for all energy solutions for homes, businesses and industries across the nation and around the globe.

Deregulation is introducing competition into the gas and electric industries, increasing customer choices and making it easier and less expensive to obtain energy. EnergyOne simplifies those choices with a full range of cost-effective energy solutions.

As in telecommunications, new competitive pressures in electricity markets, whether driven by technology or regulatory changes, will create opportunities for new source offerings and pricing packages. Traditionally, utilities have focused on delivering electricity of uniform reliability to all customers, with prices largely determined by the average embedded costs of serving those customers. In a world of retail competition and customer choice, successful firms will develop service and pricing packages that respond to a wide variety of preferences and values. A customer whose business focuses on semiconductor fabrication, for example, may willingly pay a premium for uninterruptible power. Other electricity customers, by contrast, might accept lower levels of reliability than that traditionally provided by electric utilities, in exchange for more attractive pricing.

New technologies for providing uninterruptible power are rapidly expanding, and include advanced batteries, flywheels, and superconductor-based storage devices. Utilities will need to embrace such technologies if they are to effectively respond to customer preferences; otherwise new market entrants will serve these demands. The opportunities in this area are evidenced by the wide array of recently established partnerships and joint ventures between utilities and firms developing advanced storage technologies.

Customers who are especially price conscious may be willing to gamble on their ability to line up their own electric power supplies, accepting the attendant risks in exchange for the opportunity to reduce electricity costs. Many customers, however, will likely not want to take such risks or will want to be actively involved in the electricity business. Such customers might wish to enter into long-term contracts that would meet their electrical needs (or all energy needs) at a known price. There are opportunities here for electric utilities or other energy service providers to combine skills in providing power with those focusing on end-use equipment. This approach would involve packaging an optimal combination of power supply, control technologies, and improvements in end-use efficiency.

5.2. The Role of Emerging Technologies

The fundamental question underlying forecasts of technology-based changes in industry structure, of course, is the extent to which such technologies can penetrate key markets. Over the next decade, market penetration for advanced technologies will be driven by a combination of 1) changes in service, quality, and reliability; 2) trends in traditional utility capital and operating costs; and 3) the effects of market structure and regulation on pricing practices. The players will be influenced by a variety of factors, including entry conditions, regulatory practices, and the roles utilities themselves choose to take with respect to new technologies. Thus, technological change represents both threats and opportunities to today's utilities.

5.2.1. Distributed Technologies

Many distributed electric power technologies have been thought to possess far-reaching potential. Often motivated by environmental considerations and/or so-called "small is beautiful" ideology, industry experience in the 1970s and early 1980s demonstrated that many of these technologies were either too costly or too burdened with practical difficulties to reach commercialization on a broad scale. Indeed, in many cases, developmental activity withered once significant government or utility subsidies were removed. The situation can be summed up somewhat cynically with the phrase, "ten years away for the last thirty years." However, recent advances in technology—much of it deriving from computer-optimized design and manufacturing practices—have begun to bear more promising fruit. Some of the gains have been realized as a result of R&D investments in other industries. For example, General Motors' Allison Division recently reported development of an all-polymer fuel cell with expected costs that compare favorably with even low-priced electric utility rates. While its development was motivated by potential demands in the automotive market, there is no inherent reason the technology cannot be employed in modular fashion at fixed locations, and several electric utilities have recently announced partnerships or strategic alliances with firms developing commercial fuel cell technologies. Similarly, other automotive R&D investments have led to residential- and commercial-scale storage flywheels expected to yield cost-effective applications for electricity storage before the end of the decade.

To the extent that emerging technologies offer the potential to reduce costs and increase earnings, shareholders will have the incentives to invest in them much as shareholders of telecommunications or manufacturing firms have an interest in exploiting cost-cutting technological advances, such as broad-based two-way telecommunications capacity or new automated manufacturing equipment. Similarly, to the extent that emerging technologies have implications for the way the electricity production and delivery process is structured, utilities—however constituted—may find it in their interests to design the electricity production process around the technology, rather than "shoehorning" the technology into existing processes (Awerbuch 1992; Hammer 1990).

At the same time, however, there remain substantial obstacles to fully exploiting the most significant new electric power technologies, even in the face of high potential value. It is extremely difficult, for example, to develop planning processes that address the potential for fundamentally different technologies without having a clear idea of what roles utilities will play vis-à-vis other entities in the industry. In the United Kingdom, electricity is now vertically de-integrated, with a generating pool and a spot market to determine generation prices. Such a structure clearly serves as a barrier to entry for certain DR technologies, namely small-scale generation unable to compete with the short-run marginal costs associated with the existing duopolistic structure of the power supply part of the industry.[8]

5.2.2. Exploiting Complementarities

Another way to view DR is as a bundle of technologies offering complementary benefits among multiple production processes, including power generation. Several utilities are now entering partnerships or joint alliances with DR providers using technologies that include fuel cells, advanced storage devices (batteries, flywheels, and superconductors), and remote equipment control. As we discuss below, control strategies for end-use electric equipment creates additional opportunities for non-electricity information services, all of which form a rich set of commercial opportunities allowing firms to exploit complementary benefits (Milgrom and Roberts 1990).

As is frequently the case with new technology, recognition (let alone quantification) of such benefits is made difficult by existing accounting mechanisms, organizational practices, and production constraints (e.g., Awerbuch 1992). The situation is made even more difficult by the history of vertically integrated utilities as monopolies with exclusive service territories and cost-of-service ratemaking. The traditional accounting framework used by these utilities is determined almost entirely by regulatory reporting requirements; it cannot provide electric utility decision-makers the information needed to understand the key drivers of production costs.

5.2.3. Other Accounting and Capital Budgeting Issues

Finally, there remains the reality that some emerging electric power technologies, while offering substantial promise, may cost more in the near term than conventional technologies, particularly in the presence of short-term capacity surpluses and substantially depreciated existing plants. How these issues play out will depend on the nature of the restructuring described earlier. There is also the issue of potential bypass associated with such technologies, should they not be promoted by utilities. There may be some instructive lessons here from telecommunications, where consumers have been surprisingly willing to pay a price premium for technology (such as the 18" antenna satellite television receiver introduced in 1994) simply because it offers an alternative that frees them from an existing cable television network. The growth in satellite video distribution has exceeded even the most optimistic market forecasts, even in areas with wired cable service (King 1995).

One dynamic that could contribute to DR adoption lies in the inherent price volatility associated with energy input factors for traditional electricity generation (Baldwin and Clark 1992). A desire to reduce the risks associated with changes in electricity prices could promote DR adoption on the part of end users and distribu-

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[8] The structure consists of two privatized generating companies with fossil-fired generation and a remaining quasi-state entity comprised of existing nuclear plants. Generation below one megawatt (MW), however, is treated as outside the pool, thus allowing possibilities for a subset of generating facilities for R&D support and system optimization.

tion companies. The latter, freed of concerns about amortizing fixed generation costs, could well have an interest in promoting DSM if it reduced price or demand volatility, especially if this action were profitable. The same applies to on-site generation. Both "market-driven" DSM and the provision of on-site generation, however, represent new business modes to electric utilities, in much the way that value-added services were new to RBOCs accustomed to functioning as regulated monopolies providing commodity telephone service.

It is essential, therefore, that utilities successfully respond to technological change. Utterback and Suarez (1993) describe technological change in seven industries (typewriters, automobiles, television sets and picture tubes, transistors, integrated circuits, calculators, and supercomputers) over the past century, and conclude that a firm's major source of failure is its inability to change its organizational structure and practices along with the evolution of technology in the industry.

6. TELECOMMUNICATIONS/ELECTRIC POWER SYNERGIES

The development of new services in telecommunications and electricity is creating the possibility of substantial synergies between the two industries, leading to several joint ventures and strategic alliances between electric utilities and telecommunications firms.

There has yet to emerge, however, a clear model for capturing the mutual benefits from associating electricity and telecommunications. By and large, electric utilities are well-positioned to play a role in meeting new telecommunications needs and opportunities because of their financial resources and the economic gains that are possible with more highly differentiated pricing structures and automated control of electrical equipment. Electric utilities also possess ample legal authority to build telecommunications facilities relevant to their charter to provide electricity services. Legal charters and legislatively granted rights of way endow electric utilities the authority to build such facilities; and many have already done so for purposes of system control and, in some cases, direct control of end-use electrical equipment.

What is new, however, is the emergence of incentives for using broad-based, switched telecommunications to realize efficiency gains in the planning and operation of electric power systems. For example, both Entergy and Central and Southwest Corporations are building two-way fiber coaxial broad-based networks using First Pacific Networks' processing "fully-distributed digital switch." This investment opportunity arises from competitive advantages associated with combining enhanced energy services with possibilities for deferring otherwise needed distribution, transmission, and generation expenditures.[9]

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[9] Major telecommunications players are also entering this market. IBM has formed a partnership with Tampa Electric, while Public Service Gas and Electric and Louisiana Gas and Electric (LG&E) have en-

In a parallel development, Novell, Inc., the leading computer network company, has joined forces with UtiliCorp to piggyback information signals onto conventional power lines, so they can be read and transmitted from homes and businesses. If this technology (tentatively named *Powerline*) performs consistently with laboratory tests (suggesting transfer capabilities greater than two megabits of information over power lines), the possibilities for transporting interactive video and other broadband information services will be close at hand (Schuler 1995). Moreover, new compression technologies suggest that overcoming that threshold is feasible in the near term. The initial focus of such applications, however, is on energy-related services, providing customers with the ability to automate key services such as lighting, space conditioning, and security systems, as well as giving them information on energy usage.

Published analyses suggest such strategies yield significant economic gains: e.g., Entergy estimates it can avoid $1.70 in 20-year power supply costs for each dollar it invests in broadband telecommunications infrastructure through improved provision of 1) real-time pricing information to electricity customers, and 2) direct control over devices such as water heating, air conditioning, and pool pumps that have the technical potential to be operated in response to electric power system demand conditions with no loss in consumer amenity value (Rivkin 1995).

While these considerations are important, they don't account for 1) the greatly increased need for electric utility related communications associated with practically any retail wheeling scenario; or 2) the potential for arm's-length contracting practices combined with new statutes that would provide electric utilities a role in furthering universal access objectives for telecommunications.

It is likely that the transformation now underway in electric power will reinforce needs for real-time information flows to and from customers, even those who find their own supply sources. It will not be merely DSM that will motivate electric utilities to implement broadband two-way communications but supply transmission and distribution system management as well. Recent developments in DR technologies will likely accelerate integration of the industries, quite possibly in ways that are both novel and significant.

For the technical, economic, and social potential of these intrinsic synergies to be realized, a number of difficult issues must be resolved. While one fiber optic cable may have sufficient capacity to carry all foreseeable services for a single customer, the issues concerning competition will not be easily resolved, especially as they affect failed attempts by electric utilities to enter telecommunications markets. Even if

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tered into alliances with AT&T and a variety of smaller vendors (with several additional partners) to deploy two-way broadband network communications for upwards of 500,000 residential customers during the coming decade. LG&E also has signed a 40–year agreement with TKR Cable of greater Louisville to enable new services from both companies. LG&E's conduit and pole space will be used for TKR's fiber optic cable; while LG&E has rights to specific bandwidth on the cable system for monitoring and controlling electric and distribution systems and providing customers with information and automated energy services. Pacific Gas and Electric Company recently invested $6.2 million into a 1,000 home energy services trial with Tele-Communications, Inc. (TCI) to take advantage of similar opportunities (King 1995).

vertical de-integration in electric power is widespread, the absence of workable safeguards could allow regulated distribution companies to pass costs associated with failed telecommunications ventures on to captive ratepayers.

7. IMPLICATIONS FOR ELECTRIC POWER REGULATORY POLICY

Technological change in partially regulated industries characterized by network economics and essential facilities poses important challenges to regulatory policy. As described above, the disruptive nature of technological change can permit firms to enter markets that have been dominated by natural monopolies. This has clearly been the case in telecommunications, is very much the case with wholesale electricity, and is likely to emerge for retail electricity and electrical services as well.

Similarly, the likely reactions of regulators to the availability of new technologies strongly influence decision-making by current suppliers. For example, regulatory policies that preclude full recovery of depreciated book values for obsolete assets provide significant disincentives for firms seeking to adopt innovative technologies embodied in new capital equipment; such policies may therefore serve to further increase technological obsolescence. This is especially true in electric power, where embedded costs associated with generating assets generally represent a substantial part of a utility's total capitalization. While much of the debate on stranded investment in electric power has focused on fairness to shareholders and the obligation to honor the *regulatory compact* under which investments in existing capital equipment were made, these influences on technology adoption are critical to any debate concerning industry restructuring and alternative regulatory regimes.

One of the primary questions facing regulators is how to structure incentives to enable firms to take best advantage of scientific and technological opportunities. In the classical rate-base regulatory model the utility's reward structure is asymmetrical: a poor decision (*ex post*) is punished (through denial of full cost recovery), but a good decision (for example, one that reduces cost) is not rewarded.[10] Telecommunications regulators have widely adopted price cap rules that explicitly introduce such incentives; similar initiatives in the electric power industry are being explored and/or introduced under the umbrella term *performance-based regulation* (PBR) in several regulatory jurisdictions around the country.

Most observers agree that some form of PBR is likely to be applied to monopoly functions such as transmission and distribution. Several PBR systems have been in place in the US for decades as manifested in specific regulatory arrangements between public utility commissions and electric utilities for particular performance attributes such as power plant availability factors. More recently PBRs have been designed and implemented more comprehensively, focusing on most or all regulated

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[10] In practice, the existence of regulatory lag introduces some incentives that reward shareholders for decisions that result in cost reduction.

operations. The California Public Utilities Commission, for example, approved San Diego Gas & Electric's July 1994 request for a broad-based PBR which gives SDG&E the flexibility to lower rates and counter potential bypass and ties earnings to the utility's ability to lower costs relative to predetermined cost indices. Such PBR systems are either variants of the classic RPI-X price cap regulation[11] that has been widely applied in telecommunications, or involve tying revenues and/or rates of return to specific performance measures relative to historical levels or cost indices.

For electric power, it is this systematic onus for minimizing costs—whether induced by PBR, retail competition, or both—that creates incentives favorable to a broad array of emerging technologies. For example, site-specific efforts to improve efficiency can defer needed T&D investments, thus improving earnings. The same incentives apply for a comprehensive retail competition scenario.

Pricing and other conditions for access to electric power transmission and distribution networks, however, are likely to remain both contentious and technically difficult, as has been the case in telecommunications. As discussed, regulatory policy can address access pricing in a variety of ways, including cost-based approaches, recovery of incumbents' opportunity costs, or leaving determination of access charges to the provider's own assessment of relevant costs and market conditions.[12]

8. CONCLUSIONS

Many of the important parallels between telecommunications and electricity have not received extensive attention in the academic economics literature or the energy policy community. These parallels suggest the current debate on regulatory reform and industry restructuring for electric power can benefit from the relatively rich body of literature and theoretical modeling that exists as a result of more than a decade of experience with deregulation, vertical de-integration, and the development of new technology serving both as substitutes for and complements to traditional telephony.

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[11] Such regulatory approaches typically entail freezing prices at current levels, allowing adjustments only in response to predetermined indices reflecting factors beyond the control of the regulated entity.

[12] Relying on the threat of *ex post* antitrust enforcement and/or litigation as a deterrent to the inappropriate exercise of market power.

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DISCUSSION

Shepherd, *Monopoly and Antitrust Policies in Network-Based Markets such as Electricity,*

AND

Oren and Ray, *Services in an Unbundled and Open Electric Services Marketplace*

AND

Mitchell and Spinney, *Technological Change and the Electric Power Industry*

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DISCUSSION

Though the three preceding papers address quite different topics, all three contain a similar theme—that market power can be used by dominant companies to game the system to the disadvantage of new entrants and small players. This is particularly critical for new and distributed technologies which tend to not be associated with the dominant players in the electric supply sector. In these papers, there was little mention of how to mitigate or avoid market power problems. Therefore, rather than critiquing what the authors have already written (which is quite good), this paper will focus on what was left out—who has the responsibility to deal with these issues in the real world, and what are the practical implications of market power for technological change and innovation?

CREATING AND MAINTAINING COMPETITIVE ELECTRICITY MARKETS

Restructuring the electric industry and maintaining competitive markets is a multijurisdictional task. Unlike gas deregulation where the Federal Energy Regulatory Commission (FERC) had the central role or telecommunications where the Federal Communications Commission played the major role, in electricity restructuring the state utility regulators and legislators hold a key position along with the FERC in plotting the future course of the industry.[1]

The FERC and state regulators have recently been depicted as being in jurisdictional competition with each other. But in fact, though some areas of responsibility overlap, there are distinct differences in both their responsibilities and their expertise. Moreover, their market concerns tend to have a different focus. FERC is concerned with the effectiveness of the US electric system to support interstate commerce: the economic efficiency of electricity transmission and auxiliary services, network reliability and quality, and fairness among similarly situated competitors. State regulators are concerned about the quality and cost of electric services to retail customers: customer rates and tariffs, network reliability and quality, quality of service, risk mitigation, environmental impacts of electric services, fairness to customers and among customer classes.

The Role of FERC

The FERC performs a number of tasks related to market power and antitrust in a restructured electric industry.

- FERC (in conjunction with state regulators) approves mergers and acquisitions;
- Establishes the rules for wholesale competition (open access transmission rules and comparability of transmission pricing,approval of wholesale tariffs, reserving transmission capacity and relieving constraints, and principles governing Independent System Operators);

[1] The U.S. Department of Justice and anti-trust laws in general are not discussed in this paper since the focus is on prevention of anti-competitive behaviors rather than punishment.

- Defines ancillary services which must be provided as part of open access transmission tariffs, and approves the prices of those services;

- Approves regional transmission groups and to some extent through the RTG process and review of mergers and acquisitions, they could potentially redefine regional markets.

In addition, FERC could, through its merger approval responsibilities, prevent reconsolidation (as we are seeing in the telecommunications industry) and monitor power pool rules of participation and codes of conduct to protect against systematic discrimination, market power abuses and anti-trust behaviors. The extent to which FERC will undertake these tasks is not entirely clear though their inquiry into the "modernization" of the Commission's approach to mergers indicates their willingness to further explore the area (See Hoecker, 1996).

Though federal regulators have the jurisdiction and opportunity to monitor and mitigate undue use of market power, practically speaking they are unlikely to have the staff, resources or time to monitor, review and remedy the myriad of opportunities and cases of electric industry market abuse that are likely to arise over the next decade. At best, they can set standards of conduct and bring action against prominent offenders. FERC is the most effective agency to monitor mergers and acquisitions, to look at competition across state borders and to ensure that regional rules of participation and codes of conduct are appropriately written and exercised to encourage broad competition. But the bulk of the oversight of industry activities and practices will most likely fall on the shoulders of state utility regulators or no one at all.

The Role of State Regulators

State legislators make changes to a state's public utilities codes and set the context and direction within which new industry structures and rules will be crafted. State regulators, if proactive may direct those changes and have the responsibility to implement those changes and oversee the industry to protect the public's interests. State regulators are really at the center of restructuring activities. A state's investor owned electric utilities are unlikely to undergo any significant changes in their industrial organization or regulation without active participation by state regulators. Given that both the structure of the electric industry institutions as well as their codes of conduct, rules of participation and service have an influence on the ability of incumbent or dominant firms to exert market power, the first line of defense in avoiding abusive market practices lies at the feet of state regulators. State regulators have a number of responsibilities which provide opportunities for dealing with market power problems.[2] These include:

- Approval of mergers (in conjunction with the FERC);
- Establishment or approval of the functional structures that will govern participation in new electricity sector markets (generation, transmission, distribution);
- Influence over the design of wholesale market rules recommended by utilities under their jurisdiction;
- Establishment or approval of the rules for retail competition in their state;
- Regulation of retail cost recovery (or the rules so governing);
- Authority over the unbundling and pricing of distribution services;
- Control over the discretionary actions of monopoly utilities during the transition to a more competitive market;
- Development of consumer protection mechanisms.[3]

If one of the key issues (according to Shepherd) is to avoid removing regulation too soon before a workable market has been established, then state utility regulators and legislators are the ones who must assume most of that responsibility. If in the unbundling of electric services a key issue (according to Oren and Ray) is to avoid allocating costs in a way that disadvantages other competitors and small customers, then state utility regulators are the key decision-makers in this task. If a major issue of technological change (according to Mitchell and Spinney) is to avoid or overcome barriers to new entrants particularly those embedded in existing accounting, organizational practices, and production constraints, then state regulators again have a major role to play. State utility regulators are the ones who can insist that new accounting and organizational practices are put into place that are technology neutral and, possibly even favorable to innovation and the entry of new products.

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[2] Shepherd's paper, Table 2—Nineteen Categories of Market Imperfections, Table 4—Common Causes of Entry Barriers particularly Section II. Endogenous Causes: Voluntary and Strategic Sources of Barriers.

[3] The area of consumer protection is one that can be assumed by either state utility regulatory commissions, attorneys general, or the legislature. This is a critical new area of concern for the electricity sector. It is not an area in which most state regulators have been active in the past but where they could play an important role in the future.

The Role of the United States Department of Justice

The role of the US Department of Justice (DoJ) in electricity market power issues is quite different from either that of the FERC or the states and for the purposes of this paper, somewhat less interesting. While the role of the FERC and states vis-a-vis market power is primarily preventative, the role of the DoJ is primarily punitive. Their role is to prosecute offenders and enforce federal anti-trust statutes. The FERC and the states have a broader public interest than does the DoJ. They must be concerned whether the public at large is being harmed by such practices as well as the harm that might be experienced by other competitors.

NEW TECHNOLOGIES AND MARKET POWER ISSUES

Innovation is critical to a healthy economy. Activities and rules that reduce competition and the ability of customers to purchase the products and services they desire are the antithesis of innovation. New technologies are particularly vulnerable to market barriers caused or exacerbated by market dominance and tight-oligopoly conditions. The reasons for this are as follows:

- New technologies (particularly distributed generation technologies) are not generally favored by incumbents;

- Manufacturers and developers of innovative technologies are usually smaller entrepreneurs and new market entrants;

- Innovative technologies in the electric industry frequently have different characteristics (e.g. intermittent, modular, distributed, economies of manufacturing rather than scale of construction) and are not easily accommodated by traditional accounting and operational practices;

- New technologies are particularly susceptible to discretionary actions by incumbent firms (See Shepherd, Table 4.II);

- Innovative supply and demand reduction technologies are primarily favored by smaller customers. This brings into play other barriers such as: i) high transactions costs relative to small power consumption; ii) who and how to aggregate small customers in order to offer a range of attractive services; iii) customer loyalty or malaise; iv) allocation of unbundled distribution costs among small and large customers; v) the difficulty of small customers influencing the mix of resources available in the marketplace;[4] and vi) a lack of accurate information as a basis for informed customer decisions;

- Because new, modular generation technologies tend to be very capital intensive, financing for innovative technologies in a volatile and uncertain marketplace will be very difficult.

If there is excess generating capacity (as is the case in much of the country today), new technologies cannot compete unless: i) the new technology is incredibly cheap; ii) the existing technology is very expensive; or iii) some regulation or legislation causes the economics to change. Firms that own or control existing generation facilities can use their position to block entry by new technologies.

Stranded cost recovery compounds this problem to the extent it allows very expensive generation technologies to compete at low or no cost (since recovery is provided through high customer charges), thus discouraging competition by new entrants. This situation is exacerbated when capital recovery for improvement and operation of old plants is permitted on a going-forward basis. Finally, non-cost justified stand-by rates and demand charges can be used to discourage self-generation particularly during the period of transition if an incumbent firm is able to exercise discretionary actions with insufficient oversight.

CONCLUSIONS

As can be seen from this brief discussion, state and federal regulators have a number of opportunities and tools at their disposal for shaping the new competitive electric industry in a manner that can mitigate or avoid many of the predictable market power problems. What is required is the interest in understanding the anti-competitive behaviors most likely to emerge in the electricity sector and the foresight to put into place the structures and rules appropriate to avoiding or mitigating these problems.

There needs to be developed a "no regrets" strategy that allows state regulators to maintain sufficient control over the reformed industry to correct problems (particularly anti-competitive behaviors) when they arise. At the same time, reformed state regulation needs to remain sufficiently flexible that it does not encumber the market where it is working well. This may not be easy, but it is necessary if the public is to receive benefits from a restructured electric industry as promised. It is also necessary if the U.S. electric industry is to foster innovation and maintain its global position of technical and institutional leadership.

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[4] For example, though numerous public opinion polls indicate residential and small commercial electric customers overwhelmingly prefer purchasing power generated by renewable facilities, to the extent these customers remain captives served through a one-size-fits-all resource mix, that renewables preference may not be translated into a demand for renewables in the generation supply market.

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Part VI

Network Architecture and Standardization

12

INTERCONNECTED SYSTEM OPERATIONS AND EXPANSION PLANNING IN A CHANGING INDUSTRY: COORDINATION VS. COMPETITION

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ABSTRACT

A new framework for the operations and expansion of the electric power industry would integrate technical and economic objectives under competition into a reliable, real-time, near-optimal industry. Proper integration of existing assets into the

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framework and valuation of the services that they provide to the system, could greatly reduce the problem of stranded assets. The achieved optimality depends on the type of economic and technical feedbacks in real time.

CRITICAL ROLE OF COMPUTERS, CONTROLS AND COMMUNICATIONS FOR EFFICIENT ENERGY MANAGEMENT

High technologies, such as computers, controls and communications (the 3C technologies) will play a critical role in enabling generation and the transmission grid to function flexibly. They will:

1. Allow more efficient use of existing resources in a changing industry.

2. Facilitate the evolution of future system structures that are economically efficient and reliable.

Utilization of these technologies may have a direct impact on stranded costs. In fact, real stranded cost could be significantly lower than typically quoted figures if existing generation resources are used efficiently as new generation is added. Utilities will play a crucial role in promoting the efficient use of existing resources. They should be encouraged—through economic incentives—to use these technologies. This is needed because they have no current regulatory incentives to be efficient.

The efficiency of a network-based electric power market depends on:

1. The technical constraints of the network that prevent profit driven supply and demand forces from functions as they would in normal markets.

   Standard supply/demand principles must be applied judiciously in the case of network-based products and services such as electricity since system constraints can impede normal market functioning. For example, insufficient transmission capacity can create what Mark Reeder [in this volume] calls "load pockets," areas where network-based competition fails.

2. Application of 3C technologies that facilitate the most flexible management of supply—whose value generally changes as a function of location and time of use—in order to ensure reliable and economically efficient operation of the entire system.

We must assess the efficiency attainable in using system-wide resources, taking into account both the dependence on the characteristics of the network and the applications of the 3C technologies.

In revisiting the basic objectives of operating an electric power network, we recognize that the power system shares a common objective with industries without network externalities, which is to provide sufficient supply to meet the given demand. To meet this objective, industries utilize various mechanisms, such as bilateral agreements, futures markets, spot markets, and instant markets. Numerous economic studies have dealt with aspects of these markets, such as concentration of market power in competitive industries, or stranded cost of industries in transition. All the theory developed for those industries is directly applicable to a power industry in transition.

The story, however, does not end here, because, unlike other industries, the regulated electric power industry has an explicit obligation to meet demand fully as it changes. This obligation is imposed not only by regulation but also by the technical features of power network design, which requires that generation and demand balance on an almost instantaneous basis in order for the AC (alternating current) power system to remain intact.

The cost of uninterrupted, reliable power supply is, at present, the bundled cost associated with this requirement to balance the transmission system at each network node over various time scales, ranging from seconds through minutes and hours. Service of the same quality must be provided for at least 10 minutes following an unexpected event, such as large generator or transmission line outage.

The role of a transmission network in providing such service is essential, in both normal and emergency conditions, when such unexpected events take place. Under normal conditions, the transmission network distributes large blocks of the least expensive generation to many geographically distant locations. Under emergency conditions, the same network must deliver the power to the right locations at any cost. Some of the power used for emergencies is too expensive for meeting demand under normal conditions. Given the fact that the present network has neither storage nor direct switches for controlling power flows through specific paths, the economically efficient management of energy is particularly challenging.

In order to provide for an efficient operation of a power network in a changing industry, one must develop economic incentives for the utilization of various high technologies that provide considerable flexibility in managing available supply in response to time-varying demand. Moreover, it is possible to use high technologies as catalysts for evolution of the system into a sufficiently adaptive form that is capable of providing unbundled (price-and product-quality responsive) service at high system-wide efficiency.

We view this lack of incentive for the application of technologies as a particularly relevant problem which is widely ignored in the present debate. As a result, one quickly realizes that the role of the potentially highly effective technologies is not well understood, in terms of either their contribution to the reliability and dynamic efficiency of the overall system, or their economic values.[1]

[1] In the restructuring debate much emphasis is on the high technology and sustainable energy supply. We point out that, in particular during the transition from a fully regulated industry, even more important is the role of technologies generally referred to as 3C.

When the telecommunications industry underwent restructuring, the stock markets applauded the change. When the recent California debate indicated that power industry was about to restructure, just the opposite occurred; the stocks of the California electric utilities dropped. Compared to the situation in the telecommunications industry, the electric power industry approaches transition with two strikes against it:

1. Total installed generation in the United States exceeds total demand, and demand is predicted to grow slowly. This situation implies significant total stranded cost.

2. The power sector has, traditionally, been viewed as a sector unaffected by high technologies, in comparison to many information-intensive industries, such as telecommunications. The restructuring of telecommunication industry allows a utility-type industry to evolve into one that gains from new technological innovations as it deregulates. Very few people, however, consider the benefits available from applying high technologies to the power industry.

We believe that application of 3C high technologies could play a significant role in reducing excess/stranded generation cost in this country. Moreover, these technologies, when properly used and valued, could be the most effective catalysts for transforming an industry in transition into the industry we all wish to have, eventually. Our principal point can be summarized as follows: *there are significant savings to be realized from using many of the existing supply resources during the transition, instead of abandoning them prematurely. In particular, we argue that the typically quoted estimate of stranded cost will prove excessive, provided the 3C technologies are brought into play in a meaningful way. Doing so requires careful integration of technical processes and economic incentives.*

Unfortunately, because of the unique nature of this network-based industry, we can show that if one relies only on basic "supply/demand" market forces, the system may never evolve into a dynamically efficient and reliable system. This claim is based on the observation that in a network based industry, without storage and transmission line switches, network constraints to "supply/demand" competition become externalities which can drastically change the dynamics of evolving economic processes. The following discussion illustrates the point, without providing rigorous proof.

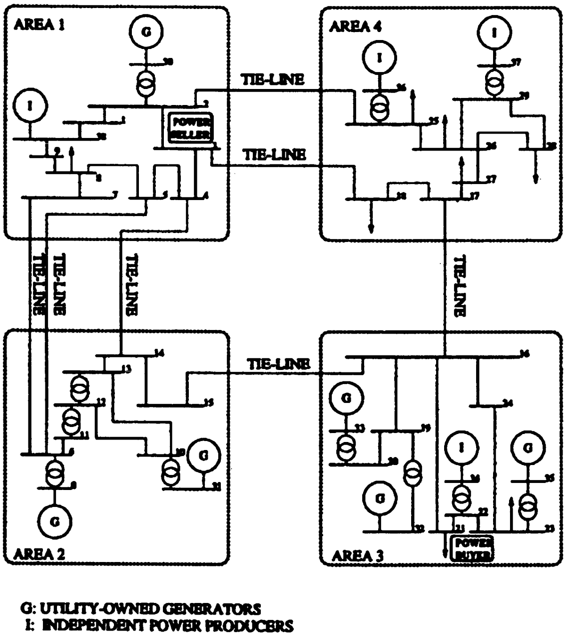
Typical Scenario for Assessing the Role of High Technology in Evaluating Stranded Cost

First, we observe that energy prices vary significantly across the United States, ranging from almost 2 cents/kWh through 13 cents/kWh. However, these differences are only apparent across vast geographical areas. The generation/demand mismatch (stranded cost) within individual states, utilities, control areas, or power pools is a function of the installed generation, its cost and demand. Some states have more stranded cost, as measured at the individual state level, than others. The energy prices reflect bundled costs/values of generation and do not reflect i) The dependence of generation value on its location, and ii) the dependence of generation value on time of use.

Role of Existing Generation in Dealing with Transmission Congestion

A typical scenario of the system discussed is shown in Figure 1. One could think of this figure as a conceptual sketch of the Eastern United States, consisting of horizontally structured control areas (pools, utilities, etc.)

Figure 1. The Nested Hierarchy Structure.



The generation/demand pattern on such a large system is presently not close to the profile which could be obtained on the basis of an economic dispatch computed for the entire system. In other words, while pools within this large area routinely perform economic dispatch for their own generation, the power exchange within neighboring pools is not optimized. Furthermore, if such dispatch were performed, and an attempt were made to dispatch optimally, it is likely that this most attractive supply/demand pattern would not be feasible because of the congestion on some critical transmission paths. That, in turn, would require use of less efficient generation to supply the most attractive economic transactions. It is possible that some generating units considered stranded because of their relatively high operating costs, may provide very cost effective means for relieving congestion; while too expensive to be used for most economic generation when no system constraints exist, the value of this generation for eliminating transmission congestion may be critical.

In sum, in order to meet existing demand patterns efficiently by using currently installed generation, two analyses are needed to identify inefficiencies that can be eliminated without building new generation. These are:

- (i) Perform an unconstrained economic dispatch for very large geographical areas, such as the eastern US. This produces the generation profiles needed to supply total demand.

- (ii) Perform a constrained economic dispatch that reflects thermal constraints on transmission lines.

The difference between the total operating costs developed in end case is the stranded generation cost due to transmission constraints. These stranded costs could be minimized either by using 3C technologies to eliminate technical problems, or by using existing generation that is less economically attractive to facilitate the economic transactions of most interest.

The most efficient use of existing generation occurs when the generation/demand pattern obtained from unconstrained economic dispatch is feasible. The results of this calculation should be used to analyze the large estimate of unused generation. But, if this generation/demand pattern is not feasible because of the transmission constraints, an estimate should be made of the best locations and capital cost needed to enhance the existing grid. A trade-off between the transmission grid/generation enhancement, on one hand, and operating less efficient patterns of supply, on the other hand, should be assessed.

We are not aware that any study of this sort has been undertaken to assess, realistically, the stranded cost in the eastern US. High technology computer algorithms—which are relatively simple in concept although computationally intensive—can estimate, realistically, the inefficiencies across large geographical areas.

Note: The complexity of operating constraints is much more involved; the example of thermal constraints is an obvious illustration that is easy to follow without getting into the details of power systems operation. For details of this, see [Ilić, et al, August 1996]. It is essential to understand that, in the eastern US, however, the typical obstacles to the most economic use of available generation have been voltage-related; this required the use of oil-fired units which are economically unattractive. We cannot overemphasize this fact: expensive oil-fired units are *not stranded* as long as no other generation is available for meeting demand at locations where because of voltage-related problems market is infeasible or impractical to transfer inexpensive generation. Portions of the transmission system have been enhanced over the past several years to partially eliminate voltage-related transfer problems. The complexity of the issue is striking when one looks more closely into the process that has taken place. Because, at present, no standardized performance for voltage regulation in an interconnected system is adopted, individual utilities have added equipment (particularly capacitor support on the primarily inductive transmission grid) to "move" the voltage problem from their area to someone else's area!

The voltage-related operating constraints experienced in the recent past should not only teach us about the value and cost-allocation problems related to the transmission network, but also about the need to apply high technologies to facilitate economic use of power over vast electrical distances.

Role of Existing Generation in Regulating System-Wide Frequency in Response to Non-Compliance with Scheduled Transactions

At present, large interconnected power grids are divided according to control areas. These are responsible for automatic correction of any generation/demand mismatch in their specific jurisdictions in order to keep the average frequency in the area close to nominal, while at the same time keeping the power exchanges with neighboring control areas close to agreed-upon values. Often, only a few generating units, known as "regulating units," participate in this control function. The cost of operating these "regulating units" is much higher than the cost of operating units for economic dispatch (i.e., for meeting scheduled demand).

In a changing industry, it becomes increasingly difficult to differentiate among causes of net generation/demand imbalances in each control area without additional metering. However, because of the high cost of regulating net imbalances in response to random deviations from system inputs, it is important to account for deviations from scheduled transactions in such a way that this cost is borne by those market players not complying with scheduled contracts.

There are at least two possible ways to deal with the deviations from scheduled transactions. First, since these deviations are not known at the beginning of a contract, they can only be accurately estimated at the end of the contract.[2] This circumstance prohibits one from having accurate, transparent, *ex ante* pricing for non-compliance with the schedules. These can be charged either at the end of each contract, or one could impose very high penalties for deviations from scheduled transactions.

Another possibility to deal with deviations is to encourage so-called "fringe regulation" in response to fast deviations from schedules at each end-user level[3], and require minimal coordinated regulation at the control area and/or the interconnected system levels. The total cost of dealing with system regulation in this way could be reduced significantly from the cost of current schemes such as automatic generation control (AGC). The end user has the option to provide this service itself, and only pay for minimal regulation needed in response to sustained deviations from schedules.

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[2] Some forward looking utilities have good understanding of statistical behavior of their load; this will become a critical information for minimizing the risk of investing into system regulation.

[3] Aggregate end-users can perform this function, too.

Role of Existing Generation in Providing Operating Reserve for Reliable Service

The cost of operating reserves is created by the current regulatory requirement for an uninterrupted high quality power supply, even when unexpected changes in equipment status occur. One would need very little reserve (inventories) if the obligation for the uninterrupted power were relaxed.

This is the most complex service to deal with in an accurate way, and is, most likely, the function which has led the generation pattern into its present form. The economic value of operating reserve is not identical to the economic value of inventories in other industries, because the main role of operating reserve is to balance the system despite very large unexpected failures, such as generator and transmission line outages. In other words, even the generation resources which are not actively used for supplying basic demand play a critical role in the overall reliability of an interconnected power grid. For the system to respond in a reliable way to a large, arbitrarily located disturbance, operating reserve must be distributed fairly evenly throughout its entirety. It is for this reason that we believe that much of the presently installed generation has a significant role in enabling the most attractive economic transactions to take place. Some existing generation that may be essential for maintaining reliable operation in a changing industry even though that generation has relatively high operating costs.

The magnitude of operating reserves needed for reliable service must be studied in great detail before units that appear to be stranded are retired. This may reveal that large portions of assets currently thought to be stranded can be used for facilitating reliability.

PERFORMANCE OBJECTIVES FOR OPERATIONS PLANNING

The basic performance objectives of operations planning in a regulated industry can be summarized as follows:

- **The purpose of operations planning in a regulated industry** is to provide sufficient generation and other controllable equipment (e.g., capacitors, reactors, flexible AC transmission system [FACTS]) at the interconnected system level to simultaneously:

  Task 1—Meeting demand: Meet the given (anticipated or scheduled) time-varying demand at least operating cost;

  Task 2—Transmission losses: Compensate for transmission losses (real and reactive) that occur on the system as the anticipated demand is supplied;

Task 3—Operating constraints: Meet various operating constraints (such as thermal constraints on transmission lines, voltages at both demand and supply locations);

Task 4—Flexible generation: Provide real-time flexible generation to balance deviations from the anticipated demand as they occur, and

Task 5—Stand-by generation: Provide stand-by generation in case any single outage occurs on the system ([N-1]) security criterion.

This sort of real-time operations planning provides continuity of high-quality power (measured in frequency and voltage) power supplies to end users, despite the user's possible variation from scheduled demand, and despite unexpected, major changes in equipment status. In order to minimize service interruptions, typical operations planning allows for a 10 minutes reserve in case of unexpected contingencies.

In order to meet performance tasks (1)-(3) (meeting demand, transmission losses, operating constraints), the system operator at present relies primarily on static network and generation modeling tools such as load flow studies, economic dispatch simulations, or optimal power flow (OPF) analyses. Such models assume that the state of the system is known with certainty, which while not quite accurate, is nonetheless workable, because many system functions are under central control and utilities still have an obligation to serve the needs of their service territories.

The forecasted variables (load and unit outage statistics) are predictable enough for a system operator to rely on static modeling tools. Analytical tools for dynamic system regulation and for providing reserves under contingency conditions are complex and not standardized. System operators do their best to meet recommended dynamic performance under normal and emergency conditions, often using system-specific solutions.

At present, economic dispatch/scheduling (task 1)[4] and loss compensation, (task 2) within the static operating constraints (task 3) are *integral services provided by all generating units participating in economic dispatch for the anticipated demand.* Only *deviations from anticipated demand caused by small random fluctuations rely on automatic generation control (AGC)* (task 4). Typically, a large system has only a handful of units directly dedicated to systemwide regulation in response to relatively small, random variations. For frequency regulation, these units are known as the AGC units. The generation reserve for system protection in the event of major outages (task 5), on the other hand, is planned in such a manner that the most economic units are used whenever possible in the actual operation.

At present, operations planning for generation is accomplished at a systemwide level, with the single *(bundled)* objective of performing all five tasks at the least

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[4] This task can be defined and analyzed as the basic supply/demand problem without externalities.

possible total cost, in order to reach *ideal technical efficiency* of generation production.[5]

Open Operations Planning Problems in a Changing Industry

All five tasks are performed in a coordinated way using all available generation resources. Proposed industry changes are aimed at performing task 1 in a competitive instead of coordinated fashion. The problem of balancing supply and demand (task 1) has been studied in many industries. Principles of competitive supply/demand markets, and their implications for economic efficiency, are directly applicable to task 1. In addition, and though not a subject of this paper, important sub-problems related to creating an efficient market in a deregulated electric power industry must also be resolved; these include issues of stranded generation cost and market power.

In this paper we assume that a competitive supply/demand market exists, and that it could take an arbitrary structure, ranging from fully coordinated through entirely bilateral. We refer to the basic market participants in such an arbitrary industry structure as competitive market participants (CMPs) [Ilić, et. al., May 1996]. The purpose of this paper is to stress open questions related to tasks 2–5, and to suggest possible solutions so that performing these tasks enables the main supply/demand market (task 1) to operate in an efficient, nondiscriminatory manner, and so that those performing tasks 2–5 are compensated by the CMPs according to their use of the services. Some of these tasks are unique to electric power systems, mainly because the electric power networks cannot easily re-route power quantities, in contrast to packet-switched telecommunications networks and valve controlled-flows in gas networks. Only recently have new technologies been made available that may potentially serve as electric valves [EPRI TR-100504, March 1992]. To further distinguish the electricity system, energy cannot be stored at any significant level, either.

Given this distinction from other industries, one is faced with several fundamental questions concerned with tasks 2)-5). To start with, it is not clear, *a priori*, that all of these tasks must remain coordinated at the systemwide level. It is possible that CMPs could perform some of functions 2–5, if they chose to do so. If CMPs perform the tasks, though, it is critical to specify a minimal technical performance at the level of individual market participants, all of which involves truly novel and difficult engineering questions.

Furthermore, if some of these services must remain coordinated in real-time at the interconnected system level, one must decide how should the resources for performing these services be created and used in real-time. Ilić, Graves, et al. [April 1996] describe why many of these resources must be provided prior to the time they

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[5] For a detailed treatment of optimization objectives in operating large power systems, and a discussion of how deregulation might change these objectives, see [Ilić, et. al., May 1996].

are used. Equally important are questions related to the price-charging mechanisms for the services that remain coordinated.

The fundamental problem is that tasks 2–5 are dependent on how task 1 is accomplished, since their main objective is to balance the system when the main supply/demand market fails to do so. Also, power quantities traded in the primary market may change once the charges for services 2–5 are known. This interdependency could be solved in more than one way, as follows:

- (i) One approach is to create resources for meeting tasks 1–5 in a coordinated way, retain all technical services as they are, and introduce coordinated mechanisms for creating market price for such bundled technical services. The only cost allocation (unbundling) that takes place in this scenario is based on the ownership of these resources. Various forms of proposed poolcos are centered around this scenario.

- (ii) A second approach would allow for an arbitrary mechanism for task 1, with some of the tasks 2–5 performed at the end user level according to a prespecified technical performance, and perform a minimal subset of 2–5 at the interconnected system level. Truly interconnected operating services (IOS) could be created ahead of time in a competitive manner and used in a coordinated real-time way.

In order to solve the interdependency problem in the second manner (above), one needs provision of economic feedback to CMPs for providing IOS. Moreover, the price-charging mechanisms for IOS may differ depending on how efficiently IOS is created and used in real-time.

Performance Objectives for Operations Planning in a Changing Industry

Given the unprecedented input uncertainties caused by industry restructuring, it is essential to provide a modeling, analysis, and control framework that will keep the system together. Doing so, in turn, requires a review of the operating and control principles of present system structures and assessment of the need to change them in order to support new operating modes. This paper examines in particular, the question of the *minimal coordination required at the interconnected system level*, necessary to maintain system integrity in a changing industry (tasks 2–5), while allowing for competitive supply/demand (task 1).

Until now, power system monitoring and control have been based on a hierarchical structure in which the monitoring and control tasks are shared by different hierarchical levels. Local (primary) controllers on individual generating units are, at present, decentralized, in that they respond to deviations of local outputs from the set values assigned from higher levels. The set values of primary controllers are determined at a control area (secondary) level, assuming weak interconnections among the areas. *The control areas are, however, not systematically coordinated at* *present, leading to deviations from optimal systemwide performance and a possibility of systemwide instability.*

In addition to strictly technical considerations, adequate control structures are important for future operation of large electric power systems because the type of control structures used for keeping the system together in response to strictly profit-driven system inputs (generation and demand) strongly affects systemwide efficiency under competition. Several recent reports recognize the trade-off between competition and coordination in terms of systemwide efficiency.

Optimizing the performance objective of task 1 alone does not recognize any costs of performing tasks 2–5 caused by the need to facilitate the market transactions, unless specific rules are imposed. For nondiscriminatory pricing this cost must be accounted for. This is the single most important reason why the social welfare measure of efficiency is not directly applicable to the power industry, and further explains why an entirely bilateral market does not work. A bilateral market intended for managing supply/demand is not capable of taking into consideration the economic value of performing tasks 2–5 unless additional economic signals are provided.

The Question of Minimal Coordination in a Deregulated Power Industry (Tasks 2–5)

This question is closely related to the technical question concerning the possibility of performing tasks 2–5 at the CMP level and providing the corresponding power quantity locally. Some qualitative discussions of this question can be found in [5,17]. Here we attempt to illustrate possible solutions by means of relatively simple examples.

Transmission Losses (Task 2)

Consider the often quoted IEEE 39 bus system, which represents an aggregate of the New England electric power system. The one-line diagram of this system is shown in Figure 1. Assuming that a real-time information network (RIN) provides basic load flow data (line resistances, reactances, and the *base case* operating conditions), a simple algorithm can be derived for estimating transmission losses created by each CMP. This algorithm is based on the so-called *localized response property of an electric power network*, which implies that voltage phase angle deviations caused by a change in power input at an arbitrary location i monotonically decrease away from the location of power change. This property can be used for accurate estimates of transmission losses (real and reactive) caused by a CMP changing power quantity at location i. For example, total (real) power transmission losses caused by a real power deviation of 50% of nominal generation at bus 37 when computed using the exact load flow are approximated at 95% accuracy by using local computations [1]. The nominal generation at bus number 37 is 13% of total system generation. The localized effect of power changes at bus i is reflected in a relatively rapid decrease of transmission losses caused by the power change at this bus. The localized algorithm requires re-enumeration of load-flow data according to a *tier concept*; first tier consists of bus(es) at which the change of interest takes place, the second tier consists of buses directly connected to buses in tier 1, and so on. One could show that transmission losses in lines belonging to the first tier are 15% of total losses, losses in tier two are additional 21%, losses in tier three 20%, and so on. This suggests the possibility of very effective approximation methods at each end user level, without even computing all transmission losses. This highly accurate estimate can be provided in a very straightforward manner, *locally*, by each CMP. *Once the power loss caused by the CMP is estimated, the market participant can simply increase its input to compensate for the estimated power loss it has caused on the grid.*

This result leads to several policy-related issues. First, the case could be made that a service normally viewed as appropriately being provided by a system operator, could actually be provided with a high accuracy by each individual market participant. It remains to be decided if a flat rate for transmission losses as suggested in [16] is a more viable alternative than a simple local compensation of transmission losses.

It has been shown recently [Cordero, 1996] that reactive power losses created on the grid can be estimated in a similar fashion locally. Given this finding, it is possible to provide reactive power compensation at each end-use level for local reactive power use (in the case of a heavily inductive demand, like air conditioning) as well as estimated reactive power losses to the grid caused by this particular CMP. While the details are under development, it is intuitively clear that given the highly localized response property of reactive power,[6] the answer is likely to confirm possibilities for dealing with reactive power loss in a distributed way by each end user.[7]

Minimal Dynamic Regulation (Task 4)

Both control structures for real-power generation needed to meet anticipated loads, and of dynamic regulation structures such as AGC, rely on very reduced information; this makes them feasible in real time. In a changing industry, more information and measurement are necessary to include non-utility-generators participants under systemwide regulation. However, it is essential to not introduce revolutionary changes without first considering the information and measurement structure on which the present operation depends.

Meeting a requirement to provide non-uniform power quality to specific levels in the nested hierarchy structure is a serious technological challenge, given the present state of system regulation as a starting point. One can view this problem as allowing

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[6] Reactive power does not travel far.

[7] The problem of network-dependent Task 3 (voltage support and transmission line constraints) is discussed in the context of the planning problem later in this paper.

specific market participants to operate at those levels of reliability, frequency and voltage quality chosen by each of them, locally. *The problem at the interconnected system level then becomes one of regulating power flows among the participants in such a way that the system remains functional.* It is suggested, here, that meeting pre-specified frequency and voltage quality at the specific levels of the nested hierarchy should be performed by the members of specific hierarchical levels in accordance with random deviations from their sustained changes.[8] The only systemwide (coordinated) regulation should be that needed to suppress sustained deviations in system inputs. This is known as *default regulation* [5], which, if properly handled, can maintain the average system frequency within acceptable limits.[9] This control design leads to improved dynamic performance and economic efficiency over the present regulation. Most important, for very complex systems the approach simplifies the picture by extracting only relevant information at each level of hierarchy which is essential for allocating charges to specific market participants in an efficient way. A summary of numerical results is described using the same standard IEEE 39 bus system shown in Figure 1.[10]

[N-1] Security: Question of Inventories (Task 5)

Operating reserve is the second most important service that must be provided in a coordinated way. This is in addition to maintaining (average) frequency at the interconnected system level.

While maintaining average frequency in a coordinated way is essential for reliable delivery of high quality power, the coordinated provision of operating reserve is needed primarily for economic reasons. As Fink [1995] observes, it may be possible for each market participant to provide local operating reserve, although such a scheme effectively doubles the required generation resources since for any unit in service, there exists a reserve unit located at the same place in the system. This is highly inefficient from the perspective of an interconnected system: the underlying logic for an interconnected system stems from the efficiency gained by using someone else's resources when they are not otherwise needed, or when an emergency occurs.

General practice has been to install reserve resources, that are not used continuously, in order to provide margins within which it is possible to accommodate unexpected events of various types. Along these lines, the North American Electric Reliability Council (NERC) requires each utility to have enough reserve to allow it to provide uninterrupted service for 10 minutes following any single contingency in its area.

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[8] This is known as *fringe control*, see Fink [5].

[9] For one possible design that allows for functional separation of fringe and default controls.

[10] For potential technical/accounting problems in a changing industry related to automated balancing of the system in response to non-compliance with supply/demand contracts (task 1).

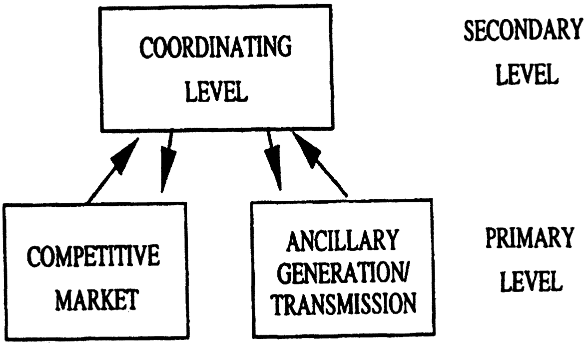
The operating reserves issue becomes more complicated with the prospects for industry change. Obviously, that it would be extremely uneconomic to impose reserve requirements on each individual CMP since this would double the required resources. A more reasonable approach is to create a coordinated, interconnected operations service as one of the system market (SM) services. Allocating the entire cost of reserves to individual CMPs can, in concept, be usage-based. For example, the ratio of the CMP's generation to the total system reserve could be used as an indicator of the SM reserve value to this CMP, with the understanding that, as at present, the operating reserve will not be used continuously, but will be paid for by each CMP. This can be viewed as a required insurance charge. The mandatory charge for operating reserves implies uninterrupted service except in certain extraordinarily difficult scenarios. One could take a different point of view, and introduce an optional charge for operating reserve. If a CMP does not purchase this service, it may be interrupted with high probability. It is not clear, however, that in the US, where dependence on high quality power is high, the optional approach would be a realistic one.

HIERARCHICAL STRUCTURES IN A DISTRIBUTED INDUSTRY

In formulating optimal methods for maintaining system integrity in response to competitive supply/demand pressures, we suggest a conceptually new information structure. Two types of structures are required. One set is relevant for physical processes or technical operation under competition, while the other is for financial processes, i.e. pricing. These two cannot be assumed to be the same because we are dealing with (i) the process of gaming for profit on the competitive generation side, (ii) demand-side management for benefit maximization, and (iii) system services (tasks 2–5) trying to define themselves. Absent consideration for the performance of the interconnected system, objectives of competitive supply/demand participants are *highly distributed*, with utilities lagging behind in defining the economic value of Tasks 2–5.

For purposes of further analysis in this section, we view the electric power industry as a hierarchical system, some of whose input changes are driven by the market. In a single-utility setup under open access, one has, at least, a two-level hierarchy. As shown in Figure 2, at the primary (lower) level, competitive supply/demand enters the system as one type of market (task 1). The second market, at the same level, represents interconnected operations services, whose basic function is to coordinate systemwide performance (tasks 2–5). The role of the secondary level is limited to coordination, and it can be interpreted as an independent system operator (ISO), whose functions are not fully defined at this point. The need for its existence and the functional details are described in detail in [9] and were summarized above. *A particular case of this two-level structure is the present (secondary-level) system coordination of the single primary level comprising the entire demand and generation (bundled tasks 1)-5)).*

Figure 2. Single Utility Viewed as a Two-Level Hierarchy



A PROPOSED APPROACH TO MARKET INTEGRATION WITH TECHNICAL FUNCTIONS

Based on our analysis here, we suggest an approach to real-time systems control and its pricing in a competitive market which requires

- (i) Efficient creation of systems control services (for meeting tasks 2–5) over different time frames to meet specified performance criteria for the anticipated dynamics of CMP transactions.
- (ii) Systems control implementations that guarantee systemwide performance.
- (iii) Meaningful pricing mechanisms for systems control sold to the CMPs.

If those approaches are implemented systematically, a changing industry should achieve success, as measured by societal benefits, rather than by benefits solely to specific subsystems in the system hierarchy. Our approach is based on a gradual evolution of present systems control, taking into account that system inputs include native load demand as well as the transactions of CMPs.

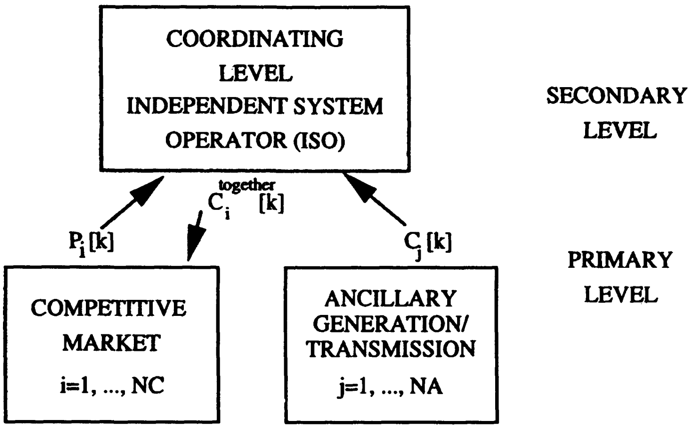
We have suggested that the pricing and provision of minimal interconnected operations services (IOS) to maintain system functioning should be coordinated at the interconnected system level, taking into account the actions of CMPs. This leads to our proposed iterative integration of these processes.

Coordinated system services are needed, in part, because of transmission system constraints (task 3). But even the ISO cannot know precisely where those constraints will appear, or how severe they may become, prior to evaluation of transactions proposed by the CMPs. Thus, some degree of economic decoupling between the ISO activities and the competitive market (CM) is inevitable. However, it is natural to consider an iterative approach to resolving the need for simultaneous information about transactions and about system conditions.

The main reason we suggest real-time implementation of this sort is that it brings both worlds together—the proponents of competition and of centralized pricing. The integration of operations and pricing will allow (i) for competitive supply/demand (task 1), (ii) for coordinated management and pricing of generation-based systems control services (tasks 2–5), (iii) market participants to switch in time from being CMPs to participating in system market, and vice versa, at will.

Figure 3 illustrates this integration in an iterative, two-level bidding market; it is iterative in the sense that CMP interactions are anticipated by the ISO and the pattern of interactions determines how the SMPs will be used. In turn, the costs of system services are charged to and recovered from the CMPs. By sending and receiving relevant signals to and from both markets, the ISO ensures that the trade-off between more CM transactions and higher SM charges is brought to an equilibrium. The CM is distributed, with price terms and conditions of transactions between CMPs remaining proprietary. Only the power quantities and locations of the transactions are communicated to the ISO. In contrast, the SM is a coordinated function that conveys a nondiscriminatory price for performing tasks 2–5 to each CMP, according to (at least) its relative impact on system reliability. This requires new administrative procedures for communication between the ISO and the CMPs/SMPs, as well as new computational tools for determining the marginal impact of each transaction on the system.

Figure 3: Iterative Process of Accommodating CM from the ISO Level.



The concept can be viewed as *successive bidding* at the market participant level, driven by additional information from the second level; a particular market participant will stop bidding when its total cost of tasks 2–5 exceeds the revenue it can get for its own power. As time goes on, market participants can change sides and switch from competing for profit to participating in tasks 2–5 and vice versa. The relative values of one move or the other will be electrical system-dependent. The iterative process can be shown to approach system-wide economic efficiency. The proposed scheme is not complex to implement, provided that coordinated, nondiscriminatory cost-charging signals are computed and given to the market participants on a regular basis.

The suggested implementation of such a market structure is based on present utility practices for managing ancillary generation and keeping the system functioning. Implementation could be accomplished by having an operator at the coordinating level for strictly technical functions "evolve" into an ISO which accommodates the bids for power, as well.

One should bear in mind the conceptual differences between (i) providing systems control and pricing at each subsystem[11] level, independently from the rest of the system and (ii) providing coordinated, hierarchically structured management of performance objectives at each subsystem level as well as at the interconnected system level, and the corresponding coordinated pricing for generation-based systems control from the highest level. In analyzing performance of alternative structures under present consideration (such as "poolco," bilateral, and multilateral) in terms of their performance relative to ideal efficiency, *it is important to be specific about this division of responsibility and a potential discrepancy between the technical signals and their value allocated under a specific industry structure.* While our treatment here is brief, we suggest that *all three alternative industry structures are particular examples of the two-level operations framework described here.*[12]

AN ILLUSTRATION OF THE ITERATIVE MARKET INTEGRATION

This section gives an example of the pricing mechanism using a typical three-bus system shown in Figure 4. The generator cost curves and the load utility curve are quadratic:[13]

$$C_1 = c(P_{G1}) = P^2_{G1} + P_{G1} + 0.5 \tag{1}$$

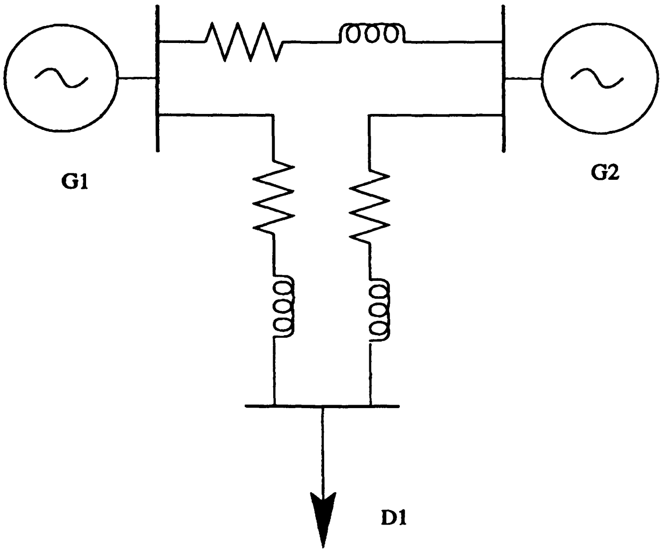
$$C_2 = c(P_{G2}) = 2P^2_{G2} + 0.5P_{G2} + 1 \tag{2}$$

$$u(P_L) = 34.1666P_L - P^2_L \tag{3}$$

[11] Term *subsystem* is used here in its most general sense and it could represent individual non-utility market players, distribution systems, or any other unit arranged by market aggregators.
[12] For comparison of the proposed framework to poolco and bilateral structures, see [9].
[13] Data is hypothetical in this example.

where Ci is the generation cost, P_{Gi} is generation produced, P_L is load demand, and u_L is its utility function. Generator 2 acts as the system market participant (SMP) and generates power needed to balance the system in response to an elastic demand at bus 3.

Figure 4: Typical 3 Bus Example.



First, the system market price is obtained without consideration of losses (task 2) or congested transmission lines (task 3). Market equilibrium occurs at the intersection of the aggregate supply and demand curves. In this example, the demand curve is simply the marginal utility curve of the load:

$$P_L = 17.0833 - 0.5P \tag{4}$$

where P is price. The supply curves for the generators are:

$$P_{G1} = 0.5P - 0.5 \tag{5}$$

$$P_{G2} = 0.25P - 0.125 \tag{6}$$

so the aggregate supply curve is:

$$P_G = 0.75P - 0.625 \tag{7}$$

and, market equilibrium occurs at $P_L = 10$, $P_{G1} = 6.5833$, $P_{G2} = 3.4167$, and $P = 14.1666$. If the system had no losses or transmission constraints, then a viable operating point has been reached which minimizes the total cost of all players.

If losses are present, then P_{G2} will need to be increased from 3.4167 in order to make up those losses. In order to allocate the cost of the excess generation, generator 2 will calculate the cost derivatives $\partial C_2 / \partial P_{G1}$ and $\partial C_2 / \partial P_L$. A new nodal price will be calculated for the load by finding the weighted average of $\partial C_2 / \partial P_L$ for $0.5P_{LOSS}$ units of power and $P_1 = P = 14.1666$ for the remaining units of power purchased. The 0.5 represents one-half of the total market share in this case, since there is only one buyer. Similarly, the nodal price for generator 1 is obtained as the weighted average of $\partial C_2 / \partial P_{G1}$ for $(6.5833/20)P_{LOSS}$ units of power and P_1 for the remaining power sold. The new nodal prices P_{G1-2} and P_{L-2} are obtained by recursively solving the following equations:

$$P_{L-(k+1)} = P_{L-k} + \left(\frac{\partial C_2}{\partial P_L} - P_{L-k} \right) \times \frac{f_L P_{LOSS}}{P_L} \tag{8}$$

$$f_L = \frac{P_L}{2P_L} \tag{9}$$

$$P_{G1-(k+1)} = P_{G1-k} + \left(\frac{\partial C_2}{\partial P_{G1}} - P_{G1-k} \right) \times \frac{f_{G1} P_{LOSS}}{P_L} \tag{10}$$

$$f_{G1} = \frac{P_{G1}}{2P_L} \tag{11}$$

After receiving the new price information, the market players adjust their power levels accordingly; the slack bus computes a new generation level and new price signals and the process iterates until convergence. This process converges linearly for the example studied to yield system optimum.

In the presence of line congestion (task 3) instead of losses, the process is exactly the same, except that P_{LOSS} is now replaced with $\left(P_{ij} - \overline{P}_{ij}\right)$, which is the amount of power flow through the line in excess of the stated maximum. In this case, the cost C_2 must include the penalty factors for the *soft transmission line constraint and the partial derivative price signals* must be calculated accordingly. In this case, the cost C_2 takes the form

$$C_2 = c(P_{G2}) + \sum_{i=1}^{N} \sum_{j=1}^{N} a_{ij} \left(P_{ij} - \overline{P}_{ij}\right)^2 \tag{12}$$

where P_{ij} is the power flow from bus i to bus j, $\overline{P}_{ij}$ is the thermal limit on line ij, and a_{ij} is a weighting coefficient. The sum is taken over all iteration steps. If both losses and congestion are present, then P_{LOSS} is replaced with the sum of the losses and the excess transmission line power flow.

SYSTEM EXPANSION PLANNING IN A CHANGING INDUSTRY

Here[14] we assume that anticipated changes in the industry will bring about functional separation between transmission, generation and distribution. It should be obvious that, under such *vertical disintegration*, present performance objectives for operations and expansion planning must be re-defined, and that at least three qualitative changes may affect the way these objectives are defined:

- (i) Objectives of generation performance are not coordinated at the system-wide level;

- (ii) Demand is more uncertain than at present; wheeling transactions that exclude the utility which has traditionally served this demand creates uncertainties in what is referred to as the native load; moreover, it is not clear how demand elasticity would change the statistics of the present demand.

- (iii) Significant changes in supply/demand dynamics, both temporally and locationally, could require qualitatively different transmission support than presently available. Given existing rights-of-way constraints, it may become necessary to enhance the transmission grid by adding devices that are capable of making the grid flexible to dynamic system changes. In other words, a need may arise to have actively controlled grid parameters in order to accommodate competitive market requirements. If the requirements on the grid are imposed for economic transactions, it is essential to define the value of the transmission/distribution grid to the market over the time horizons over which the enhanced performance is needed.

Creation of Systems Control Services

It is pointed out in Ilić [1996], possibly for the first time, that this process must be viewed as a *dynamic* one, evolving over the time horizons determined by the type of systems service intended. These services range from the continuous local stabiliza-

[14] For a rigorous treatment of the problem formulation in a regulated industry, we recommend to the interested reader Fischl's [1975].

tion (via governors and excitation systems) through the unit commitment, and beyond and any resources dedicated to these services *must be created in advance*. As the market and operating conditions vary, the locations and amounts of projected systems control services will vary. This requires very active learning and projections of system conditions, native load (or what is left of it), the CMPs, and creation of the SMPs.

As SMPs are created, it is important to consider that at present these are two qualitatively different types of systems control services: (i) generation-based systems control services (for frequency- and voltage), and (ii) transmission network-based (primarily for voltage support, although with FACTS these may have more of an impact on frequency regulation as well.) These two system control services are viewed as qualitatively different in a changing industry, because, at least in principle, the generation-based systems control could be made competitive, rather than cost-based. Moreover, generation-based systems control has significant operating (fuel) cost. The transmission equipment remains a monopoly, and as such is cost-based. The transmission cost primarily comes from capital costs, and to a much lesser extent from the O&M.

This dichotomy creates potential problems when setting the mechanisms for enhancing the transmission grid. *Economic incentives must be developed for enhancing the grid (e.g., by means of FACTS), instead of just creating generation-based systems services.* This is a very complex question because it involves trade-offs between making longer term commitments to generation-based services, on the one hand, and commitments needed to enhance the grid, on the other. In light of this a particular need emerges for developing economic incentives capable of comparing the cost of out of merit generation to the cost of enhancing the grid to avoid this inefficiency. This algebra is tricky; payoffs are seen over (what used to be) planning time horizons: e.g., over a ten year period it may be more cost-effective to build a FACTS device than to continue to operate out of merit generation needed to avoid transmission grid congestion.

When assessing the process of creating of systems control services over longer time horizons (months and years), this issue must be addressed very carefully. Because of market uncertainties, the analysis will result in some measure of risk taking. Regulators should clearly define the responsibilities of various players over the longer time horizons.

This SMP creation effectively replaces the generation planning process; the point made here is that transmission planning must be carefully integrated into the competitive environment.

Sole use of financial instruments such a s transmission congestion contracts [Hogan, 1992] as a proposed approach for eliminating transmission congestion in a changing industry, does not lend itself directly to a coordinated establishment of resources such as generation and transmission grid enhancements. The impact of approaches of this type on systemwide efficiency must be studied.

Performance Objectives for Distributed Generation Expansion

Distributed investments for new generation effectively replace the present generation expansion planning performed at the system level. It is critical to recognize that the performance objective, as defined at this level of the hierarchy, will differ qualitatively from the present, e.g., a generator does not have information about locational and temporal demand variations at the interconnected system level. Instead, such a generator is directly aware only of bilateral firm, longer term contracts (including hedging) between the potential investor and various levels of the industry structure (ranging from individual market players through aggregate subsystems, independent system operators and like). The expected operating cost over the time relevant for investment is equally uncertain, as at present. An interesting operating cost component is associated with the expected cost of not serving the committed power or not having the right amount at the right time to take advantage of the opportunities offered by the short-term market needs. This component may become significant in a changing industry driven by the customer choice. It is not obvious that the capital cost component is the only one on which reliable decisions should be made. The investment risk is defined in terms of uncertainties associated with the probabilities in both of these two operating components.

Value of Transmission System to Distributed Generation

This value has been recently discussed in the context of transmission capacity rights to distributed market participants, their availability and economic value. From the entirely decentralized viewpoint of a power seller or buyer, the notion of a *guaranteed transmission right* to enable an economic transaction from a particular seller to a particular buyer on the grid is a very attractive notion. If such a guarantee can be provided at fixed cost, any risk associated with not being able to deliver power would be eliminated, at least in principle. The distributed market players would, in many ways, prefer to think of the transmission service as an externality of fixed value, in order to eliminate any risk of their supply/demand transaction being a function of other players outside their direct control. This may be a reason for using financial instruments to eliminate the risk. The most often discussed instrument of this type is the notion of so-called *transmission congestion contract*, proposed by Hogan [1992]. Desired future transmission rights, which could be sold at request and at cost would provide long term guarantees that the pre-specified capacity will be available to their owners, whenever needed. For this concept to become used and useful, one must first determine how this would become feasible in actual system operation and how could transmission rights be initialized and their value determined. For purposes of distributed decision making at the seller and buyer levels, we assume that one such possibility exists and it is an additional fixed cost when planning for investment.

Second scenario is to assume that transmission would be available, with some probability, but that it is not fully guaranteed. One could view the value of the transmission system to distributed market investors as an expected operating cost component, consisting of both operating generation cost, and the cost of not serving demand. There are advantages and disadvantages of this second scenario, relative to the use of financial hedging instruments. First, because of technical reasons, it is difficult to commit an unconditional transmission capacity independently from anything else that is happening.[15] The economic reasons for and against firm transmission rights are even more involved. One has to be extremely careful with the type of uncertainty tradeoffs required. For firm, long-term capacity contracts it is perhaps justifiable to define transmission rights based on available transmission capacity (ATC), and the initial, stranded transmission network investments. It is not necessary to have a strictly financial instrument to define firm transmission rights. These could be made available based on computing available transmission capacity for firm system inputs over times relevant for investments. The total fixed cost of transmission serving this firm component of power can be allocated to various distributed users, and could be usage-based as proposed in [e.g., Zobian and Ilić, 1996]. We are not concerned here with computing this charge. Instead, we argue that the decentralized problem formulation for generation investment greatly depends on how is the value of transmission accounted for.

A distinction must also be made between transmission value for a firm contract component, on the one side, and its expected value that is created by modifying the operating cost, on the other side. Careful definition and allocation of this value to various market players is essential for providing efficient economic incentives at the interconnected system level. *It is conceptually wrong to mask the deviations in operating cost components by introducing operating conditions-insensitive financial instruments for these components.*

The availability of the transmission grid, on a non-firm basis, must reflect the same types of uncertainties as the system input uncertainties, from both supply and demand. The actual inefficiencies caused by inability to transfer are directly reflected in managing the system at the suboptimal social welfare cost. *It is argued, in this article, that the best system that the planners could do is to plan the enhancements on the grid for the expected system input dynamics.* The risk to investments caused by deviations from the expected values should be borne in a fair way by all market participants. It is not meaningful to hedge against these types of uncertainty. Another way of encouraging efficient use of resources is to consider operating cost as consisting of three potentially equal components (1) use of generation, (2) varying demand, and (3) use of available transmission capacity. *All three components are complementary to each other.* With this in mind, we propose that the value of transmission to distributed decision makers consists of three qualitatively different components: (i) long-term value associated with firm service; (ii) uncertain, shorter term components; (iii) noncompliance effects. *Our general idea underlying efficient decentralized decision making is similar to the idea of peak-load pricing; each decision maker should be given a disincentive to use the transmission at the locations likely to cause transmission line overloads (congestion [Hogan, 1992, Wu, 1995]. If*

[15] These are given in Ilić, Yoon, and Zobian [1996].

this is done, we conjecture that the interconnected system is likely to develop into a dynamically efficient system over the time horizons relevant for investments.

Accomplishing all of this is an almost impossible task without having any reliable expectations of the operating cost components. The only certainty at present may be with regard to the actual ranges of the expected fuel cost. *A dynamically efficient enhancing of the transmission grid and the efficient creation of system service generation can only be effected at the interconnected system level. This argument is in the essence of our suggestion that without active (minimal)*[16] *information provided at the systemwide level, the system may either become technically unreliable, in the sense that the reliability of service may either drastically drop or the systemwide dynamic efficiency may deteriorate. Because of this it becomes important to develop means of projecting the costs of system support in a reliable way.*

CONCLUSIONS

Operations planning and system expansion in a changing industry have two distinct aspects: task 1 (supply/demand), on the one hand, and tasks 2–5 which are unique to the power system industry, on the other hand.

Our information, modeling and analysis framework recognizes this distinction, and facilitates task 1 in real-time operations by means of creating markets for the unique services, using them in real-time in an efficient manner and allocating charges for system services so that systemwide dynamic efficiency is approached, while allowing for a competitive task 1.

An often stated reason for deregulating electric power industry is to increase systemwide efficiency as measured in terms of increased net social welfare. At first, it appears that this goal is no different than in any other competitive industry. However, for an industry that is in transition, with non-uniform initial conditions, without clearly defined or understood economic incentives for the system support, it is important to analyze system efficiency as a dynamic measure over time horizons ranging from those relevant for distributed investment decision making, through those time horizons relevant for short-term operations planning. Two important issues remain. First, the social welfare cost must be computed over all market players, CMPs and SM participants. Second, the transmission value function does not explicitly enter this equation. It only indirectly affects total efficiency, i.e. it is common good to all.

To analyze the unique features of the electric power system, we have proposed a general framework for operations planning under open access. A similar framework can be developed for the efficient creation of system market services which are needed to balance the system as the economic transactions occur.

The key to getting the structure right is understanding that th delivery of electricity is not the same as the delivery of a typical commodity---such as bananas.

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[16] In the sense described earlier for tasks 2)-5).

To date, most debate over industry organization has centered on the provision of competitive generation. As we have demonstrated, the required network support plays a key role in furnishing electricity and may provide the solutions to some of the financial problems that the industry faces.

To sum up, a competitive electric system can operate efficiently and reliably, and mitigate the problem of stranded assets, provided that it properly utilizes 3C technologies, and it offers the required incentives for the provision of decentralized support services.

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13

RULES OF THE ROAD AND ELECTRIC TRAFFIC CONTROLLERS:

MAKING A VIRTUAL UTILITY FEASIBLE

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ABSTRACT

A virtual utility is defined as an entity that operates and manages multilateral transactions in an electric power system yet owns no transmission. Interaction among multiple virtual utilities using the same transmission grid will have an effect on transmission losses in the system and on the security of one party to another as a result of network congestion. Means for formally measuring and quantifying these interactions are presented. The effect of these interactions in various time frames is discussed, and rules for translating the knowledge about losses and security into rules for the road are presented.

INTRODUCTION

A "virtual utility" may be defined as an entity that owns or operates a multitude of assets connected to the electric power grid, but these assets are not necessarily con-

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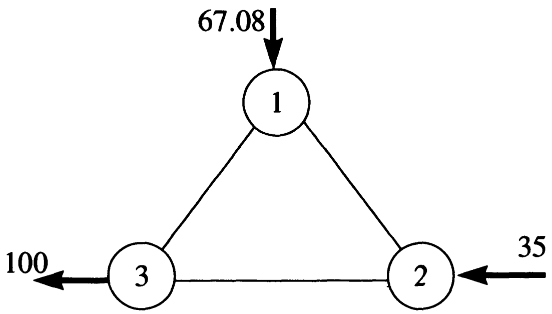
tiguous and may by themselves be insufficient to meet all the necessary elements required for the delivery of power. The concept of a virtual utility presupposes access to a transmission grid. It is further assumed that such a utility would be operated to serve a particular group of customers, who themselves may be dispersed throughout the electric grid. In the organizational model most compatible with the views of this paper, the grid is "owned" by a transmission access provider (TAP) and operated by an Independent System Operator (ISO).

An example of a virtual utility would be a cooperative with many small producers which must rely on a third party for their interconnectivity. Another example may be a power broker that has acquired the right to certain generation assets. All of these "virtual utilities" have in common their need to utilize the electric transmission grid. They also have in common the non-point nature of the supply and/or the demand.

One way to view a virtual utility is as an evolution of the concept of "bilateral operation" into fully "multilateral contract" method for running the system, where contracts involve multiple delivery points and multiple extraction points simultaneously. Although any multilateral transaction can be decomposed into a number of elementary nodal injection transactions, it is necessary to think of the entire aggregate of all combined nodal transactions as one transaction. This paper takes the viewpoint that a virtual utility manages multilateral transactions in the system.

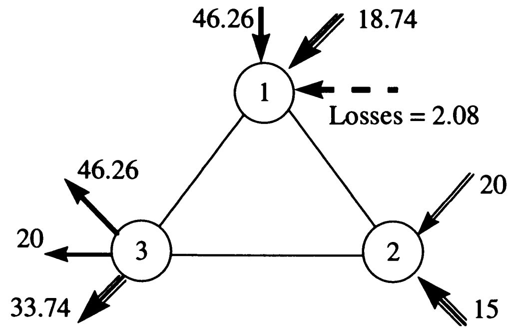
This viewpoint can be readily illustrated. Consider a conventional node-oriented view of the system as shown in Figure 1. In this view, a "pool" operator purchases power from two producers and sells it to one consumer. Observe that, because of losses, the total generation exceeds the total load. This example is taken from Wu and Varaiya (1995).

Figure 1: A conventional view of an integrated utility consisting of two generators and one load. Because of losses, generation exceeds demand.



In contrast, the same physical scenario can be the result of a number of multilateral transactions established by (in our example) three different parties. This view of the same physical reality is illustrated in Figure 2, where we see three different transactions taking place: a transaction from a supplier at bus 2 and customers at bus 3, a 46.26 MW transaction from bus 1 to bus 3, and a combined (brokered?) transaction involving suppliers at buses 1 and 2 and customers at bus 3. The losses have been identified separately. The "allocation" of losses is discussed later in this paper.

Figure 2: A "virtual utility" view of the same network.



The electric transmission grid, like a highway system or air traffic corridors, is subject to congestion and the need for everyone to obey certain rules of the road to make it all possible. Unique features of the transmission grid are the pervasiveness of certain actions (*i.e.*, problems at one end of the grid can affect users at the other end) and the rapidity with which localized problems can develop and spread, leading to unacceptable blackout conditions. Another unique attribute is that electric transmission entails losses, and that these losses are affected by the actions of others. For a virtual utility concept to work, rules of the road must be developed and enforced such that universal access is assured without sacrificing network integrity.[1] In the above example, two immediate questions arise. First, it is obvious that all three transacting utilities share responsibility for system losses. How is a fair "allocation" of the losses determined? The second question arises if congestion occurs. For example, assume that the flow capacity from bus 1 to bus 2 is limited. How does a limit on a specific flow impact all the transacting utilities? Answers to these and related questions lead to the rules of the road described in this paper.

The rules include certain cooperation requirements that may not have a precedent in other industries. The rules depend on the time frame to which they apply. The paper uses a time-scale classification. In the fastest time frame, from a few seconds to a few minutes, the grid operator acts much like an air traffic controller or a highway patrol officer charged with assuring the safety of those he/she is charged with monitoring. This involves the minute by minute operation of a system and the dealing with emergencies as they arise, as well as documenting the events that lead to the emergency and actions required to relieve the emergency for a *post facto* analysis of events if required. On the next longer time frame, from an hour to a few days, the same or a different grid operator will be responsible for dealing with in-

[1] What here is called "rules of the road" has been called "code of conduct" by the National Grid Management Council of Australia, draft document of April 1995, and by the Victoria Power Exchange (VPX) of Melbourne, Australia. The concepts are similar, except that we rely less on allocation of embedded costs than do these documents.

formation pertinent to the scheduling of power transactions, including establishing the feasibility of proposed actions and determining *ex ante* security costs and losses. Finally, on a monthly and yearly time frame, rules have to be developed to coordinate network expansion and additions. This is the realm of the Transmission Access Provider.

This paper proposes rules of the road for each of these time frames, and assesses their potential impact on the proposed structural changes in the industry. These rules are based on the determination of correct marginal cost of losses and marginal cost of security and the association of these costs with any transaction of interest. The determination of these costs is *similar for all three time frames*, but the manner in which these costs are utilized depends on the time frame.

FUNDAMENTALS OF POWER TRANSMISSION

This section describes some essential technical aspects that are fundamental for under-standing the rules of the road under which a power system must operate. While the description is narrative and free from excessive technical detail, some of the concepts require technical explanations beyond those given here. For further details refer to *Power Generation, Operation and Control* (Wood and Wollenberg 1995).

Almost all electric power produced and transmitted in the world is done in the form of alternating current (AC) three-phase power. In a few isolated instances, the power can also be transmitted in the form of direct current (DC) power. Power distribution (the delivery of power to customers) is often done in the form of single phase AC power, derived directly from the three phase power, although large customers often accept three phase power. This paper focuses almost exclusively on the generation and transmission of three phase AC power.

The following are a few of the most salient features of three phase electric power:

- Power is the product of voltage times current. For this reason, the transmission of power over long distances is done at high voltages. High voltages require more insulation, but the currents needed to deliver a given amount of power are lower. Voltage levels are changed by means of transformers.

- Transmission lines and transformers in an electric power systems are usually "meshed." That means that, like a roadway system, there are multiple paths from any location to any other location in the system. One of the consequences of this is that the loss of a single transmission line or transformer does not result in a disruption to the users of the system. Radial connections are often reserved for connections to single generating units or for distribution system at lower voltage levels. However, unlike a highway system, the distribution of flows among these meshed components is dictated by the parameters of the grid at grid design time. Normally the flow on individual lines or transformers cannot be directly controlled.[2]

- There must be almost perfect balance between generation and load at all times. An excess of demand results in a slowdown of every generator in the system (a drop in frequency, *i.e.*, cycles per second). An excess of generation results in a slight speedup of every generator.

- The frequency is the same everywhere in the system, at all times. Every generator is turning at the same exact speed everywhere in the grid within the entire interconnected system. For a large grid, frequency deviations are quite small. For this reason, for large grids, the system is organized into control areas, and a quantity called the Area Control Error is used to control frequency. If a portion of the system becomes isolated from the rest, frequency deviations can become quite large.

- Somebody, somewhere, must monitor frequency such that an exact number of cycles occurs over every 24 hour period so the power frequency can be used to control electric clocks in the system.[3]

- System losses affect the balance between generation and load: since the flows are not predetermined, neither are the losses.

- There is a need to remove faulty components rapidly; short circuits can lead to currents that are quite large and damaging. Faulty components must be removed automatically, using relays and circuit breakers. There is a compelling need to coordinate the operation of these circuit breakers, in order to contain the effect of any system fault to the smallest possible portion of the system. This coordination requirement extends to facilities owned by anyone connected to the grid.

- The voltage in the system is controlled primarily by means of reactive power[4] injection. The voltage varies by time and location, depending on the specific flows in effect at any given time. There is a need to maintain the system volt-

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[2] There are some exceptions: tap-changing and phase shifting transformers can control flows to some degree, and so can some devices known as FACTS (Flexible AC Transmission System), which, by means of high power electronics, can help redirect flows quickly.

[3] Quartz clocks do not depend on system frequency to keep time.

[4] One interpretation of reactive power is "back and forth" power. It is power that flows from the generators to the loads during a portion of its cycle, only to be returned back to the generator during a different part of the cycle, oscillating back and forth 120 times per second. It produces no net work. However, it is not possible to sustain voltages without reactive power. The need for reactive power arises for two reasons: many loads demand reactive power, and any flows in the system (even unity power factor flows) create a need for reactive power

age at all locations and under all conditions between relatively tight tolerances.[5]

- Generators can be particularly effective sources of reactive power if they are in the right place. Limits of the ability of a generator to provide reactive power are subject to somewhat complex limits of capability. Under low load conditions, it is sometimes necessary to dispose of excess reactive power. This is often done with reactors, but generators can usually help.

- There needs to be just as careful a balance of reactive power in the system as there must be a balance of active power, with the further complication that reactive power must be produced in the vicinity of where it is required. Reactive power does not travel very far.

- Every component in the system can only carry a current up to a given "thermal limit." Even when thermal limits are not an issue, there is a theoretical maximum amount of power that can be transmitted through a transmission line or transformer at any given voltage. An attempt to transmit more than this amount of power will result in system separation, possibly leading to a blackout. The problem of determining the maximum power transfer capability under all credible contingencies and their consequent transient effects can be computationally intensive, which raises concerns about computational errors that could potentially lead to system blackouts. As a result, transfer limits are set somewhat conservatively.

- There is a maximum "natural" permissible length of any transmission line. To be feasible, long lines require advanced forms of compensation which can lead to concerns about sub-synchronous resonance (SSR), a particularly troublesome form of unstable system behavior. An alternative technology for long lines is to resort to high voltage direct current transmission, which is not limited in feasible length and not subject to SSR phenomena.

- Feedback controls are used throughout all engineering systems to regulate quantities to desired values. Numerous such controls exist throughout the power system to control voltage and system frequency. Such controls act reasonably fast, although a control that is too aggressive and acts too quickly can lead to system instability, which can in turn lead to a partial shutdown of a system.

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[5] These requirements for reactive power can be met by static capacitors (very slow, applicable in discrete steps, and less effective when most needed, at low voltages), generators and synchronous capacitors (almost every generator is capable of providing at least some reactive power) or electronic components such as Static Var Compensators or STATCOM devices (very fast but expensive, new technology). Reactive power adjustments can be quite effective means for reducing losses in the system. Adjustable "tap" transformers can also be quite effective to regulate voltage and/or flows of reactive power in the grid.

- Controls can sometimes issue conflicting orders, and therefore they must be coordinated. An obvious coordination requirement is that two controls cannot regulate the same quantity at the same time unless very tight coordination is used.

- Voltage collapse becomes an important problem near loads and other portions of the system without active means for controlling reactive power injection.[6] This problem has become quite prominent in recent years as systems are "stretched" closer to their limits.

- The system is in a constant state of change.

In summary, the power system is a highly interconnected structure subject to a multitude of requirements for its proper operation, including the need to maintain balance between active power supply and consumption. It is difficult to control individual line flows in the system. System capacity and capability is limited by several factors, including overheating of individual lines, availability of reactive power, and the necessity to preserve system integrity in the presence of contingencies. Operating a power system requires tighter coordination among suppliers than is generally required in other industries.

FERC

In March 1995 the Federal Energy Regulatory Commission (FERC 1995) issued its well known Notice of Proposed Rulemaking (NOPR). This proposed regulation describes mechanisms for restructuring the electric power industry. The NOPR is based on the belief that price coordination, as is now practiced by utilities, is not justifiable in the absence of a non-discriminatory tariff for open access to transmission services and is inconsistent with emerging competitive markets.

Electric power delivery entails a number of essential actions and/or services. Implicit in the FERC NOPR is the recognition that in a less regulated environment certain services will no longer be embedded or bundled, as is the case now.[7] In particular, requirements for the transmission and delivery of electric power go beyond the provision of the power itself. The NOPR explicitly indicates the need to develop separately stated rates for the transmission of power and for these "ancillary services," which in FERC's words refer to:

> Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system (1995).

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[6] In simple terms, voltage collapse occurs when a decrease in voltage causes an increase in current, which leads to a further decline in voltage and a further increase in current until the system fails.

[7] Unbundling is discussed further in a paper by S. Oren and D. Ray in this volume.

This view refers to "obligations" and to "transmitting utilities." Another view of ancillary services is offered by Alvarado (1996a).

> Ancillary services are activities that pertain to the provision of all electric services necessary for the efficient and reliable generation, transmission and delivery of active power by means of an set of electrical voltages with a sufficiently stable frequency, sufficiently stable voltage and sufficiently stable clean waveform. Ancillary services exclude the actual power itself.

The NOPR defines six ancillary services:

1. Reactive power and voltage control.
2. Loss compensation.
3. Scheduling and dispatch.
4. Load following.
5. System protection. (This is a misnomer. What FERC meant here are the provision of reserve and redundancy services.)
6. Energy imbalance, in reference to activities pertaining to maintaining a proper balance between agreed upon supply and agreed upon generation at all times.

FERC offers several suggestions and ideas regarding the provision of these services which presently are part of the normal "cost of doing business." Emerging markets will recognize the value of ancillary services with proper financial incentives. To the extent that some of these services are essential, we may also wish to develop rules asserting the means in which they are to be provided: either by regulations that specify how the service is to be provided, or by creating a market for the provision of the service. Reality may necessitate both approaches (Kirsch and Singh 1995; Alvarado 1996b). While not a requirement, the management of these ancillary services is probably best carried out by means of an independent system operator (ISO). To the extent feasible, the ISO creates and/or uses markets to provides these services. (For a classification of services according to active/reactive, actual versus insurance, and by time frame refer to Alvarado 1996a.)

LOSSES, CONGESTION AND SECURITY

This paper targets the "rules of the road" needed for a virtual utility to operate. To attain the FERC goal of non-discriminatory access to transmission, it is essential to come up with rules that ensure proper access to the transmission network. The key notion behind this entire discussion is that actions in a power system are intimately intertwined and cannot be readily separated. Action by one party affects other parties. Thus, before describing possible rules, we must discuss three important topics related to the *interactions* among multilateral transactions: losses, congestion and security.

Losses

Losses are an inevitable part of electric power transmission. While they generally are relatively small, often less that 5% of total power generated, several factors are worth noting:

1. While 5% may seem small, it is a substantial amount of power lost. More importantly, the *marginal* losses can be considerably higher, as high as 12%, 15% and even upward of 20%.

2. The losses vary by location (or, in the case of the virtual utility, by transaction).

3. Losses vary by time of day and by the presence or absence of other transactions.

4. There is a tradeoff between losses and the cost of capital equipment, so that larger transmission line conductors reduce losses but increase the required investment.

5. Losses and penalty factors are not the exclusive domain of generators: loads play a vital role in loss determination. Thus, penalty factors for loads are necessary. In fact, the penalty factor associated with a multilateral transaction is the composite of several injection and extraction penalty factors.

Total system losses can be determined by accurately metering power injections and loads. They can also be accurately calculated given the system parameters and the operating status or "state" of the system. Incremental losses are, by contrast, quite difficult to measure but relatively simple to calculate. A method based on the Jacobian of the transmission system matrix and the knowledge of the dispatch pattern or the desired transaction readily gives the incremental losses. The method is simple, both in concept and implementation (Alvarado 1978, 2031-2040).

- First, write and solve all the equations of power flow balance (power in equals power out) for each node in the network except the node with the "marginal unit" (also called the slack node). These equations are written in terms of voltages and phase angles at the nodes. Call these equations $f(x)=0$, where x represents the voltages and angles. A single additional equation for the power at the slack node is denoted by f s(x)=0.

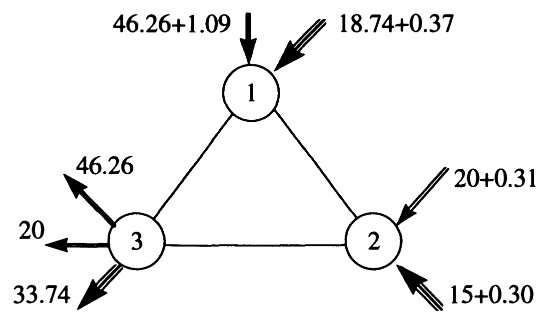
- Second, construct and evaluate the Jacobian matrix fx for this set of equations, leaving out the equation for the marginal unit. Also, separately, compute and evaluate the Jacobian vector for the marginal unit, fxs.

- Third, solve the matrix problem fx b = - fxs for b. The inverses of b are the penalty factors. A penalty factor of 1 at a bus denotes that 1 MW of power delivery at the bus requires the production of 1 MW (implying zero marginal losses). A penalty factor of 1.1 denotes that to deliver 1 MW of power the system needs to produce 1.1 MW of power. For reactive components, a penalty factor of 0.1 denotes that for an increase of 1 MVAR of power at a bus the system needs to generate 0.1 MW of active power.

Allocation of total losses to given users or transactions is another matter altogether. If one were to allocate total losses based on a sequence of incremental losses, the allocation would become "transaction order dependent" because marginal losses are greater for latter transactions. There is no unique answer to the problem of loss allocation. However, there appears to be a "reasonable" answer which is order independent. It is based on the fact that the total system losses can be expressed approximately as a quadratic function of the transaction levels. The greatest advantage of expressing losses as a quadratic function of the transactions is not so much to simplify the computation (there seems to be no inherent advantage to doing so), but the elimination of the order dependency in the allocation of losses to transactions. Obtaining the explicit quadratic expressions is not as important as knowing that the underlying function is quadratic. Specifically, *quadratic losses suggest allocation of losses among transactions proportional to marginal losses*. For the example in Figure 2, this method leads to the same distribution of losses illustrated in Figure 3.

Summarizing, every transaction has a precisely quantifiable marginal loss associated with it. It is possible to use the well-accepted methodology of penalty factors to compute the marginal losses for any transaction and use these marginal losses to allocate total losses.

Figure 3: Loss allocation based on marginal losses for each transaction. This allocation is not unique, but it is transaction-order independent.



Congestion

Congestion occurs when a given or proposed transaction cannot take place because of physical limitations of the transmission network. Congestion, as understood here, is a simple phenomenon: a given amount of power cannot flow on a given line or through a given corridor or set of lines with the consequence that the flow must be reduced. There are, however, no implications of cascading system failure or blackouts when considering these problems.

Figure 4 illustrates the congestion ideas in economic terms using marginal price-demand curves. The "ideal" or competitive equilibrium point E where marginal cost equals marginal benefit is not attainable because of congestion. The operating point under these conditions is B.[8]

If we assume, as is normally the case, that the equilibrium point in the presence of congestion is B rather than E, the following observations are true:

- The consumer foregoes some benefit (consumer surplus) H-B-E-F-G-H.

- The producer foregoes some surplus G-F-E-C-D-G but recovers additional profits H-B-F-G-H.

Point B is not the only viable operating point, it is simply the one that arises as a result of normal economic analysis. However, the spread between benefit and cost at the limiting congestion point gives rise to an opportunity cost. Any price in the "spread" is "viable" from the perspective of both consumer and producer in the sense that this price is above marginal cost and below marginal consumer benefit. If the supplier price is set at the upper end of this range, point B, this results in a consumer surplus loss. On the other hand, if a regulating or some other entity sets the price at the lower end of this interval, point C, consumer surplus is maximized while the supplier still meets its marginal cost requirements. However, unless some of the surplus is allocated to network expansion it may not be feasible for the transmission access provider to expand and remain profitable. Economies of scale in transmission facilities suggest that marginal pricing alone will not recover all capital costs.

Congestion presents a unique opportunity for a virtual utility. The effect of congestion is to "regionalize" the markets. It becomes impossible for parties outside the congested region to compete because of their inability to deliver the power. The well-publicized capacity rights[9] are a means for hedging against this possibility by those interested in competing within markets that may become congested.

Congestion in a radial line is quite simple: those downstream from the congested line form a regional market within which outsiders cannot compete. This is illus-

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[8] Although theoretically the jump would be to infinity, the magnitude of the jump is actually bound by the value of load interruptions, since at some point users would be willing to be interrupted.

[9] Capacity rights were introduced by William Hogan precisely as a means for hedging against congestion. A party wishing to guard against congestion may purchase capacity rights that make him/her indifferent in case congestion develops.

trated in Figure 5. If the line is not congested, both markets see a price of \$0.03/KWh. If the line becomes congested, the marginal cost to deliver power to bus 2 becomes \$0.07/KWh, even though power is still available at the lower price.

Figure 4: Congestion prevents attaining the natural equilibrium point E where marginal cost equals marginal benefit.

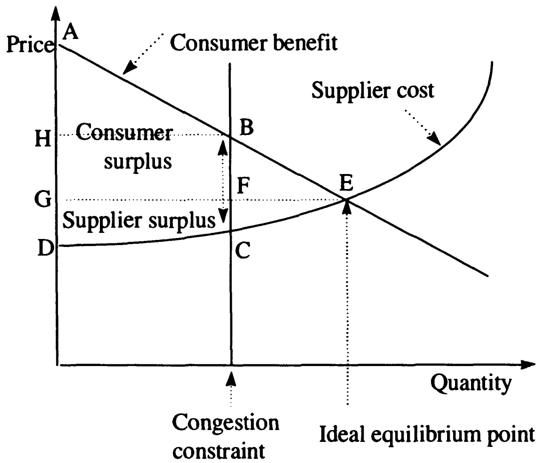
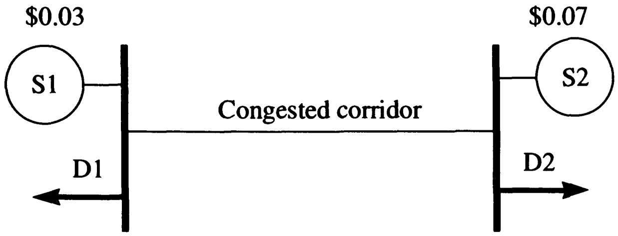


Figure 5: The presence of a congested corridor creates separate markets.

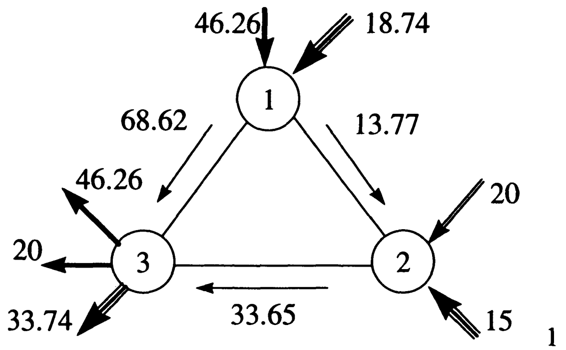


Congestion, thus, argues for the necessity of zonal or regional pricing. However, in a network situation the definition of the zones or regions is not simple, and small changes in flows that lead certain lines in and out of congestion can result in drastic changes in the zonal marginal costs.

Congestion can also be the result of voltage problems. In essence, the problem is that generally the value of reactive power is relatively small. However, under some conditions, availability of sufficient reactive power becomes absolutely essential to the ability to deliver real power. While reactive power can be provided by reactive power sources, reactive power can also be provided by almost all generators. Thus, under congestion conditions resulting from insufficiency of reactive power, generating units in the right locations can become far more valuable because of their reactive power capabilities than remote units (possibly even those with a lower marginal production cost). In simple terms, it is never desirable to have all generating units in one part of a large system, even though those units may be the most economical in terms of real power. The value of reactive power can make higher marginal active cost units desirable if the marginal value of both active and reactive power is taken into consideration.[10]

Congestion in a network is never simple because electricity flows through individual lines according to the laws of physics rather than according to contracted or agreed upon paths. For simplicity, the example from Figure 2 has been illustrated again in Figure 6, this time without losses (for expository simplicity) but illustrating the actual individual line flows. Observe the lack of correlation between injections, transactions and flows.

Figure 6: Illustration of actual flows in a network.



An understanding of the effects of competition under network congestion situations in a network can be gained by first considering an even simpler, two node case, as illustrated in Figure 7. This case consists of two transactions sharing the congested corridor. Each transaction has a single supplier S and a single consumer demand D.[11] The marginal costs of supply for each supplier, the demand marginal benefit functions and the equilibrium points are illustrated in Figure 8: equilibrium point(s) for a two supplier, two consumer case with no congestion. Ordinary economic analysis suggests the aggregation of S1 and S2 as well as D1 and D2 prior to analysis, as indicated. The natural equilibrium point is then E. However, this aggregation obscures one of the point of this paper: the possibilities that are afforded by the separation of the two markets.

Assume that congestion develops. Congestion does not constrain either transaction. It constrains the sum total of the two. This is illustrated in Figure 9.

[10] A cooperative solution to the problem of reactive power supply may give a different answer than a strategic solution to the same problem. That is, withholding reactive power by a supplier can increase the benefit to this supplier by creating a congestion situation that precludes competitors from participating in the supply of power within a given zone or region. Of course, proper valuation of the reactive power that a supplier can provide reduces this incentive.

[11] It is possible, of course, to aggregate both demands and both supplies and produce a single composite demand-supply curve. However, in this case we elect to treat each transaction independently to illustrate the interaction among the transactions, which would be lost in the composite or aggregate curve.

Figure 7: Illustration of competition effects under congestion conditions.

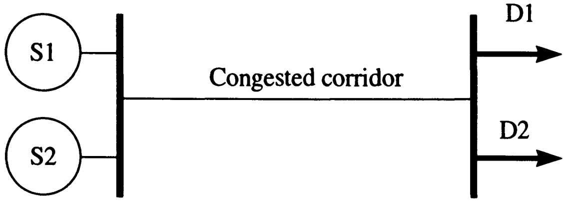


Figure 8: Equilibrium point(s) for a two supplier, two consumer case with no congestion.

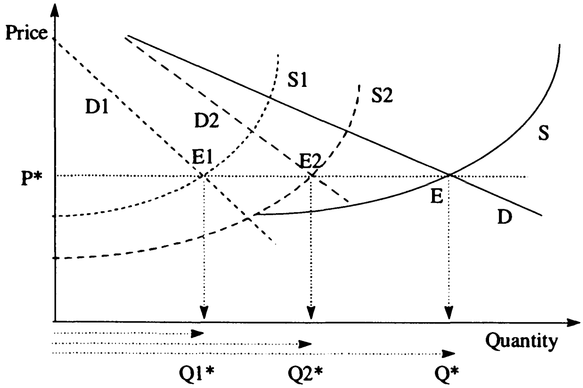


Figure 9: Effect of congestion when there is perfect interaction among two transactions.

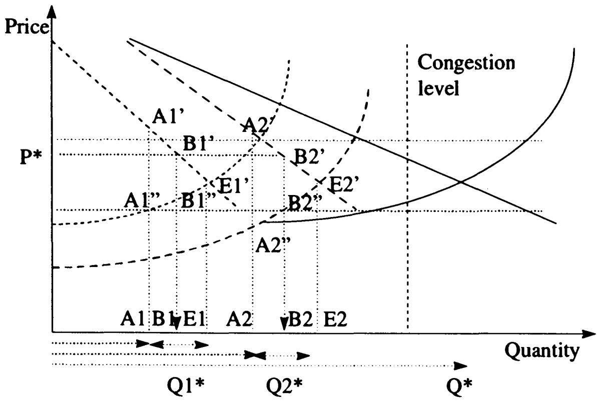
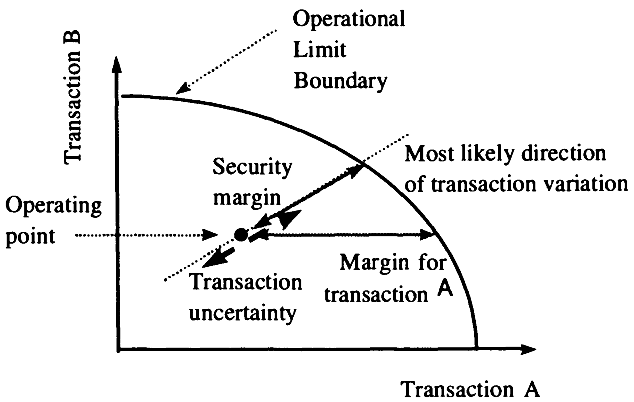


Figure 9 requires some explanation. Because of congestion, both optimal equilibrium E1' and E2' points may not be attained simultaneously. The equilibrium will have to be somewhere in the ranges Q1* and Q2*. The points indicated by price level P* corresponding to equilibrium points B1' and B2' results in equal consumer benefit. If this point is attained by pricing at levels B1' and B2' respectively, the respective consumer surpluses are lost but the consequent "congestion charges" give rise to income appropriate for congestion relief. As mentioned earlier, however, any price in the intervals B1'-B1" and B2'-B2" is viable from either the consumer or the producer viewpoint.

Figures 7, 8 and 9 consider the case of perfect congestion interaction: for every MW of demand increase in transaction A there is a corresponding 1 MW decrease available for transaction B. In a network situation things are not always this simple. In fact, several possibilities exist. It is essential to be able to formally quantify the marginal interaction between transactions at or near congestion points. This can be done by means of the notion of Operational Limit Boundary, or OLB. The OLB concept is illustrated in Figure 10. The distance from a given operating point in transaction space to this operational limit boundary is called the security margin. The nature of the OLB itself is not that important. What is significant is that only certain combinations of transactions are feasible before congestion is attained. Also important, as Figure 11 illustrates, is that changes in one transaction level may affect the margin for another transaction. In general, however, the relative effect of one transaction on another may vary quite a bit, from the case where one transaction has no effect on another, to the case where the increase on the level on one transaction can have a beneficial effect on the margin for another transaction. Several such situations are illustrated in Figure 12.

Figure 10: The Operational Limit Boundary.



The situation illustrated in Figure 12(c), where an increase in the level of a transaction increases the security margins of another transaction, always appears counter-intuitive. However, in situations where the OLB is defined by a congested line or corridor, any transactions that produces flows counter to the prevailing congested flows is beneficial from the perspective of system security.

Figure 8: Illustration of various interaction possibilities. (a) indicates that changes in transaction B have almost no effect on transaction A, but that changes in the level of transaction A can have a great impact on B. (b) illustrates the case of

almost equal interaction (as above). (c) illustrates the situation where an increase in the level of transaction A can be beneficial to B. (d) illustrates the case where there is interaction, but it does not matter since congestion is not likely to occur.

Figure 11: The normal direction quantifies the interaction due to congestion of transaction A on transaction B and vice-versa.

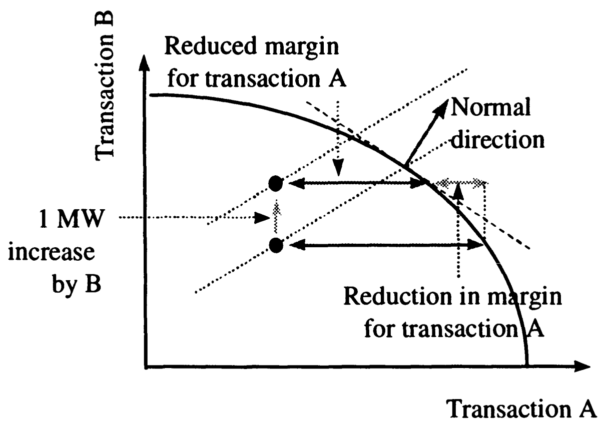
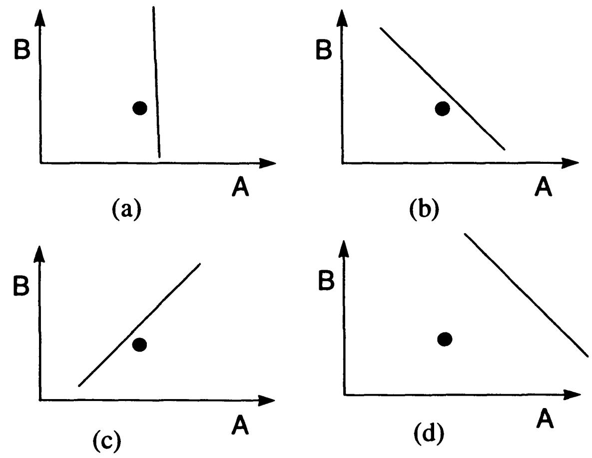


Figure 12: Illustration of various interaction possibilities. (1) indicates that changes in transaction B have almost no effect on transaction A, but that changes in the level of transaction A can have a grate impact on B. (b) illustrates the case of almost equal interaction (as above). (c) illustrates the situation where an increase in the level of transaction A can be beneficial to B. (d) illustrates the case where there is interaction, but it does not matter since congestion is not likely to occur.



We conclude this discussion by indicating that the determination of the normal direction to the congestion in transaction space is a solved problem using an extension of the Jacobian method described for the quantification of penalty factor computation. The details are not presented here.

Security and Security Costs

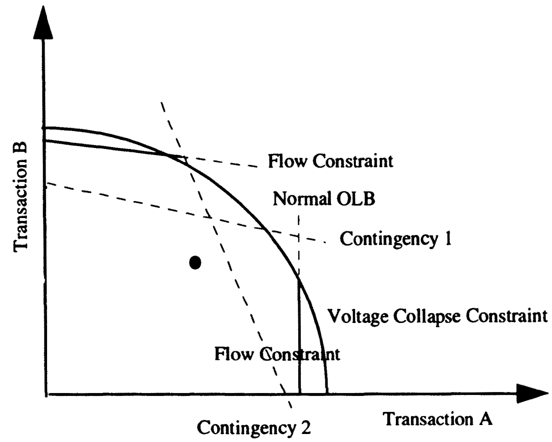
System security refers to the ability of the system to satisfy the demand at all times in spite of credible events such as line outages or generator outages. Security brings in *probabilistic aspects* into congestion computations. Events that may lead to unacceptable congestion may require that the system not operate in certain otherwise feasible regions. As defined above, the OLB defines a region in transaction space within which acceptable operation is possible under a given set of assumptions. Any operating point within this region is feasible. It is also assumed that any attempt to operate outside this boundary will result in the need to immediately and forcibly reduce demand, or risk a complete system shutdown. The cost of these outages can be quite high. Because the demand levels are uncertain, the location of the demand is uncertain. Thus, if the probability of the demand being outside the boundary is not negligible, there will be a cost associated with the probability that the Operational Limit Boundary will be exceeded (Alvarado, Hu, Stevenson and Cashman 1991, 1175-1182).

Because of the nature of electric load, the level of demand will vary. Of greatest interest is the point within the OLB at which the most likely direction of transaction variation intersects the OLB. Figure 10 illustrates a line denoting a direction within which the transactions are expected to vary. The distance to the OLB gives an indication of the probability of reaching the OLB under any set of conditions. The normal direction at the point where this line intersects the OLB gives a wealth of information about which transactions affect which other transactions, and it permits the quantification of the interaction among transactions. Given the distance and the normal direction, plus the cost of outages, a quantity called the "marginal security cost" can be computed for every transaction. This cost denotes the contribution of the transaction level to system security. It is the nature of security costs that they become rapidly negligible as one moves away from constraints.

Conventional economic theory suggests that, under conditions of congestion, efficient pricing takes place where marginal benefit equals marginal cost. Knowledge of the marginal security cost permits the development of pricing strategies where this is the case, by considering both marginal *energy* costs and marginal *security* costs within pricing decisions.

The OLB is not unique. It changes as a result of system events such as component outages. Figure 13 illustrates a number of hypothetical OLB regions from a number of possible events. In traditional engineering thinking, the true OLB is the innermost composite of all boundaries due to all credible contingencies. This viewpoint fails to consider the probability of the events. It also fails to take into consideration the possibility of some drastic action that may be effected (such as forcible interruption) that could be called upon in case one of these circumstances were to arise. The correct methodology constructs a probabilistic boundary

Figure 13: The OLB as the composite of several contingency OLB conditions.



The net result of taking these factors into consideration is a formal methodology for quantifying system security cost based on marginal outage costs and the probability of various system conditions that lead to that cost.

RULES OF THE ROAD

The requirement for open access to transmission facilities is likely to lead to a functional separation between transmission services on one hand, and generation and distribution services on the other. One vision can be based on the evolution of the model of bilateral transactions to permit arbitrary overlapping multilateral transactions. The complete separation between transmission and supply can be "softened" by transmission capacity rights.[12] The remainder of this paper assumes that, for all practical purposes, no virtual utility directly controls transmission assets. Although contracts can be negotiated between the transmission utility and the generation utility to provide for certain rights to the transmission network, these rights must be carefully considered. The viewpoint taken here is that the virtual utility is an entity that deals with aggregate supply and demand, and that a transmission utility establishes rational rules of the road under which the virtual utility must operate.

[12] A concern relating to a utility that owned both generation rights and transmission capacity rights is the similarity between such a utility and a more conventional vertically integrated utility, which would be an extreme case of a utility owning both transmission and generation.

Economically efficient operation of the system requires the use of marginal cost information in the operation of the system. Thus, the model proposed here assumes that all transactions take place on the margin and on a sufficiently small time scale. As a possible example, we can assume that half-hour bids and contracts will be managed.

This section summarizes possible rules of the road for a virtual utility to be able to function properly. The discussion is organized according to time frame. It is expected that operating a power grid will require actions within all these time frames, and that different suppliers may provide bids for operating within each of these. That is, some suppliers may be in a position to off bids to meet the operational requirements within one or another time frame better than some other supplier. Furthermore, bids and decisions on system operability will take into consideration the regionalization of the system, which in turn depends on available equipment and operating conditions.

Instantaneous Time Frame: A Few Seconds or Less.

In this time frame, the operator of a system is critically concerned with maintaining system integrity. If situations develop that require action within this time frame, the only likely mechanism for a system operator is to exert immediate control action, which may include load and/or generator disconnection. Thus, within this time frame it is probably necessary that parties using the system surrender ultimate control to the independent system operator for emergency actions. Even within this time frame, however, there are ample opportunities for a market to develop. An example of this is the design and utilization of no-notice interruptible rates. The challenge in the design of interruptible rates is to design them in such a way that a user remain indifferent to whether he/she has entered into these rates or not. Since availability of the system can never attain 100%, those wishing levels of service in excess of levels that can be provided by the system may (and do) rely on uninterruptible power supplies and emergency generator technologies.

More complex is the issue of dealing with security concerns in an anticipatory manner.[13] Once again, the system operator must be permitted to establish network limits based on security considerations. The impact of these limits on any transaction under any set of conditions must be made known. If the system does not attain a particular limit, security concerns are simply ignored. If the system reaches a condition where expected transactions exceed a limit, the security problem has been transformed into a congestion problem, to be dealt with as any other congestion problem. Thus, the system operator will be responsible for determining limits of

[13] The traditional criterion is the "n-1" criterion applied to transmission: the outage of any one piece of equipment should result in a still-operable system. Operating under conditions where this is not true is considered to be operation outside the OLB, and steps must be taken to make the system reliable. The viewpoint in this paper takes a probabilistic view of this same problem: the expected values of the security costs can be determined in an anticipatory manner using the methodologies described herein.

system operability and making this information available to all utilities participating in transactions.

Limits can be quantified by using the notion of an operational limit boundary in transaction space. For a given set of transactions, the distance(s) to the boundary(ies) are determined, and the normal direction(s) at the boundary are computed. This information is then translated into "security cost" components that are transmitted to all transacting parties. Using this notion, any action that moves the system away from the OLB fastest would benefit from these security costs, whether that action involves the curtailment of a transaction or the rendering of a new transaction as economically feasible.

Short Time Frame: From a Few Seconds to One Hour

In this time frame the operator of the system must deal with maintaining system frequency, dealing with congestion and minimizing and allocating responsibility for marginal losses.[14] The following are proposed means for an independent system operator to deal with these issues within this time frame:

- System losses are determined in real time based on actual operating conditions and the marginal impact of losses to any change in the level of any transactions[15] is determined at all times. There needs to be a monitoring system in place to compute these marginal losses based on system conditions. Under the (quite reasonable) assumption that losses vary approximately quadratically as a function of the level of the transactions, the total system losses at any time can be apportioned in direct proportion to the marginal losses.[16] The accurate computation of the marginal losses by the system operator is straightforward. Users of the grid will be given a choice of conducting "loss inclusive trades" (being told, for any transaction, by how much must generation exceed demand) or purchasing loss compensation services from the operator using a "pool price" which depends on system conditions.

- A virtual utility can reduce system losses by taking certain actions. This is particularly true for any reactive power resources. For example, at times injection of reactive power at certain locations can reduce losses. A transaction

[14] In systems of the future, the marginal losses can be used in an *ex ante* manner as penalty factors that are applied to bids, or these penalty factors can be used in an *ex post* manner as part of the settlement charges. For this latter approach to be economically efficient requires that the transacting parties know ahead of time their approximate magnitude of their loss settlement charges for each period under each system condition, so this information can be taken into consideration when bids are issued.

[15] Marginal losses for transactions can be computed by first determining the "bus-oriented" marginal losses with an arbitrary generator as the marginal unit, and then applying these numbers to the appropriate transaction.

[16] Disturbing as it may seem, there are cases where certain transactions are beneficial from the perspective of losses, where an increase in the value of a transaction reduces losses. These transactions will have a negative cost associated with them.

that included reactive power supply would benefit when marginal losses are computed if there is benefit to the reactive power. Information about reactive power needs must therefore be provided to suppliers in the form of economic signals (Dandachi, Rawlins, Alsac, Prais and Stott 1995). As an alternative, the system operator could have simply arranged for the purchase of reactive dispatch rights from suppliers of reactive power, to be dispatched by the operator as needed.

- Congestion can lead to the necessity to change the generation pattern of a system. It is relatively straightforward to compute the projection of the effect of any marginal multilateral transaction on a given congested flow. Coefficients can be sent to all parties regarding the directions incompatible with the congestion. As soon as congestion develops, a market for the relief of the congestion develops, fueled by the higher prices that those on the restricted end of the congestion will be willing to pay.[17]

- Security, like congestion, is a result of capacity restrictions in the transmission system. Unlike congestion, however, security is viewed as a condition that generally results from a contingency event, and the failure to act upon this condition can lead to a widespread blackout condition. One alternative to attain system security is to assign to the independent system operator the task of purchasing sufficient security, which may be done by paying suppliers to be on line and operate at less than their full output, in order to reserve some capacity for possible events and outages. Where does this money come from? Grid users who want a secure system.

Long Time Frame: Beyond a Few Hours

In this time frame, the system operator of a system is concerned about having sufficient bidders and sufficiently disseminated resources so that unusual congestion situations will not develop and that adequate voltage support will be available at all times. In this regard, the system operator may be in a position to disseminate information about expected system conditions and available equipment, load forecasts and predictions of possible future needs. Within this time frame, a virtual utility may seek to secure adequate capacity rights before entering into short term transactions to hedge against the possibility of congestion.

Within this time frame it is also possible to add transmission capacity. Because of the continued monopolistic role of the transmission grid, its expansion will probably have to continue to be regulated. Criteria for network expansion should be based on the determination of the common benefits that are attained by expansion.

[17] This is the reason why some in the industry have advocated the use of "capacity rights" to manage congestion, with the notion that the owner of capacity rights will be indifferent to the choice of delivering the power or being paid when the power cannot be delivered by the higher rents that will be collected as a result of the congestion.

That is, the optimal expansion of a regulated transmission access provider would be done much as it is today, based on the least cost overall expansion of the system taking into consideration not only the cost of the expansion itself, but also the expected value of the long term marginal benefits to all participants (including lower losses). This benefit accrues as a result of the expansion of the OLB to reduce security costs due to congestion, and also as a reduction of energy costs of transmission. The principles outlined in this paper can thus be used to assess the need for transmission additions.

CONCLUSIONS

In a power system, everybody interacts with everybody else, instantaneously and at all times.

- The rules of the road must be organized according to time frame, with different requirements but similar computational formulas for each.

- Congestion regionalizes power markets. Location always matters, but in the case of congestion it becomes quite important. As congestion levels change, so do the regions.

- Interaction can be quantified quite precisely using the distance to the Operational Limit Boundary and the normal vector at this boundary.

- It is essential that all computations be done *ex ante*.

ACKNOWLEDGMENTS

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DISCUSSION

Ilić, Hyman, Allen, Cordero and Yu, *The Walrus and the Carpenter: Two Views on Network Services for Virtual Utilities, Interconnected System Operations and Expansion Planning in a Changing Industry*

AND

Alvarado, *Rules of the Road and Electric Traffic Controllers*

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PROEM

The sea was wet as wet could be,
The sands were dry as dry,
You could not see a cloud, because
No cloud was in the sky:
No birds were flying overhead—
There were no birds to fly.

The Walrus and the Carpenter
Were walking close at hand:
They wept like anything to see
Such quantities of sand:
'If this were only cleared away,'
They said, 'it would be grand!'

'If seven maids with seven mops
Swept it for half a year,
Do you suppose,' the Walrus said,
'That they could get it clear?'
'I doubt it,' said the Carpenter,
And shed a bitter tear.

—Lewis Carroll

INTRODUCTION

Background

In the US, as elsewhere, the electric utility business is being transformed. Doing so will require sweeping away great quantities of existing regulatory and market structure. Although seventy times seven economists and engineers, regulators and citizens, professors and utility folk have been working away for more than half a year, we still have not got clear how this should be done.

What is a virtual utility? This paper was written in part on a flight from Amsterdam to New York. The ticket said "Northwest Airlines;" the airplane, the stewardesses, and the air sickness bags all said "KLM." By the magic of code sharing, Northwest maintained the illusion of transporting passengers across the water while dispensing with the accouterments (an airplane, stewardesses, and air sickness bags) that traditionally defined such service.

Similarly, the virtual utility meets specific customer energy needs without necessarily owning all —or any —of the physical plant which traditionally defines such service. Many traditional as well as non-traditional options are available to the virtual utility, including distributed generation, power purchases/sales, and demand-side management programs. Decision-making at the virtual utility is heavily influenced by the proper assessment and management of risk.

This paper is an invited review and commentary on two preceding papers by Alvarado and Ilić *et al.* The papers, from well-known sources, address issues of network architecture and standardization which are central to the virtual utility.

General Observations

Years ago, there were two main categories of engineering, each with its own approach to economics:

- *Military engineering, where the economic objective was to use all available resources to maximize the likelihood of the job getting done.* Eisenhower's approach to D-Day comes to mind: everything was thrown into the problem.

- *Civil engineering, where the economic objective was to find a way to get the job done cheap enough to make a profit.* If costs were too high, the job was abandoned. Costs and revenues were carefully analyzed in selecting an approach and in deciding whether to continue. Classic mining engineering is an example.

In the traditional vertically-integrated utility a third approach developed:

- *Define service standards, and build to those standards at the lowest possible cost, with a social agreement that revenues would be set to recover costs plus a modest profit.* Notice here an important decoupling of engineering and economics. The economic benefits to society were assumed to exist and were not quantified, economics of pricing withered to sterile accounting, and visible economics consisted only of straight-forward comparisons of present worth of costs.

In these two papers, and in fact in the debate on restructuring in general, there is a much more profound coupling between engineering and economics:

- *The power sector is modeled as a true engineering/economic system.* Alvarado and Ilić *et al* apply systems analysis tools, plus a knowledge of the engineering behavior of the power system, adding economic models and control mechanisms.

Need for integrated engineering/economics

This intimate union of economics and engineering, the only sensible approach to solving the problems of restructuring, is very challenging because there are so many areas where answers are not clear —and are obscured further by very simple idealized economic constructs which must be adapted intelligently to make a system work.

Need for care in applying economic prescriptions

[Alfred Kahn 1970] provides an illustration of this last point. He says that "The central policy prescription of microeconomics is the equation of price and marginal cost. If economic theory is to have any relevance to public utility pricing, that is the point at which the inquiry must begin." He then hastens to spend 21 pages explaining why this must be only a starting point: practical issues prevent an immediate application of straightforward idealized economics.

A thoughtful World Bank economist reaches similar conclusions, specifically with respect to pricing in developing countries, but applicable to the US as well: "Worshipping the principle of [marginal cost] pricing may do as great a disservice to economic efficiency as does the politicization of pricing issues. . . *Pricing has to be relieved of sacrosanct efficiency objectives and should come to grips with more mundane and immediate commercial ends.* . . . Generally speaking, responsive pricing or 'profane yet intelligent pricing' tends to rate better than strict or routine use of inflexible or unwieldy formulas that serve elusive efficiency goals or rest on ill-conceived arguments . . . ." [Teplitz - Sembitzky 1992].

Some services are needed but not wanted

Additional complications come from the fact that some services are of no direct interest to the virtual utility or its customers —they will not want to buy them —but are necessary to keep the network running for all parties.

Measurement

It can be tricky to measure the degree to which some of these services are in fact provided, and to unbundle and measure their costs and benefits. It is interesting to note that as the structure of the industry moves toward further disaggregation of the functions and services, analysis tools for measuring and simulating the behavior of the system are tending towards further *integration*. As Alvarado points out "In a power system, everybody interacts with everybody else, instantaneously and at all times."

Finally, we note that in the process of leaving the regulated environment, the electric industry will force development, at least in the transitional phase, of yet another engineering discipline:

- *Political engineering is needed to develop politically acceptable solutions to technical and economic problems.* The need to balance the economic interests of stakeholders with the political implications of potentially diminished authority by state public utility commissions will undoubtedly impact technical decisions. Also the dissolution of the regulatory covenant upon which investors made their decision to purchase electric utility stock will have political implications as investor/voters scrutinize the impact of various technical alternatives. One only has to follow the public hearing process on deregulation within any state to appreciate the diversity of forces which are trying to influence the final structure (and ultimately the technical framework) of the electrical utility industry in that state.

Road Map Through This Paper

Having subjected Gentle Reader to our philosophizing, we will give personal reactions to the papers of Alvarado and Ilić *et al.* We first summarize what seem to be their main conclusions and points, and then comment on these.

CONCLUSIONS

Both papers are highly theoretical; considerable research is required in order to implement their recommendations. Table 1 provides a comparison of the overlapping issues discussed in the papers by Alvarado and Ilić *et al.* We expand on these issues below.

Conclusions of Alvarado

Alvarado looks at three important time periods and proposes "rules of the road" *to be established by the system operator* for each of these. Every virtual utility must operate under these rules:

Instantaneous time frame (few seconds), where the system operator must have wide powers to deal with technical emergencies, largely ignoring economics. Rules in this time frame are:

- *Parties surrender control during emergencies.* Reliability of service may be negotiated. Those customers requiring high reliability levels may consider alternative options.

- *Operator determines and enforces security limits.* Alvarado formulates operating principles, for maintaining system integrity in a virtual-utility market. This includes the outline of an approach for sending price signals to drive the system away from a congested state, where part of the network cannot serve all contenders. The approach is to measure the distance in a state space from the current operating state to the nearest boundary of the feasible region. When the state gets too close to the feasible region boundary (referred to as the Operating Limit Boundary), price signals will be sent to encourage parties to take action which will drive the system away from the boundary.

Short run (seconds to hours), where economic signals are important inputs to system operation:

- *Operator determines and allocates marginal system losses.* Alvarado proposes a method for measuring I^2R (heat) losses on the network and allocating their costs to various parties. He observes that loss allocation is arbitrary, though it is true that the last MW of power flowing on a line causes higher losses than its predecessors. Alvarado suggests a quadratic method for allocating all losses. It avoids the nightmare (which is not consistent with marginal cost pricing) of having to attach priorities to each MW. The later (lower priority) flows shouldn't be charged for much higher losses than the earlier MW are.

- *Operator assesses reactive needs* and disseminates economic information to elicit the provision of these services or alternatively, pre-arranges for the purchase of such services.

- *Operator manages congestion.* Information is disseminated to all parties as to what transactions would make matters better or worse.

- *Operator purchases "security".* Alvarado extends his approach to dealing with security problems —defensive operation of the system to keep it at least one contingency away from cascading outages. This may be implemented by assigning to the system operator the task of "purchasing sufficient security."

Long run, where economic and technical signals affect planning:

- *Operators plan for security.* Ensuring that unusual congestion situations will not develop or that they can be dealt with effectively.

- *Transmission expansion planning.* Regulated activity, based upon benefits to be attained.

Conclusions of Ilić et al

Ilić *et al* focus on defining performance objectives for different levels of the power sector hierarchy. Their point is that these objectives can help guide the development of power sector structure, services, and control strategies for various players. Five short-run performance objectives are grouped under two headings.

A primary objective, characteristic of many other markets:

1. Meet MW demand at least cost (competitive profit-maximizing may maximize social welfare)

Secondary objectives, independent of the above, calling forth ancillary services which are unique to the electric power market:

2. Compensate for I^2R losses (A simplified approach is suggested for allocating these costs. The authors claim that most losses occur near the generator or load injection points. Therefore losses due to a particular transaction can be computed with local information only, without having to compute total system losses.)

3. Meet technical operating constraints (coordinated by fiat by the second-level system operator)

4. Provide flexible generation to balance load and generation in real time (coordinated by a single operator with system-wide authority)

5. Provide stand-by generation to cover outage of a single system element (mandatory insurance coordinated by second-level system operator)

They recommend iterative bidding for MW (objective 1), centralized purchasing/provision of services 3 and 5, and a combination of localized/centralized strategies for services 2 and 4.

In addition, Ilić *et al* formulate a set of performance objectives for system expansion planning. They argue that the resources for system control services must be created in advance, and that transmission planning must be integrated into the competitive environment by providing the right economic incentives.

COMMENTARY

Comments on Paper of Alvarado

Alvarado's three time frames make sense. Control actions during emergencies must be computed and implemented in a short period of time to avoid cascading damage. This is done most effectively in a centralized manner. Thus, establishing that parties must surrender control during emergencies makes sense. His approach to loss allocation is also reasonable, and should be applied for average or sampled states rather than trying to send this information to all players in real time. The real-time congestion and first-contingency and capital costs will dominate the loss costs; trying to capture losses' stochastic variations is gilding the lily.

Alvarado's approach to measuring the distance from a state to the boundary of the feasible region is very attractive. But a great deal of R&D is needed before the approach can be turned over to users. In particular, we are less sanguine than is Alvarado about the practicality of measuring the distance from an operating state to the edge of the feasible region, even considering congestion alone (dealing with security-defined boundaries is tougher). This is because i) the boundaries are state-dependent and constantly changing, ii) they represent a higher-dimension surface which is hard to compute and characterize, and iii) the nearest boundary point may not be the only or most critical one.

Table 1. Comparison of Papers.

Alvarado	**Ilić *et al***
Assumed Industry Structure:	**Assumed Industry Structure:**
• Independent System Operator	• (Independent) System Operator
• Multi-Lateral Transactions	• Poolco, Bilateral, Hybrid
System Operations:	**System Operations:**
• Market for MW	• Market for MW
• Network Services:	• Network Services:
— *Losses*. Determined ex-post, allocated according to a quadratic method. Losses may be provided for in "loss inclusive trades" or purchased from operator. Reactive supply may be coordinated to reduce system losses.	— *Losses*. Estimated and made-up *locally* by each player. May apply to both active and reactive losses.
— *Congestion*. Send price signals to drive system away from a congested state.	— *Congestion*. Centralized (Responsibility of System Operator).
— *Dynamic Regulation*. Centralized (Responsibility of System Operator).	— *Dynamic Regulation*. Distributed control with the system operator providing limited coordination.
— *Security*. Operator may purchase "sufficient" security.	— *Security*. Operating reserves to be coordinated by the system operator.
System Planning:	**System Planning:**
• Operators plan for long-term security.	• Generation resources required for security must be created in advance.
• Transmission expansion planning is a regulated activity.	• Transmission expansion planning is also regulated. Generation/transmission trade-offs. Risk management associated with transmission congestion is key.

In existing utility practice, transmission congestion limits are determined from security concerns. We note that the computation of such limits may become a subject of contention and debate in an increasingly competitive industry. This is so since most security criteria (such as n-1) are deterministic and somewhat arbitrary, in the sense that it is difficult to quantify with any accuracy the benefits associated with their enforcement. Eventually, this may precipitate the adoption of probabilistic security criteria.

We are doubtful that "security cost" signals transmitted to all parties will entice these to back-off from transactions that cause congestion in the instantaneous time frame, as proposed by Alvarado. In addition, actual congestion/security limits enforced by the system operators must be as consistent as possible with the limits disseminated in advance. This is a difficult task since transactions affect limits and vice versa. In order to avoid setting limits which are too conservative, rules must be established beforehand to give the operator room for control.

Alvarado observes that when the network is constraining, there is a consumer surplus, part of which should be dedicated to reinforcement. A problem is that once the reinforcement is done, the consumer surplus vanishes, sending a perverse signal to the transmission owner *not* to reinforce.

It seems incongruous to price goods which are as highly capital intensive as electricity services on the basis of rapidly varying short-run costs.

Prof. Schweppe [1979], whose paper on homeostatic control is a classic in exploring the competitive market, noted that little optimality is lost by averaging over reasonable periods.

Comments on Paper of Ilić et al

The authors' observation that most losses due to a particular injection (generation or load) are local is intriguing and appealing. It is certainly consistent with the fact that changes in injections in Maine will affect flows in New Hampshire but not in Georgia. This issue deserves more attention, particularly in the case of geographically-widespread multi-lateral transactions. Also, it is important to determine whether losses, as calculated by the method advocated by the authors, are "transaction-order" independent.

This paper makes implicit the horns of the compulsion-vs.-pricing dilemma; i.e., on the one hand, we want to reduce centralized control as much as possible, but on the other, we do not know how to set up a completely price-based market with decentralized decision-making that will maintain system integrity.

Ilić *et al* propose a mixed market embodying both centralized control and wider use of pricing. This seems attractive. They assume a hierarchical structure, including control at the system-wide level (e.g., the eastern interconnection).

This highest-level control seems unattractive. Today, the main system-wide function is to adjust frequency set-points occasionally to true-up clocks. This is done voluntarily, costs nothing, and causes no inconvenience —and is at heart a nicety. Although some [e.g., Hirst and Kirby, 1995] assume that this function must be performed, and at a system level, we do not see the need for it. Anyone who needs highly accurate time better have a quartz clock. All mechanical and digital clocks drift —and even a synchronous clock will systematically lose time just because supply is interrupted, even if for a few seconds, due to random outages. Clock error is really just a measure of how well the utilities are matching generation to load by valve action rather than from rotating inertias.

The second, next lower level control is (we suppose) a pool or a regional transmission network. At this level, it seems reasonable that decisions will be made regarding standards of reliability, etc., with inter-regional consultation as at present. We do not see the need for standards imposed on high at a system level.

An important point raised by Ilić *et al* is that standards and procedures developed for a power system composed of a few large vertically-integrated utilities cannot be grafted to a much more fragmented market. Most obviously, it costs little for a utility with 50 units to keep one spare as protection against an outage. For a one-unit EWG to do the same would be prohibitive. Developing appropriate standards needs careful thought.

EPILOGUE

'The time has come,' the Walrus said,
'To talk of many things:
Of shoes—and ships—and sealing-wax—
Of cabbages—and kings—
And why the sea is boiling hot—
And whether pigs have wings.'

—Lewis Carroll

Paraphrasing O. Henry, there is stuff in the virtual utility to satisfy the most garrulous of walruses, to drive the least lachrymose of carpenters to tears, and to populate the alternative realities of the most fantastic of poets.

Certainly to design a new market, replacing a century-old structure, is a task to be taken with great care. In particular, the virtual utility will require careful attention to engineering and economic definition of transmission services, as well as the development of methods to measure and charge for them.

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Part VII

From Monopoly Service to Virtual Utility

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THE FUTURE STRUCTURE OF THE NORTH AMERICAN UTILITY INDUSTRY*

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ABSTRACT

A dramatic restructuring is under way in the North American electric utility industry. The structure of vertically integrated utilities operating in protected territories will be replaced by one of "value networks." We examine the regulatory, market and technological forces leading to the new industry structure. We describe five major changes that we believe will result as the industry becomes more competitive and customers have choice. We discuss how these changes will result in six industry

* Jay Michaud, a vice president of Index's Genesis research service, also contributed to this article.

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segments: generation, transmission, distribution, power markets, energy services and information technology-based products and services. Then we explore what utilities must do to move from vertical integration to value networks.

1. INTRODUCTION

The $250 billion U.S. electric power industry is in the midst of a transformation of historic proportions. The industry structure of the past — vertically integrated utilities operating in protected geographic markets — will soon go the way of the gas lamp. Participants in the future electric power marketplace will be more diverse in their corporate structure and product offerings. Some will operate in narrow niches and others across state and even national geographic boundaries. All will focus on specific areas of competence and, as a result, may be forced to invest in a narrower range of assets and earn a return for their investors in a broader range of ways.

In this paper, we outline a new utility industry structure. We discuss the factors that we believe will lead to an industry that fragments into a wide range of service providers in an expanded range of businesses. We explain how the disparate segments will be linked together to serve customers through three emerging types of "value networks" rather than integrated providers. The first value network will be based on regulated boundaries. The second will be based on linkages created by "virtual" utilities — firms that supply a range of energy services but no longer own all the assets necessary to supply these services. The third will be based on customer-initiated linkages. As a result of these new networks, customers themselves will be able to more easily assemble a panoply of power services that best suits their unique needs.

The purpose of this paper is to paint a vision of this emerging future. We are cognizant that such predictions are always risky and that nobody possesses a crystal ball. Nevertheless, we believe that articulating such a vision is critical because it helps shape the debate and thus, indirectly, the evolution of the industry. Our vision is based on analogies drawn from other regulated and unregulated industries that have undergone similar dramatic changes. In addition, we extrapolate from current utility industry initiatives that provide a glimpse into what the future might hold.[1]

In articulating our vision, we start with the factors forcing a restructuring of the power business — a restructuring that is moving utilities from vertical integration to a newer structural form, "virtual value networks." We then describe how the industry will evolve into six discrete business segments, from power generation to energy services. Dominating each segment will require different core capabilities. Utilities will have to learn or import many of these capabilities from industries

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[1] Mitchell, Bridger, and Peter Spinney. 1996. "Public Utilities, Technological Change, and Industry Structure," in paper submitted to the Symposium on the Virtual Utility [April 1996]. Mitchell and Spinney highlight the benefits, as well as the limitations, of reasoning by analogy. They show areas in which there are close parallels — yet sharp differences — between deregulation in the telecommunications industry and the electric utility industry.

where competition, powerful customers and choice have prevailed for years. Furthermore, the market leaders in each business segment may come from outside the traditional boundaries of the utility industry. We then describe three value network models that might define the future structure of the industry. Finally, we discuss the challenges that the vertically integrated utility of today will face in migrating to this future.

When one examines the forces affecting the electric power industry, it seems likely that a competitive market will emerge and trigger a radical restructuring of the industry. Three major forces — regulatory, market and technological — will ultimately lead to a disaggregated industry with great opportunities for those who can organize the overall value chain for consumers.

1.1 Regulatory Forces

The regulatory forces in the electric utility industry are properly seen as part of a broader wave of deregulation that has swept across America since the 1970s. During the Carter administration, it became apparent that the regulatory framework that had served us so well since the Great Depression was no longer viable and needed to be overhauled for the future competitiveness of the nation. In industry after industry, from airlines and trucking to banking and telecommunications, we increasingly have come to rely on the invisible hand of the market rather than the visible hand of government (Vietor, 1994). In each case, old industry structures have fallen by the wayside, and new ones have emerged.

In the electric utility industry, the 1970s marked the breakdown of a consensus among regulators, utilities, consumers and the public that had existed since the turn of the century. The foundation of the consensus was a long period of national prosperity, cheap energy and ever-rising energy demand. But with the first oil shock in 1973, this consensus began to crumble. Energy prices shot up, becoming a significant item in the bills of consumers and corporations. Utilities, saddled with higher costs (in part due to uneconomical nuclear power plants), increased their rates significantly. Dealing with public outcry, regulators in many states were forced to hold down rates, which in turn led utilities to halt projects adding generation capacity. Regulators countered again with the passage of PURPA in 1978 to attract alternative suppliers to the market (Navarro 1996; Hyman 1994; Hirsh 1996).

By the 1980s, a whole new independent power producing (IPP) sector had been formed. IPPs have used primarily cogeneration technologies to provide cheaper power to their customers. In the 1980s, IPPs built the majority of new power capacity, creating competition in the wholesale market. From 1980 to 1992, the percentage of total U.S. electricity generated by nonutility sources rose from 2.9 percent to 9.9 percent (Hyman, 1994, p. 150). As a result of this cheaper power, customers and legislators have pushed for greater competition within the wholesale market through the 1992 Energy Policy Act, which mandates access to the transmission grid for wholesale wheeling. States regulators were left to decide whether they wanted to extend this policy to retail wheeling.

The breakdown of consensus has led to a plurality of regulatory directions. California, Massachusetts, Michigan, Illinois, Connecticut, Minnesota and Rhode Island have moved aggressively to enhance competition. States like Maryland, Pennsylvania and Texas have resisted. Confronted with this plurality, many utilities are trying to influence regulators in their states to preserve the status quo, although these efforts seem more like trying to plug a breach in the dam with one's finger. As Vietor's (1994, p. 328) case histories of regulatory forces in other industries clearly show, "regulation can depart only so far from economic or technological realities before becoming unworkable. ... Regulation needs to work with market forces and technological progress, rather than against them."

1.2 Market Forces

The market forces for change are coming from both consumers and producers. Even though retail wheeling is not yet permitted in most states, consumers increasingly have been finding ingenious ways to step around these regulatory barriers. Navarro (1996) documents some of the clever ways in which customers have breached regulatory barriers. A particularly interesting case is the community of Falls Church, Virginia, which recently decided to seek an alternative to the perceived high electricity rates of Virginia Power. The community purchased a set of meters and applied to the Federal Energy Regulatory Commission (FERC) to be considered a distribution company that could buy wholesale power from any other supplier, thereby forcing Virginia Power to provide transmission access. Virginia Power has appealed this petition, but it shows the rising trend for consumers to use strategies such as municipalization to procure the cheapest power prices they can.

This example should not be considered an isolated instance. Consumers have growing pressure to cut their power bills. Since the 1970s, real household incomes in the U.S. have been flat or declining. With less disposable income, residential consumers are no longer willing to pay high prices to their local utility if they can get cheaper power elsewhere. A 1993 study by Cambridge Energy Research Associates found numerous instances in which residential customers were paying electricity charges 50 percent higher than the charges being paid by their neighbors in a geographically contiguous area. Such disparities are simply untenable, and, as the Falls Church example shows, consumers will not let regulatory barriers restrict their economic interests.

Industrial consumers have been even more aggressive than their residential counterparts, since energy costs comprise approximately 5 percent of total operating costs of most manufacturers (and as much as 30 percent in such energy-intensive industries as aluminum processing and steelmaking), manufacturers have significant incentives to reduce their energy bills. The case of Raytheon Co., a multibillion-dollar firm and one of the largest employers in Massachusetts, is instructive. Like many U.S. manufacturers since the 1970s, Raytheon has been losing market share to lower-cost domestic and international competitors. Raytheon, one of the largest employers in Massachusetts, has threatened to move much of its manufacturing out of state unless it is granted markedly lower rates by Boston Edison. Companies in many other industries have adopted similar tactics, including switching to lower-cost suppliers through municipalization.

In utility circles, most discussions on market forces center on consumer demands, although equally strong competitive forces are being unleashed by power producers themselves. A good example, also provided by Navarro (1996), is that of Sithe Energies in New York, an IPP that aggressively moved into Niagara Mohawk's territory and signed contracts with two of its major industrial customers. The recent spate of mergers and acquisitions in the utility industry, including hostile bids, clearly shows the increasingly predatory behavior of power producers themselves. With producers facing limited growth and declining earnings prospects, such competitive behavior is to be expected. Indeed, to attract capital and satisfy shareholder demands, utilities may have little choice but to abandon their friendly competitive restraints of yesteryear. The electric utility industry should prepare for brutal competition, much like we've seen in airlines, trucking and telecommunications.

1.3 Technological Forces

The experiences of other industries also suggest the powerful disruptive effects of technological change. Research has shown that radical technological innovations such as radial tires, mini-steel mills, the personal computer, digital switching, automatic teller machines and wide-body aircraft can transform industry structure and destroy the competitive advantage of entrenched industry leaders (Tushman and Andersen, 1986; Utterback and Suarez, 1996). The utility industry is confronting the possibility of such technological discontinuities in every segment of its value chain.

The largest technological force for change has been the end of economies of scale in generation technology. From 1949 to 1965, the cost of an incremental kilowatt of generating plant capacity fell 37 percent as the size of the generators increased (Hyman, 1994, p. 116). In addition, Yeager (1994, p. 27) reports that as the power industry approached the thermodynamic limit of the Rankine steam cycle, the coal-pound equivalent to produce a kilowatt-hour declined 23 percent (Hyman, 1994, p. 117). Since then, however, newer generation technologies such as combined cycle and cogeneration plants have been producing power at efficiency levels of 54 percent to 84 percent vs. conventional power plant efficiency level of 35 percent to 48 percent (Smith and Thambimuthu, 1992, p. 43). Another new force in generation has been the advent of cheap, renewable energy sources such as wind and solar (Hoff and Herig, 1996).

In transmission, there have been major improvements in power control technologies. Some companies are experimenting with DC transmission that does not need transformers. If this technology comes to fruition, it will allow us to double the capacity of the current transmission grid and may reverse the battle between AC and DC transmission won by Westinghouse over Edison at the turn of the century (Hyman, 1994; Watley, 1994).

On the distribution end of the industry value chain, information technology is emerging as a powerful force of change. New technologies — such as high-speed powerline networks, automated real-time meters and other "gateway-to-the-home" devices, and the rise of the ubiquitous Internet — have made it possible for the marketer and seller of electricity and related services to be distinct from the provider of electrons (kwh) (Buday, Champy and Nohria, 1996; Dar 1995). This fundamental shift in the relationship of utilities to their customers means utilities are in danger of losing all direct contact with customers and of being relegated to the commodity end of the business. Retail stock brokerage firms have experienced this disintermediation first with the rise of discount brokers and now with the advent of on line trading, such as Charles Schwab's e.trade. New, on line intermediaries in automobiles, real estate, employment, media, banking and other industries are proliferating on the Internet, threatening to separate traditional producers from their end customers (Buday, Champy and Nohria, 1996).

These three forces and their disruptive potential cannot be reversed. Utility executives will have to understand how these forces will affect the cost of their product, the purchase and delivery of value-added services, and their relationship with customers.

2. FIVE ASSERTIONS ABOUT THE FUTURE

The experiences of other industries that have confronted the confluence of the three forces — regulatory, technological and market — indicate that, in general, industry boundaries were expanded, barriers to entry were lowered or eliminated, markets were increasingly segmented, new distribution channels were created, prices were reduced, pricing mechanisms were more complex and diverse, and new products and services proliferated (Vietor, 1994: pp. 319–322). In this section, we build on the experiences of these industries to place some directional markers for the future economics of the utility industry. In putting these five stakes in the ground, our purpose is not to invite quibbles about whether the numbers are exactly on target; it is difficult to forecast such things with accuracy. These numbers represent our best guess about the magnitude of the changes that the utility industry must confront.

2.1 Prices

It is widely held that the restructuring under way in the utility industry will cause the unbundling of electricity prices. We estimate that competition and consolidation will result in as much as a 40 percent decrease in the average wholesale price of electricity, from around 5 cents/kwh today to at least 3 cents. The typical industry benchmark for the wholesale price of electricity in a competitive market setting is 3.5 cents (Studness, 1994). We think our 3-cent estimate is more realistic, based on our surveys of more than 80 utility executives.[2] The primary reason we believe the price might be lower than conventional industry forecasts is that the utility industry is much like the airline industry: There is significant overcapacity and the marginal price of the product is close to zero. Moreover, new capacity can be added quickly and at little cost disadvantage. As Lester Telser, a prominent economist at the University of Chicago, has argued, in such markets price competition can be vicious and show little restraint. The experience of the U.S. airline industry is a case in point (Smith, 1995). Average ticket prices have declined steadily since 1978, and the airline industry hasn't posted operating margins (before interest and taxes) of better than 5.5 percent since deregulation (Ghemawat, 1995). In the last five years, the industry as a whole has lost nearly as much money as it has made since its inception in 1914. Yet price wars continue unabated (Smith, 1995, p. 43).

2.2 Contracts

Building on the experience of the natural gas industry, we project that the ratio of long-term to short-term contracts for electricity will decline rapidly. Long-term contracts for the gas industry went from 90 percent to 80 percent in 18 months after FERC issued order 380, and the spot market quickly grew to 2.5 trillion cubic feet on a total market of 18 trillion (Vietor, 1994, p. 146). In the first nine months of 1994, the spot market for electricity was approximately $250 million, up from $50 million in all of 1993 (Simon, 1994). This dramatic rise makes us predict that the spot market for electricity could be as large as 30 percent of the total market, which will open up a whole new industry segment in risk management, including electricity futures contracts, exchanges and power brokering.

2.3 New Products and Services

One of the outgrowths of deregulation is a flurry of new products and services related to the core product. For example, since the breakup of AT&T in 1984, the telephone industry has been a hotbed of innovation in products and services. New products and services include 800 and 900 numbers; Intra-LATA WATS options; improved customer equipment, such as PBX and sophisticated telephones, calling plan discounts and software-defined services, such as call waiting, caller identification and voicemail (Vietor, 1994, p. 222, p. 226). The industry has also expanded into other related products and services such as publishing, cellular, and information services. A study of the seven regional Bell operating companies showed that by 1994, 10 years after deregulation, over 30 percent of their revenues came from sources other than local phone service (Noda, 1996). We predict that growth in the electric utility industry will come primarily from such new products and services and that the most successful utilities will derive a similar proportion of their revenues from services other than kilowatt-hours.

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[2] Surveys were conducted at CSC Index utility conferences [February and July 1995].

2.4 Global Scope

With the prospect of little growth in total U.S. demand for electricity, utilities will have to go abroad to grow, in addition to expanding beyond their core service domestically. Most of the demand for new power will come from Asia, including China, India, Indonesia, Vietnam and other rapidly developing countries. The pursuit of global markets is a well-developed strategy in other deregulated industries: AT&T, for example, pursued this option with its 1988 purchase of a 20 percent stake in Italtel. MCI, Sprint and others have made major overseas investments since then. This trend, it seems, will be mirrored by electric utilities, such as CMS Energy, that have built or are participating in the management of power production facilities in developing countries, as well as others like the Southern Co., UtiliCorp, and Central and South West that have acquired distribution entities or entered into joint ventures in Britain, Australia, Canada and New Zealand.[3]

2.5 Information Intensity

In industries such as airlines and banking, the need for information to support the making of markets (and, thus, the growth of information technology to handle the transactions) has grown exponentially. A similar pattern has occurred in the natural gas industry. To improve the way gas is tracked, marketed and accounted for, this industry has invested heavily in information technology over the last 15 years (Amey, 1996). There's no reason to expect the electric utility industry will behave any differently. In an industry in which power is increasingly sold as a commodity on open markets, the amount of information and computer technology to make efficient markets will grow exponentially. Consider the simple problem of residential metering. Meters in most U.S. homes are only read monthly. To enable real-time pricing of residential electricity rates would require gathering, processing and distributing this information on a minute-by-minute basis, which can only be done through sophisticated information technology. Ideally, each electron should be a "smart" electron — i.e., having information associated with it, such as who generated it, who needs it, how it was used and when it was used (Dar, 1995). Given this need, we estimate that in the next five years, assuming that information will be available at least on an hourly basis, the information intensity of this industry will be at least two orders of magnitude greater than it is today. Certainly, supporting these information flows will require substantial investments in computers and communications technology. Equally, there will be a payoff from these investments because the information and its processing will be priced and sold separately.

While these five directional markers — prices, contracts, new products and services, global scope and information intensity — do not represent an exhaustive set of parameters for thinking about the future of the industry, we believe they are among the most important because they provide concrete indicators about costs,

[3] *Forbes*, July 4, 1994, p. 66, and *Wall Street Journal*, August 8, 1995, p. B5.

revenue sources and investments that will be necessary. Even by themselves they have profound implications for the future structure of the industry.

3. SIX FUNDAMENTAL SEGMENTS OF THE INDUSTRY

The need to make dramatic cost reductions, to increase revenue from sources other than kilowatt-hours, and to expand globally will force utilities to bring unprecedented focus to the three "traditional" segments of the energy value chain: 1) generation, 2) transmission and 3) distribution. In addition, the opportunity to participate in national energy markets and to capture a profitable share of the emerging energy services and information based-businesses will expand the energy value chain to include three new segments: 4) energy services, 5) power markets, and 6) information technology-based services and products. We believe these six segments will define the electric power industry of the future.

3.1 Generation Companies

Future generation companies, operating in a marketplace characterized by customer choice, eventually will have to sell power for an average of 2.5 cents per kilowatt-hour at the wholesale level, about half the current rate. This will force companies to find ways to dramatically reduce both their embedded and operating costs. The generation sector will split into two camps: those companies that achieve unprecedented cost reductions through scale economies in operations and fuel procurement and those companies that employ radical new generation technologies that dramatically lower per kilowatt-hour cost.

We predict that a half-dozen or so utilities will end up as mega-generators, controlling perhaps 80 percent of total generation capacity. The remaining 20 percent will be sourced from many niche generators employing advanced generation technologies. This will be a far cry from today's vertically integrated industry structure, in which the largest producer (Southern Co.) has only a 3 percent share of the total U.S. market.

So far, regulators of the electric utility industry have permitted a number of utility mergers, including Cincinnati Gas & Electric with Public Service of Indiana (now CiNergy); others such as Wisconsin Energy with Northern States Power, and Baltimore Gas & Electric with Potomac Electric are being evaluated. We believe that many other deals will gain approval as regulators pore over the prospects of cheaper power from the elimination of duplicative costs.

However, these mergers are only the first stage in the consolidation of the generation sector. Future deals will become very complex and will involve swapping or selling assets or spinning off business units and not just the merger of two vertically integrated utilities.

The railroad industry went through a similar consolidation after deregulation. By 1985, mergers and acquisitions had produced six very large railroads that comprised 76 percent of the nation's rail mileage, 82 percent of total rail revenues and 85 percent of railroad ton-miles (Vietor, 1994, p. 14). This trend toward consolidation has continued in the 1990s with the merger of Burlington Northern and Santa Fe, Union Pacific's purchase of Chicago & North Western and the proposed $3.9 billion merger of Union Pacific and Southern Pacific. Indeed, in most mature industries, there is a tendency for production to be dominated by as few as three major companies. While this degree of concentration may not play out in the power industry, it provides a sobering benchmark for those who continue to see a fragmented generation sector (Sheth, 1996).

One perceived impediment to the consolidation we predict is the magnitude of the stranded asset problem (estimated to be as large as $300 billion). In a recent study, Charles Studness [1994] points out that the bulk of the stranded asset problem is due not to the high fixed costs but to the high variable costs of today's high-cost producers. Indeed, he notes, if every utility in the country were to be managed more efficiently such that their variable costs were equal to the industry leader today, the magnitude of the stranded cost problem would diminish to no more than $30 billion (Studness, 1994).

We think that the most efficient operators of tomorrow will, in fact, be able to operate at a variable cost that is lower than the best-in-class today.[4] Thus, the core capabilities of the survivors in the generation business will be cost management and operating efficiency.

3.2 The Intelligent Transmission Network

The emergence of full-fledged retail wheeling (through pool purchases and contracts for differences as well as pure bilateral contracts) will require enormous amounts of data to be captured, processed and made available to buyers and sellers of power. As transmission traffic becomes more complex with many buyers and suppliers all making hourly deals, unprecedented scheduling and control of the flow of power will be required. Thus, full open access will give rise to the intelligent transmission network — a national, "smart" power grid.

The early stages of open transmission access now being defined by the FERC,[5] is forcing utilities to make their proprietary transmission systems available to others for wholesale bilateral contracts. While many questions are left unanswered, it is clear that information requirements will be orders of magnitude greater than in the past. Responding to this reality, the FERC has requested comments on Real-time Information Networks (RINs) to make transmission availability and costs transparent to prospective buyers.

[4] Evidence of this can be found in the natural gas industry, where the variable costs of the average gas pipeline today are lower than the lowest variable costs 10 years ago [CSC Index internal study, 1996].

[5] FERC, through its Notice of Proposed Rulemaking (Docket No. RM95–8–000), the so called "mega-NOPR."

An alternative open access model is being explored in California, where the Public Utility Commission is considering the creation of two new transmission entities: the Independent System Operator and the Western Power Exchange. Electricity would be auctioned on the power exchange, where the lowest bid and asked prices would be matched. That power would then be scheduled and dispatched to utility distributors by the independent system operator (who is not under the utilities' control). This model (essentially a pool model), will also require vast amounts of information.

Clearly, those who succeed in the transmission business will have strong core network operating and grid maintenance capabilities. These transmission companies may well extend their scope to include gas pipelines and other transmission systems.

3.3 Distribution Companies — The WireCo

The segment of the value chain between transmission and the end power customer will split into two components. Some companies will specialize in stringing, maintaining and enhancing the distribution system to meet consumer needs while providing basic customer service and simple billing. These "WireCos" will remain regulated by the state utility commissions. Other companies will evolve to provide expanded and new services to end customers. This set of companies will be discussed in the section following.

For WireCos, life will look much like it does today in the distribution business segment — they will deliver power to all customers within their service territory. The WireCos will comprise all functions and processes needed to acquire power and to design, construct and maintain the distribution.

However, these companies may lose direct contact with many of their customers to intermediaries. They would be left providing access to these intermediaries (much like in transmission) and providing "full" service only to small customers who have either little opportunity to leave (read: the less attractive customers) or who have simpler needs. More affluent customers, most commercial accounts and the large commercial and industrial customers will be served by sophisticated intermediaries providing home and energy management services as well as power brokering.

The WireCo of the future will actually be a very good, low-risk business. Adequate returns could be ensured through an enhanced regulatory model that would provide for increased profit potential through a variety of incentive regulation schemes. In all probability, the assets of the WireCo will be written up through the breakup of the integrated utility. This will only serve to help offset any stranded investments the integrated utility may face and increase the revenue level of the WireCo. The ultimate return on investment in this business will still be controlled by the regulators.

Of course, the WireCo will serve all customers (including some who have poor payment histories), putting pressure on earnings. Regulators may deal with this type of issue through an access charge that all users of the distribution system will pay.

Or legislation will take care of delinquencies through a state-wide tax. In any case, it is clear that these "bare bones" distribution companies will be held harmless to preserve universal access (the successor to "obligation to serve").

There could be consolidation in this segment, too, because the key here will be operating costs and logistics. Current municipalities may discover that it makes little sense for them to own and maintain local wires and that more reliable and effective service can be provided by a bigger utility. One power distributor we know of is exploring such a partnership and forward integration possibilities with some of its major municipal customers.

3.4 The Emerging Businesses — The EsCo

"Beyond the meter" has become a widely used phrase in the literature to represent business opportunities that may exist to provide customers with greater services. We believe these opportunities will fall into two business segments: the home gateway for home energy services and the energy service company, or "EsCo," for large customer energy management consulting. Nearly every utility is experimenting with "beyond the meter" services, banking on a brand name that consumers have come to trust. However, the industry has not seen the full-blown home gateway or EsCo yet.

Some residential customers and small commercial accounts have the consumption profile to desire (if not need) high-concept energy management services such as online customized billing, remote appliance scheduling and control, and appliance energy usage monitoring. Experiments in providing such services are currently under way in Walnut Creek, California (a joint venture with PG&E, cable operator TeleCommunications Inc., and Microsoft Corp.[6]), and in Laredo, Texas (a pilot run by Central and South West[7]). Central & South West's subsidiary, CSW Communications, intends to offer demand-side management services through the network, including automated meter reading, customer messaging, in-home bill estimates and remote customer billing. The remaining network capacity will be offered to service providers, extending telephony, video, data and other information services.[8]

These experiments highlight a critical characteristic of the home gateway: The firms that have the assets and competencies to play are not necessarily utilities. Utilities can supplement their capabilities through partnerships, as they do in these two ventures. However, it is not at all clear why the cable and telephone companies need the utilities. In fact, home energy management services are really a component of a much broader home services offering (such as information content and entertainment), to which utilities have little ability to contribute.

Indeed, energy management may potentially be the application that will allow the cable and telephone companies to pay for their way onto the television set-top box. Therefore, we believe that few utilities will find their "descendants" in this segment. Those who make it (possibly Duke Power, which has taken steps to exploit

[6] *San Francisco Chronicle*, June 9, 1995.
[7] Newsbytes News Network, File n0704001.8, July 3, 1995.
[8] PR Newswire, June 26, 1995, File: p0626175.600.

its rights-of-way by laying extensive networks of fiber-optic cable into new residential subdivisions) will have had to weather fierce competition from the other players in the home.

EsCos will specialize in bundling power with related energy management and consulting services for very large consumers — in effect, moving further up their customer's energy "value chain." These players will not only procure cheap energy (not just electric power), but they will work with their customers to tailor strategies and process improvements to reduce their energy costs. A key target market segment for the EsCo will be the middle market — office buildings and complexes, institutions and retail chains — which has many special needs that have heretofore been ignored by utilities (e.g., lighting services). EsCos will need to be capable of providing national account management, high reliability and customized billing. Companies such as Utilicorp, with the advent of EnergyOne, have already begun to position themselves for such a world.

Success in this business requires deep knowledge of the energy needs of customer segments and an individual customer's business. It also demands competencies in customer relationship management and consulting. Here, utilities will find it a struggle to adapt their competencies quickly enough to the demands of this segment.

3.5 Power Markets

We envision the nationwide power distribution system giving rise to a major commodity trading and purchasing market for electricity. Similar to a stock exchange, a whole industry will emerge for electricity "market makers" — companies engaged in the daily buying and selling of power. In fact, based on the experiences of other commodity markets, the financial transactions generated in electricity market eventually will dwarf the dollar volume generated by the physical movement of electricity over the transmission network.

There is evidence that these power markets are already forming: Utilities, investment houses and a variety of other companies have positioned themselves to be traders and brokers of the hottest new commodity — electricity.[9] Evidence from other industries suggests that the number of energy brokers will rise quickly. For example, when the trucking industry was deregulated, the number of freight brokers rose from 60 in 1980 to 4,500 in 1985 (Vietor, 1994, p. 13). Likewise, independent gas brokers filled the post-regulation void in the natural gas industry, where the "carriage" by pipelines of gas sold by others doubled in 18 months. (This occurred prior to the establishment of a forward market for gas.) There is every reason to expect a similar explosion in the electric power market.

If utilities want to play in this arena, they must quickly develop skills as risk managers who can deliver hedges, options and other futures. Of course, this market will be broader than just electricity; all forms of energy will be part of the currency. Indeed, the possibility of directly or indirectly linking the various markets suggests,

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[9] Companies like Morgan Stanley, LG&E Energy and Duke-Louis Dreyfus have obtained power marketer licenses.

all the more, that the "spot market" will be larger in volume than is imagined. In fact, it is our belief that BTUs — not kilowatt-hours or barrels of oil — eventually will be the unit of energy measurement by which power is sold in commodity markets. As a result, today's electric utilities must not think of themselves as being in the "electricity" business, but rather in the broader power supply business.

3.6 I/T Products and Services

In the future, the primary products and value-added services of utilities will be based on the hardware and software tools they have developed, the associated resident skills, and the information they have about customers and their behavior. Everyone, it seems, is selling brokering systems, bulletin board applications, and FERC and power pool accounting packages. Some utilities are mining their deep experience in meter technologies to create the automated meter of the future, hoping to capitalize on a broader market to drive costs down.

By itself, information on customers will become extremely valuable. In fact, we believe utilities are sitting on a potential gold mine of information. Everything from customer usage information to specific appliance information and usage history is valuable to somebody. We believe that utilities will be able to sell such appliance data to appliance manufacturers and retailers as well as to provide real-time usage information to the original manufacturer to enable predictive maintenance products.

In addition, the fiber-optic cables that utilities are laying also provide opportunities for revenue. Although this seems like an attractive business opportunity on the surface, experience shows that it is dangerous to invest in such infrastructure, as standards, technologies, and usage change very quickly, and such changes can strand this investment overnight.

In the end, utilities that are focused on acquiring, managing and using information will find enormous potential business opportunities. For airlines such as American and Delta, reservation systems are more profitable businesses than flying planes.[10] While we don't suggest that information services will be the only profitable part of the future utility industry, we do use this analogy to highlight the enormous potential of this segment. In addition to market-making systems, we expect services like transaction processing and billing, consumer-tracking and marketing information systems — as well as infrastructural services such as intelligent buildings — to be important parts of the information services segment of the future electricity industry.

[10] Harvard Business School case 9–195–101, "Canadian Airlines: Reservations About Its Future (A)," p. 2, revised Oct. 25, 1995, and American Airlines Annual Report, 1990. It is estimated that in 1990, American's reservation system, SABRE, had pretax profits of $150 million on revenue of $500 million. American Airlines as a whole, after backing out SABRE, lost nearly $250 million on revenues of $10.5 billion.

4. THE VALUE NETWORK ALTERNATIVES

The electric utility industry has been traditionally structured into vertically integrated monopolies, each having direct ownership of all the components of the value chain (often including the coal mine). The businesses have been managed to assure bondlike yields and risk profiles to their shareholders. The asset structure, operating culture, policies and processes have all been designed absent an explicit focus on customer value. The evolution of the industry will make unprecedented demands on vertically integrated utility. Few will survive in their current form.

As the existing industry breaks into the six business segments that we discussed earlier (generation, transmission, distribution, power markets, energy services and information technology-based products and services), creative new entrants will emerge. These players will focus on specific customer niches such as large industrial customers, affluent home owners and lucrative segments of the office market. They will differ from the utilities of old in two major ways: they will focus on selected high-profit, high-growth niches, and they will not own all or even most of the assets in the value chain. Rather, they will "cherry pick" and configure only those value-adding activities that are meaningful to a customer segment. In essence, these companies will have created a whole new value chain — one we call the "value network" (Venkatraman and Michaud, 1996).

In a value network, one company exploits the strengths of each value provider and coordinates production and delivery across companies. Value networks have emerged in other industries over the last several years, including athletic shoes (Nike), retail financial services (Charles Schwab and AT&T Universal Card) and personal computers (Dell). Dell, for instance, has disintermediated the high-cost dealer/distributor system with a 1–800–telemarketing arrangement. It uses sophisticated contract manufacturers such as Solectron for the PC assembly and calls on Roadway Logistics to manage all inbound and outbound logistics worldwide. While Dell appears to be a fully integrated PC company, it in fact does not own or operate most of the value-creating activities.

The leader in a value network coordinates the activities of other companies in the network, choosing and assembling the capabilities to deliver value to a specific customer segment. By not owning all the assets in the new value chain, the company is a "virtual" organization. The leader, in fact, cherry picks only those value-adding capabilities meaningful to a customer segment. For instance, in the utility industry, the leader of a value network targeting high-income homeowners could aggregate a range of home energy services without owning all the pieces.

The rallying cry for this new "utility" may very well be: "We can *design* the model for the specific, value-creating activities in a specific customer segment, but *we don't have to own and operate it all!*"

In any utility value network, the players will use different governance mechanisms such as partnerships, alliances, joint ventures, specialized contracts and outsourcing arrangements to manage their relationships. Advances in the integration of computing and telecommunications and the emergence of a new information-intensive business infrastructure will greatly speed the development of these new networked business models.

In fact, in the absence of regulation and physical asset constraints, the electric power industry would naturally evolve into customer-specific value networks where the players (producers, brokers, market aggregators) compete independently for a share of total market.[11] The physical assets, network economics and political legacy of the utility industry suggest, however, that with little or no communication and coordination among players, a value network would be uneconomical. Instead, the disaggregated business segments of the emerging electric power industry value chain would be better leveraged if linked and coordinated by new players acting as leaders in a value network.

This new value network structure will thus enable a coalition of players to exert greater market power and expand their business scope. The new organizing entity, a value network leader, will connect and coordinate the various players, each of which possesses highly distinctive yet complementary operating and process-based competencies, to deliver new levels of customer value. Operating across geographic boundaries, this virtual utility will no longer have to own all the assets necessary to deliver value out to end consumers. Instead it will source specific competencies from within an extended network.

We foresee three value network models evolving in the electric power industry of the future: regulated, virtual, and customer-initiated. Initially, regulators at both the state and federal level will shape the organization of the value network for a specific geography. Over time, however, more virtual utilities and customer-intitiated value networks will emerge to provide alternative, powerful energy alternatives for customers of all sizes.

4.1 The Regulated Value Network

Today's industry structure will rapidly give way to an initial form of a value network that is designed primarily by regulators. As states begin the process of transitioning the electric utility industry to competition, they will mandate organizing entities to control the scheduling and dispatching of generating stations, to control the flow of power over the transmission system, and to provide distribution and energy services to ultimate customers. Additionally, specific rules will be crafted to guide the industry in areas like dispatch priority and flow control.

In California, a Memorandum of Understanding recently agreed to by a number of stakeholders and now submitted to the California Public Utility Commission would create the foundation for a regulated value network, the Independent System Operator and the Power Exchange. Electricity would be auctioned on the power exchange, where the lowest bid and asked prices would be matched. That power would then be scheduled and dispatched to utility distributors by the independent system operator, and, therefore, would not be under the utilities' control. Other such

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[11] The consumer products industry is a good example of this. Producers, such as Dow-Corning or DuPont, provide raw materials to manufacturers like S. C. Johnson, which in turn provide products to retailers such as grocery chains, which in turn provide products to end consumers.

regulatory designs are under way in many states, from Wisconsin to New York and Massachusetts.

Such regulated value networks will not be optimized for any one set of companies or segment of customers. Rather, they will be structured to satisfy the majority of stakeholders. This will be a logical first step in industry restructuring as many complicated political issues must be dealt with through the transition, such as stranded costs that may be recovered from "competitive transition charges" and the "obligation to serve."

4.2 The Unregulated Value Network

Today's EsCos are the first breaking wave of an emerging value network in the power industry — the virtual value network. Dissatisfied with the "one-size-fits-all" structure of the regulated value network, many customers will demand that unique linkages of value providers be created to meet their individual needs. This virtual player will aggressively manage its own assets and competencies, emerging as a sophisticated intermediary designed to optimize the value chain to deliver superior value to specific customers. No longer defined by the regulatory obligation to serve or constrained by the structure of rate-based economics, these entities will demand dramatic improvements in performance by the value-providing comparnies in each market segment.

The idea of a virtual corporation that links competencies that it may not own has been developed at length by several authors (Davidow and Malone, 1994; Nohria and Berkley, 1994; Chesbrough and Teece, 1996). A virtual utility may extend its reach far beyond the regulation-imposed boundaries of today's electric power industry As the gateway companies of the future form alliances and partnerships with transmission, distribution and information products providers, the scope of their product offerings could expand to include every external service to the home: electric, telephone, cable, Internet access and beyond. The virtual utility serving large industrial customers may begin to describe the value offering of its network as a "universal infrastructure support," offering not just energy and energy service, but telecommmunications, computing and facility services for both centralized facilities and large distributed networks of telecommuting employees.

Virtual utilities may, therefore, include power marketers and brokers and aggregators, energy service companies and some distribution companies. Each will be successful because of their ability to understand discrete customer needs and then manage the network of value providers to deliver and meet those needs.

4.3 The Customer-Designed Value Network

The final value network that will emerge in the future industry will be initiated and managed by customers themselves. The largest users of energy will see opportunity in linking their own unique value network to meet their specific needs. While virtual utilities and EsCos will initially focus on the largest customer segments, technology and direct market access will offer the capability for customers of all sizes to construct value networks of their own. Once data sources for pricing and supply information are widely available, intelligent agents over the Internet will provide direct access for customers to the purchase and transmission of power. Customers will be able to contract directly for their energy requirements and then source their energy related products and services from individual suppliers (Dar, 1995)

5. FUTURE FOCUS

The first, and most critical, questions today's utility must face are those of future focus and capabilities. There will be numerous paths to profitability through a value network — every player will not, and should not, become a virtual utility linking together the value components to meet customer needs.

Companies will be very successful by focusing on individual segments of the value chain. However, they will have to rescope their operations to compete with other focused service providers or to maximize their return under a performance-based rate-making scheme. The cost structures, risk levels and investor profiles for different business segments will vary substantially, with regulated transmission and WireCo's remaining closest to today's traditional utility profiles. Power marketing and information-based segments will be dramatically different, with limited hard assets and pricing based on value rather than cost.

For companies seeking to compete as virtual utilities, nothing short of reinvention will be sufficient to enable success. The business structure and management requirements for the virtual utility are polar opposities to the classic characteristics of an integrated utility. The time horizon for organizational responsiveness will shift to product cycles of months and possibly weeks — a far cry from the traditional planning horizons of years and decades.

In this type of environment, what are the critical skills for a virtual utility? At a minimum, the virtual utility must be able to: 1) establish and sustain successful partnerships, 2) nurture creativity about the structure of products and services, 3) focus beyond the traditional bounds of the electic power marketplace (both geographic and business definition), 4) manage operations and costs to match unique business opportunities, 5) consider information technology as the single most important strategic asset and 6) truly hear and understand customer needs.

Today's utilities ultimately will have to choose where to participate in the future industry. The issue, as a result, is not so much whether to choose, but when. Today's utilities should thoughtfully consider the future picture of the industry and plot a course. The investments they make, customer relationships they nurture, and people they recruit and retain should all help move toward these goals.

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Part VIII

Perspectives

15

THE BOTTOM LINE: A SUMMARY AND ANALYSIS OF THE VIRTUAL UTILITY CONFERENCE

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The virtual utility must provide better service at lower prices than the conventional integrated utility. If it can do so—and the conference participants have outlined how—then the virtual utility will become the central player in the new energy market.

Se a résposta e o sistema, deve ter sido uma estúpida pergunta.—Brazilian graffiti, 1986.

Consumers will not care how the virtual utility works. They should not care. They, should, instead, ask three questions:

1. When I flick the light switch, will the lights still go on?
2. Will I pay less, or, at least, not more?
3. Will I get something that I want that I am not now getting?

The answer to question # 1 must be "yes". The answer to #2 should be "yes", but, as a minimum, "not more". The answer to #3 should be, at a minimum, "maybe". I realize that some customers will give up reliability for a better price, and that some customers, now paying too little, should pay more. But, from a political and public relations standpoint, offering less reliability and higher prices makes the virtual

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utility concept a non-starter. As for new services, most people cannot imagine what they would want. They did not know that they wanted call waiting, either.

Of course, investors, regulators and participants in the electric industry will want to know more about the mechanics of the virtual utility. They need more information, in order to determine the profit potential and risks of the new system. They need to know how structural deficiencies might affect the marketplace. They need to know how the reorganization of the industry affects their standing within it.

What is a virtual utility? To paraphrase Michael Weiner (Weiner, et. al., in this volume), it is an organization that supplies a range of energy services, but does not, necessarily, own the assets needed to supply those services. This organization may, as a principal line of business, supply energy services. Or it may consume energy services during the production of its product, and wish to take control of its energy services by creating an in-house virtual utility. Note that I said "energy". This conference focused on electricity. Customers will not specify the type of energy, and virtual utilities will furnish what best accomplishes the customers' purposes. I did not specify, either, how the virtual utility achieves its task. The customer wants results, not explanations.

In order to achieve its goal, providing a competitive energy service in the most efficient manner, the virtual utility must assemble its offerings from a wide choice of services and products available to it in the market on a non-discriminatory basis. Current suppliers, in order to sell to virtual utilities, must unbundle their offerings so that the virtual utility can assemble the best packages of components for its own customers. Presumably, this unbundling will force suppliers of components to concentrate on what they do best. The virtual utility, then, will deliver to the ultimate consumer a package of better and lower-priced services than now obtained from the integrated utility. Otherwise, the switch from the integrated to the virtual utility is not worth the anguish, confusion and financial trauma that it will produce.

Now back to practical issues. Will the virtual utility concept work operationally? How will existing energy suppliers fit into the new framework? What institutional arrangements will assure that consumers—and society—reap the benefits of the transformation? How do the conference participants address those simple questions?

Instant Replay

The conference participants presented a surprisingly cohesive view of the future of the electricity supply industry, as well as advice on how to make the new industry work efficiently. Let me count the ways.

First, why did a smoothly running electric industry get into trouble? The utility industry, according to Richard F. Hirsh (Hirsh, in this volume), reached its present state because it could not deal with stresses to the system and did not assimilate new technology. The traditional model, he says, cannot survive. As for as a consensus view of the future, though, "the politics of power... has become so complex... that a single vision of the future may not be possible." That seems an inauspicious beginning, but we do not need a single vision. Rather, we need an energy system that delivers the multiple products that the consumers may want. We had a single vision before. It delivered to consumers what it wanted to deliver. In the future, those with unusual products can bring them to market without the blessing of a central authority. Those products will succeed or fail depending on whether consumers buy them.

An intensive user of capital, the utility industry was always subject to second-guessing by regulators, so it developed peculiar, overly-cautious, backward-looking, regulatory-driven accounting and capital budgeting procedures. Recently, utilities discovered that all that accounting for minutia did not tell them—in a meaningful fashion—their costs (Merrill Lynch, 1994). They now try to tackle capital budgeting as a business might, instead of just trying to minimize their revenue requirements. Shimon Awerbuch, Elias G. Carayannis and Alistair Preston (Awerbuch, et.al., in this volume), though, highlight another problem: existing capital budgeting procedures favor "incremental enhancements to the existing process", take a static approach, and discourage new technologies. Raj Aggarwal (Aggarwal, in this volume) asserts that utilities must adjust capital budgeting "away from regulatory requirements" in order to "reflect opportunities and costs based on the new (but still unclear) ... structure..." Utilities must assess the worth of expenditures based on expected cash flows, and even the option value of entering new lines of businesses, and technological discontinuities.

Some of you may see these comments as the irrelevant musings of bean counters. To me, they are ruminations about corporate culture, and what constitutes acceptable risk taking within that culture. Consider two points. The existing processes discourage thinking outside the box. Utilities could, therefore, lose out to aggressive new entrants, uninhibited by the utilities' accounting and budgeting straitjackets. Utilities, under that scenario, could end up as the low-margin suppliers to the virtual utilities. They would lose control of their markets in the same way as did IBM, Sears, Howard Johnson and Western Union. Yet utilities continue to spend large sums of money in ways sanctioned by existing budgeting procedures that do not measure the real risk of those investments. Such investments include increases in regulated plant achieved through mergers justified by static analyses of operating savings. In other words, utilities may not make the capital investments that they should and they still make the capital investments that they should not. Utilities must jettison the artifacts of their old culture, including the budgeting procedures that lead them to wrong decisions. That is the message.

A few weeks ago, the *New York Times* carried a story that said that large corporations were firing their economists. Rather than attempt to predict the future, the businesses now employ financial mechanisms to hedge against untoward events. That is risk management. Utility managers used to worry about physical things, such as capacity, load, kilowatt -hour sales and reserve margins. Now discussions about the future of the industry sound as if they belonged on the trading floor of Merrill Lynch or in a B school finance seminar: contracts, options, futures and how to organize a liquid market. Participants in the power markets will have to develop schizophrenia, and not confuse moving electrons with moving money.

The new system, according to Chitru S. Fernando and Paul R. Kleindorfer (Fernando and Kleindorfer, in this volume), should provide "transparent and efficient markets for both long-term and short-term transactions, dynamic efficiency and innovation, customer-focused operations and system integrity." That system requires coordinators, transmission owners and power pools. Intermediaries will facilitate "the emergence of liquid markets." In order to operate in this new market, all participants will have to quantify the value of all the services required to keep the system operating. Rather than simply furnish a service to an integrate network and collect payment through a rate of return on all assets, the participants will charge for services, producing a legion of financial transactions. Furthermore, participants will have to understand that different ownership, management and regulatory structures will produce dissimilar results. This concept is not well understood by policymakers or industry executives, who seem to believe that any organization will do, without considering that coincidence of ownership and management will produce better investment and operating decisions. (The creation of transmission cooperatives that run but do not own assets, whose investment decisions will be directed by committees, is an excellent example of misunderstanding of the value of ownership.)

Pricing practices will change, too. Frank Graves and James Read (Graves and Read, in this volume) expect existing two part (capacity and energy) pricing to give way to one price. Furthermore, in commodity markets "prices are volatile... prices rather than quantities are the principal locus of risk bearing." The generating plant becomes the equivalent of a call option on power. Is this a market for consumers, or a market for financially savvy organizations that know how to manage risk? To me, it is the market for a virtual utility.

Thomas E. Hoff and Christy Herig (Hoff and Herrig, in this volume) take a different approach. Rather than hedge risk through the financial markets, they propose that players in the market "own physical assets that have low risk attributes...", namely renewable sources of energy. Both consumers and vendors can play this game. Renewable energy aggregaters could sell to consumers who want energy with the risk characteristics of renewables. Or aggregaters could raise money to develop renewable resources from those who want to invest in renewables.

The flexibility of the new system opens the way for marketing of renewables. The absence of government mandates for purchase, though, will sweep away those renewables that cannot meet conventional market tests. Most renewable proponents, unfortunately, only know how to market their product to the government. That might account for their modest success to date.

At this point, the conference veered from sophisticated discussions of finance to a field I had not paid much attention to for a long time. Years ago, when in graduate school, I studied industrial organization. Over time, though, as I eschewed economic tracts for more profitable reading, I concluded that economic practitioners had developed an overwhelmingly panglossian view of the virtues and inherent perfection of the marketplace. Whatever market structure existed was right, and government interference with the working s of the market was wrong. Alfred E. Newman, the hero of my high school days, I thought, seemed a frontrunner for the Nobel Prize in Economics, if he would only change his writing style. But, effective competition does not spring forth from a formerly monopolistic structure fully developed, like Athena from the head of Zeus. Those in charge of breaking up the old industry organization must make sure that the new one works.

Politicians and ideologues may rush to decision, declare victory and walk away. William G. Shepherd (Shepherd, in this volume), however, asserts that declaring a market competitive does not make it competitive. The competitive market requires at least five comparable firms competing, with none dominant, and relatively free entry. "Premature deregulation, before those conditions are reached, is a cardinal error and is usually irreversible." The moral: start thinking about structure now. And watch out for mergers that might pass muster from regulators based on fuzzy judgments about public benefit. If we want effective competition after deregulation, do not make that goal harder to achieve by allowing the market to become less competitive now.

The new industry could offer not just lower prices but also a host of services from many providers. Shmuel S. Oren and Dennis J. Ray (Oren and Ray, in this volume) view unbundling as vital for "the provision of opportunities for new entry, for new rivalry among existing suppliers, and for new services for customers." Restructuring breaks up the vertically integrated utility, separates energy from delivery services, and opens a new world for financial risk management. Unbundling, however, requires the identification and pricing of numerous services, and a determination of who pays for what. Unbundling gives customers whatever they want. If we can customize shoes, why can't we customize energy services?

Just in case that you think this is pie-in-the-sky, look at another networked industry, telecommunications. Bridger Mitchell and Peter Spinney (Mitchell and Spinney, in this volume) , however, conclude that "there are many important parallels... which have not received extensive attention...", a list of which includes the impact of the emergence of new technologies on the industry, the risks of bypass, the workings of incentive regulation, the consequences of inadequate depreciation, and the implications of distributed functions. Perhaps those working in the electric sector should spend less time telling the world why their business is different, and spend more time learning why it is not.

Today's electric industry may not be economically efficient. It may face severe financial difficulties in its present form. But it is dependable. Nobody will want to enter an elevator knowing that lawyers, economists and bankers designed the new power system. Marija D. Ilić, Eric H. Allen, Roberto Cordero and Chien-Ning Yu (Ilić, et. al., in this volume) caution that the industry will need to define its performance objectives, "establish... measures of dynamic efficiency, and ... fair and reasonable charge allocation for the system services under open access." That sounds obvious, but doing so will require the sort of tedious work that gets pushed aside by people who prefer grand gestures. I worked in an industry in which firms collapsed due to inattention to the back office. The top executives just weren't the type to mess around with low class stuff. You didn't make big money in the back office. You just lost big money. Fernando Alvarado (Alvarado, in this volume) notes that virtual utilities, operating on the same transmission grid, "will interact." The grid controllers must measure those interactions, in order to allocate costs and price each service rendered. In addition, the " electric... grid, like a highway... is subject to congestion and the need for everyone to obey certain rules of the road..." The power system will need coordination. Someone may have to give orders. Maybe not a committee.

So far, nobody has told us that the new system will not function. They have shown that we have a lot of work ahead of us to make it work right. I have not sensed that caution in the public discussions of structure. After all, competitive electric systems do work elsewhere, to varying degrees. But no competitive system operates in a country as large and diverse as the United States. Perhaps we do need a transition period in order to experiment and then get it right. If so, utilities would gain much needed breathing room, as well. But do not expect more than a few years. I doubt that customers will wait longer for their much-promised succor.

Finally, what form will the new system take? Michael Weiner, Nitin Nohria, Amanda Hickman and Huard Smith (Weiner, et. al. in this volume) paint an unambiguous picture. In other industries, the introduction of competition was followed by lower prices to consumers, the decline of the role of the long term contract in dealings, new products, global expansion, and greater reliance on information technology. The same trends should prevail in the electric supply industry. The structure of the industry will change, breaking up into generation, transmission, distribution, power markets, energy services and information-based products. Today's utilities "will have to choose where to participate in the future industry." Note that message: they may not have the skills to participate in all aspects of a competitive energy industry. Will a utility that sharpens its focus now gain a competitive advantage over those that hope to continue doing everything?

THE BOTTOM LINE

I will now return to my original questions. Consumers of electricity have little interest in the niceties of industrial organization or the extraordinary engineering needed to keep the system running. The customers—who are always right—will call the tune. Investors want profits, not explanations. Regulators should worry about the end-results of public policy, not the engineering aspects of the business. William of Occam was right. I will keep it simple. Here is the bottom line.

Question # 1: When I flick the switch, will the lights go on?

Answer # 1: Yes. Or, to put it another way, nobody said no. But the planners clearly have a lot of work to do, in order to make sure that the new system operates in an optimal manner. The new system may need several years of debugging, too. The participants will dispute the pricing of all the parts that go into producing the service, making sure that those who put burdens on the system must pay accordingly. Otherwise, a market-driven system will produce no better results than what we have now.

Question # 2: Will I pay less?

Answer # 2: That depends ... Here is why:

- I might specify a different quality of service, taking advantage of choice that I did not have before. I could pay less or more, but for something different.

- If I were on the receiving end of a cross subsidy now, I would worry that competition is nothing more than a code word for removing my subsidy. If I lose my subsidy, then the price of electricity might go up for me but down for the customer that has been paying the subsidy.

We should not, however, take a static view of the world. Competition means choice and it means new operating procedures. We will return to choice in Question # 3. Competition really works if it drives down costs and prices so much that formerly-subsidized customers, after losing their subsidies, are no worse off—and maybe even better off—than before. We do not know if that will happen, but we do know that 30-50% cost or price reductions did take place after the deregulation of several industries (Global Business Network, 1995). That experience does not prove that electric prices will fall as much, but it does give us hope. We might gain more confidence by examining cost estimates for the next generation of electric generators, which could sell their outputs at prices 30% lower than many existing generators, and still produce a profit for owners (Balzhiser, 1996). In a full- blown competitive market, existing producers will have to price their output to preempt the competition, or they will lose out to newcomers. They will have no choice but to cut costs from existing plant, introduce new plant, or suffer a reduction in profit. Customers will gain. I am not sure that I can say the same for the existing electric suppliers. There is, however, a catch in the analysis. The government may prevent consumers from realizing immediate benefit from competition. It could do so in two ways. It could levy a "non-bypassable" surcharge designed to recover so-called stranded costs, which, in effect, appropriates the benefits of cost savings for electricity supply investors and assorted entitlement holders. Or, the government might not address industrial organization issues seriously, allow a small number of players to dominate the industry, and let those players keep most of the benefits of operational savings for themselves.

The answer to Question # 2 should be yes, but it really is: maybe, probably, eventually, but not certainly for everybody right away.

Question # 3: Will I get something I want that I am not getting now?

Answer # 3: Probably. Other industries that underwent deregulation discovered that they had customers with different wants, and brought forth a plethora of new offerings, sometimes the same product offered with a new pricing scheme, sometimes completely new services. Forget about public utilities for a minute. Think about the transformation of the stock brokerage industry after fixed rates disappeared, and the houses had to subsist on a thin margin or find other products to offer. The electric utilities are, in a halting fashion, trying to fashion energy and telecommunication services for a competitive marketplace. Financial markets, already, are developing an array of products to help energy users and producers cope with the future. I am not sure that I want what they offer, now, but I did not know that I wanted a VCR until someone had invented it. So far, my electric company has offered me only bills and threats to cut off my service because I am not home at the convenience of the meter reader. That will change. I can't wait. Just think how long it took the Bell System, in its monopoly days, to find a color other than black.

The conference, unfortunately, left three important issues up in the air. It concentrated on the virtual utility as a virtually all-electric firm. Yet, once firms organize that are not tied down by existing assets, they need not concentrate on providing one form of energy. They will provide whatever the customer needs to to achieve certain goals in the most effective fashion. The virtual utility could sell gas, oil, waterpower, electricity or energy saving devices. It could manage resources or operate machinery for customers. It might run distributed generating systems not connected to the grid. The way regulators attempt to price the electric services and recover costs of transition might determine the way the virtual utility operates. Does the non-electric nature of the virtual utility affect our analysis?

The conference speakers rarely touched on what might happen to existing utilities. Utilities take comfort because they know the customer, they have the wire to the customer, and the customer likes them. Or so they believe. Years ago, when Florida Power & Light bought Colonial-Penn Insurance, the FPL people explained that their customers and Colonial-Penn's had the same profile, so they could help Colonial Penn sell more insurance. I asked my Miami brother-in-law if he intended to buy his auto insurance from the new combine. He told me that FPL stood for Florida Plunder and Loot. I figured that he wasn't going to switch his auto insurance. Utilities may have an exaggerated notion of their position. No doubt, they will keep many customers due to inertia. Whether they keep the best customers is another matter. Furthermore, the rules might be drawn in a way to take the customer contact away from them. The conference speakers discussed issues of accounting, budgeting and culture that indicated to me that utilities will have a hard time overcoming a century of habit, and while they are trying to do so, newcomers will arrive at the scene unencumbered by all that baggage. Utilities might want to think of themselves as future virtual utilities, but they are stuck with the assets, and might end up serving the virtual utilities rather than the ultimate customers.

Finally, in the past two decades, policymakers have spent enormous amounts of time and money trying to devise energy policies that take into account environmental externalities. Almost all those policies were predicated on the assumption that the energy markets were segmented, closed systems. Once regulators had devised the solution to the problem, presumably, nobody could evade that solution. How do environmental issues fit into the new world of the virtual utility?

Unbundling, which opens the door for accurate pricing and new services, also requires a new set of operating procedures and attitudes. Someone has to put together the end product for delivery. The virtual utility does that job. The virtual utility, which assembles information, services and products, will become the central player in the new energy market.

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16

THE VIRTUAL UTILITY AND ENVIRONMENTAL STEWARDSHIP

Carl J. Weinberg
Weinberg Associates

The Virtual Utility Symposium provided a marvelous opportunity for individuals that normally do not interact or even talk to each other to exchange ideas and concepts for an industry undergoing major changes. All of the participants will carry back a great deal of information and interpretations reflected by individuals other than those we are accustomed to.

While I have a technical focus, I generally try very hard to understand or at least formulate some guideposts for judgment; to postulate some broad criteria to guide my thoughts. As someone once said " If you don't know where you are going any road will do." Here, then ,are four broad criteria I use as my guide to evaluate actions being considered in the area of restructuring.

1. Economic Productivity

   Do the actions proposed provide us with better products or the same products with less cost? Overall do we gain economically?

2. Social Equity

   Is it fair to all, or at least, can it reasonably be expected that it will do no harm to those that are defenseless?

3. Environmental Stewardship

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Does the "new" way incorporate means or lead us to improve the natural environment or get us closer to living in a symbiotic relationship with nature?

4. Social Sustainability

   Does the change provide for a better quality of life or advance the ability of society to sustain itself?

I readily admit that these are not precise parameters but at least they provide me with some guideposts or cause me to ask some questions. The real difficulty is to find balance among these objectives. Fortunately I don't have to provide such balance since my charge is to focus on the Environmental Stewardship implications of the virtual utility

Karl Rabago (in this volume) raised this issue but it is not given sufficient consideration at this Symposium. It is discussed in the restructuring debate only as an afterthought. I believe we need to move it to center stage. Whatever new utility system emerges for the electric industry it must include environmental stewardship as an important component. It is essential that we gradually move toward an environmentally cleaner system. This is the cheapest "insurance" or "no regrets" strategy. If we are to move in this direction, we need to consider renewables and energy efficiency as major components of a restructured industry and the resulting market place. As yet this has not happened, rather the focus has been on the structure of a competitive wholesale market based on lowest price.

Renewables are a mixture of technologies. Applications span wholesale and retail markets, and go beyond the meter to the customer's premises. All these technologies have some common characteristics:

1. Compared to fossil fuels, renewables utilize the sun's flux over a much shorter term . Several years for biomass, yearly for hydro, daily or seasonally for wind, and even the instantaneous flux for photovoltaics. This is in sharp contrast to the stored flux of thousands of years represented by fossil fuels. The instantaneous flux of the sun can produce electrical energy many times the amount of present and future demand. The sun is after all the primary energy input that maintains this planet. The closer we come to using this flux on the shorter term the more sustainable becomes our energy system.

2. The closer to instantaneous solar flux a technology uses the more it is dispatched by nature and not by humans.

3. In general, renewables have high initial cost and as a corollary, such immediate term flux technologies also have low operating costs. Photovoltaics which rely on the instantaneous flux of the sun have essentially no operating cost, or for all practical purposes, zero short-run marginal cost.

4. The overall environmental impact of renewable technologies is significantly lower than fossil alternatives.

Restructuring debates as yet do not take these characteristics into account. Tom Hoff and Christy Herig (in this volume) discus some of these and other characteristics, and attempt to quantify the "value" they bring to a competitive electric market. If nothing else, renewables put an upper cap on the price of fossil fuels; that cap is not far from the "market" price.

It is interesting to note that much of the discussion at this meting is focused on interconnectivity (transmission) and its essential role in a competitive market. Yet many renewables are more competitive where interconnectivity does not exist. Also many of the schemes for bidding and dispatch assume that electrons (kw-hrs) are generic and their source of production is irrelevant. Yet the source of production does seem to matter. Many customer may in fact not be indifferent to the source of electricity production. The rational for renewables requires that we do, initially, provide identity to these electrons. It is no wonder that renewables are having a rough time surviving in a proposed system that implicitly assumes characteristics which disadvantage renewables.

Bill Sheppard (in this volume) certainly sounds a warning that the deck may be "stacked" against renewables and efficiency. Looking carefully at California one can see the potential for conditions to develop that inadvertently (or I hope it is inadvertent) drive out renewables unless specific provisions such as the Renewables Portfolio Standard or a System Benefit Charge are enacted.

There is a changing dynamic in the underlying technology of the electric industry. There is a shift away from "constructed energy" to "manufactured energy" (Figure 1). The new technologies, from gas turbines to high compact fluorescent lights, from windturbines to photovoltaic panels follow production economics. Prices drop as a function of the volume or quantity produced not the size/scale of each unit. There are other important characteristics that follow this shift in technologies. Innovation is introduced as quickly and as often as it can be incorporated into the production line. Installation time is measured in days and months, not years. For example; fifty Megawatt gas turbine powerplants have been installed in less than thirty days. Wind power plants can be installed in 10 or 20 Megawatt sections in less than six months, and can continue to be expanded without shutdowns.

Gerry Braun of Solarex and other Manufacturers talked about the decreasing cost of photovoltaic systems. System costs currently hover around $6 per peak watt installed and will be dropping to $3 per peak watt. Even today and increasingly as these costs drop, photovoltaics will be integrated into houses or buildings. Currently, one can buy a small house kit that can have the ability to operate independently from the grid (Figure 2). The package includes a broad range of highly efficient appliances that provide for a very modern life style. These designs are becoming increasingly available in a wider range of homes including three and four bedroom designs. Karl Rabago showed the first evening, photovoltaics integrated into roofing shingles. This roof not only keeps out the rain but also provides electricity, or at least part of the electricity for the house. Clearly an illustration, at the point of use, of electrical production and efficient energy use.

There is presently under development a hybrid electric vehicle. This miniature utility has a powerplant, a storage and a power management system, and is being developed by a cooperative agreement between the big three automakers and DOE.

It is designed to fit into the existing space of the standard automobile powertrain, and to be produced a cost of $2000.00 or less. Such a system produces approximately 40 kw, and at a cost of less than $50.00 per kw. Auto manufacturers understand the importance of secondary markets in increasing production volume. If several million units can be produced for automobiles ,it would not be a great stretch to produce a million units for residential or commercial electricity production. The price of $2000 would add less than $20 to a monthly mortgage.

Figure 1. Emerging Utility Technologies.

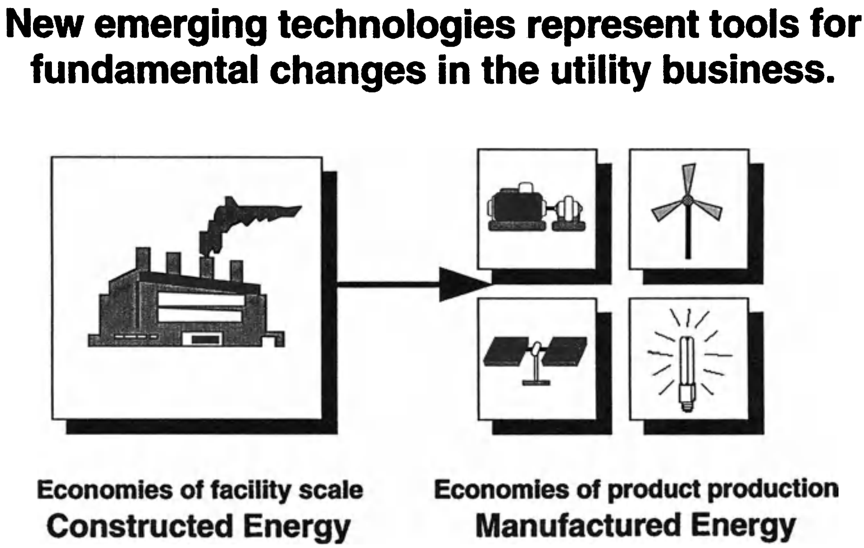


Figure 2. A Mail Order House for One or Two.

A small affordabe, luxury home kit combines superior energy efficiency and innovative design to meet the needs of one- and two-person households.

Among the advantages of the small scale of a Mini House is that the home need not be connected to the electric company.

- **Kit $20,000**
- **Stand alone package $10,000**
- **Off-grid appliance package (DC) $4000**

Refridgerator	Blender	TV
Microwave	Mixer	All lights
Computer	Radios	Hair dryer
Printer	Clocks	Dishwasher
Clothes Washer	Satellite Dish	

- **Fannie Mae accepts mortages**

One Design Inc.
724 Mt. Falls Rd.
Winchester, VA 22602
Solar Today, March/April 1995

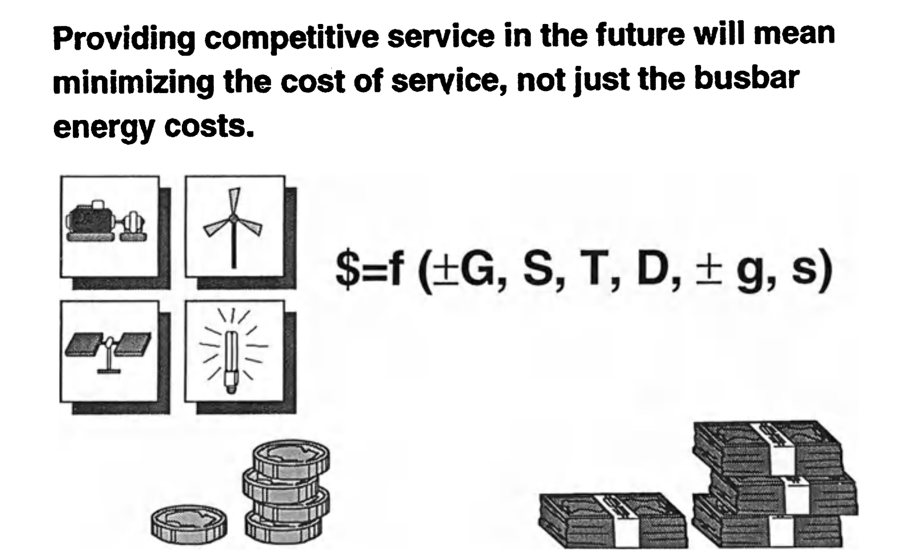
This development process helps explain why we are seeing the adaptation of energy systems from other markets to the electric utility market. Miniature turbines (25kw) adapted from Auxiliary Power Units (APU's) used in aircraft worldwide, or slightly larger systems (200kw) adapted from tank and military engines. Proton exchange membrane fuel cells also being developed for hybrid electric vehicles translate to smaller sizes (10-20kw). These are nibbling at technologies that may be as cheap per kw at sizes less than 200kw, than gas turbines are at sizes greater than 100 MW's. And gas turbines are already cheaper than large boiler type powerplants. The trend is toward the miniaturization of power plants.

These developments are quite relevant to the virtual utility. The application of these technologies requires the use of renewables, or cleaner fuels and the incorporation of efficiency. All of these technologies lead toward a cleaner energy system and therefore toward environmental stewardship. These smaller systems may also provide solutions to transmission constraints that maybe more cost effective than transmission line extensions. At the very least, they represent practical alternatives that must be considered. The general implication is, however, that they either make the "wires" less important, or allow them to be utilized more effectively.

Traditional components of the cost of service are generation, transmission and distribution, although the emerging technologies introduces a new set of components in the equation. While these make the equation more complicated they also increase options for providing energy services to customers (Figure 3). This approach provides a means for introducing a great deal of innovation into the industry. Restructuring of the industry must include a set of rules that reflect technological change so that incentives for innovation are not lost. We all are well aware of the innovations and options introduced when the telecommunications industry was deregulated. (See Mitchel and Spinney in this volume) This innovation is continuing not only in technology, and services, but also in organizational structures. No one specifically made innovation part of the restructuring yet that is implied when options and customer choice are expanded. The utility industry and regulators generally equate customer choice with retail access. To me, however, customer choice is more than simply choosing another large supplier. It represents the expansion of options for energy services which opens the market for the virtual utility.

This issue was nicely addressed by Amanda Hickman, presenting the paper by Weiner et al. (in this volume), who describe unraveling of the value chain, we would call it unbundling. The ultimate outcome is that customers have the ability to assemble their own value chain. When one thinks about assembling a value chain, it is easy to begin to understand the importance of other developments, particularly the information technologies. Two way communications with customers will enhance their ability to assemble their value chain and thereby will also affect the provision of energy services. It could easily lead to the provision of energy services on the customer side of the meter by non-utility companies. There is no reason that energy services could not be obtained through the phone company or cable TV provider or local natural gas providers who could easily extend their services to include electricity, and energy efficiency. This convergence of technologies and applications has the potential for allowing innovation to occur with customer choice playing a central role. We are being asked to make more and more choice around our own values. These include health care, provisions for future retirement, investment and relationship between ourselves and our employer. Considering these choices doesn't make energy choices seem so difficult.

Figure 3. Cost of Service Equation for Tomorrow's Utility.



Why do I emphasize customer choice, meaningful customer choice, the ultimate customer choice.? I believe that the customer will place value on the environment. If it is true, as shown by survey after survey, that the citizens of this country do place value on the environment, then the ability of customers to assemble their own value chain becomes an important component of environmental stewardship. We also need to understand that there is a new kind of customer presently growing up ; our children who will enter the energy market in a decade or less. When I watch my Grandchildren it becomes clear that they will become a different kind of customer. My 12 year old grandson, just prepared a report on Egypt. He went to the library checked out some books and then browsed the Internet. He found a wealth of written material and pictures from a variety of sources, including museums, travel agencies, travel guides, encyclopedias and the Egyptian Embassy. He downloaded this material, reorganized it, edited it, merged in the pictures, adjusted the fonts and layout, printed it, and there it was. This was not done in a instant, it took work. He spent a great deal of time thinking about his focus and subject matter, but he assembled, rather quickly, a great deal of material from around the world.

Perhaps even more instructive was a recent interaction between my six year old grand daughter and her grandmother. They were playing a computer game. My wife, an "old style" customer, has difficulty with the mouse - "How do you make it move?, Do you click once or twice?" - she turns to Chelsea, " How did you learn to do that?." Chelsea thinks for a minute, shrugs her shoulders and says "Grandma, you just know." We need to understand that these are the new customers and they will be here in a decade or less.

This takes me back to the value chain with a view towards renewables, energy efficiency, environmental stewardship, unbundling and the components that the customer will reassemble to form his or her individual value chain. We have heard some excellent papers dealing with these issues. The authors discuss how coordination might take place but if you examine the rules, you find that in many cases they prevent renewables from being dispatched in which case customer choice cannot be fulfilled. Customer choice requires differentiation of the source of electrons, or at least of the technology that produces them.

Some of the papers discussed the impact of various transmission pricing schemes, nodal and zonal. Since renewable production needs to occur where the resource is located the pricing schemes make a difference. Pancacking nodal rates, where there is an added cost each time a node is passed, increase the cost of transmission and therefore disadvantage renewable technologies where the resource is at some distance from the load. Similarly for distribution pricing where again the various schemes can work for or against cogeneration or distributed systems. Finally there is the question of the gateway to the customer. Who will provide the connection? should there be net metering? who pays for the gateway? Little discussion has taken place regarding the impact of restructuring at the retail level, and what market rules need to be considered. The retail market however is where a great deal of innovation will occur, and represents a great opportunity for the virtual utility to flourish. But whatever structure evolves, it needs to incorporate concerns for innovation and environmental stewardship.

To me the virtue of the virtual utility concept is that it forces us to think "outside the box." Any restructuring of the electrical utility industry should open the box, remove the sides and the bottom, and allow innovation to emerge. It must be a market structure that allows us to move toward the "Future of the Future," not the "Future of the Past." And that future needs to include the concept of environmental stewardship. We really need more discussions like this to remind us where we need to go, and to help us think about how to get there, with the environment in mind.