CONSENSUS-BUILDING IN ELECTRIC UTILITY REGULATION

by

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Abstract

The electric utility industry and its regulatory environment are at a number of complex, controversial, and critically-important cross-roads. Utilities, intervenors, and even the public utility commissions are no longer able to initiate and sustain changes unilaterally. Meanwhile, traditional approaches to regulation -- adjudication and rulemaking -- are often contentious, costly, and produce results that stakeholders do not perceive as either legitimate or practical.

The inclusion of supplemental consensus-building processes appear to offer a positive alternative to traditional approaches alone. Technical sessions, settlements, collaborative processes, and negotiated rulemakings are several consensus-based options currently being tried.

I begin this dissertation by briefly tracing the historic rise and fall of consensus on electricity issues in society from the early 1900's to the present. Next, I introduce the theory of alternative dispute resolution (ADR) and its nexus to electricity regulation, before presenting an analytic framework for evaluating the successes and failures of such processes. I then analyze four cases in detail, including: (1) the Pilgrim nuclear power plant outage settlement, (2) the demand-side management collaborative processes in Massachusetts, (3) the New Jersey resource bidding policy settlement, and (4) the formation of integrated resource management rules in Massachusetts.

I conclude that supplemental consensus-building can enhance the legitimacy of electric utility regulation, and produce more practical remedies and plans. However, I also conclude that contrary to conventional wisdom, such processes do not tend to save process-related resources in the short-run even though long-term net benefits can be positive and substantial. I recommend the need for a paradigm shift among regulators and other stakeholders to more actively cultivate consensus. At the end of the dissertation, I present eight principles for improving and expanding consensus-building in electric utility regulation.

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I am finishing this dissertation at the house I built with my family in the Berkshire Mountains 15 years ago (during one of many interludes from my formal schooling). I sit watching the green, moss-covered boulders and the purple crocuses emerge from under the season's final snow melt, while reflecting on the path that led me to the West Coast for a decade and eventually back to write this dissertation. The memories are simultaneously enervating and overwhelming. So many people have inspired and assisted me on this journey that the following acknowledgements are admittedly incomplete:

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Chapter 1: Introduction

Problem Statement

Electricity is vital to our society. It runs the lights, motors, computers, and VCRs that we rely on both for our productivity and for our pleasure. It is also one of our largest single expenditures. In 1990 alone, U.S. ratepayers paid utilities $179 billion for electricity (U.S. Department of Energy 1991).

Not surprisingly, electricity issues also engender some of our most impassioned debates. Beginning with discontent over rapidly increasing electricity rates in the early 1970's (after over half a century of declining costs), electricity-related disputes have expanded tremendously. Examples of these controversies include utility investments in nuclear power plants, the environmental impacts of electricity resources, the role of demand-side management as an alternative to supply-side resources, and the introduction of competition in electricity generation.

Attempts to resolve these disputes usually occur in adjudicatory and rulemaking proceedings before state public utility commissions (PUCs).[1] Adjudicatory, or contested case, proceedings generally involve the application of PUC rules and policies to individual utilities. Rulemaking proceedings generally develop policies and procedures which apply across all utilities. But, traditional adjudicatory and rulemaking proceedings often prove unsatisfactory. Specifically, utilities and intervenors (e.g., consumer groups, environmental organizations, independent power producers, and public advocates) contend that the processes are expensive, and produce results that are unfair, inefficient, and difficult to implement. Appeals of PUC decisions to the courts are not uncommon.

Recently, utilities, intervenor groups, and PUCs have initiated supplemental, consensus-building processes. Although settlements among litigants in rate cases are not new, such settlements have been occurring with increasing regularity. Moreover, new and expanded forms of consensus-building are being tried. These efforts include facilitated technical sessions, collaborative processes, and negotiated rulemakings and address a broad array of substantive issues.

Purpose and Approach

Neither participants nor scholars have directed much effort at evaluating supplemental, consensus-building in electric utility regulation despite its increasing application. The primary purpose of this dissertation is to investigate whether such processes can improve upon the ability of traditional adjudicatory and rulemaking processes to resolve disputes.

To address this central question, I identify current controversies in electric utility regulation and assess the short-comings of traditional approaches used to resolve them. I then focus on a difficult methodological question: How should the success of supplemental consensus-building efforts be measured vis-a-vis traditional processes? For instance, is it adequate just to look at whether a consensual agreement was achieved among traditional adversaries, or whether participants saved time and money? Or, is it necessary to look more deeply at both the process and the results? I will explore these methodological issues in some detail, and then recommend and apply an analytic framework in my case study evaluations.

The last set of issues I address in this dissertation are prescriptive. If consensus-building has potential benefit, how can its application be expanded and improved? I examine the range of consensus-based processes that are available, and evaluate when each is appropriate. Finally, I explore how such processes can be best structured. I pose, analyze, and provide recommendations on questions regarding the timing, content, inclusion of interested parties (including the PUC itself), use of facilitators and mediators, and the dovetailing of consensus-building processes with traditional regulatory and adjudicatory procedures.

To assess these questions, I evaluated four case studies in detail. This methodology allowed me to combine formal case records (e.g., testimony, exhibits, PUC orders), over 75 in-depth interviews, personal observations, secondary literature and other data. The four cases were selected to represent a spectrum of approaches to consensus-building in electric utility regulation. They were also selected to represent the cutting-edge in consensus-building efforts rather than typical rate case settlements.

Two of the cases involve adjudicatory proceedings, and the other two focus on rulemaking and policy formation. Three of them occurred in Massachusetts, while the fourth took place in New Jersey. My concentration of Massachusetts cases is due to two factors. First, as a Senior Economist and later as Assistant Director of the Electric Power Division at the Massachusetts Department of Public Utilities, I worked on all three cases in Massachusetts and was instrumental in the design of the consensus-building process in one of them. My participant-observer status provided me with unique insights which greatly assisted my analysis. Second, the cases met my selection criteria for diversity, innovation, and significance -- both the process and outcome of each is nationally recognized.

Applicability

This dissertation stands at the intersection of two fields of inquiry: electric utility regulation and public dispute resolution. I structured it to make contributions to both.

The findings should also be relevant to several other areas. One is the regulation of other activities under PUCs' jurisdiction -- natural gas, telecommunications, and water -- where regulatory procedures are identical to those used in resolving electricity-related disputes. Another is for those involved in regulatory matters before the Federal Energy Regulatory Commission, which uses similar adjudicatory and rulemaking procedures to regulate inter-state electricity and natural gas transactions. Finally, federal and state administrative agencies who are involved in regulating other substantive areas (e.g., environment, health, and safety), given both the pervasiveness and similarity of adjudicatory and rulemaking procedures, should find the dissertation useful.

Overview

In Chapter 2, I will provide a brief history of electric utility regulation. I will trace the decline of widespread support for the electric utilities (and the laissez-faire policies of state regulators) in the face of rising costs, environmental concerns, and other factors beginning in the early 1970's. I introduce the concept of interventionism by state regulators and identify its strengths and potential short-comings. At the end of the chapter, I use five current controversies in electric utility regulation to emphasize the difficult choices currently facing society with respect to electricity issues.

In Chapter 3, I provide an analysis of the theory, practice, and evaluation of consensus-building in electric utility regulation. I begin the chapter with a description of alternative dispute resolution theory as presented by Roger Fisher and William Ury in their popular book <u>Getting to Yes</u>, and a discussion of the theory's relevance to electric utility regulation. I then explain the direct nexus between this theory and consensus-building experiments in electric utility regulation. I provide a detailed description of the range of consensus-building mechanisms currently in use. At the end of the chapter, I present criteria for evaluating the successes and failures of consensus-based supplements to traditional regulatory processes.

In Chapters 4 and 5 respectively I examine in some detail the use of consensus-building in adjudicatory and rulemaking proceedings before state PUCs. I begin the chapter on adjudication by documenting the rise in major contested case proceedings before state PUCs over the past decade, and then examine some of the short-comings of traditional adjudicatory approaches to resolving disputes. I also note the concurrent growth in consensus-based settlements before presenting two detailed case studies. In the first case, I analyze a settlement over the prudency of Boston Edison Company's extensive expenditures during a 32-month outage at the Pilgrim nuclear power plant. This settlement, reached among long-standing adversaries after extremely protracted and contentious litigation, illustrates numerous potential benefits of using supplemental, consensus-building in the context of traditional adjudicatory proceedings.

The second adjudicatory case in Chapter 4 involves a series of collaborative processes to design state-of-the-art, demand-side management (DSM) programs for the electric utilities in Massachusetts. In contrast to the Pilgrim case, the DSM Collaboratives represent a new and growing type of settlement process that occurs prior to a contested case proceeding and focuses on future utility plans rather than past decisions. The DSM Collaboratives are also unique because they represent on-going consensus-building efforts (several have lasted over three years so far) and because the utilities have already provided the non-utility parties with over $3 million to procure their own outside technical experts. I conclude the chapter by briefly summarizing the major findings regarding the use of consensus-building in adjudicatory proceedings.

I trace the history of agency rulemaking from its inception in 1946 with the passage of the federal Administrative Procedures Act to the present in the beginning of Chapter 5, noting the increasing judicialization of the administrative rulemaking process and some key criticisms of its effectiveness. Next I present an alternative, negotiated rulemaking model, popularized by Philip Harter and practiced with increasing regularity in some federal agencies.

I then examine two cases. The first involves the development of complex Integrated Resource Management rules by the Massachusetts Department of Public Utilities. The Department used a series of structured technical sessions attended by over 100 interested parties, and incorporating outside facilitation, both before and after formulating proposed rules. The second case is the negotiated settlement process used to develop comprehensive resource bidding policies for the New Jersey Public Utility Board. Thirteen parties, representing a broad range of stakeholders, spent over half a year negotiating the detailed mechanisms and actual wording for new state policies. I conclude the chapter by briefly summarizing the major findings regarding the use of consensus-building in rulemaking proceedings.

In Chapter 6, the final chapter, I highlight the benefits of using supplemental, consensus-building to resolve current and future disputes in electric utility regulation. I argue that both intervenors and PUCs can increase the effectiveness of their interventionism by cultivating consensus. I end the dissertation by proposing eight principles for improving consensus-building in electric utility regulation.

Endnotes (Chapter 1)

1. In actuality, only 14 states call the agency with authority over electric utility rates, "public utility commissions". 25 states (including Washington D.C.) call them "public service commissions", and 12 states call them something entirely different (e.g., "public utility or service boards", "department of public utilities"). However, PUC is the most commonly used term in the literature, and is used throughout this dissertation to refer to all of the above.

Chapter 2: The Decline of Consensus in Electric Utility Regulation

I begin this chapter by tracing the decline of widespread support for electric utilities (and the lassiez-faire policies of state regulators) following rising costs, environmental concerns, and other factors. I then introduce the concept of "interventionism" by state regulators and explore its strengths and weaknesses. Finally, I describe five current controversies in electric utility regulation to emphasize the difficult challenges we face in this area.

The Birth of Electric Utility Regulation

The regulation of industry in the United States began at the state rather than the federal level, and the initial focus was on regulating railroads. Although state regulation of railroads began in 1839 with a short-lived commission in Rhode Island, it was most prominently pioneered after 1869 in Massachusetts under the influence of Charles Francis Adams (McCraw 1984). At the time, the railroads were accused of exploiting their monopoly positions by charging high and discriminatory prices and providing poor service (Barkovitch 1989). However, in contrast to today's relatively independent and powerful state Public Utility Commissions (PUCs), the railroad commissions of the nineteenth century were built around the notion that the appropriate role of government was to persuade business through negotiation rather than to coerce it (id.). Apparently this approach was not a rationalization in the wake of weak enabling legislation, but a philosophic belief of Adams and others that regulation should focus on policy formation through independent investigation, advice, and direct negotiation (McCraw 1984).

In 1907, New York and Wisconsin became the first states to pass laws creating comprehensive commissions to regulate electric power and other utilities (Anderson 1981). The Wisconsin statutes simply expanded and strengthened the authority of its railroad commission to cover electricity, while New York created a new commission to regulate gas and electricity. Over the next six years, two-thirds of the states passed similar enabling legislation and the rest of the states were not far behind (id.).[1]

It is not uncommon today for electric utilities and other regulated industries to bemoan the excesses of regulation. However, the initial impetus of state regulation came largely from the electric utilities themselves. Beginning in 1898, Samuel Insul, head of Commonwealth Edison in Chicago and president of the National Electric Light Association (NELA), led a crusade to establish state regulatory oversight of electric companies in exchange for exclusive production and distribution franchises (Anderson 1982, Hirsh 1989). In 1907, apparently convinced more by the threat of continued local regulation or even municipalization (i.e., having the local government own and operate the electricity system) than by Insul's original pleadings to eliminate inter-utility competition, the NELA unanimously approved a strong statement by its Policy Committee supporting the concept of state regulation of their businesses (Anderson 1982, Hirsh 1989).

However, the upswell of support for state regulation of the electric utilities did not begin and end with the utilities. Also instrumental was the reputable National Civic Federation which appointed a diverse and prominent group to study the issue for two years (Anderson 1982).[2] In 1907 the Federation adopted a majority report signed by 19 of its 21 members that recommended replacing the status quo of unsupervised competition with either state regulation or public ownership:

> Public utilities are so constituted that it is impossible for them to be regulated by competition. Therefore, they must be controlled and regulated by the government; or they must be left to do as they please; or they must be operated by the public. There is no other course. None of us are in favor of leaving them to their own will, and the question is whether it is better to regulate or to operate (id., p. 45).

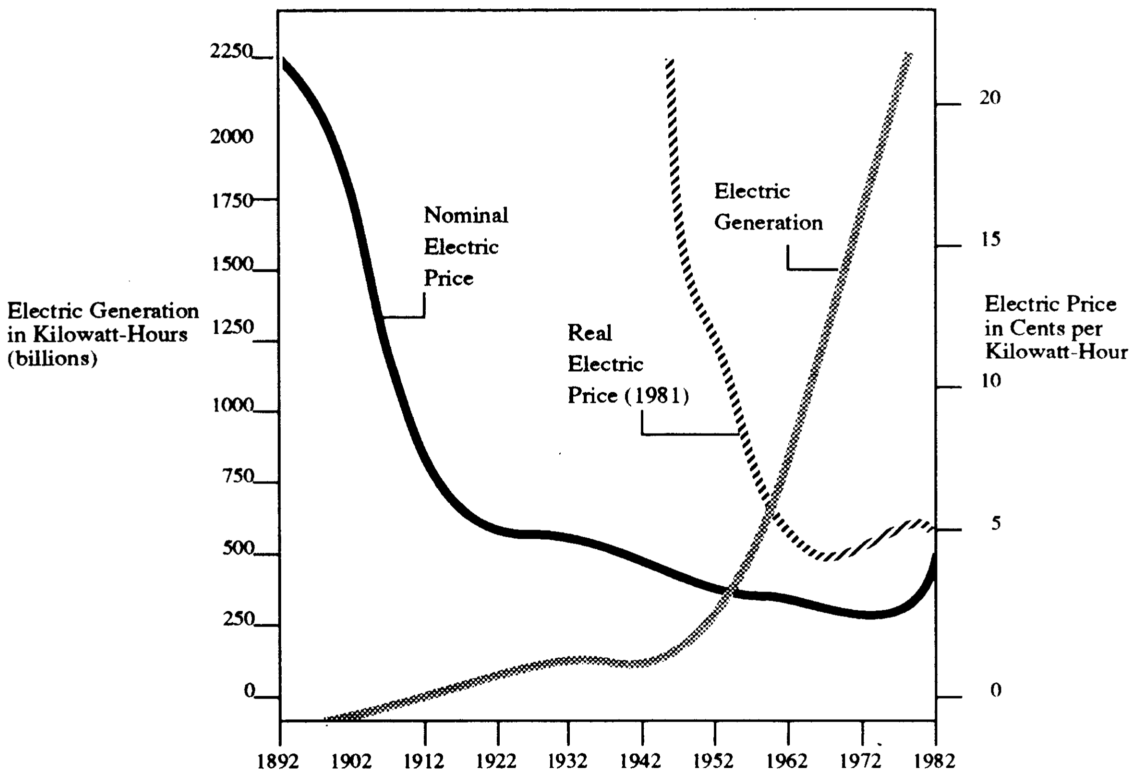
In addition to its overall recommendation, the report included many specific suggestions for crafting new state commissions that were used as the basis for the commission structures ultimately adopted (id.).

The growing consensus for state regulation of electric utilities was capped by the support of progressive governors in New York, Wisconsin, California and New Jersey. Apparently each Governor used his support of government control of private enterprise to establish his political reputation -- each eventually ran for president (Anderson 1982).[3] With support from all sectors of society (with the exception of some municipalities which viewed the movement as a preemptive strike on local ownership), statutes establishing public utility commissions and authorizing them to regulate electric utilities were adopted rapidly throughout the country.

Implied Consent

Electric utility regulation was relatively non-eventful from the time when state PUCs began regulating electric utilities through the early 1970's when a series of trends and events converged to shatter the quietude. During this period, electricity use expanded tremendously, reaching beyond its initial roots in lighting services until it was inextricably intertwined with every facet of American life. A recent book by David Nye, Electrifying America, vividly describes how the integration of electricity into society transformed the city, the farm, the industrial base, and our domestic lives (Nye 1990).

Figure 2.0
U. S. Electricity Sales and Electricity Prices 1892-1982



Source: Edward Kahn (1988), <u>Electricity Utility Regulation and Planning.</u> P.11.

The increased demand for electricity resulted in the construction of increasingly larger and more efficient plants (Hirsh 1989, A.Kahn 1988). Through numerous technological breakthroughs, economies of scale, and falling fuel costs, the utilities were able to continuously bring down the cost of producing electricity until the early 1970's. The price of electricity to consumers correspondingly fell in nominal terms from approximately twenty-five cents/kwh in 1910 to less than a nickel/kwh in the early 1970's (E.Kahn 1989). As Figure 2.0 above illustrates, the real decrease in rates to consumers was much more dramatic. Figure 2.0 also shows the large corresponding growth in electricity generation.

Although the state PUCs had the authority to regulate the utilities' services and rates (i.e., primarily to make sure it did not make excessive profits and that rates were "fair and reasonable"), there existed a laissez-faire approach to regulation. This may have been due in part to inadequate resources at the PUCs and some judicial debate about the scope of their authority.[4] But, there was also little public pressure to "reign-in" the utilities. Between electricity's perceived usefulness and its declining price, the public held both the product and its producers in high esteem throughout this period and there was little or no intervention before the PUCs (Hirsh 1989, E.Kahn 1988).[5]

Rate cases were rare during this period. When they did occur, they were non-controversial compared to today's often hotly contested cases. As late as the mid-1960's, only three or four rate cases were initiated per year in the entire nation (Anderson 1982). The PUCs probably could have justified requiring utilities to lower rates more frequently during this period.[6] But they rarely instigated investigatory proceedings -- waiting instead for the utility to file a case (Anderson 1982). When cases did occur, the regulators concentrated solely on a utility's rate of return and level of service. Pricing, operations, and planning issues were left to utility managers' discretion. "Unintrusiveness" was the norm of PUC regulation (Barkovitch 1989).

If rate case adjudications were rare prior to the early 1970's, the use of rulemaking and other techniques by the PUCs to articulate and advance electricity-related policies and standards were virtually non-existent (Trebing 1967). There was an implicit consensus that utilities were performing satisfactorily and that there was little need for active PUC intervention either to restructure the industry or to second guess utility decision making. Richard Hirsh, in his book Technology and Transformation in the American Electric Utility Industry, writes:

> ...the stakeholders in the electric power matrix had formed an implicit consensus about the technological system and its management. Benefits accrued to all: consumers enjoyed electricity whose unit price declined gradually. Investors profited from steadily increasing dividends and share prices of utility stocks. Managers congratulated themselves for their aptitude in running a complex technologic enterprise...And regulators sat quietly on the sidelines, providing little interference in what appeared to be one of the best examples of natural monopoly. It was an elegant system...(Hirsh 1989, pp. 176-177).

The End of Consensus

Hirsh's book describes how the initial seeds of the ensuing discontent were technological in nature and were sewn in the 1960's, despite the common belief that a series of financial, economic and regulatory problems during the early 1970's led to the end of the implicit consensus on matters concerning the electric utility industry and its regulation (Hirsh 1989). Specifically, the technological innovation that was the driving engine of the electric utilities' success during the preceding half century reached a plateau. Both plant size and the thermal efficiency of new units peaked during the 1960's and remained flat through the 1970's.[7] Utility rate cases rose dramatically from three to four per year during the mid-1960's to 45-to-94 per year during the 1970-1972 period largely as a result of this leveling-off and prior to the sharp rise in oil prices in the wake of the OPEC oil embargo during 1973-1974 (Anderson 1982, p. 70).

The quadrupling of oil prices in the 1973-1974 period immediately increased fuel costs to utilities -- particularly in the northeast where utilities had recently converted many of their coal burning plants to oil. Other fuels essentially tracked the rise in oil prices: rising energy prices in turn sparked inflation. Inflation increased the cost of capital to the utilities at a time when many of them were building new plants to meet anticipated load growth, and increased their non-fuel operating costs, too. As a result, utilities turned to regulators for permission to raise rates and pass their increasing costs directly along to consumers. Alfred Kahn in the new introduction to his classic text The Economics of Regulation: Principles and Institutions explains the predicament:

> After two decades of relative quiescence, during which regulators were comparatively complaisant about costs falling faster than rates and earned rates of return tending systematically to exceed levels determined previously to be "just and reasonable," requests for rate increases began suddenly to press hard one upon the another, as each award proved to be inadequate even before it went into effect, and achieved returns fell systematically short of the cost of capital (A.Kahn 1988, p. xxiii).

By the mid-1970's, consumer advocate groups were springing up throughout the country to protest utility rate increases. They were joined by a burgeoning environmental movement which had succeeded in getting Congress to pass the Clean Air Act in 1970, and had recently turned some of its attention to electric utility regulation. Environmentalists' sought to force utilities to better account for environmental externalities through better pricing, planning and investment (Roe 1984, Lovins 1976). Consumer and environmental forces joined to oppose capital-intensive, nuclear power plants which many utilities were banking on, but proved to be lightening rods for citizens concerned about increasing prices and potential environmental disasters. Increased citizen protest led to both more difficult and time-consuming siting procedures for new plants (both nuclear and other technologies), and prolonged construction periods.

In 1974, the year after the OPEC oil embargo sent energy prices skyward, residential electricity usage actually decreased for the first time in the century. Though the decrease was not large, 1/10 of 1 percent, the change was shocking to an industry that had grown accustomed to 7 percent annual growth over the past couple of decades (i.e., a doubling of electricity use every decade) (Hirsh 1989). The electric utility industry was suddenly faced with the disconcerting specter that customers would respond to rising electricity prices by conserving electricity (both through investments in energy efficiency and lifestyle changes), self-generating, or fuel switching. It forced utilities to reconsider their ambitious plans for new plant construction, as well as to discontinue some plants already under construction.

An increasing confrontation between citizens and utilities was exacerbated in the late 1970's and early 1980's by the second oil price shock during the Iranian crises, the Three-Mile Island nuclear plant accident in 1979, and double-digit inflation. Some of the frustrations culminated in demonstrations at nuclear power plants such as Seabrook in New Hampshire and Diablo Canyon in California where arrests often followed acts of civil disobedience. But much of the confrontation occurred in the hearing rooms of the state PUCs. Richard Hirsh describes the transformation as follows:

> Once a benign and polite activity that ratified decisions already made by power companies, utility regulation became a hornet's nest as commissioners relearned the nature of their business...hesitated to pass along rate relief...[and] companies earnings suffered (Hirsh 1989, pp. 112-113).

Hirsh assigns much of the blame for the ensuing conflict to the management of the utilities. He argues that they failed to acknowledge the technological stasis upon them,[8] and then failed to appreciate "that their industry was a publicly regulated industry in which an active consensus was necessary, especially during unusual times like the crises-laden 1970's" (Hirsh 1989, p. 148).[9] Some of the blame, however, must rest with the regulators who also failed to recognize the technological stasis; and when they did, responded poorly. In the end, assignment of blame is less significant than the recognition that the broad support for the electric utility industry, together with a laissez-faire approach to regulation assumed by state PUCs, ended rather abruptly in the 1970's.

Interventionism

The tidal wave of rate increase requests that deluged state PUCs in the 1970's put the spotlight not only on the utilities requesting them but on the PUC regulators (and the regulatory processes) charged with resolving these contentious cases that usually resulted in unpopular rate increases. Whereas past efficiency improvements at generating facilities allowed real electricity rates to decrease for all customer classes, society was now forced to decide how to distribute increasing costs between utilities and ratepayers, among existing customers, and finally between present and future generations. Moreover, there was a growing debate about whether the electric utility industry should continue to rely on large, centralized generating facilities that utilized non-renewable resources (e.g., oil, coal, nuclear) or whether it should switch to a system built on renewable energy (e.g., solar, wind, hydro) and energy efficiency (Lovins 1976).[10] Intervenors (e.g., residential and industrial ratepayers, environmentalists, and other government agencies) turned to the regulators for support because they did not trust utilities to adequately resolve either the distributional issues or the long-term planning issues.

Regulators, in turn, were required to make decisions in areas that they had previously left to utility managers. These areas broadly included rate design and cost allocation issues, and utility planning, procurement and operating decisions. To resolve these issues, regulators had to take a much more active role both as judges and policy-makers than they had in the past. In 1974, economist Paul Joskow observed that regulators were somewhat reluctantly forced into abandoning their previous modus operandi of passive conflict minimization, in favor of a more activist approach to regulation (Joskow 1974). But as Barbara Barkovitch points out in her book Regulatory Interventionism in the Utility Industry: Fairness, Efficiency and the Pursuit of Energy Conservation, although the regulators may have been reluctant at first, beginning in the mid-1970's many rose to the occasion:

> Writing in the early 1970's, he [Joskow] did not anticipate the shift in ideology that would lead to regulators who craved the limelight and actively pursued major regulatory policy changes -- rejecting the traditional paradigm. For such regulators, intervention was not an aberration but an integral part of the job (Barkovitch 1989, p. 49).

Barkovitch's book focuses on the "interventionism" (as she calls it) of the California PUC during the mid-1970's and early 1980's on energy conservation matters (or more commonly labeled today as demand-side management or DSM). However, the history of electric utility regulation since the mid-1970's is replete with parallel examples in other state. I briefly describe three of the most significant early interventions including the California PUC's, to illustrate the phenomenon and make several points about this period.

Marginal Cost Pricing in New York

The New York Public Service Commission pushed to change the way electricity was priced. Prior to the arrival of Alfred Kahn, the preeminent regulatory economist from Cornell as Chair of the New York PUC, electric utilities throughout the country priced electricity at flat or declining block rates. The rates were also not differentiated by time-of-day or season. While this made sense in a constantly declining-cost industry, promotional rates made little sense during times of increasing cost when consumption needed to be discouraged.

According to Thomas McCraw in Prophets of Regulation, when Kahn arrived at the PUC in June 1974 he immediately set about converting the PUC Commissioners and staff, the utilities, and the intervenors to the notion of marginal cost pricing (McCraw 1984).[11] He initiated a series of generic hearings which he personally presided over to take testimony on the issue and to engage in a dialogue with interested parties (id.). At the beginning of the hearings he said, "I hope we can proceed as cooperative seekers of truth rather than as adversaries seeking an advantage over one another" (id., p. 251).

By the end of the generic hearings, the concept of marginal cost pricing had the strong support of a strange coalition including the Long Island Lighting Company and the Environmental Defense Fund; tacit support from most of the other utilities; and continued strong opposition primarily from large commercial and industrial users who feared paying higher rates (McCraw 1984). Rather than moving to a rulemaking procedure to promulgate standards that would apply industry-wide, Kahn preferred to institutionalize the concept on a case-by-case basis. In LILCo's next rate case, time-of-use pricing was established, charging higher rates during the summer months and peak hours when the cost of generation was highest and lower rates in other times. Kahn agreed that the target revenue extracted from any one customer class would remain unchanged after the new rates went into effect (i.e., the shifts in revenue burden would be from off-peak users to on-peak users only within customer classes) apparently in an attempt to gain the support of the large commercial and industrial consumers, but somewhat in violation of pure marginal cost theory (id.).

The adoption of marginal cost pricing in New York was an important substantive change in PUC regulation would be adopted in various forms in most other states over the next decade. Kahn worked successfully to shape a political consensus on his ideas (McCraw 1984). Still, a separate PUC Order requiring Consolidated Edison to abandon its declining block rate structure for residential rates issued during the original generic hearings was indicative of Kahn's intentions to intervene on this issue and institutionalize marginal cost pricing -- whether or not he could persuade everyone else of its virtues.

Demand-Side Management in California

In California, under the leadership of Robert Batinovich and Leonard Ross who were appointed shortly after Governor Jerry Brown took office in 1975 (and after intervention from environmental groups and others), the CPUC pushed the utilities (both gas and electric) to begin aggressive DSM programs (Roe 1984, Barkovitch 1989). The PUC, for instance, in 1978 ordered all the utilities to weatherize 90 percent of the homes in their service territories in five years by offering 8 percent loans for ceiling insulation, and installing low-flow showerheads and water heater blankets to customers free-of-charge (Barkovitch 1989). Although the PUC's Order was appealed to the state Supreme Court which ruled that the PUC exceeded its authority by ordering utilities to undertake aggressive DSM programs, the California Legislature shortly afterwards granted the CPUC that authority explicitly. The CPUC immediately continued its quest to have utilities install DSM as an alternative to new supply and as a way of mitigating customer rate increases (id.).

In 1980, under the leadership of another Brown-appointee, CPUC Chair John Bryson, the PUC pushed PG&E, the largest investor-owned utility in the country, to enhance its residential weatherization programs by offering zero-interest loans to its customers (id.). Many other DSM programs were also ordered by the CPUC as it continued to become involved both in the oversight and program formulation of the utilities -- refusing to play either a passive or disinterested role (id.).[12] By 1984, California utilities' expenditures on electricity DSM alone reached $127 million per year which was probably an order of magnitude higher than expenditures in any other state (Calwell and Cavanagh 1989, Raab 1991). Other state PUCs eventually followed California's lead and began pressuring the utilities to invest in DSM.

Although many utilities could see advantages to DSM as a means of mitigating rising customer bills, and some perhaps could understand the advantages of load management (i.e., shifting customer use from peak to off-peak periods); few, if any, concurred with the CPUC's new philosophy that DSM was as good, if not better, than existing supply-side resources. The CPUC, particularly under Bryson, still made some attempts to build consensus by addressing the fears and concerns of the utilities.[13] However, the CPUC's intended interventionism on this issue was inevitable and virtually unstoppable as Jerry Brown saw his election as a mandate to pursue DSM and renewable resources.[14]

Nuclear Power Plant Cost Disallowances Across the Country

The treatment of the utilities' nuclear power plant investments perhaps captures the intensity of this period and the regulators' growing interventionism like no other issue. Originally touted as the next great technological break-through, promising to produce electricity that would be "too cheap to meter", nuclear power was first criticized for being unsafe and later for being both unsafe and too costly. Although substantial debate goes on regarding the causes of escalating costs associated with nuclear power (as well as the safety and health risks), between the early 1970's and the mid-1980's there was a six-fold increase in the real cost of nuclear power (Flavin 1987). Plants that were completed after the mid-1970's were consistently and substantially over budget and late. Furthermore, since 1974, no new nuclear plant has been ordered by US utilities that was not subsequently canceled (over 100 reactors have been canceled -- including many that were under construction) (Flavin 1987).

Whenever utilities came before the PUCs to request rate increases to recover their nuclear investments, parties intervened to argue for major disallowances on the grounds that the utilities had acted, and continued to act, imprudently by embracing nuclear power. By 1986, the PUCs' disallowances were projected to total as much as $35 billion for both canceled and completed nuclear plants -- amounting to almost 54 percent of the utilities total equity in those plants (A.Kahn 1988, p. xxvii).[15] These massive disallowances marked a significant departure from what was virtually a guaranteed pass through of new plant costs to ratepayers prior to the 1970's.

Previously, PUCs rarely disallowed imprudent expenditures despite having had both the authority and the responsibility to do so. Because imprudence is difficult to prove, the PUCs' willingness to apply a prudence standard to disallow tens of billions of dollars of nuclear investment was a sign of the contentiousness of the times and of regulatory interventionism.[16] Moreover, several states including Massachusetts, Pennsylvania and Kansas added new and more rigorous standards (known as "used and useful" standards) to justify disallowing even larger portions of nuclear investments than the prudence standard alone would have permitted (Kalt et. al. 1987). In addition to disallowing costs associated with imprudent management decisions made throughout the course of construction and operation, PUCs could disallow costs if the plants were not currently needed to meet demand or cheaper sources were available under new "prudent, used and useful" standards.

Utilities and others argued that these new standards unfairly transferred risks once shouldered by the ratepayers to them, and constituted a breach of the regulatory bargain (i.e., the utilities agreement to accept financial returns that were below monopoly rates in exchange for guaranteed recovery of prudently incurred expenses) (Kalt et. al. 1987). The disallowances threatened to have a chilling effect on investment in new facilities (id.). Moreover, the disallowances (which were also applied occasionally to coal plants), continued to further fracture the relationship among consumers, utilities, and regulators which had started to deteriorate as prices began rising in the late 1960's and early 1970's.

Problems With Interventionism

The increased involvement of intervenors in the regulatory process, combined with the interventionism of PUCs beginning the mid-1970's, led to many significant changes in the electric utility industry. Such changes included the movement towards marginal cost pricing, the offering of DSM programs by some utilities, and major disallowances for past expenditures in new supply-side facilities. However, there was not a consensus about how the electric industry should be structured or regulated. Instead, despite decisions on many contentious cases by the state PUCs, underlying electric utility issues often remained controversial and unresolved. Even where the PUCs' new-found interventionism appeared to resolve matters, this too proved illusory.

In California, for example, the utilities' investment in DSM programs declined considerably after 1984 despite continued public interest (Calwell and Cavanagh 1989).

In fact, it was not until 1990 that California's DSM programs were revitalized after the four largest California utilities and 13 representatives of public and private interests reached an agreement through an innovative and extensive DSM collaborative process (Raab 1991, Raab and Schweitzer 1992). Included in the collaborative agreement were provisions to provide utilities with financial incentives based on shared-savings. This represented a major inducement that had not been present when the CPUC pushed utilities to run DSM programs in the late 1970's and early 1980's (Raab 1991). The California PUC endorsed the collaborative process and suggested it would be willing to provide financial incentives to the utilities for successful DSM performance.

The California DSM case illustrates the potential difficulty of sustaining changes ordered through regulator interventionism without broad support. A second example of the short-comings of regulator interventionism occurred in Massachusetts in connection with its "prudent, used and useful" standard. The Massachusetts case illustrates the potential for producing unintended and undesirable results from regulator interventionism. In the late 1980's, while Massachusetts was still experiencing the "economic miracle" that Governor Dukakis boasted about during his bid for the Presidency, the capacity situation was tight and brownouts had already occurred in the summer of 1987. The regulators were extremely concerned that utilities would not adequately invest in new generating facilities to meet the expected load projections, after having disallowed substantial nuclear-related costs in the mid-1980's through its "prudent, used, and useful" test. To remedy the situation, the Massachusetts Department of Public Utilities (DPU) opened a rulemaking process. As discussed in Chapter 5, the four-year rulemaking process completely revised the rules for the ratemaking treatment of new facilities, as well as producing Integrated

Resource Management (IRM) Rules. An elaborate technical negotiating process was used to develop the IRM rules that actively solicited the views of interested parties and sought to build consensus.

The point of these illustrations is not to make a case for the failure of regulator interventionism, nor to call for a return to the days of laissez-faire regulation. Such a return, would neither be possible nor desireable, given the complexity and controversy of the current issues in the electric utility industry and the regulatory environment. It is, after all, the PUCs' job to regulate by acting quasi-judicially in rate cases (and other adjudications) and quasi-legislatively in rulemaking (and other policy deliberations). More importantly, regulators often bring unique and insightful ideas to the regulatory arena.

Instead, what I introduce here, is the notion that interventionism (and electric utility regulation generally) can be improved when consensus is cultivated. Clearly some of Alfred Kahn's success was due to the consensus-building he was able to pursue along with his interventionism. It is likely that DSM in California and IRM in Massachusetts will be more successful now that regulators and others have begun to use consensus-building supplements to their traditional regulatory efforts.

These are issues that the remainder of this dissertation will explore in detail. First, I conclude this chapter with a brief overview of some of the major substantive controversies currently facing the industry with respect to the planning, operation, and ratemaking treatment of electric utility investments. The primary purpose of this synopsis is to underscore that this is an industry in transition with many issues that need to be resolved. The dissertation then focuses on whether or not (and if so how), consensus-based supplements to traditional regulation can assist regulators and society in resolving their differences, while preparing us to deal with the myriad of future controversies that will inevitably surface. In the next chapter, I explore the theory, practice and evaluation of consensus-building in electric utility regulation, before turning to the detailed case studies in Chapters 4 and 5.

Synopsis of Current Controversies in Electric Utility Regulation

Current controversial issues facing the electric utility industry through its regulatory environment can be clustered into five areas: (1) minimizing societal costs, (2) utility investment in demand-side management resources, (3) competition in electricity generation, (4) inter-jurisdictional conflict, and (5) incentive ratemaking. This list is not meant to be exhaustive -- other important and controversial issues certainly exist. The purpose is to provide a flavor of the current challenges facing society regarding electric utility issues. Moreover, it will provide the reader with a primer to many of the substantive issues at the core of the case studies that follow.

Minimizing Societal Costs

Traditionally, the goal of electric utility power planning, acquisition, and operation decisions has been to minimize the direct cost (i.e., out-of-pocket costs) of electricity for consumers. Additional social costs or benefits associated with electricity production, distribution and consumption, were not explicitly accounted for in the decisionmaking calculus. However, since the mid-1980's, many utilities have been required by regulators to expand their evaluation criteria to explicitly incorporate other costs and benefits -- most notably environmental externalities (Cohen et. al. 1990). This required expansion has taken several forms including: (1) looking to environmental factors as a tie breaker when choosing between resources with comparable direct costs, (2) explicitly favoring less polluting resources with a simple cost credit for cleaner resources or a penalty for dirtier resources (Northwest Power Planning Council 1983, Wisconsin PSC 1989, Vermont PSB 1990),[17] and (3) using cost adders based on emissions (i.e., $X/ton of pollutant) that must be combined with direct costs when comparing resources (New York PSC 1989, Massachusetts DPU 1990, Nevada 1991, California PUC 1991).

Many states now either require that utilities minimize social costs or are considering such action. However, both the underlying rationale for including externalities and the methods for doing so remain controversial, among regulators and within society (NARUC 1990). Some argue that states which have included such considerations have already gone too far (Browne 1991, Joskow 1991, A.Kahn 1991, and Maine PUC 1991). These critics generally argue that state PUCs lack the authority and expertise to regulate pollution beyond already stringent federal and state standards. They also question the efficacy and fairness of requiring utilities to further internalize externalities without also imposing such restrictions simultaneously on all sectors of the economy across the country. Finally, these critics argue that the use of cost adders is technically flawed.

Meanwhile, supporters of including environmental externalities in utility decisionmaking often argue that even the most stringent approaches taken by some states do not go far enough (Pace University 1990, Bernow et. al. 1991, Chernick 1992, Krause 1991). Specifically, these critics argue that the most aggressive approaches currently required only apply to new resources and do little to address decisions about existing resources (i.e., retrofit, fuel-switching, retirement of existing plants, and system dispatch). Some also argue that the methods need to be expanded to (1) incorporate pollution over the entire fuel cycle instead of focusing solely on smoke-stack emissions, and to (2) apply to all environmental impacts (e.g., nuclear waste, habitat destruction from hydro development) instead of focusing solely on air pollutants. Finally, these critics argue that some of the environmental externality adders being used by states may be too low, and that other externalities besides environmental ones should be included (e.g., economic and security).

It is unlikely that the controversy surrounding environmental factors in electric utility regulation will dissipate anytime soon given the growing public concern on environmental issues, and the fact that electricity generation still accounts for a significant portion of pollution in the United States (i.e., two-thirds of sulfur dioxide, one-third of nitrogen oxide, and one-third of carbon dioxide) (Moskovitz 1991). PUCs will probably continue to push utilities to include environmental externalities in their resource decisionmaking, if for no other reason than to internalize the cost of complying with more stringent regulations anticipated in the future.[18]

Utility Investment in Demand-Side Management Resources

Amory Lovins' article "Energy Strategy: The Road Not Taken" published in <u>Foreign Affairs</u> in 1976, sparked extensive debate over the technical feasibility and the appropriateness of substituting DSM resources for supply-side options. A virtual consensus has emerged that <u>society</u> should pursue energy conservation opportunities that cost up to the price of new supply. However, there is no consensus regarding the appropriate role of <u>electric utilities</u> in delivering and financing DSM programs.

The proponents of active utility involvement argue that utilities are well situated to broker DSM programs by helping overcome substantial market barriers which keep ratepayers from investing in DSM (e.g., inadequate information, split incentives between landlords and tenants, limited access to capital) (Cavanagh 1988, Lovins 1986, Lovins and Hirst 1989, Northwest Power Planning Council 1988). They further contend that utilities should be willing to pay up to their avoided cost (i.e., the cost of additional new supply-side resources) to procure DSM. Such a strategy, they argue, should result in the minimization of the overall cost of delivering electricity services to society and lower the average customer's bill, even though electricity rates may rise in the process.

Opponents generally argue that utilities are in the business of selling kilowatts, and are not particularly well-suited for delivering DSM or "negawatts" as Lovins calls them (Anderson 1991, Costello 1987, A.Kahn 1991, Joskow 1988, Ruff 1990). Moreover, they argue that a utility's obligation to finance DSM programs should be limited to the difference between its avoided cost of new supply and the current rates.[19] Such a limitation, they argue, will avoid raising rates for everyone and increasing the bills of customers that do not participate in the DSM programs. Moreover, they contend it will send the proper price signal to customers who do participate.

As the debate continues, electric utility investment in DSM in the United States has grown to more than $2 billion dollars per year (Moskovitz et.al. 1991).[20] At least ten utilities are spending over 3 percent of their revenue on DSM investments (id.). PUCs are generally requiring utilities to spend up to their full avoided cost on DSM, if necessary, to gain customer participation. However, as both rates and non-participants' bills continue to rise, customer backlash against utility DSM programs -- particularly in these difficult economic times -- is likely. In addition, the recent push by some intervenors and PUCs for utilities to include fuel switching measures in their DSM programs (i.e., requiring utilities to pay to switch their customers using electricity for certain end-uses such as water- or space-heating to alternative fuels) is intensifying the debate on DSM.

Competition in Electricity Generation

In 1978, Congress passed the Public Utilities Regulatory Policy Act (PURPA) requiring utilities to purchase power from cogenerators, and from small power producers using renewable resources (Qualifying Facilities or QFs). At that time, utilities essentially produced all the electricity delivered to their customers through the power grid.[21] Since the passage of PURPA, however, an increasing percentage of new generating resources are being provided by QFs and other Independent Power Producers (IPPs) that do not meet PURPA's definition for QFs. There are currently 43,000 MW of IPP generation on-line, representing 8 percent of total generation (RCG/Hagler, Bailly, Inc. 1992). With nearly half the state PUCs requiring or permitting utilities to solicit the majority of new resources through bidding systems open to QFs, and often to other IPPs and even to DSM providers, the new generating resources supplied by non-utility entities should continue to increase.[22] Estimates of the market share of non-utility generators for new generation over the next decade range from 25 percent to 50 percent (GAO 1990, Joskow 1989, RCG/Hagler, Bailly, Inc. 1992).

This major restructuring of the electricity generation sector in the United States is not occurring without substantial controversy. The controversy falls into two general areas: (1) the appropriateness and design of the processes -- most notably bidding -- to accomplish this restructuring, and (2) concerns with the restructuring itself. Table 2.0 shows many of the controversial questions at the heart of the debates on bidding.

Different PUCs and utilities (in the absence of state rules) have addressed these controversial questions in divergent ways (Duane 1989).

Table 2.0
Controversial Questions on Bidding

1. Is it appropriate to integrate DSM into supply-side bidding?
2. Should utilities participate in their own bidding processes?
3. If utilities do not participate, how will it be determined what portion of need will be bid and what portion will be delivered by utilities?
4. Should bidding processes use self-scoring systems or should utilities be given greater flexibility in resource selection?
5. What non-price factors should be evaluated and how should they be structured? Also, how should price factors be weighed against non-price factors when comparing resources?
6. Should utilities be allowed to negotiate contracts for power outside of, or even instead of, a bidding framework?

Source: Author's Questions

The concept of infusing competition into electricity generation is generally accepted. However, there is a debate on how far and how fast it should be done (Gerber 1988, Joskow 1989, Hamrin 1989, Nail and Belanger 1989, Tierney 1989, E.Kahn 1990,Stalon Na Lock 1990). Some fear that increased dependence on IPPs could jeopardize system reliability, and raise electricity prices (Gerber 1988, Joskow 1989). Others argue just the opposite (Hamrin 1989, Nail and Belanger 1989). There has also been concerns expressed about whether competition should apply only to new resources, or whether existing resources should also be subject to competition. Finally, many argue that unfettered competition would be unwise before transmission access and pricing issues, and other issues that touch on questions of inter-jurisdictional authority are resolved (Hempling 1990, Steinmeier 1990).

Inter-Jurisdictional Conflict

The primary focus of this dissertation is on intra-state PUC regulation. However, an analysis of the major controversies facing society on electricity regulatory matters would be incomplete without mentioning some of the inter-jurisdictional conflicts that currently exist between the state PUCs and the Federal Energy Regulatory Commission (FERC), and also among the states. Federal-state conflicts stem from a separation of authority between federal and state regulators on electric utility issues which is fuzzy in many areas, and has required increasing intervention from the courts in recent years to sort out (Vince et. al. 1990, Stalon and Lock 1990). A central issue is the right of state PUC's to review the prudence of investments by multi-state holding companies under FERC's jurisdiction as they relate to retail subsidiaries under state jurisdiction. A recent court case ruled that states can not review the prudence of FERC-approved allocations.[23] However, states continue to argue that this infringes on their prerogative to regulate utility supply planning.

Transmission issues are another source of friction. States have jurisdiction over transmission certification and siting. FERC has authority over interstate electricity transmission. The two have butted heads over state-sponsored efforts to push utilities to provide IPPs with open access to transmission at market-based prices (Stalon and Lock 1990, Tierney 1990). The National Association of Regulatory Utility Commissioners (NARUC) and others have opposed reforms to the Public Utility Company Holding Act (1935),[24] until states' concerns over transmission access and pricing, and the future of state' oversight of utility energy planning are adequately addressed (Steinmeier 1990, Hempling 1990, Stalon and Lock 1990, Vince et. al. 1990).

A third set of issues entails the implementation of PURPA. FERC has challenged some states on the consistency of their implementation procedures with federal law (e.g., New York PSC's requirements that utilities pay QFs prices above avoided cost). Finally, mergers between utilities in different states require approval by the PUCs in the effected states and FERC -- giving each entity an effective veto. Recent merger cases have proven extremely contentious both between the federal and state entities and among the states (e.g., the PacificCorp and Utah Power & Light merger, and the Northeast Utilities and Public Service of New Hampshire merger).

Jurisdictional tensions between states also exist, although they are usually driven more by concerns over the inter-state distribution of costs and benefits than on underlying principles of legal authority. The merger cases are a good example of this phenomenon. Another good example are disputes on the selection of supply-side resources or the design of DSM programs by PUCs in neighboring states where retail companies are serviced by a common multi-state company -- particularly where states have different preferences and planning rules. Differing regulations on environmental matters is also a source of concern among states. States with relatively tough environmental standards can increase the cost of electricity for others, and can even cause the export of pollution to states with lower standards.

Given the current trends to merge and consolidate utilities into holding companies and power pools on the one hand, and to infuse competition in generation on the other, jurisdictional disputes between federal and state entities and among state PUCs will undoubtedly remain in the limelight throughout the 1990's.

Incentive Ratemaking

Traditional cost-of-service ratemaking essentially reimburses electric utilities for their expenditures and provides a reasonable return on long-term investments. Regulators typically can disallow recovery for imprudence and other factors. The ratemaking system, is based almost exclusively on the threat of regulatory reprisal, and does not inherently encourage utilities to control costs or pursue least-cost resources (Joskow and Schmalensee 1986, Moskovitz 1989). Over the past decade, however, state regulators have begun to experiment with modifications to the ratemaking process by providing utilities with more direct incentives to minimize the cost-of-service.

By 1986, over 20 states had imposed modest operation and maintenance incentives for some generating facilities under their jurisdiction (Joskow and Schmalensee 1986). Regulators in some states have expanded incentive ratemaking to cover investments in new resources. For instance, Massachusetts adopted rules in 1988 that require utilities to seek preapproval for new resources and major capital additions through a process that would fix ex ante a price that utilities will be paid for delivering electricity (Massachusetts DPU 1989). Twenty-three utilities in 15 states are allowed to earn incentives on their DSM investments which share the savings (i.e., the difference between the next supply plant and the cost of DSM) between them and their ratepayers (Destribats and Rosenblum 1992, Nadel et.al., 1992). In 1991, PUCs in Washington and Maine adopted the most sweeping ratemaking incentive mechanisms to date when they approved proposals to decouple profits from sales by fixing utility revenue at a set amount per customer (Moskovitz and Swofford 1991).[25]

Traditional adversaries of electric utility regulatory issues now support initiatives to design and implement incentive-oriented ratemaking schemes. However, others continue to maintain that incentive schemes are unnecessary. They argue that utilities' obligation-to-serve requires them to provide least-cost and reliable service. But even those who agree that experimentation with incentive ratemaking schemes is appropriate and necessary, continue to disagree over when and where incentives should be applied, and also over how incentives should be structured and sized.

Endnotes (Chapter 2)

1. Federal regulation of electric utilities did not commence until the 1920's and 1930's as utility holding companies merged utilities in different states and utility activities (e.g., wheeling power over the transmission and distribution system) crossed over state lines (Barkovitch 1989).

2. The executive committee of the Federation included such diverse membership as Samuel Insul of Commonwealth Electric, John Mitchell, president of the United Mine Workers, and Louis Brandeis then a lawyer in Boston and future Supreme Court Justice (Anderson, 1982).

3. The Governors included Charles Hughes (New York), Robert La Folette (Wisconsin), Hiram Johnson (California), and Woodrow Wilson (New Jersey) (Anderson 1982).

4. In several U.S. Supreme Court cases between the 1890's and mid-1920's, Courts appeared fairly protective of utility management discretion. Since the mid-1920's, courts have upheld commissions rights to regulate utility operating and other costs. The courts have also placed the burden of proof for establishing the reasonableness of expenditures with the utility rather than commission (Barkovitch 1989).

5. The one exception occurred when the utility holding company structure collapsed during the depression. As a result of this collapse, increased federal oversight of the corporate structure of the utilities occurred through the newly-formed Securities Exchange Commission. Political fallout also refueled the debate over the issue of public vs. private power and resulted in the formation of the Bonneville Power Administration, the Tennessee Valley Authority and the Rural Electrification Administration by the federal government (E.Kahn 1988).

6. Steadily declining marginal costs should have allowed regulators to more regularly reduce rates while maintaining utilities expected rates of return. However, since utilities rates were based on their historic costs there was no great incentive for them to come in for rate cases, compared to when marginal costs are increasing.

7. See pages 4-7 of Hirsh's book <u>Technology and Transformation in the Electric Utility Industry</u> (1989), for some excellent graphs depicting these trends.

8. Hirsh defines technological stasis as the cessation of technological advances in an industrial process. He argues that stasis comprises more than a hardware problem -- representing a condition that occurs within a social system of engineers, business managers, regulators, financiers, and the general public.

9. Barkovitch points out that although the fuel and financing cost increases the utilities faced during this period were not necessarily of their own making, their inability to respond to the changes by continuing to construct large, expensive, capital-intensive facilities was problematic. She also points to their resistance to

environmental regulation, new technologies, and new rate designs as evidence of an "obliviousness" to the changes required of them by new circumstances (Barkovitch 1989).

10. The choices facing the industry were perhaps most eloquently and influentially stated in a Foreign Affairs article in 1976 by Amory Lovins entitled "Energy Strategy: The Road Not Taken?", in which he suggested that the nation must choose between a "hard" and "soft" (i.e., sustainable) energy path. Although there is a greater acceptance today that the two paths will both remain fixtures on the energy landscape for the foreseeable future, beginning in the mid-1970's the political debate was more sharply focused on trying to choose between these allegedly mutually exclusive paradigms.

11. Alfred Kahn had detailed his thoughts on marginal cost pricing in The Economics of Regulation: Principles and Institutions which was published in 1970 and remains to this day the primary textbook on regulatory economics.

12. The CPUC also ordered a residential appliance program, a conservation voltage reduction program for the distribution system, and several commercial and industrial programs (Barkovitch 1989).

13. For instance, in the early 1980's the CPUC adopted a decoupling mechanism known as ERAM which guaranteed utility revenues regardless of reduced sales from DSM or other factors. It also tried to have utilities design programs to avoid raising the rates of non-participants, even though that could jeopardize capturing all DSM that was cheaper than new supply.

14. Jerry Brown openly espoused the philosophy of "appropriate technology" and brandished E.F. Schumacher's book Small is Beautiful during his campaign.

15. Alfred Kahn quotes an unpublished study by Lewis Perl of National Economic Research Associates (White Plains, N.Y.). Joskow also claims that utilities were disallowed tens of billions of dollars, and claims they accounted for 20 percent of nuclear investments (Joskow 1989). Meanwhile, the North American Electric Reliability Council pegs the disallowance value at only $13 billion (NAERC 1990).

16. Former FERC Commissioner Charles Stalon points out that increased prudence reviews were in part due to a fear that increased rates would increase the amount of bypass (i.e., customers self-generating, or fuel switching) causing even more pressure on rates (Stalon 1990).

17. When Congress authorized the Northwest Power Planning Council (which oversees the Bonneville Power Planning Administration) in 1980, it required the Council to provide conservation with a 10 percent cost bonus when comparing it to other resources largely on environmental grounds. Wisconsin provides all non-fossil fuel fired resources (including conservation) with a 15 percent credit. Vermont provides conservation with a 15 percent advantage over other resources (5 percent based on lower externalities, and 10 percent based on lower risk).

18. The federal Clean Air Act Amendments of 1990 may reduce the impetus for state PUCs to attempt to further internalize externalities associated with certain pollutants such as sulfur dioxide because by setting up a market trading system and effectively pricing the externality, it can be argued that most, if not all of the externality has been internalized. However, for other pollutants such as carbon dioxide, state PUC efforts may actually increase in anticipation of future federal laws in this area.

19. A more subtle variation of this approach which is known as the "non-participant" or "no-losers" cost-effectiveness test has been advocated by some who maintain that it is fine for the utility to pay up to its full avoided cost for DSM as long as most of the cost is recovered directly from participants (Cicchetti and Hogan 1988, Katz 1990). Many have argued that this is simply the "no-losers" test wolf in sheep's clothing (Lovins and Hirst 1989).

20. Although Moskovitz et. al. maintain that DSM investment in 1990 was slightly less than $2 billion, continued escalation of expenditures since then should easily put the total price tag for 1992 above $2 billion.

21. Although 3 percent of the total electricity generated was produced by industry in 1978, the year that PURPA passed, it was all used exclusively to meet all or part of their own electricity needs and was not sold to the utilities (Joskow 1989).

22. As of May 1991, 11 states had bidding rules; 8 allowed bidding but had no rules; 6 were developing rules; 11 are currently considering or would consider bidding in the future; and 15 are not currently interested (Robertson 1991). As of February 1992, 90 RFPs have been by utilities and government agencies for 22,000 MWs, with 190,000 MWs being bid, and 12,500 MWs being awarded so far (Robertson 1992).

23. In Mississippi Power & Light Co. v. Moore (108 S.Ct. 2428 (1988)), the state upheld FERC's position that states may not review the prudence of FERC's allocation of costs among holding company subsidiaries. This decision raised concerns among state PUCs that their broader authority to review utilities' power planning and acquisition decisions in comparison to other possibly less costly alternatives which had been established in another court case -- Pike County & Light Co. v. Pennsylvania Utility Commission (77 Pa. Commw. 268, 465 A.2d 735 (1983)) -- could be in jeopardy (Stalon 1990).

24. The reforms to PUCHA propose opening up competition by, in part, allowing unregulated utility subsidiaries to compete with other QFs and IPPs.

25. California and several other states have had a more limited decoupling mechanism for some time.

Chapter 3: Introduction to the Theory, Practice and Evaluation of Consensus-Building In Electric Utility Regulation

In Chapter 2, I traced the historic decline of consensus in electric utility regulation, and ended by describing a myriad of on-going contentious issues. The remainder of this dissertation focuses on how attempts to resolve these and other issues related to the electric utility industry and its regulatory environment may be enhanced through the infusion of supplemental, consensus-building processes into traditional regulatory procedures. In Chapters 4 and 5, I focus on consensus-building in PUC adjudicatory proceedings and rulemaking proceedings, respectively. This chapter serves as a brief introduction to the theory, practice, and evaluation of consensus-building in electric utility regulation.

First, I will describe a new paradigm for consensus-based negotiation which has emerged in the literature during the last decade under numerous banners including: "principled negotiation", "integrative bargaining", "win-win or mutual-gain negotiation" and "alternative dispute resolution (ADR)". After describing the theory, several concerns that have been raised about ADR in the literature will be offered and analyzed. Second, the direct nexus between negotiation theory and the theory of consensus-building in electric utility regulation will be explored. Third, I will briefly describe the range of consensus-based processes that currently exist in electric utility regulation. Finally, I will analyze the strengths and challenges of various approaches to evaluating the success of these consensus-based processes.

Consensus-Building Theory

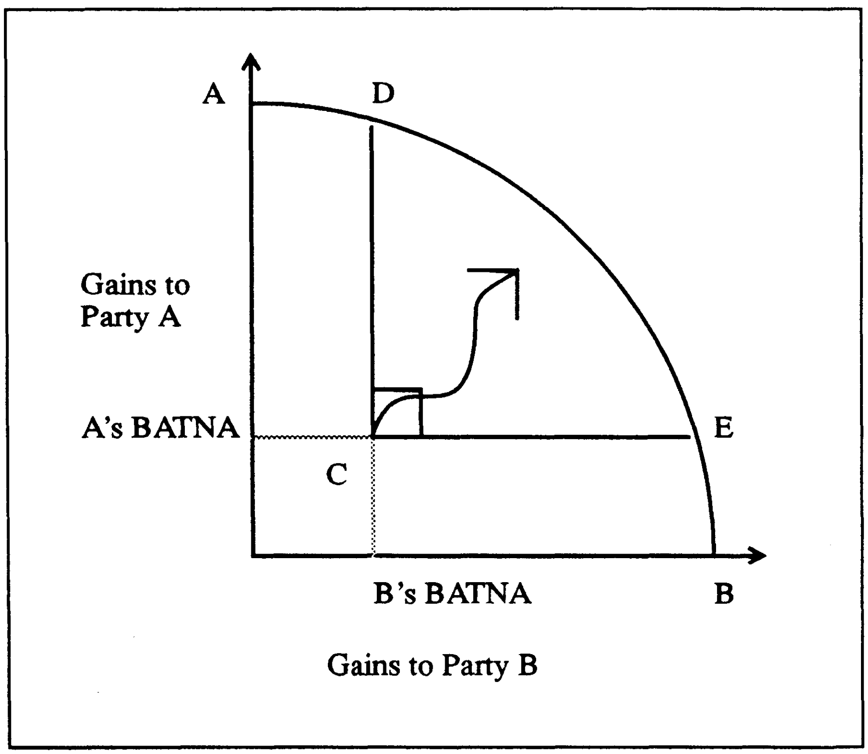
Towards a New Negotiation Paradigm: Getting to YES

Negotiation has always been used in our society to resolve both private and public disputes[1] and, as I will describe in Chapter 4, negotiated settlements have been a fixture in the landscape of electric utility regulation for a long time. There have been many critiques of traditional negotiation practices and suggestions for improvements. However, the publication of Getting to YES: Negotiating Agreement Without Giving In by Harvard Professors Roger Fisher and William Ury in 1981, succeeded in crystallizing and popularizing an approach to negotiation which has enjoyed increasing influence over the past decade.[2] The central tenant of Fisher and Ury's "principled negotiation" approach is that disputes can be more successfully resolved when parties shift their focus from "distributive" to "integrative" bargaining. Distributive bargaining (which has also been called "win-lose" or "zero-sum" negotiation) is based on the premise that there is a fixed pie or pot of money such that increasing one person's share can only be accomplished by decreasing the shares of others. Integrative bargaining assumes that the pie is not fixed but can be expanded in ways that can make everyone's portions larger.

In graphic terms, as shown in Figure 3.0, there exists an entire array of resolutions to most disputes that are superior to "no resolution" (i.e., point D which represents both A and B's best alternative to a negotiated agreement or BATNA), and would be seen as improvements by all parties (i.e., points in area CDE). In economic terms, these are called Pareto improvements, and these improvements can be made until the Pareto curve is reached which represents a set of outcomes that are all equally efficient (represented by AB). Improvements can be made because most disputes are multi-issued, and to the extent that parties value issues differentially, efficient trades can be made.[3] Howard Raiffa, in The Art and Science of Negotiation (1982) provides the following examples of where such trades are possible:

> ...the potential of finding joint win-win situations depends on the exploitation of differences between beliefs, between probabilistic projections, between tradeoffs, between discount rates (a special case of intertemporal tradeoffs), between risk preferences (Raiffa 1982, p. 286).[4]

Figure 3.0
Integrative Bargaining



Source: Adapted From MIT-Harvard Public Disputes Program

To succeed in shifting to a more integrative bargaining paradigm, Fisher and Ury suggest that disputants must abandon traditional positional bargaining and adopt a more collaborative, joint problem-solving orientation. This somewhat radical concept is based on the assumption that we can better satisfy our own interests only through seeking to better satisfy the interests of our opponents. Getting to Yes articulates a strategy for approaching this task which I paraphrase in Table 3.0.

Table 3.0
Fisher and Ury's Strategy for Integrative Bargaining

1. Focus on Underlying Interests Rather Than Positions.
2. Invent Options for Mutual Gain.
3. Decide on Objective Criteria or Underlying Principles for Resolving any Remaining Distributive Components to a Negotiation.
4. Separate the People From the Problem (i.e., Be Hard on the Issues and Soft on the People).
5. Seek to Strengthen Your Own Negotiating Power by Improving Your Best Alternative to a Negotiated Agreement (BATNA), While Better Understanding the BATNAs of Those You Are Negotiating With.

Source: Adapted From Getting to Yes by Fisher and Ury.

Fisher and Ury's original treatise on principled negotiation stands as the major pillar of the alternative dispute resolution (ADR) literature. However, numerous other important works have focused on refining the concepts and on creating ways to incorporate them in traditional procedures. Most notable from the perspective of this dissertation, are works by Philip Harter on the use of ADR in administrative agency decisionmaking -- particularly on negotiated rulemaking;[5] and works by Lawrence Susskind on resolving public disputes, the advantages of using assisted negotiation (e.g., mediation), and on the use of ADR specifically in the context of electric utility regulation.[6] (Aspects of these important works will be discussed in various places throughout this dissertation, and detailed descriptions are omitted here.)

Three Criticisms of Alternative Dispute Resolution

Fisher and Ury's overall approach to negotiation has generally received wide support. However, it has also been criticized in several ways. I discuss here three criticisms along with the rejoinders that have been offered, and brief comments on the relevance of the debates to electric utility regulation. I believe an airing of these issues is useful to more fully understanding the overall theory and its applicability to resolving disputes in electric utility regulation. These three issues are (1) the problem of power imbalances in negotiations, (2) the handling of distributive questions within the context of integrative bargaining, and (3) fundamental limits to the use of ADR. Other potential criticisms have been raised, but are more narrowly-focused, and are discussed at the appropriate places in the following chapters.

Power Imbalances

Fisher and Ury have been accused of paying insufficient attention to preexisting power imbalances among parties (White 1984, Fiss 1984, McCarty 1985, Amy 1987, Bazerman 1987).[7] These power imbalances, it is argued, can undermine any real progress towards reaching equitable, integrative settlements. In an article entitled "Negotiating Power", Fisher acknowledges the potential problems of differential power relations, but claims that negotiating power is not static and can be enhanced in numerous ways (Fisher 1983). He argues that negotiating power is often "perceived" power and can be enhanced through skill and knowledge, good relationships, the development of strong alternatives to a negotiated agreement, the creation of elegant solutions, the emphasis on the legitimacy of a proposed approach, and the construction of affirmative commitments (i.e., reasonable offers) (id.). In a separate article, Susskind adds to this list the ability to form coalitions and the use of mediation as two additional methods to temper power imbalances (Susskind 1985).

The initial distribution of power is often unclear in public policy disputes generally, and electric utility regulation specifically. For instance, although electric utilities certainly have more resources at their disposal than most intervenors, it would be wrong to assume that utilities are always the most powerful player in the regulatory arena. It is more appropriate to assess the relative distribution of power in the regulatory context against the benchmark of parties' ability to persuade the PUC to decide in its favor, or the courts on appeal. To the degree that significant uncertainty exists in this regard, as I would argue is usually the case, the starting distribution of power is less clear. If parties can muster sufficient resources to intervene in a case in the first place,[8] and if all the parties agree to try and settle (i.e., reach a consensus), the ability to veto that consensus immediately gives all parties significant power. That power can be further enhanced by resorting to some of the negotiating techniques that Fisher and Susskind have identified. In the cases in the following chapters, we will see exactly this phenomenon.

Inadequate Attention to Resolving Distributive Issues

A second criticism of the theory of "principled negotiation", as originally defined in Getting to Yes, is that it pays insufficient attention to the fact that some negotiations are largely distributive, and all negotiations have distributive elements (White 1984, Raiffa 1982, Lax and Sebenius 1986, Bazerman 1987). Going back to the model in Figure 3.0, even if joint problem-solving could succeed in expanding the pie all the way to the Pareto curve of efficient solutions, parties would still need to decide where along arc DE they should end up -- and any movement along the arc results in the gain of one party with a corresponding loss to the other. Such tension, it is argued, is never totally absent from even the most integrative negotiating process, since it is unlikely that people will quit worrying about how the pie they are jointly focused on expanding will ultimately be divided even when they are still far from the Pareto curve (Raiffa 1982, Lax and Sebenius 1986, Bazerman 1987). In a chapter entitled "The Negotiator's Dilemma: Creating and Claiming Value" in their book The Manager as Negotiator (1986), Lax and Sebenius describe the problem:

> There is a central, inescapable tension between cooperative moves to create value jointly and competitive moves to gain individual advantage. This tension affects virtually all tactical and strategic choice...Neither denial or discomfort will make it disappear (p. 30).

Fisher, while acknowledging that distributive elements are present in virtually all negotiations maintains that such tensions can be tempered without resorting to traditional "hard" bargaining (Fisher 1984, Fisher et.al. 1991). First and foremost, Fisher reemphasizes that disputes are usually multi-issued and that expanding everyone's options by focusing on integrative solutions will relieve some pressure from distributional tensions. Residual distributional tensions can be mitigated by refocusing the debate away from deciding who gets the last dollar, to a question of how to jointly decide on objective criteria for resolving the distributional questions (id.). Fisher acknowledges that this is not always easy. However, he argues that by refocusing the debate, distributional questions can be approached in a more principled and productive way (id.). Other authors, most notably Raiffa, Lax and Sebenius have attempted to provide both elaborations and variations on Fisher's recommendations for dealing with this inescapable tension between creating and claiming value.[9]

This issue is directly relevant to electric utility regulation, particularly to rate cases where the overall focus on determining a rate-of-return, a level of disallowance, or a cost allocation appears extremely distributive. But as I will show in the cases in the following chapters, particularly the Pilgrim nuclear power plant outage settlement case in Chapter 4, that is not completely true. The initial focus of the Pilgrim outage litigation involved a seemingly distributive question on how the money associated with a nuclear outage should be divided between utility stockholders and ratepayers. Parties to the case negotiated an extremely integrative settlement that involved tying shareholder earnings to future performance of Pilgrim, and commencing an aggressive DSM effort. In so doing, they were able to better satisfy their own long-run interests, while settling the more narrow distributive question de facto. Even the most mundane rate case generally involves several parties and a multitude of issues that parties' value differentially, thus raising the possibility of integrative settlements to seemingly distributive problems. Still, difficult distributive issues must constantly and ultimately be resolved in electric utility regulation.

Fundamental Limits to ADR

A third criticism is that certain types of cases are not appropriate for ADR and should be considered off-limits. In an article entitled "Against Settlement" in the Yale Law Journal (1984), Owen Fiss makes such an argument:

> My universe [where I do not think ADR is appropriate] includes those cases in which there are significant distributional inequalities; those in which it is difficult to generate authoritative consent because organizations or social groups are parties or because the power to settle is vested in autonomous agents; those in which the court must continue to supervise the parties after judgement; and those in which justice needs to be done, or to put it more modestly, where there is a genuine social need for an authoritative interpretation of law. I imagine that the number of cases that satisfy one of four of these criteria is considerable.

There is a general agreement even among ADR advocates that certain disputes involving questions of fundamental constitutional rights (e.g., civil rights, abortion) are not good candidates for ADR, although many would quibble with Fiss about where to draw the line (Fisher and Ury 1981, Mendel-Meadow 1985, Susskind and Cruikshank 1987). In addition, as Susskind and Cruikshank point out, once courts have defined what is legal and illegal with respect to these rights, consensus building might assist in protecting them, or in reconciling them with other valid interests. The authors also observe that people often try and obfuscate what are essentially distributional questions by coating them in the vernacular of constitutional rights (Susskind and Cruikshank, p. 17).

It is not immediately clear where in electric utility regulation issues of fundamental constitutional rights exist that should automatically preclude attempts at ADR. Rate cases, for instance, which involve the distribution of costs and benefits between ratepayers and utility shareholders, and among ratepayers, can hardly be considered as addressing a fundamental right. A recent Supreme Court decision in Duquesne Light Co. v. Barash indicated the court's willingness to allow PUC's substantial latitude in disallowing utility investment prior to considering it a "taking" of property (Kolbe and Tye 1991). Still, utilities often argue that issues such as the inclusion of environmental externalities in resource planning or requirements to have utilities pay for their customers to switch fuels (i.e., as an energy efficiency measure) violate their rights. However, it is not clear that these actually constitute fundamental rights, and as we will see in the cases in the following chapters, settlements have already been forged between traditional adversaries in some states on even these contentious issues.

There may, however, be particular instances when a fully litigated case is preferable to a negotiated settlement within the context of electric utility regulation.

Former New Mexico Public Service Commissioner Marilyn O'Leary, an enthusiastic supporter of using ADR, has argued that in certain instances when cases are extremely controversial, or there is a need to publicly illuminate the details of utility actions or proposals, ADR may be inadvisable (O'Leary 1986). However, there does not appear to be any types of electric utility adjudications or rulemakings where categorical exclusions from the use of ADR are necessary a priori. Recently, the New York Public Service Commission, in formulating revised settlement guidelines and rules, reversed an earlier decision it had made to exclude rate design issues from settlements (NY PSC 1992).[10]

Nexus Between Principled Negotiation and Consensus-Building in Electric Utility Regulation

Here, I briefly describe the nexus between the theoretical literature on ADR and its use in resolving electric utility regulatory disputes. As discussed in Chapter 2, electric utility regulation had been contentious for two decades. In addition to numerous controversies before PUCs, there have also been major controversies associated with the siting of electricity generation facilities (Bacow and Wheeler 1984). It is therefore not surprising that many of those involved in the electric utility industry and its regulatory environment, particularly the utilities, have looked to ADR for assistance.

Initial exposure to ADR theories for many has been through Fisher and Ury's original book which has sold over 2 million copies. More importantly, numerous direct attempts have been made both to train participants in these techniques and to develop actual procedures at various state PUCs based on ADR theories. For instance, in 1985-1986 the Edison Electric Institute contracted with the Public Disputes Program at the Program on Negotiation at the Harvard Law School to conduct well-publicized experiments in three states to use assisted negotiation on a variety of issues. The issues included (1) the negotiation of a rate shock moderation plan in New Mexico associated with the "coming on line" of the Palo Verde nuclear power plant;[11] (2) the negotiation of a demand forecasting methodology and resource selection criteria for Boston Edison Company in Massachusetts; and (3) a resource planning rule for the PUC in Colorado (Susskind and Morgan 1986A and 1986B). The experiments met with mixed, short-term success due to several complicating factors. However, they were successful in familiarizing participants with ADR techniques and proved to have numerous long-term benefits (O'Leary 1986, Susskind and Morgan 1986A and 1986B, Technical Development Corporation 1987, Richardson 1990).

In addition, many of the participants in the electric utility regulatory arena have been trained in ADR techniques. Lawrence Susskind, professor at MIT and Director of the MIT-Harvard Public Disputes Program, has conducted ADR training workshops for the PUC staffs and commissioners at in Maine in 1988 and New York in 1990. Also, in both 1989 and 1990, the Public Disputes Program conducted two-day trainings on using ADR in utility ratesetting, rulemaking and least-cost planning. Over 115 state regulators, utility representatives, public advocates and others attended these sessions from 30 states, Washington D.C. and Canada.[12] Half-day trainings in ADR and electric utility regulation have also been conducted at two of NARUC's national conferences, and at two seminars for senior PUC staff at Lawrence Berkeley Laboratories -- reaching over 100 additional people.[13] Other ADR-related trainings have also included participants from the electric utility regulatory arena.[14]

The concepts embodied in ADR have clearly filtered into the language and the practice of many utilities and PUCs. A recent article in which PUC Commissioners from 13 states were asked about ADR, showed both a great deal of familiarity with the theory and a surprising amount of experimentation with ADR approaches at the PUCs (Public Utilities Fortnightly 1990).[15] There has also been a steadily increasing stream of articles in the literature as well as papers delivered at national conferences primarily by participants in these processes about their experiences (Boucher and Weedall 1991, Chouteau 1991, Cohen and Chaisson 1990, Cohen and Townsley 1990, Cowell 1990, Ellis 1989, Hicks 1990, Lehr 1990, McIntyre and Reznicek 1992, Nogee 1990, O'Leary 1986, Raab 1989, Raab and Schweitzer 1992, Richardson 1990).

In the next section, I provide an introduction to the practice of consensus-building in the context of electric utility regulation. The final section in this chapter provides an approach for evaluating the success of consensus-based processes.

The Practice of Consensus-Building in Electric Utility Regulation

Consensual Options

Settlements, which by definition represent a consensus among disputants, were used to resolve electric utility rate cases prior to the early 1980's (when Fisher and Ury popularized the concept of ADR). It would not be accurate to assume that all settlements prior to 1981 were distributive, while today's settlements are expansive and integrative. Undoubtedly there are more similarities than differences between past rate case settlements and current settlements both in terms of the issues addressed and the degree to which integrative bargaining (even though past disputants may not have called it that) was utilized.

What has changed, however, is a more conscious recognition of both the theory of and need for consensus-building within the context of electric utility regulation. This recognition has led to numerous efforts by regulators, utilities, and intervenors over the past decade to develop both formal and informal consensus-based processes. Table 3.1 provides an overview of the range of consensus-building mechanisms currently in use.

Table 3.1
Consensus-Building Mechanisms in Electric Utility Regulation

Seminars and Conferences
Technical Sessions and Workshops
Policy Dialogues
Advisory Committees
Case Settlements
Prospective Collaboratives
Negotiated Rulemakings

Source: Author's List

All of the activities listed in Table 3.1 are appropriate supplements for either adjudicatory or rulemaking procedures (except for case settlements which are associated with adjudicatory proceedings), and policy dialogues and negotiated rulemakings (which are appropriate primarily to rulemaking proceedings). The list provides a spectrum of consensus-building activities beginning at the top with seminars and conferences which represent the least intensive activity in terms of seeking consensus and ending with negotiated rulemaking which represents the most intensive.

Seminars and conferences are occasionally used to provide participants with information about a particular subject or issue. Dialogue is not the primary focus, although contrasting perspectives are often provided. Technical sessions and workshops in the context of adjudicatory or rulemaking proceedings are often provided to give parties the opportunity to explore technical issues outside the hearing room (usually off the record, but occasionally at great length). In addition to attempting to illuminate factual matters, technical sessions and workshops generally expose participants to each others' perspectives while providing an opportunity to engage in dialogue. Policy dialogues allow for similar exploration, but focus on policy issues.

Convergence of opinion will often surface in technical sessions, workshops, and policy dialogues even though consensus is not necessarily actively pursued. Often areas where there is some convergence serve as the basis for subsequent settlement in adjudications, or policy proposals in rulemakings. However, even when no consensus emerges, such processes can still help to more sharply focus the subsequent formal proceedings by providing a greater common understanding of the facts, parties' interests, and the areas of agreement and disagreement. This sharper focus can in turn make it easier for PUCs to intelligently decide unresolved issues.

Advisory committees are often used by utilities and occasionally by PUCs to review past activity and provide suggestions for future action. Although advisory committees often strive to attain consensus recommendations among its members, that is not always the case. Many advisory committees never aspire to provide anything more than feedback, albeit in an organized fashion. Moreover, even when advisory committees do strive for consensus, the entity seeking advice (e.g., the utility or the PUC) is rarely a formal party to the consensus. Still, such processes can be extremely helpful in building consensus on an informal basis.

Settlements in rate cases and other adjudicatory proceedings are based on reaching a formal consensus among the utility and the various intervenors on as many issues as possible. Settlements happen before, during or after hearings in contested cases. When PUCs have advocacy staffs (i.e., people who are empowered to litigate cases as full parties but are precluded from discussing the cases with their commissioners)[16] that are involved in a case, they are usually party to any settlement that may be forged. Uncontested settlements (i.e., those where all parties to a proceeding are in accord) are subsequently submitted to the commissioners for their review and approval, often after review by a hearing officer. Contested settlements follow a similar path but generally involve an opportunity for dissenters to file written objections or cross-examine the signatories of a settlement in subsequent hearings.

For reasons that will be described in Chapter 4, the use of settlement to resolve contested cases on electric utility matters is rapidly becoming the rule rather than the exception. For instance, over the past decade a majority of major electric utility cases before the New York Public Service Commission have had settlement discussions and many were settled by most parties on most issues (Ron Elwood Interview). At the Federal Energy Regulatory Commission, parties have consistently settled 70-80 percent of the contested electric cases since the mid-1980's (John Orecchio Interview). It is worth noting at this juncture, however, that despite the extensive use of settlements, only a few state PUCs and FERC currently have formal settlement guidelines (Elwood and Marland Interviews).[17]

Prospective collaboratives are a relatively new form of consensus-building in electric utility regulation, and represent an extension of the settlement concept. Settlements in traditional contested rate cases generally involve resolving issues associated with past decisions and expenditures. In contrast, prospective collaboratives involve designing future plans or programs for utilities, or policies for PUCs. A second distinguishing feature of prospective collaboratives, is that they often occur outside of an immediate contested case or rulemaking proceeding. However, collaborative results are generally subject to PUC review and approval, like other settlements.

The best examples of prospective collaboratives to date are the demand-side management (DSM) collaborative processes that have sprung up across the country since 1988 (Raab and Schweitzer 1992). A DSM Collaborative brings together a utility (or group of utilities) with its traditional adversaries to jointly design comprehensive DSM programs for its customers. The utility almost always provides funds for the non-utility parties to secure their own independent technical experts. A case study in Chapter 4 explores the prospective collaborative process by focusing on DSM Collaboratives in Massachusetts. Such approaches are likely to become increasingly popular both to resolve DSM issues as well as other prospective issues.

The final consensus-building mechanism on the list is negotiated rulemaking. In negotiated rulemaking, parties come together to reach consensus on a new rule. If consensus is reached, the rule would be issued as the PUC's own proposed rule for public comment. Negotiated rulemaking is not yet common practice at state PUCs. However, the continued increase in rulemaking activities at the PUCs, combined with a growing acceptance of negotiated rulemaking at federal agencies (in the wake of numerous recent applications and the passage of a federal law in 1990 requiring federal agencies to consider negotiated rulemaking),[18] is likely to result in future experimentation with this consensus-building mechanism. Chapter 5 discusses negotiated rulemaking at length, and includes a case on the formation of bidding policies for Qualifying Facilities (QFs) and other energy sources in New Jersey which was similar to federal agency use of negotiated rulemakings in most respects.

Assisted Consensus-Building

All of the mechanisms for consensus-building described in the previous section can be conducted exclusively by the parties themselves, or parties to a dispute may seek the assistance of facilitators or mediators. Reasons for considering the use of assisted negotiation to resolve public policy disputes such as electric utility regulatory issues include the following:

> Most public disputes are highly complex, for example, and the affected groups are hard to identify and difficult to represent. Disputing parties often have great difficultly initiating and pursuing discussions. Emotional, psychological, or financial stakes may be so high that the disputants are unable to sustain the collaborative aspects of unassisted negotiation. Finally, power imbalances may preclude direct and unassisted dealings among disputants (Susskind and Cruikshank 1987, p. 136).

Professional neutrals can help to provide facilitation, mediation, non-binding arbitration, or some combination of these services (id.).

To date, most consensus-building endeavors in electric utility regulation have relied on unassisted negotiation. Where assisted negotiation has been used, the assistance has usually come from within the regulatory agency itself. For instance, New York occasionally uses a settlement judge other than the Administrative Law Judge presiding over a rate case to oversee settlement activity. Currently less than ten percent of settlements in New York use settlement judges (Elwood and Crary Interviews). At FERC, which has a similar internal settlement judge option, approximately 10-20 percent of the electricity cases that are settled use settlement judges (Orecchio Interview).

While outside neutrals are rarely used in PUC matters, there are some examples. I already mentioned the Edison Electric Institute experiment which contracted with the

MIT-Harvard Public Disputes Program to provide mediation services in three cases. Also, one of the many DSM Collaboratives has used an outside mediator with some success (Raab and Schweitzer 1992). The Massachusetts DPU employed outside neutrals to facilitate the technical session process it used to develop its Integrated Resource Management rules (this case is featured in Chapter 5). Finally, the New York PSC recently issued an order concerning its new settlement guidelines and rules which included an option for participants to use settlement judges from outside the PSC (NY PSC 1992). The role of assisted negotiation will be revisited in more detail both in Chapter 5 and in the concluding chapter.

Evaluating the Success of Consensus-Building Processes

Introduction

Little effort has gone into rigorously evaluating whether the addition of settlement and other supplemental consensus-building processes in electric utility regulation (such as those described in the previous section) have been successful. Yardsticks for measuring success are rarely articulated ex ante, or explored ex post. The literature on the subject is primarily descriptive, and has almost exclusively been written by participants in the processes (Cowell 1990, Wall and Griffin 1990, Cohen and Chaisson 1990, McIntrye and Reznicek 1992, Bergmann 1992). Efforts to comment on the successes and failures of consensus-building processes have often focused on what I consider to be a narrow, sub-set of criteria (i.e., whether consensus was reached, whether the regulators approved the programs, and whether time and money were saved in the process).

In this section I explore a broader range of criteria that should be used to evaluate the degree of success of consensus-building supplements. Each approach to measuring success will be described and assessed. In addition to looking at largely process-related criteria such as reducing the time and cost of litigation, the approaches include ways to judge whether the process produced substantive improvements over traditional regulation. To this end, the use of both objective and subjective criteria including the stated satisfaction of participants, are explored. The analytic challenges of using each criteria type are highlighted. Finally, at the end of the chapter, I describe three questions which combine various criteria to look at the overall legitimacy of the process and its results; the practicality of the remedies, plans and policies; and the process-related savings.

Process-Related Resource Savings

Consensus-building activities such as settlement are most commonly advocated as a way to streamline the adjudicatory and rulemaking procedures of administrative agencies like PUCs (Harter 1982, Susskind and McMahon 1985). Specifically, it is argued that time and resources related to the process itself can be saved. Any attempt to analyze this hypothesis must first accurately assess the time and resources that the consensus-building process typically requires. As the cases in the following chapters illustrate, these resources, which include both those associated with the parties' participation as well as any outside technical or process-oriented (e.g., mediation) expertise used, are often substantial.

The analysis must then compare the time and resources for consensus-building against what would have been expended had the cases been resolved conventionally. Assessing the likely time and costs that would have been incurred without the consensus-building activity (i.e., the traditional adjudicatory or rulemaking process) is complex. The first step is to determine the costs that would have been necessary to complete the proceeding before the PUC. In an adjudicatory proceeding such as a rate case settlement, savings in the traditional process might include a less substantial PUC final order, the absence of legal briefs, fewer hearings, or possibly less discovery depending on where during the process the settlement occurs. Similar savings must be assessed in a rulemaking proceeding, although as we will see in Chapter 5, since rulemakings are rarer than adjudications and PUCs have more flexibility in shaping them procedurally, establishing a baseline is more difficult.

Obviously, the further along in the process settlement occurs, the smaller the potential for savings. Since, as we will explore in Chapter 4, most settlements in major electric cases happen after hearings are completed, savings may not be as large as is often assumed.[19] If consensus-building does not result in settlement, the savings associated with the PUC process may be even smaller, and possibly even negative, since participants will still need to litigate (or in rulemaking -- comment on) unresolved issues (Raab and Schweitzer 1992).

However, the framework for analyzing whether a particular consensus-building process saved time and resources must extend beyond the PUC's immediate proceeding. Such a framework should also incorporate savings associated with any reduced subsequent litigation including appeals to the courts, as well as any savings associated with implementation of the settlement or a PUC order or rule. To the extent that consensus-building in general, and settlement in particular, reduces appeals, subsequent litigation, and implementation problems, the long-run, process-related savings from consensus-building may be more significant than any short-term savings.

Potential long-term, process-related savings seem likely. However, they are even more difficult to ascertain than the initial savings in the PUC process. With respect to appeals, one must estimate both the probability of an appeal and its likely cost. Estimating the savings from avoiding or streamlining future litigation as well as maximizing implementation compliance is highly speculative and difficult to estimate. Furthermore, these latter two questions must be analyzed over a sufficiently long timeframe to adequately trace the effects (i.e., at least several years). Efforts can, and I believe should be made to at least describe, if not estimate, these benefits.

Finally, even when a thorough evaluation of the process-related costs and savings along the lines I have just described can be completed, it is important to understand that this still only tells part of the story. It does not represent a net benefit analysis from a societal perspective. A more thorough net benefit analysis must also include the benefits (or costs) to society from any changes in the substantive outcome as a result of the consensus-building process. In other words, even if consensus-building costs more than a traditional process (using the approach I described above), if the substantive outcome can be shown to be superior, than the net benefits to society are also likely to be positive. In my opinion, the question of net societal benefits is far more important than the much more narrow, but more commonly asked question of whether process-related savings have been achieved. The remainder of this chapter focuses primarily on ways to approach this critical assessment.

Whether Consensus Was Attained

Since the object of consensus-building supplements to traditional regulatory procedures is by definition a search for consensus, any evaluation must look at whether consensus was attained. The more comprehensive a consensus is, both in terms of the issues it resolves and the parties it includes, the greater the potential for success. However, failure to reach consensus should not automatically be seen as indicating a fatal flaw in a consensus-building process. Often agreement is not the formal goal of such processes (e.g., technical sessions, policy dialogues, advisory committees). Even when it is the goal, as in settlement, prospective collaboratives, or negotiated rulemakings, consensus is often not reached on all issues or by all parties. One must look closely at both the resolved issues and those which were not resolved before judging the degree of success of such processes.

A collaborative process cannot be judged by consensus alone, since partial settlement where some issues must be litigated or further disputed, may be preferable to a complete consensus where critical issues, however thorny, were never on the table (Honeyman 1990). It must be determined whether important issues were omitted from what otherwise appears to be a complete consensus; or, alternatively, whether the unsettled issues in a partial settlement were inappropriate for settlement or unrealistic. It also must be determined whether all relevant interests were adequately represented. Complete consensus only on select issues, by select parties, or both, could result in an unstable agreement over time.

Consensus-building supplements to traditional regulatory processes where consensus is not achieved can also succeed in educating the participants about the substantive issues as well as the interests of all parties. This effort can help better focus everyone's input into the formal process before the regulators. It can also contribute to settlement at a later date (Richardson 1990). In the end, consensus, like saving process-related resources, is an important but incomplete factor in evaluating the success of consensus-building processes.

PUC Approval and Judicial Review

Consensus-building processes do not exist in a vacuum; rather, most are embedded in traditional regulatory procedures and must ultimately stand the test of both regulatory and judicial scrutiny. If consensus is reached, for instance in a rate case settlement, it must be approved by the PUC. If a PUC decision approving a settlement is appealed, it in turn must be sustained by the courts.[20] It would be difficult to consider a consensus-building process successful if it was in large part rejected by the regulators or overturned in the courts. Such a rejection would be indicative of a process's failure to adequately reflect political and judicial reality (Raab 1991). However, if the parties were able to reconvene to address the issues raised in the rejection of the initial consensus, success could be salvaged.

For these reasons it is critical that any analysis of a consensus-based process trace the results all the way through the traditional regulatory and judicial channels. That said, as Chapters 4 and 5 explain in more detail, uncontested rate case settlements or rules are rarely rejected by PUCs. This appears to be particularly true at PUCs where there are advocacy staffs that directly represent the PUCs' perspective in negotiations. In other states, such as Massachusetts, where the Department of Public Utilities has historically had an advisory staff but not an advocacy staff, the Commission may show a greater willingness to reject otherwise uncontested settlements. Appeal to the courts would not be an issue since parties would generally not have the right unless a PUC rejects an uncontested settlement or other type of consensus.

PUC rejection of settlements or other consensual agreements that are contested by one or more party or do not resolve all issues are still relatively rare. The likelihood of appeals to the courts when there is a contested settlement increases, but also is not that common; and such appeals are certainly much less frequent than in contested cases absent any settlement or consensus-building procedures.[21]

In terms of gaining perspective on the relative success of a consensus-based process, one must carefully scrutinize the reasoning behind any rejection or call for modification by a PUC. To the extent that the concerns they raise could have been better accommodated in the consensus-based process, it could be concluded that the process had some short-comings. I discuss ways for better integrating PUC perspectives in consensus-based processes in the concluding chapter.

Interpreting the meaning of judicial review vis-a-vis the consensus-based process, if and when it occurs, is more challenging. Inference is complicated, since the courts will be ruling on the PUC's decision about the settlement, rather than the settlement itself. There is also an underlying tension regarding the role of the courts in reviewing agency decisionmaking over the issue of deferral to agency expertise on the one hand, and interpreting legislative intent while guaranteeing due process on the other (Breyer 1987).[22] Against this back-drop, whether courts need to take a "hard look" at agency decisions involving negotiated settlements has been debated in the literature and is discussed in more detail in Chapter 5 (Susskind and McMahon 1985, Harter 1986, Wald 1985, Sturm 1991). Again, the important point here is that if a court overturns an agency decision related to a settlement it must be carefully analyzed to see how it reflects on the consensus-based process itself.

Substantive Improvement

While the three criteria for success described in the previous sections -- saving process-related resources, reaching consensus, and surviving regulatory and judicial scrutiny -- are all important, and must be examined, they are insufficient by themselves for gauging success. The criteria do not directly address whether the outcomes of a consensus-building processes were actually "good", or at least "better" than what would have occurred without them. I am not arguing that saving time and money, and getting traditional adversaries to come to a consensus, are not important ends in themselves; however, I believe that the ultimate success of utilizing a consensus-building process should not be assessed without also examining how it resolved the substance of the controversies.

Selecting an Appropriate Baseline

To analyze how successfully a consensus-based process resolved substantive disputes, a comparative baseline is needed. It is not enough to determine whether the outcome of a consensus-based process is "better" than the preexisting conditions and arrangements. At a minimum, the substantive outcome of a consensus-building process must be compared to what may have occurred if the traditional regulatory process had run its course without the consensus-building supplement. Such an approach would need to speculate about what a utility, the PUC, and possibly even the courts would have done absent the consensus-building activity.[23] Decisions in comparable past cases or the resolution of similar controversies in other states can be examined to try and determine such a baseline. Empirical studies could be used, for example, to evaluate the DSM programs of utilities that participated in collaborative processes and those that did not.

A top-down comparison which assesses whether the resolution was as "good" as possible is an alternative from the bottom-up comparison which focuses on what would have happened without the consensus-based process. This approach, which has been described most eloquently by Howard Raiffa in the theoretical literature, examines whether all the joint-gains have been captured by the parties (i.e., Have the parties negotiated their way to the Pareto optimality curve shown earlier in this chapter?) (Raiffa 1982). Specifically, one would attempt to identify changes in the final resolution of the substantive issues that represent improvements for some without making others' worse off.[24]

Together these two analytic approaches can provide important insights by triangulating the consensus-based decision between the status quo and some notion of optimality. However, the bottom-up comparison by itself is adequate to determine whether adding such supplements can improve regulatory processes. It is the primary baseline used in this dissertation. The top-down approach can help point to ways to improve the consensus-building process itself, and it too is pursued here though less rigorously.

Searching For Objective Criteria

Determining whether the resolution of the substantive controversies embodied in a consensus-based process were successful is challenging, regardless of which baseline is used. An evaluator should define evaluative criteria without relying solely on the views of the participants themselves (the subject of the next sub-section). Criteria related to notions of efficiency, fairness, wisdom and stability seem appropriate for analyzing public policy disputes generally and electric utility regulation in particular (Susskind and Cruikshank 1987).[25]

However, before these notions can be effectively applied they must be more rigorously defined. Yet, defining these criteria is not straight-forward. In Deborah Stone's insightful book Policy Paradox and Political Reason (1988), the author describes the difficulty in defining fairness by explaining how the distribution of chocolate cake to her class can be done according to at least eight entirely defensible definitions of fairness (e.g., equal slices, unequal slices but equal value, unequal slices but equal statistical chances). Stone points out that similar, ultimately subjective, determinations must be made even with respect to efficiency:

> Efficiency is...always a contestable concept. Everyone supports the general idea of getting the most out of something. But to go beyond the vague slogans and apply the concept to concrete policy choice requires making assumptions about who and what counts as important. There are no correct answers to these questions. The answers built into analyses of efficiency are nothing more than political claims. By offering different assumptions, sides in a conflict can portray their preferred outcomes as being more efficient (Stone 1988, p.53).

This dilemma is not new to electric utility regulation, which makes value-laden determinations and tradeoffs with respect to distributional and other issues constantly (Zajac 1978, Trebing 1981). After all, what is a "just and reasonable rate" in the end, if not a judgement? A more concrete example regarding cost allocation may be useful here. To decide whether a utility's demand-side management (DSM) expenditures are equitably distributed among ratepayers, one needs to decide if a fair cost allocation of the DSM expenditures is (a) to all customers by a fixed cents/kwh, (b) directly back to the participating customers, (c) on a fixed cents/kwh but only back to the customer class eligible for a particular DSM program, or (d) a portion of the expenses to all customers and a percentage back to the customer or customer class. One's perspective on this issue would undoubtedly be influenced by one's view about whether DSM is a resource that all ratepayers should pay for, a service that only participating customers should pay for, or some combination of the two.

How is an outside analyst supposed to independently choose among seemingly internally consistent, but mutually exclusive criteria? For simplicity, analysts could adopt the yardsticks (i.e., the cost-effectiveness test and cost allocation policies) of the jurisdiction in which the case they are analyzing occurred. However, where consensual processes cross jurisdictional lines in which regulators use different yardsticks, analysts would need to apply different tests in the same analysis. If the yardsticks themselves are the subject of controversy in the case, as is common, the selection of operational criteria by an outside evaluator would be even more confounded. Yet, without such criteria, evaluation can not readily proceed.

The main point is that some fairly subjective decisions must be made to develop presumably objective criteria. Analysts can and should develop criteria to evaluate the success of consensus-based processes and public decisionmaking generally. However, I am not convinced that criteria definitions which are essentially self-selected by an evaluator can be considered objective, even if they can be objectively-applied subsequent to selection. For these reasons, evaluators must at a minimum be explicit about the criteria they choose to apply. Such criteria, as illustrated in the cases in Chapters 4 and 5, must not only be explicit, but must usually be finely-tailored to the relevant issues in each case. An alternative, discussed in the next sub-section, is to turn to the participants themselves to help define the evaluative criteria.

Tapping the Insight of Participants[26]

Notions of fairness, wisdom, stability and possibly even efficiency are inherently subjective and in the end political determinations (Schuck 1979, Stone 1988). It therefore seems essential for evaluators to focus their attention directly on the participants when analyzing the success of a consensus-based process (Raiffa 1982, Susskind and Cruikshank, 1987, Sturm 1991). Susskind and Cruikshank, for instance, conclude:

> In our view, it is more important that an agreement be perceived as fair by the parties involved than by an independent analyst who applies an abstract decision rule (Susskind and Cruikshank 1987).

Ultimately the success of a consensus-based process must be tied to how well the substantive outcome satisfies the various interests in society.[27] An analyst therefore must attempt to see the process and its results through the eyes of the participants in addition to the other evaluative criteria discussed above. Interviews are essential to accomplish this end. Other effected parties that were not participants to the process, including the regulators themselves, must also be interviewed. Therefore, focusing only on the participants when assessing the success of a consensus-based process may reveal little more than the "collective irrationality of the negotiators" (Forester and Stitzel 1989), particularly when important stakeholders have been excluded.

Legitimate stakeholders (i.e., participants plus other effected parties) can provide invaluable insight about the substantive results. An evaluator should ask interested parties whether resolution of the issues in dispute produced results that satisfied their interests better than they would have expected through the traditional process. Also, stakeholders can help identify potential improvements to the final resolution of the substantive disputes and serve as a sounding board for possible improvements suggested by the analyst or others. In this way, a much richer picture of the process and its results emerges.

However, often there is not consensus among participants about the outcome. Different participants usually feel differentially satisfied, and see various shades of success even when a consensus is reached. It is then the evaluator's task to better understand the nature and scope of any dissent to qualify the characterization of a consensus-based process as "successful".

Another potential problem is related to the old adage that "hindsight is 20-20". It would be preferable to establish a baseline by interviewing parties at the outset of a consensus-building process as to their interests, aspirations, and expectations (as well as their own definitions of other evaluative criteria (e.g., equity, efficiency, wisdom)). However, this is rarely done because most evaluations are initiated ex post. Even if it could be done ex ante, parties are often not clear about their objectives, or are unwilling to discuss them for fear of compromising their positions. This generally leaves evaluators in the difficult position of having to rely on hindsight to ascertain both the baseline interests and the satisfaction of those interests. Finally, since things always look different on the ground than on paper, participants and effected parties should also be interviewed several years after a final consensus or PUC decision to garner the benefits of hindsight in the face of implementation experience.

This approach to measuring substantive success should not be used in isolation even if interviews of participants are expanded to include other parties that were not directly involved in the negotiations, and can be repeated several years after the process has concluded. Other factors already discussed must also be used--including attempts by evaluators to objectively apply other pre-determined criteria (even if they are not objectively conceived).

Towards a Workable Evaluative Model

As should be clear by now, measuring the success of adding consensus-based processes to traditional electric utility regulatory procedures is not a simple task. In this chapter I have, however, suggested a series of factors that can each provide important insights. These include the degree to which consensus was reached, the reaction of the PUCs and the courts, and whether the substantive resolution of contested issues represents an improvement from what would have happened in the absence of consensus-building.

I evaluate these important factors in each of the four case studies in Chapters 4 and 5. Also, in the conclusions of each case study, I combine factors to address three over-arching questions: (1) Were process-related resources saved?; (2) Did the supplemental consensus-building process enhance the legitimacy of the traditional process and of the final results?; and (3) Were the final remedies, plans and policies more practical because they used a consensus-building process? I have already discussed the first question regarding process-related resource savings in detail, and nothing further is explained here. However, before proceeding to the case studies, I further define the questions on legitimacy and practicality and provide a brief explanation on how the previously described factors are combined to address them.

The legitimacy of traditional regulation is enhanced by supplemental, consensus-building when the overall process and the final results are considered fairer than they might have otherwise been. The starting point for assessing this question must be with the participants themselves. Whether consensus was reached, and whether the participants believe that their interests were better served by the results of a modified process are essential questions for making this initial assessment. Ultimately, however, evaluating the legitimacy of a consensus-building process requires casting a broader net to include other parties that are effected by a decision but may not have directly participated (including future generations).

To a certain extent, examining the reaction of the PUC and the courts serve as a proxy for this broader net -- acting as, among other things, checkpoints against egregious damage to non-participants. Lack of support from the PUCs and the courts would not bode well for a finding of enhanced legitimacy. PUC and court actions are therefore integral to my analysis of legitimacy. However, I also incorporate direct feedback from non-participants in the analyses wherever they are relevant and available.

Final remedies, plans, and policies become more practical when from both a technical and political vantage point they are more implementable. However, practicality means something more than just being practicable (i.e., capable of being put into effect or implemented). To be considered practical, an approach must prove that it can not only be put into practice, but that doing so will more effectively resolve the substantive issues at hand. As such, a truly practical improvement implies both implementability and a certain dose of wisdom and efficiency.

To assess the practicality in the case studies, I look primarily to the question of whether the decisions represent a substantive improvement over what may have occurred without the consensus-based process. As discussed, I use both the opinions of participants and other effected parties, along with other appropriate benchmarks when available, to make this difficult assessment. I also look to see if the process itself used the best available information when framing the options and agreements. Finally, I seek additional insight by examining any experience with implementing the remedies, plans and policies to assess how they perform in the field.

In addition to these three central questions, I include a brief process evaluation in the concluding section in each case study. The purpose of the process evaluations is to highlight important features of the consensus-based processes, and explain critical connections with the overall successes and failures of the cases.

In the end, I do not recommend a pat formula or recipe for evaluating the success of infusing consensus-building processes in electric utility regulation. Instead, the approach I recommend for analyzing the cases in the next two chapters more closely resembles that of creating a montage or patchwork quilt. When all the factors are carefully analyzed, findings surface regarding the process-related resource savings, legitimacy, practicality, and ultimately of the overall success of both the cases themselves and the use of consensus-building in electric utility adjudicatory and rulemaking procedures.

Endnotes (Chapter 3)

1. Numerous references to literature describing this history are provided in an article by Frederick Anderson published in the Duke Law Journal (April 1985). See footnote 235 on page 325 of that article.

2. Prior to Fisher and Ury's book other works touched on many of the ideas embodied in Getting to Yes. See, for instance, Schelling 1960, Walton and McKersie 1965, Schuck 1979.

3. This graph only shows a two-party dispute. Although, graphically more difficult to show, a similar model would also apply to multi-party disputes.

4. Raiffa's book provides probably the best discussion of the theory of integrative bargaining from an economic and mathematical perspective. In the book, Raiffa claims, "We act like a zero-sum society, when in reality there is a lot of non-zero-sum fat to be skimmed off to everyone's mutual advantage" (p.310).

5. See Harter's "Negotiating Regulations: A Cure for Malaise", 71 Georgetown Law Journal, 1982 for detailed discussion of negotiated rulemaking. Also see "Points on a Continuum: Dispute Resolution Procedures and the Administrative Process" (Report to the ACUS, July 16, 1986). Although Harter's work does not directly discuss state PUC regulation, and in fact is almost exclusively focused on federal agencies, it provides an excellent discussion both about the opportunities for ADR in administrative agencies, and how to address some of the concerns raised by others.

6. See Susskind's Breaking the Impasse: Consensual Approaches to Resolving Public Disputes with Jeffrey Cruikshank (Basic Books: 1987) for analysis of ADR in resolving public disputes, and the potential for improving ADR through assisted negotiation (e.g., mediation). Susskind and McMahon's article "The Theory and Practice of Negotiated Rulemaking (3 Yale Journal of Regulation, 133: 1985) is an important addition to Harter's article on negotiated rulemaking. Susskind and Morgan's article "Improving Negotiation in the Regulatory Process" (published by Edison Electric Institute in Electric Perspectives, Spring 1986) specifically addresses the potential for ADR in electric utility regulation. See numerous other articles by Susskind listed in bibliography.

7. Although Douglas Amy's book The Politics of Environmental Mediation (Columbia University Press: 1987) is focused more specifically on the short-comings of environmental mediation vis-a-vis its handling of preexisting power imbalances, the critique is extended to ADR generally.

8. Intervention before PUCs, particularly in litigated cases, can be extremely costly and time-consuming. To the degree that interested parties cannot afford to intervene, it can be argued that the initial distribution of resources places a real barrier to a parties' participation -- rendering them effectively powerless. For this reason, intervenor

funding is offered in some states (i.e., payment of intervention costs by utilities of select third party intervenors), and has been an on-going debate in many others.

9. Other ideas put forward by Raiffa (1982) and Lax and Sebenius (1986) include mediation, focusing on single-text negotiation, and post-settlement settlements to name only a few.

10. The NY PSC was apparently concerned that rate design settlements could place undue burden on the rates of customers not party to the negotiations. However, they were persuaded that the staff's participation combined with their own ultimate authority to reject a settlement were adequate protection, and that preclusion of settlements on rate design issues might unnecessarily restrict potential overall settlements (Elwood Interview).

11. Although the Palo Verde nuclear power plant is located in Arizona, the El Paso Electric Company, a provider of electricity in cities in Southern New Mexico, were part owners.

12. The distribution of participants based on the attendance lists were 35 percent utility executives and senior managers, 34 percent PUC Commissioners and senior staff, 16 percent public advocates, and 15 percent others (industrial consumers, consultants, academics, etc.). The first training in Boston was co-taught by Susskind, Richard Cowart (Chair of the Vermont PUC), James Richardson (University of New Mexico) and Eric Van Loon (Endispute, Inc.). The second in Florida was taught by Susskind, Cowart, Richardson, and myself.

13. These trainings were conducted at NARUC's National Conference of Environmental Externalities in Jackson Hole, Wyoming (October 1-3, 1990); NARUC's Third National Integrated Resource Planning Conference in Santa Fe, New Mexico (April 8-10, 1991); and Lawrence Berkeley Laboratory's Advanced Least-Cost Utility Planning Seminar for senior PUC staff in Berkeley, California (January 1990 and June 1991). All of these trainings, which I conducted myself, included the use of a simulated consensus-building exercise and discussions of using ADR in electric utility regulation. Over 100 people attended all four events combined.

14. For instance, a five-day training by Lawrence Susskind and Max Bazerman (Northwestern University) at MIT each year always attracts numerous people involved in electric utility affairs. Similarly, seminars led by Roger Fisher have also been attended by utility representatives, regulators, and intervenors. In 1991, David O'Connor, Director of the Massachusetts Office of Dispute Resolution and myself, conducted a two-day training on ADR for over 25 staff from the Massachusetts Department of Public Utilities and the Energy Facilities Siting Council. Undoubtedly other ADR-related trainings have occurred.

15. The forum article contained the answers from regulators on three questions on dispute resolution including: 1) Does adversarial advocacy still make sense today for state utility commissions, when so much of the caseload seems to be changing from

simple dispute resolution to policy making?, and 2) What experiments have you tried (or thought of trying) for alternative dispute resolution or formulation of policy?

16. In contrast, advisory staffs can discuss cases with commissioners but do not take part in the cases as parties.

17. In fact only California and New York have been identified as having comprehensive settlement guidelines or rules. Two separate, informal surveys conducted by the staff of the New York PSC and by the NARUC's Staff Subcommittee on Administrative Law Judges in 1990 and 1991 respectively confirmed this surprising finding.

18. The Negotiated Rulemaking Act of 1990, Public Law 101-648, November 29. The act establishes a framework for conducting negotiated rulemaking, but does not require its use. Agencies planning to use negotiated rulemaking must give public notice. An agency representative must participate, but may not chair the negotiations. Meetings are chaired by a neutral facilitator or mediator. If the committee reaches consensus on a proposed rule it is submitted to the agency, for them to consider adopting as their proposed rule. Agencies may pay expenses of committee members who are needed for the process but do not have adequate resources.

19. Although focusing on settlements in the judiciary rather than those that occur in the administrative process, Carrie Menkel-Meadow concludes in an article published in the UCLA Law Review in 1985 that contrary to popular belief, empirical studies have not confirmed that settlement conferences, arbitration and mediation decrease delay of case processing time or promote judicial efficiency. She goes on, however, to advocate ADR for improving the quality of dispute resolution which she claims is a far more important reason anyway (Menkel-Meadow 1985).

20. A PUC decision is appealed directly to the state Supreme Judicial Court in most if not all states. Appeals of decisions by the state Supreme Courts go directly to the U.S. Supreme Court.

21. I base this observation, and the observation in the previous sentence on my discussions with PUC commissioners and senior staff in approximately a dozen states over the past year.

22. Breyer claims, "The present law of judicial review of administrative decision making...contains an important anomaly. The law requires the courts to defer often and strongly to agency judgments about matters of law, but it also sometimes suggests that courts conduct independent in-depth reviews of agency judgments about matters of policy" (Breyer 1987, p. 68). Although Breyer's work refers specifically to federal case law, state laws while probably different from state to state, undoubtedly reflect similar tensions.

23. It is misleading to conclude that PUC approval of a consensus (and for that matter any PUC decision sustained by the court), is a sufficient proxy for assessing substantive success. PUCs (and ultimately the courts if their opinion is solicited) are

only required to make sure that settlements fall within a reasonable range of substantive outcomes that may have emerged from a contested case. PUCs do not generally require that settlements constitute substantive improvement over the likely range of outcomes from traditional procedures.

24. Raiffa's approach is not only useful in analyzing unrealized joint gains, but it can also be applied to better understanding what gains were already realized. Hence the approach advocated by Raiffa is useful for assessing the movement from a bottom-up baseline as well.

25. It is worth noting that if "simplicity and continuity" were substituted for "wisdom", Susskind and Cruikshank's list of evaluative objectives would be identical to the Massachusetts Department of Public Utilities' criteria for evaluating rate structures (Keegan 1986).

26. This section draws heavily on a paper I prepared for the 5th National DSM Conference entitled, "When Should a Collaborative DSM Process be Considered Successful?" (Raab 1991).

27. In a recent article in Georgetown Law Journal (June 1991) by Susan Sturm entitled "A Normative Theory of Public Law Remedies", the author makes a compelling argument that the courts can enhance the legitimacy of the development of remedial priorities and plans by relying on a deliberative model centered on the consensus-based negotiations of the disputant parties themselves. This argument, and many others made in this excellent piece, which is focused on the courts rather than administrative agencies, often parallel many of the arguments made in this dissertation (e.g., she argues (1) against limiting application of the so-called deliberative model a priori, (2) for the need to look at both the process and the results, and (3) of the possibility that such an approach may increase short-run process-related resources).

Chapter 4: Adjudication

Introduction

In Chapter 3, I discussed the opportunities for consensus building in traditional PUC regulation in broad-brush terms, and analyzed criteria for evaluating the success of consensus-based processes. In this chapter I focus on PUC adjudication. After defining PUC adjudication, I briefly discuss its history including the increase in the frequency and controversy of contested cases in recent years and the turn to settlement. I introduce the opportunities for enhancing consensus building specifically in adjudicatory matters prior to analyzing two cases in-depth. One is the settlement resolving issues related to an extended outage at the Pilgrim nuclear power plant in Massachusetts. The second is the development of comprehensive demand-side management programs for utilities in Massachusetts using a unique collaborative process. In the concluding section of this chapter, I provide a brief summary of key points from the case study analyses.

Adjudication Defined

Unlike rulemaking procedures in which industry-wide policies are promulgated (the focus of the next Chapter), adjudicatory proceedings, in theory, involve applying those policies to specific cases. When agencies, such as state PUCs, adjudicate cases they act quasi-judicially and must adhere to due process requirements that are similar to those followed by the courts:

> [A]gencies when they adjudicate individual cases must use procedures that involve the traditional legal attributes of judicial due process: public notice; an unbiased decision maker; a public record upon which the decision is based; opportunity to present evidence, witnesses, and argument, and to challenge those

presented by the opposing side; right to counsel; right to a reasoned decision; and increased judicial review of the decision (Breyer 1982).

Despite many similarities between agencies like PUCs and the courts on due process requirements, there are some important differences. Agencies generally grant intervention more freely than judicial courts and have more flexibility in deciding what to allow into evidence in a proceeding (Strauss 1990). Also, in more than half the states, PUCs are bound by "open meeting" or "sunshine" laws and commissioners only confer with each other in public meetings, unlike multi-judge, judicial courts which are permitted to confer with each other prior to rendering a decision.[1] Still, all PUC commissioners, like judges in the judicial branch of government, are forbidden from ex parte contacts with utilities and intervenors (i.e., written or oral communication that is not on the public record) during the course of adjudicatory proceedings, and are required to base their decisions on the evidence in the record.

A state PUC's primary interface with the industries it regulates and the public has historically been through adjudicatory proceedings, rather than rulemakings. For instance, over the past decade, the Massachusetts Department of Public Utilities (DPU) conducted almost 1,000 adjudicatory-type cases but only two rulemakings. Although the rulemakings were extremely complex and time-consuming, as discussed in the Integrated Resource Management Rulemaking case study in Chapter 5, the fact remains that the majority of the DPU's time (and correspondingly the utilities' and intervenors' time) is still dedicated to adjudicatory proceedings.

The most common adjudications have traditionally been rate cases.[2] A rate case is used to determine what costs an individual utility should be able to recover from its ratepayers; what return on its investment it deserves; how its costs along with its return should be allocated to different customer classes; and how rates should be structured within each customer class. The procedural structure of a typical rate case is provided in Table 4.0.[3] Other adjudications before the PUCs generally follow the same procedural process.

Table 4.0
Traditional Rate Case Process

1. Case Filed (Including Testimony of Utility), Given a Docket Number, and Stakeholding Parties are Given Notice.
2. Parties Intervene.
3. Discovery Conducted (i.e., parties ask each other questions and receive responses -- usually in writing).
4. Testimony Submitted by Intervenors.
5. Contested Hearings Held (during which parties cross-examine each others' witnesses and PUC asks questions).
6. Briefs (and often reply briefs) Describing Final Positions Are Submitted by Utility and Intervenors.
7. PUC Decides Case and Issues an Order.
8. Period Provided for Parties to Request PUC to Reconsider its Decision, and for Appeal to Courts.

Source: Author's List

Rate cases generally focus on examining historic facts such as past expenditures and whether utilities complied with preexisting policies. Rate cases traditionally do not focus on future plans and objectives.[4] Other traditional adjudications that fit into the mold of focusing on past actions include prudency and performance investigations.

More recently (i.e., over the past half decade), utility-specific adjudications involving future plans in addition to past performance have come before state PUCs with increasing frequency.[5] Such adjudications are generally associated with the implementation of new PUC rules. Often they involve approval of a utility's resource plan or its resource bidding proposal, or approval of specific utility resources prior to investment (both supply-side and demand-side). These new cases reflect greater involvement in utility decisionmaking ex ante rather than ex post as was traditional. Although these cases follow the same procedural steps as rate cases and other adjudications involving historic performance, I believe they constitute a distinctly different substantive focus.

Rise of PUC Adjudication

As mentioned in Chapter 2, beginning in the late 1960's when the era of declining electricity production costs ended, the number of rate cases before the state PUCs increased dramatically. Although their number fluctuates annually they have trended upward nationally since 1970. Forty-three states reported over 100 major electric rate cases in 1990 compared to less than 50 per year reported by all states prior to 1970 (NARUC 1991, pp. 344-351, Anderson 1981).[6]

The total number of electricity-related cases before the PUCs, including the new breed connected to utility planning and future procurements, is much larger than the number of general rate cases. For instance, states reported over 2,000 electricity-related cases to NARUC for 1990 (1,390 were concluded in 1990 and 774 were pending at the end of the year) (NARUC 1991, pp. 22-166).[7] While many may be fairly routine (e.g., fuel charge proceedings) in terms of requiring only limited PUC, utility, and intervenor resources, many are not.

Table 4.1 shows the number of adjudications before the Massachusetts DPU over the last decade broken down by general rate cases, major prospective cases, and minor adjudications. Although the table shows a surprisingly consistent number of total cases, it substantiates an increase in the number of major cases during the past decade (i.e., from 4.4 per year during the first five years to 9.6 in the second five years).[8] Of particular interest are the increase in major cases related to forward-looking resource issues such as preapprovals, Qualifying Facilities RFPs, and most recently -- integrated resource management plans.

Table 4.1
Electric Utility Adjudications Before the Massachusetts DPU (1982-1992)

Case Type:	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	Total
Major Adjudications:											
General Rate Cases	7	4	4	1	2	2	5	4	3	2	35
Prospective Resource Cases	0	0	1	0	3	5	2	8	8	9	36
Sub-Total Major Adjud.	7	4	5	1	5	7	7	12	11	11	71
Other Adjudicatory Cases	89	80	87	83	99	97	91	95	87	84	892
Total Adjudicatory Cases	96	84	92	84	104	104	98	107	98	95	962

Notes: "Prospective Resource Cases" include DSM and supply-side preapprovals, QF RFPs, and Integrated Resource Management approvals.
"Other Cases" include fuel charges, power purchases, financings, ownerships transfers power contract approvals, zoning exemptions, power plant goal setting and performance and other miscellaneous cases.

Source: Massachusetts DPU Card Catalog, Compiled by Henry Yoshimura and Author

It is also important to point out that electricity is only one of many industries that PUCs regulate. Rate cases and other adjudications associated with natural gas and telephone regulation have also increased concurrently with rising electricity-related case loads. The same forty-three states reported altogether more than 40 major telephone rate cases, 80 major gas rate cases, and hundreds of water cases for 1990 (NARUC 1991, pp. 352-381). Some PUCs also regulate cable TV, motor carriers, sewer, and even solid waste (id., pp. 22-166). States reported over 30,000 cases to NARUC in 1990 considering cases related to all industries and of all case types (i.e., rate cases, other adjudications, and a sprinkling of rulemakings) (id.).[9]

Short-Comings

Since PUC staffing has generally not kept pace with the increasing number and complexity of cases, PUC resources have been unduly strained in recent years. Table 4.2 shows the number of adjudications, and the number of full-time staff at the Vermont Public Service Board between 1988 and 1991. The numbers show dockets increasing by 16 percent, hearing-days increasing 74 percent, and decisions and non-docket reviews more than doubling in less than four years (i.e., 111 percent and 119 percent respectively). Meanwhile staff increased only 10 percent from 19 full-time equivalent to 21. Although smaller than most PUCs, the trends shown in Table 4.2 for Vermont are probably typical.

Table 4.2
Vermont PSB Caseload and Staffing (1988-1991)

	1988	1989	1990	1991	Change
Hearings Held	191	247	291	333	+ 74%
Decisions Issued	210	275	293	444	+111%
Dockets Processed	176	185	190	205	+ 16%
Non-Docket Reviews	120	132	173	263	+119%
Staff	19	19	20	21	+ 10%

Notes: "Decisions Issued" includes proposals for decisions issued by hearing officers.
Includes electric, gas, telecommunication, water, and cable TV cases.
The PSB has one full-time and two half-time Commissioners.

Source: Vermont Public Service Board, Susan Hudson and Michael Dworkin

Meanwhile, the number of commissioners on state PUCs has remained constant over the last two decades -- with a median of 3 and a mean of 3.2 (NARUC 1991). It is therefore not surprising that rapidly increasing case loads threaten to compromise PUCs' ability to do their jobs effectively. Former Commissioner Ron Lehr of Colorado explains:

> [PUC Commissioners] are faced with issues of unbelievable scope, spanning several major industries, a mass of technical detail, and calendars which are so loaded with meetings and hearings as to leave insufficient time for reading, preparing and thoughtful consideration (Ronald Lehr 1990).

Not only have the number of PUC adjudications increased dramatically over the past two decades, but the cases themselves are usually more controversial and more complex. This trend began when rate cases no longer meant rate decreases but signaled inevitable increases. Utilities, and ultimately the PUCs, are now forced to decide how to allocate cost increases among customer classes as well as among customers within each customer class. In addition, as I discussed in Chapter 2, rate cases and other PUC adjudications have become the place where the prudency of past utility decisions are contested, and costs must be allocated between ratepayers and utility shareholders. Finally, the contentiousness of PUC adjudications have been further aggravated by the addition of cases associated with utility decisions about future resource options including disputes over forecasts, and resource identification and selection criteria and methods.

Most electric utility cases today are met with intervention by opposing parties and close scrutiny by the regulators. These contested cases are conducted using an adversarial process in which each side (or sides) makes every effort to present its own perspective favorably while discrediting the opinions of others. This applies regardless of whether historic facts, remedies for past decisions, or future plans are the subject of dispute. After issuing what is often exhaustive discovery requests of each other, testimony is prepared by witnesses (often by outside experts), who are then subject to detailed cross-examination. When the hearings are complete, the parties argue their cases in written briefs. The PUC' staff and commissioners are then required to wade through what is inevitably a voluminous and conflicting record, and render a decision that strives to be efficient, fair and consistent with the record.

The adjudicatory process itself is often extremely resource-intensive for the utilities, the intervenors, and the regulators. The first case in this chapter describes adjudications associated with an extended outage at the Pilgrim nuclear power plant in Massachusetts which required over 90 days of hearings, over 1,300 exhibits, and more than 25 witnesses. While the Pilgrim cases are probably situated at the more intensive-end of the spectrum (although they are by no means alone), the average rate case normally lasts between eight and nine months[10] and requires weeks of hearings and hundreds of exhibits. Written decisions by PUCs at the end of rate cases are usually hundreds of pages even for small utilities (Raab 1989B).[11]

Also, intensive litigation does not always adequately illuminate the issues in ways that facilitate the PUCs' decisionmaking. Instead, cases usually end with considerable disagreement over the historic facts, and PUCs are left to pick and choose among alternative views. Lawrence Susskind and Allan Morgan described the problems this causes in an article that appeared in Edison Electric Institute's Electric Perspectives in the Spring of 1986:

> The adversarial process also encourages the parties to discredit each other's scientific or technical studies. Indeed, the tendency in such situations is to spend a great deal of time and money undermining the claims of others rather than

improving the quality of the information available to everyone. Unfortunately, challenges to the technical work submitted by others merely confirm the general public's view that all studies are nothing more than polemics prepared on behalf of one client or another. This jockeying is very dangerous: it can lead to politically expedient but technically or economically unsound decisions...(Susskind and Morgan 1986, p.23).

Where cases focus on future utility plans that rely on unknowable facts and uncertain forecasts, the problem of discovering what is correct via litigation borders on pointlessness. While adjudication can help weed out gross forecasting deficiencies, inevitably a wide range of forecasts and subsequent options will exist. Adjudication can do little more than clarify parties' differing expectations and preferences.

Even where there is some convergence on the facts, the parties rarely agree on the appropriate remedies. This is not surprising given the subjectivity inherent in many of the decisions in rate cases and other adjudications. But as Judge Stephen Breyer in Regulation and Its Reform explains using the example of deriving a rate of return in a rate case, despite this ultimate need for regulatory discretion, adjudications still tend to obsess over unknowable decisions in non-productive ways:

...setting a rate of return cannot -- even in principle -- be reduced to an exact science. To spend hours of hearing time considering elaborate rate-of-return models is of doubtful value, and suggestions of a proper rate, carried out to several decimal places, gives an air of precision that must be false (Breyer 1982, p. 47).

Such subjectivity is inherent not only because PUCs must make distributional decisions among various parties, but because they must make difficult tradeoffs among oftentimes competing objectives such as efficiency and equity. While decision makers can look to rules and precedents for guidance, their ultimate decision must reflect the record developed in the case. However, as former New Mexico Commissioner Marilyn

O'Leary explains, the adjudicatory process itself does not generally help commissioners make these difficult tradeoffs:

> The result of parties' taking extreme positions is that the decision maker feels as if he or she is living out the story of the blind man and the elephant. It is difficult, if not impossible, to get the whole picture. The commissioners role of balancing the interests of the parties who do not reveal their true interests is difficult (O'Leary 1986, p.11).

Lastly, PUCs often--de facto--use contested cases to promulgate new policy initiatives that effect the entire industry. When PUCs try and wrestle with policy issues through adjudication, at least two problems arise besides the legal question of whether a rulemaking process is required to make industry-wide policy (discussed in next chapter). First, not all parties that will be effected by the regulations are likely to be parties to an adjudication which is normally focused on an individual utility. Second, as just discussed, adjudication tends to obscure parties true interests and polarize positions. This polarization can stifle creative approaches to policy formation.

Together these short-comings often overwhelm PUCs, making it difficult for them to craft decisions that are perceived as legitimate or praised as practical.[12] An indication of this frustration is that parties frequently request PUCs to reconsider adjudicatory decisions, or appeal them to the courts. In 1990, for example, more than half of the 22 PUCs that reported to NARUC on this issue had at least one appeal filed against their adjudicatory decisions in the courts.[13] Since virtually all courts decide appeals based on the record established by the PUC (usually with supplemental briefs and possible oral argument before the court) rather than de novo, the cost of appeals generally pale compared to the initial litigation. However, appeals are often contentious and increase regulatory uncertainty by further delaying final resolution of important issues. Over the past five years, the average time required to process an appeal of a state PUC decision was 14.3 months -- significantly longer than the 8.3 months it takes PUCs, on average, to render their decisions (NARUC 1991).[14]

PUCs usually walk a thin line in their adjudicatory decisions -- attempting to balance the interests of parties within the context of existing rules and policies. This balancing is extremely difficult when parties obscure their true interests by taking exaggerated positions. As a result, PUC decisions rarely leave all or even most of them satisfied. Even when cases are not appealed, dissatisfaction often leads to implementation problems and general intransigence. Issues that have supposedly been reconciled by a PUC decision in a case or cases often reemerge in subsequent proceedings.

The Role of Settlement

One way that parties attempt to reduce the time, cost, uncertainty and general dissatisfaction of litigation in rate cases and other adjudications is to voluntarily settle the cases. When settling, they reach a consensus among themselves with respect to the disposition of some or all contested issues, and submit the settlement to the regulators for approval. Although settlements in civil matters before the courts usually occur prior to trial, this is not generally the case in traditional rate case settlements before state PUCs. In rate cases, settlements usually occur after a utility and the intervenors have presented their cases and a record has been established (i.e., after discovery and hearings). However, settlement can occur at any time prior to a PUC's final order in a case. Recently, with the advent of more forward-looking, resource-planning cases such as the DSM preapproval case described later in this chapter, pre-filing settlements of a new variety are beginning to occur.

Settlement on regulatory issues began at the federal level. The Federal Power Commission (FPC), the precursor to the Federal Energy Regulatory Commission (FERC), originally promulgated settlement procedures in 1949. However, it was not until the early-1960's that the FPC actively promoted settlements as a way of resolving cases. At that time, it had been swamped by requests for rate increases by pipeline companies following the rise in gas prices at the wellhead during the 1950's. Due to its huge back-log, over $1 billion had been collected by gas pipeline companies subject to refund (Freeman 1965).[15] Largely as a result of this back-log, the FPC was singled out in a report by James Landis (then special advisor to President-elect Kennedy) as "the outstanding example in the federal government of the break-down of the administrative process" (Landis 1960).

According to S. David Freeman, the assistant to the chairman of the FPC at the time, by the mid-1960's, through a combination of increased staffing and active use of settlement procedures, the case back-log was erased and the agency's credibility had largely been restored (Freeman 1965). The use of settlement continued to grow at the FPC and later at the FERC, and by the mid-1980's approximately 80 percent of FERC's caseload was resolved through settlement (Harter 1984, Burns 1988). In 1980, FERC's settlement guidelines were amended to provide parties the option to use settlement judges to facilitate negotiations (Joseph and Gilbert 1990). Today, FERC is still settling 70-80 percent of its major electric cases, with only 10-20 percent of settlements using settlement judges (Orrechio Interview). FERC rarely rejects a settlement reached by all, or even most, parties (Orrechio Interview).

Although I have not found any reports detailing the early use of settlement in state PUC adjudications, it is likely that settlements in electric utility cases increased substantially after rates began to rise during the 1970's. Representatives of PUCs that I interviewed in seven states in preparing this dissertation all indicated a rise in settlements over the past five-to-ten years.[16] Table 4.3 shows the number of settlements submitted to the New York Public Service Commission for approval between 1981 and 1990.

Table 4.3
Settlements in Cases Before the New York PSC (1981-1991)

Year	Electric Cases	Other Cases	Total Cases
1981	1	2	3
1982	1	8	9
1983	2	8	10
1984	3	8	11
1985	6	6	12
1986	4	5	9
1987	5	11	16
1988	10	11	21
1989	6	10	16
1990 (part yr)	1	4	5
Total	39	73	112

Notes: Included in the Electric Cases are 7 combined gas/electric rate cases.

Source: Compiled By Author From Data Supplied by the New York PSC, Courtesy of Ron Elwood

Of the 39 electric utility settlements in New York shown in Table 4.3, 21 percent were resolved before hearings, 26 percent during hearings and 54 percent after hearings. In addition, 62 percent of the electric utility settlements were complete settlements resolving all outstanding issues, while 38 percent were partial -- leaving some issues unresolved. Less than 10 percent of all the cases shown in Table 4.3 used settlement judges, and only two settlements have been rejected by the PSC (Elwood and Crary Interviews).

The electric-related settlements in New York represent approximately 70 percent of the major electric cases during this period.[17] This rate is probably higher than many other states given New York's active encouragement of settlement. In Massachusetts, for example, there was settlement in only 14 percent of major electric cases between 1982 and 1991.[18] However, as in Massachusetts, the frequency of settlement is probably increasing across the country.

In addition, a greater diversity of issues are being settled (Burns 1988). For instance, the 39 electricity-related settlements in New York covered the following broad range of issues: avoided costs, cost allocation, cost-of-service, customer complaint procedures, decommissioning of a nuclear reactor, electric line routing and construction procedures, phase-in of a nuclear power plant into rates, rate-of-return, rate design, rate moratorium, replacement power costs, and sales forecasts. Settlements in Massachusetts have also included the preapproval of utility DSM programs, and initial resource plans.

Expanding and Formalizing Consensus-Building

Although settlement is obviously already part of the landscape of resolving adjudicatory proceedings on many issues before state PUCs, it is relatively new and evolving. Most cases are still probably not settled. Many are often only partial settlements. Some PUCs even consider certain topics off-limits. For instance, rate design settlements were considered taboo in New York and Massachusetts until recently (Elwood and Werlin interviews).[19]

The increased use of settlement would seem to necessitate that state PUCs have clearly articulated procedures and techniques for conducting settlements and integrating them into traditional adjudicatory proceedings. Yet, as of this writing, despite statutory authority to allow them in most states, only California and New York have been identified as having formal settlement guidelines and rules that apply to electric utilities (Elwood and Marland Interviews).[20] The remaining states apparently oversee settlements on an ad hoc basis (id.).

Without such guidelines or rules, many important issues including the following, are left rather nebulous and must be revisited on a case-by-case basis: (1) What subjects, if any, does the PUC consider off-limits for settlement? (2) When during proceedings can settlements occur and how will they mesh with on-going adjudication (e.g., does the clock stop during settlement discussions)? (3) What is the appropriate role of the staff and the commissioners in settlement proceedings? (4) Who should be included and noticed regarding settlements? (5) How should the confidentiality of information revealed during settlement negotiations be protected?

Even New York's detailed settlement guidelines, which were first established in 1983, have room for improvement as a New York Telephone case in 1989 and 1990 revealed. In that case, the Commission rejected a settlement where there was a significant dispute regarding whether intervenors to the case who were not parties to the settlement (which was settled by the Company and the Commission's own advocacy staff) were properly noticed of and included in the settlement process (NY PSC Opinion No. 90-14, April 26, 1990, Elwood Interview). As a direct result of that case, the New York Commission opened an investigation into its own guidelines, and approved new rules and guidelines in February 1992 (NY PSC Opinion No. 92-2, March 24, 1992, Elwood Interview). The new rules and guidelines, among other things, require that all parties be noticed and given an opportunity to participate in settlements.

New York is not alone. In April 1991, the FERC opened a Notice of Proposed Rulemaking to revisit its settlement guidelines. That same month, NARUC's Staff Subcommittee on Administrative Law Judges issued Model Settlement Guidelines for states to consider. But settlement rules and guidelines are not yet common. Debates over what they should entail go to the heart of the value of settlement in PUC regulation, and how best to tap its potential advantages while avoiding potential problems.

Introduction to Case Studies

I will conclude this dissertation with numerous recommendations regarding how best to structure settlement and other consensus-building processes. While most will be based on the case studies herein, the immediate focus of this chapter is broader. In the case studies, as described in Chapter 3, I explore the fundamental question: What benefits, if any, can settlement and other consensus-based processes add to traditional PUC adjudication?[21]

The first case study involves a settlement resolving extremely lengthy and controversial proceedings on expenditures made by Boston Edison Company during a 32-month extended outage at its Pilgrim nuclear power plant in Massachusetts. This happened after the parties' cases were fully developed on the record, and represents a more traditional, albeit creative, settlement. In the second case I examine demand-side management (DSM) Collaboratives among Massachusetts utilities and various intervenors. These collaboratives represent a new type of settlement process that has arisen to deal with forward-looking planning and implementation issues. The case is important for many reasons including the fact that the settlements occurred prior to the utilities filing their plans with the Massachusetts Department of Public Utilities.

Endnotes (Chapter 4, Introduction)

1. In reality, commissioners in states with Open Meetings Laws often confer with each other indirectly through their staffs outside public meetings.

2. Although technically the federal Administrative Procedures Act (discussed in detail in Chapter 5) classifies ratemaking as formal rulemaking, as opposed to adjudication or informal (notice-comment) rulemaking which is how agencies almost always make rules, there is little if any procedural difference between formal rulemaking and formal adjudication in the APA (Breyer and Stewart 1979). More importantly, on the state level where PUCs follow state laws rather than the federal APA, PUC ratemaking is virtually always considered to be an adjudicatory proceeding.

3. Although rate case structures and adjudicatory structures may vary slightly from state to state, or case to case, Table 4.0 provides the general structure. Any differences are relatively insignificant (e.g., a utility might file its testimony with its initial filing rather than after discovery.)

4. States that use future, rather than historic, rate case test years (i.e., rates are set by dividing the costs incurred during a single year after adjustment for known and measurable changes and return by the anticipated sales), still use the historic test year as the basis for the future projection.

5. Historically, forward-looking cases were limited to financing cases which approved the issuance of long-term equity or debt to finance a major project or retire old debt and replace it with new debt at lower rates.

6. This number does not include data from seven states which had not reported back to NARUC prior to publication. If the rate cases from these states were included the numbers would definitely be higher.

7. These actually only represent the cases from half the states. The other states did not provide information on this question in NARUC's annual survey. The actual numbers therefore might be twice as large.

8. The high number of general rate cases in 1982 (i.e., 7) is somewhat of an anomaly and may be explained by the fact that 1982 was the transition year from a republican to a democrat as Governor. It is possible that utilities believed they had a better chance of getting a substantial rate increase approved under the existing PUC than the unknown future one (Massachusetts differs from virtually all other states in that Commissioners terms are co-terminus with the Governor rather than staggered). However, the cases in 1982 were much less complex and controversial than cases today, and the PUC orders were extremely short by today's standards.

9. Again, only half the states provided information at this level of detail. As such, the real number of cases may be twice as many..

10. Although the average rate case takes 8.6 months, the range is 4 months to 30 months with a standard deviation of 4.0 months. These numbers were calculated based on NARUC 1991, pp. 946-950. Many states have adopted deadlines for reviewing rate cases. Massachusetts for example must issue an order within six months or the utility's request is automatically granted.

11. The long length of orders in non-settled cases represents a significant change even from the early 1980's. In Massachusetts, for example, orders in 1982 averaged less than 50 pages, while they average over 250 pages today.

12. In a response to a question posed to PUC Commissioners from 13 states by Public Utilities Fortnightly about the appropriateness of the adjudicatory process for policy making, most pointed more broadly to many of the overall short-comings of adjudication that I have described at length. See endnote number 15 in Chapter 3 for additional information for PUF piece.

13. The 22 states reported 39 appeals (12 states reported appeals, 10 reported none). Compiled from NARUC 1991, pp. 22-161.

14. The average time of an appeal was 14.3 months compared to 8.6 months for a typical rate case. The range of time to resolve an appeal between 1985 and 1990 was 4 months to 30 months. The standard deviation is 6.9 months. Information compiled from NARUC 1991, pp. 946-950, and analyzed by me.

15. This amount was to grow to $1.6 billion in 1963 dollars before the FPC was able to catch up (Freeman 1985).

16. The states include California, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

17. This percentage was derived by comparing the number of settlements with the number of major cases docketed during this period (i.e., 54 from 1981-1989). According to Ron Elwood who supplied the raw data, the figures should only be considered a rough approximations because of some data tracking inaccuracies, timing differences between when cases are docketed vs. when they are settled, differences between major cases and minor settlements, etc.

18. There were 10 settlements in Massachusetts out of 71 major cases (Data Complied by Henry Yoshimura).

19. The reason for the Commission's reluctance to encourage rate design settlements was a fear that it would be too easy for participants to unfairly pass costs on to rate classes that were not parties to the settlement. However, in the final version of New York's new settlement guidelines and rules adopted in February 1992, the preclusion of rate design settlements present in earlier drafts was removed (Elwood Interview).

20. In the process of revising its settlement guidelines, New York did a survey of the other states to identify other models, and found settlement guidelines only in

California and at FERC (Elwood Interview). Also, prior to formulating the Model Settlement Guidelines, a search for other models turned up nothing more than the New York survey had (Marland Interview).

21. I note that the focus of the cases are primarily on adjudicatory settlement. The other consensus-building activities explored in Chapter 3 (e.g., technical sessions) which are less rigorous in terms of consensus-seeking are only touched on here but are discussed more fully in Chapters 5 and 6.

Pilgrim Settlement Case Study

Introduction

Purpose

The purpose of this case study is to analyze the settlement crafted by Boston Edison Company (BECo), the Massachusetts Public Interest Research Group (MASSPIRG), the Attorney General's Office (AG), and the Executive Office of Energy Resources (EOER) to resolve several complicated and controversial issues being adjudicated before the Massachusetts Department of Public Utilities (Department or DPU) involving the Pilgrim Nuclear Power Plant (Pilgrim). The settlement discussions began after approximately 90 days of contentious hearings in a general rate case, and a simultaneous proceeding addressing replacement power costs incurred during a 32-month outage at Pilgrim. Intervenors asserted that Pilgrim was no longer cost-effective compared to alternative resources, and challenged BECo's decision to invest hundreds of millions of dollars more in it. Intervenors also challenged BECo's right to recover over $100 million in replacement power costs, charging that the 32-month outage was a consequence of management imprudence.

After months of negotiations, the parties settled all the issues in both cases, and the Department approved the settlement. Although the process used by the parties resembles traditional adjudicatory settlements in many respects, both the scope of issues and the solutions that the parties invented make this case unique.

This case study explores whether the settlement process enhanced the adjudicatory process and resulted in a better resolution of the issues than if the Department had decided the cases. I conclude that the settlement did not necessarily save process-related resources in the short-run. However, the settlement appears to have produced a more creative and practical solution that was also more palatable to all parties including the Department itself.

Research Methods

In preparing this case I examined a wide range of primary documentation such as Department orders, excerpts from the enormous record in the cases (e.g., transcripts, exhibits, testimony), and internal DPU memos. I also had the benefit of several secondary sources including testimony written by the participants to the settlement, and newspaper articles.

In addition, I conducted personal interviews with representatives of the four major parties to the settlement, as well as a lead staffperson and a former Commissioner at the Department. A list of all those interviewed including their affiliation and their title is shown in Table 4.4 (on the next page). An earlier draft of this case was reviewed by all those interviewed, and their comments have been incorporated as appropriate.

Finally, as a staff member at the Department during the period these cases and internal review of the Pilgrim Settlement took place, I was a participant-observer. I was involved in several hearings in the rate case (related to demand-side management (DSM)), and I participated in numerous internal discussions and meetings about both cases and the settlement. Although confidentiality obligations keep me from discussing the content of those discussions, meetings, and internal memos,[1] they helped shape my understanding of the case -- particularly with respect to what may have happened absent the settlement.

Table 4.4
Interviews for Pilgrim Settlement

Brian Abbanat	Massachusetts Department of Public Utilities, Chief Engineer of the Electric Power Division
George Dean	Massachusetts Attorney General's Office, Director of Regulated Industries Division
Thomas May	Boston Edison Company, Executive Vice-President
Alan Nogee	MASSPIRG, Energy Program Director
Rachel Shimshak	Division of Energy Resources, Director of Policy and Planning
Robert Werlin	Attorney, Private Law Firm (Former Commissioner and Chair, Department of Public Utilities)

Organization of the Case Study

I begin the case study with a description of the 32-month outage at Pilgrim, and the controversial history of both BECo and Pilgrim pre-dating the outage itself. I then analyze the actual cases before the Department which focused on monies spent during the outage, and discuss the settlement process which grew out of these cases -- highlighting its innovative and controversial aspects.

In the next section, I evaluate the Department's ultimate approval of the settlement. This is followed by an analysis of the post-settlement period including the emergence of criticism of the settlement from local citizens and the Nuclear Regulatory Commission (NRC). I examine the impact of the settlement on Pilgrim's improved operation, how the settlement has fared given the regional economic downturn, and the parties' frustrations with respect to implementing portions of the settlement.

In the concluding section, I evaluate the overall success of the Pilgrim Settlement. Specifically, I explore whether resources were saved during the process, and whether the settlement resolved the issues raised during the cases in a way that is more legitimate and more practical.

Background

On April 11, 1986, BECo began a gradual shut-down of the Pilgrim nuclear reactor to investigate a leak in one of its cooling systems. The following day, the reactor unexpectedly scrammed (i.e., an automatic emergency shutdown occurred) after valves in the main steam line running between the reactor and the turbine suddenly and unexpectedly closed. After unsuccessfully trying to reopen the valves, the reactor operators were forced to use a backup emergency cooling system to control the pressure in the reactor.

This event was not unique at Pilgrim. Apparently a similar chain of events had occurred only two weeks before at the reactor (Nogee 1988). In fact, during the early- to mid-1980's, Pilgrim was regarded by the Nuclear Regulatory Commission (NRC) as one of the most troubled nuclear reactors in the country, and its workers had the highest collective radiation exposure of any nuclear plant (Nogee 1990).[2] In 1982, the NRC fined Pilgrim's operators $550,000 (the largest fine issued by the NRC at the time) for numerous problems including design errors, inadequate procedures, plant failures, and lack of sound management.[3] It also ordered BECo to develop a "Performance Improvement Plan" in 1982 and a "Radiological Improvement Program" in 1984. In 1984, BECo shut down the plant for an entire year during which over $200 million of repairs and capital improvements were made to the plant (Nogee 1988).

The NRC was not the only regulatory body critical of BECo's management. At the time of the April 1986 reactor scram, BECo had just completed a contentious general rate case before the Massachusetts Department of Public Utilities (DPU). During the case, intervenors criticized BECo not only on Pilgrim issues, but also on its energy planning process and failure to purse other resources -- most notably demand-side management (DSM). In a scathing order, the DPU concluded, "It is clear that the Company does not believe it's accountable either to its customers or the Department" (D.P.U. 85-266-A and D.P.U. 85-271-A (June 1986, p. 14)). In addition to reducing BECo's return on equity to the bottom of its allowable range, the DPU insinuated that a change of management at BECo was in order. The DPU even took the unprecedented step of distributing its Order directly to each of the members of BECo's outside Board of Directors.

The day after the reactor scram, on April 12, the NRC sent BECo a Confirmatory Action Letter ordering a special investigation into the causes of the incident and requiring the Company to seek formal NRC approval before restarting the reactor (NRC CAL 86-10). Two weeks later, on April 26, 1986, the Chernobyl nuclear reactor accident occurred in the Soviet Union, igniting a heightened sense of concern regarding reactor safety in the United States -- especially at plants like Pilgrim.[4]

In keeping with recommendations made by an independent review panel initiated by the Board of Directors in the aftermath of the DPU's scathing order, BECo restructured its upper management in 1987 (while Pilgrim was still off-line). The Company brought in Admiral Ralph Bird, a 28-year veteran of nuclear operations at the Navy to oversee Pilgrim as Senior Vice-President for Nuclear Operations. BECo also hired executives from outside the Company, including Bernard Reznicek as Chief Operating Officer (COO), and accepted the resignation of several other executives.[5]

However, at the same time that BECo was attempting to revitalize its management, it continued to have problems with state regulators. In April 1987, the

Energy Facility Siting Council (EFSC), the agency responsible for overseeing utility energy-planning, rejected BECo's 1985 and 1986 supply plans and its planning process generally.[6] Also, public resentment of Pilgrim grew. In November 1987, MASSPIRG, a statewide consumer and environmental group, published a report entitled: "Nuclear Lemon: Ratepayer Savings From Retiring the Pilgrim Nuclear Power Plant" (Nogee 1987). The report added an economic twist to the public controversy surrounding Pilgrim, which until that time had focused primarily on safety concerns. MASSPIRG's report claimed that ratepayers could save as much as $1.5 billion over Pilgrim's anticipated lifetime if the plant was retired immediately and cheaper alternatives were procured (id.). MASSPIRG also filed a petition at the NRC which, if it had been accepted, would have required BECo to "show cause" as to why Pilgrim should not be shut down.[7]

BECo originally anticipated that the outage at Pilgrim would last only a few weeks. However, repairs and other changes spiraled in terms of both time and cost. The restart date was pushed back over 25 times. Pilgrim was not officially restarted until December 21 1989 -- 32 months after the outage began. Data provided in Table 4.5 indicates that BECo made over $200 million of capital improvements to Pilgrim between 1986 and 1988 (i.e, the period which was the subject of the adjudications before the Department). In addition, almost $300 million was spent on operation and maintenance at Pilgrim during the outage.[8] Finally, $115 million was spent on replacement power (i.e., cost BECo had to pay to secure power from the spot market to replace Pilgrim power) -- for a total of over $600 million in outage-related expenditures.

Between on-going safety concerns, BECo's substantial investment during the outage, the regulators dim view of BECo's management, and allegations that Pilgrim was not cost-effective on a going-forward basis, the stage was set for a major battle over BECo's past actions and the future of both the plant and the Company.

Table 4.5
BECo's Spending on Pilgrim During Outage (1986-1988)

Year	Capital Expenditures	O&M Spending	Replacement Power
1986	$46	$78	na
1987	$150	$172	na
1988	$15	$38	na
Total	$221	$288	$115

Source: Capital Expenditure and O&M Spending from (Nogee 1988).
1988 expenditures do not represent the entire year.
Annual distribution of replacement power costs were not readily available.

Pilgrim Cases Before the DPU

The DPU took up the issues surrounding Pilgrim primarily in two cases. The first, which is often referred to as the "outage" or "replacement power" case, was an investigation into the causes of the Pilgrim outage and the conduct of BECo while Pilgrim was off-line (D.P.U. 88-28). Hearings for the first case began in January 1989. The immediate objective was to determine the refunds, if any, of the $115 million the Company spent to replace Pilgrim power during the outage and passed along to ratepayers through the fuel clause.[9] Both MASSPIRG and the AG intervened in this case to oppose BECo's request to retain all but $7.6 million of the replacement power costs it collected during the outage.[10]

The second case was a general rate case, which was filed in April of 1989 (D.P.U. 89-100). BECo requested an $86 million, an 8.4 percent rate increase, which it justified almost entirely on expenditures associated with Pilgrim since the last rate case.[11] The immediate objective of this case with respect to Pilgrim was to determine the portion of the capital expenditures and operating and maintenance costs that should be included in base rates.

A third and earlier investigation, which had been initiated by the Department before the end of the outage and after it had received a petition by State Senator Golden on behalf of 20 BECo ratepayers (February 25, 1988), was merged into the rate case (D.P.U. 88-48). The Golden petition specifically requested the removal of all expenditures and investments in Pilgrim from rate base and the provision of rebates by the Company of damages allegedly sustained by ratepayers as a result of the operation of Pilgrim.

The Executive Office of Energy Resources (EOER) joined MASSPIRG, the AG, and Senator Golden in opposing BECo's request for the largely Pilgrim-related rate increase. Although the two cases focused on the appropriateness of BECo's historic expenditures with respect to Pilgrim -- particularly during the outage -- the interests of the intervenors were clearly broader in scope. Golden's original petition, for instance, wanted to take Pilgrim completely out of rate base and provide rebates to customers for costs charged to ratepayers even prior to the outage. EOER was concerned primarily with whether Pilgrim would be economic for ratepayers in the future. Alan Nogee, Director of Energy Policy at MASSPIRG, bluntly described his organization's interest in Pilgrim and their decision to intervene in the cases:

> Our primary interest was to shut Pilgrim down, and generally see a decreased reliance on nukes and fossil fuel generation and an increased reliance on renewables and DSM. Our strategy was to cutoff ratepayer subsidies which allowed the Company to charge ratepayers whether or not Pilgrim operated. We hoped to do this by challenging BECo's on-going investments, changing its incentives in the future, and penalizing it for past mistakes. Saving money for ratepayers in the short-run was a secondary interest (Nogee Interview).

The two cases followed typical adjudicatory procedures used by PUCs in rate cases, as previously delineated in Table 4.0. Largely because of the contentiousness of the Pilgrim issues, both cases required extensive commitments of resources by all the parties and the DPU. Although rate cases often require many days of hearings, these cases were much more intensive than usual. For instance, the outage case required 34 days of hearings filling 27 volumes of transcripts, and including 651 exhibits and 209 record request responses (i.e., requests for more information made during the hearings) (D.P.U. 88-28, 88-48, 89-100, p. 2). The rate case required 58 days of evidentiary hearings, with 20 days specifically focused on Pilgrim, and had 653 exhibits and 299 record request responses (id.). In the rate case alone, BECo sponsored 11 witnesses and nine panels with multiple witnesses, and the intervenors sponsored five individual witnesses and one panel.

Despite the extensive time spent in hearings during which both sides had the opportunity to air their views and question the other parties, as is typical in adjudicatory proceedings, the positions of the Company and the intervenors remained separated by a wide chasm. BECo maintained that it had acted prudently throughout the outage. It promised that its newly-refurbished nuclear power plant would perform better in the future than it had in the past -- bringing its ratepayers $400 million in benefits over the remainder of its economic life compared to alternatives. The Company argued that it be granted nearly all of its replacement power costs, and allowed to place all pilgrim-related capital expenditures and incremental operation and maintenance costs into base rates.

From the intervenors' perspective, the Company acted imprudently by sinking so much money into Pilgrim before, during, and after the outage without adequately exploring potentially less costly alternatives.[12] The intervenors cited an internal BECo staff report completed in October 1985, not long before the outage, which the intervenors believed indicated that even then Pilgrim was only marginally cost-effective compared to alternatives. In the rate case, EOER sponsored testimony by Paul Chernick and Jonathan Wallach in which the two consultants presented evidence that Pilgrim could cost ratepayers $2.3 billion more than the cost of alternatives if it did not substantially improve its historic performance. In the outage case, the AG sponsored testimony by MHB Technical Associates which claimed that virtually the entire outage was caused by BECo imprudence, both in terms of causing and prolonging it, as well as the Company's decision not to evaluate or pursue alternative resources. Because of the potential availability of cheaper alternatives, the intervenors argued that BECo should be denied virtually all the monies it had requested.

From the DPU's perspective, these were extremely important cases because of the large amount of money at stake, the public concern over Pilgrim and nuclear power generally, and the Commission's on-going concerns with respect to BECo's management and planning capabilities. These concerns are evident in the Commission's decision to have Commissioner Susan Tierney spearhead the investigation into the questions of the "prudence, used, and usefulness" of BECo's Pilgrim investments. In rate cases and other adjudications before the DPU in

Massachusetts, technical staff are usually responsible for hearing the cases and then making recommendations to the Commission.[13]

Towards the end of the rate case, and after hearing conflicting testimony on the myriad of variables on which the economic viability of Pilgrim hinged (e.g., Pilgrim's future capacity factor, future operation and maintenance expenditures and capital additions, the future price of fossil fuels, and the amount of cost-effective DSM to name a few), Commissioner Tierney asked the Company to rerun its model on the economics of Pilgrim using a set of prespecified parameters. The new model runs, were based on assumptions less favorable to Pilgrim than BECo had originally proposed but not as damaging as those used by the intervenors. They indicated that the plant could put ratepayers at risk for over $1 billion if Pilgrim's lackluster historic performance did not significantly improve.[14]

Although Commissioner Tierney's request, and BECo's response, appeared to foreshadow at least the possibility of substantial DPU disallowances for BECo, the outcome of the cases remained uncertain for several reasons. First, even if the Commission decided that BECo's imprudence caused and prolonged the outage, or that BECo acted imprudently in its decision not to analyze and pursue alternatives to Pilgrim, the Commission would still need to determine the portion of the costs that should be disallowed. Second, of the costs that were considered prudent, the Commission would need to decide what portion should be considered "used and useful" (i.e., needed and economic compared to alternatives), and would therefore be eligible for BECo to earn a return on. Even with the extensive record, these decisions would not have been straightforward (Abbanat Interview).

Since the DPU is traditionally limited to ruling only on past expenditures, at best the DPU could have disallowed less than $0.5 billion (i.e., roughly $100 million in replacement power plus $100 million in incremental O&M plus $300 million in capital expenditures). However, a disallowance of this magnitude was highly unlikely since the Department would have probably found only some portion of the expenditures to be imprudent and uneconomic. Even if a substantial disallowance had occurred, the penalty would have paled next to the $1 to $2 billion in potential costs to ratepayers that the intervenors alleged (i.e., compared to pursuing more cost-effective alternatives over Pilgrim's expected life). Moreover, a major financial penalty, might have done little to guarantee better performance of Pilgrim in the future. In fact it might have aggravated the situation by forcing the utility to skimp on operation and maintenance costs and by raising its cost of capital for future investments.

The Department would undoubtedly have considered the following alternative in its deliberations if the case had not been settled: removing all or a portion of Pilgrim from traditional cost-of-service regulation, and requiring that BECo only be compensated based on the value of electricity that it actually delivered. This was in many ways consistent with a new set of ratemaking preapproval rules that the DPU had adopted in October 1988, which required new utility generating facilities and major additions to existing facilities to be paid based on a fixed price for delivered electricity and capacity (D.P.U. 86-36-E). However, the new rules were not designed to be applied retroactively, although the expenditures on Pilgrim would have probably qualified as a major addition in terms of the size of the investment.[15] It was therefore not clear whether the DPU had either the legal authority or a sufficient record in the case to order BECo to change the status of Pilgrim with respect to future cost-recovery (Werlin Interview).

The Settlement

In late June 1989, after the close of hearings in the replacement power case, and while the rate case hearings were winding down, BECo's new COO Bernard Reznicek telephoned Attorney General James Shannon to explore possibilities of entering into settlement discussions on both Pilgrim cases. Soon after Reznicek's phone call, the AG, EOER, and MASSPIRG began meeting with the Company.[16] This "core" group of non-utility parties (NUPs) represented those who were most active in the cases.

According to Tom May, Executive Vice-President at BECo, though the Company felt it had put on a strong case before the DPU, it had several reasons for initiating settlement discussions with the parties:

> As part of a new management team brought-on largely in response to an extremely critical DPU order in 1986, we were trying to turn the Company around. We felt that the Company was too focused on defending its past action, without enough vision for the future. We saw settlement as a way to turn this around. Secondarily, we hoped to remove a large uncertainty that we faced if the DPU decided the case...Though we thought we had put on a strong case, you cannot have a plant down for three years and not have some serious regulatory risk. We felt there would be some disallowances but were not sure how much (May Interview).

The NUPs also felt that they had put on a strong case and that the Company faced substantial disallowances. However, they too were uncertain about the ultimate size of the disallowance, or the Department's ability to go beyond a simple disallowance to address some of their more fundamental concerns. Rachel Shimshak, Director of Policy and Planning at EOER explains:

> We were worried the DPU's orders would not be strong enough. We thought there was sufficient evidence to close Pilgrim down on economic grounds, but we doubted the DPU would do that since there was little precedent for such an extreme remedy. We also continued to have serious concerns about the safety of Pilgrim -- an area where the Department does not have much jurisdiction, if any (Shimshak Interview).

George Dean, Chief of the Regulated Industries Division in the Attorney General's Office, pointed out that even if the DPU had ordered major disallowances as the NUPs' requested (and as he fully expected) the victory would have been Pyrrhic at best. He explains: "if we had won big at the Department, we would have earned ratepayers a few hundred million dollars and turned BECo into a financial basket case." Nogee agreed with both Shimshak and Dean about both the possibilities and problems of a major disallowance by itself, and explained that a more creative resolution of the issues was needed than was likely to emerge from the DPU:

> I believed that the Department was likely to deal with the decision conventionally -- allocating the costs of past mistakes between the Company and ratepayers. Although I expected large disallowances, there would be no tangible incentive for improving future performance. Given that it was unlikely that Pilgrim would be shut down immediately, I felt we needed a creative approach to establishing incentives for future performance (Nogee Interview).

The utility, represented by three of it's top executives -- Bernard Reznicek (COO), Tom May (Sr. Vice-President), and Douglas Horan (Deputy General Counsel) -- engaged in settlement discussions directly with MASSPIRG's Alan Nogee, EOER's Rachel Shimshak, and the AG's George Dean.[17] Senator Golden, Massachusetts Citizens for Safe Energy (MCSE), the Energy Consortium, and the U.S. General Services Administration, who were all intervenors in one or both of the Pilgrim cases (but did not play an active role in the cases except for the Energy Consortium which was active primarily on rate design issues), were not included in the negotiations until the basic settlement was structured by the four core parties. Since some of these parties were represented in the core negotiating group (e.g., MCSE and MASSPIRG were closely allied), and all the parties ultimately signed the settlement, this selective approach did not appear to have caused any significant problems.

During the Summer, the parties met as often as several times a week at the AG's Office -- sometimes until eight at night. Between negotiating sessions, the NUPs often caucused and BECo's executives met with their staff. Both the NUPs and the utilities were required to do a lot of financial computer modeling to assess the tradeoffs from different settlement packages. Participants interviewed for this study claimed that the negotiations were intensive and occupied over half of their time between July when the negotiations began in earnest and October 3 when a settlement was filed with the Department.

Given the historic animosity between BECo and the NUPs (which intensified during the Pilgrim hearings), the fact that the discussions took place at all, let alone functioned fairly smoothly and ended in settlement, is impressive. In the end, the NUPs commented that they felt that BECo had put its best people forward and had negotiated in good faith. BECo also praised the NUPs for negotiating in an "honest and reasonable manner" (May Interview).

Still, the negotiations were extremely difficult and complex. As Shimshak points out, "There was no easy issue. It was a package deal, and everything was fluid until the end." Yet, despite what appeared in the hearings to be an unresolvable $2.7 billion difference in the value of Pilgrim to the ratepayers (i.e., the difference between BECo's positive $400 million value and the NUPs negative $2.3 billion value), the parties were able to find fertile ground for compromise. At least three major areas of basic agreement emerged during the negotiations which together allowed a settlement to crystalize. First, the parties agreed that if BECo was confident in its ability to improve Pilgrim's performance, it should be willing to base at least part of its future earnings directly on that performance. Second, parties agreed that the NUPs desire for greater health and safety at Pilgrim and a more serious pursuit of DSM was not inconsistent with BECo's own desires. Lastly, the parties agreed that the NUPs should be willing to relinquish part of the current disallowances they had been insisting on in return for satisfaction on the first two points.

With these underlying principles in mind, the parties were able to forge a comprehensive settlement that effectively resolved all of the outstanding issues in both the replacement power and general rate cases. The major components of the settlement are outlined in Table 4.6.

Table 4.6
Major Components of the Pilgrim Settlement

1. BECo would withdraw its previously filed rate increase ($86 million) and be precluded from filing a new rate case for three years until April 1992. (BECo would also be permanently precluded from retail recovery of $101 million in Pilgrim O&M expenses incurred during the outage, and would write off the unamortized accrued balance.)

2. However, a performance based cents/kwh charge would be applied to all retail sales between 1990-1992 based on the following performance adjustment factors.

   A. A base component would recover $20, $42.5, and $67.5 million in 1990, 1991 and 1992 respectively.

   B. If Pilgrim's capacity factor falls below 60 percent, BECo's revenues would decrease $1 million for each percent of performance shortfall down to $30 million. If the capacity factor is better than 76 percent, revenue would increase $1 million for each percent to a $15 million annual maximum.

C. There are also six management performance indicators related to health and safety indicators at Pilgrim that together could add up to $4.5 million in bonuses or $9 million in penalties.

3. BECo would retain revenue collected through the fuel charge for replacement power during the outage and through the power ascension program ($115 million).

4. BECo would spend $75 million on DSM programs over three years with no recovery from ratepayers. At least $25 million would be targeted to elderly customers, low income customers, public schools, state government facilities, and multi-family residences (at $5 million each). A settlement board would be set up to oversee these investments comprised of the Attorney General, MASSPIRG, EOER, Senator Golden, and BECo.

5. BECo would be permitted to adjust its amortization of certain property taxes and its reserve for deferred income taxes, if necessary to boost its return on equity to 11% in 1990, 11.5% in 1991, and 12% in 1992.

6. After November 1992 and before November 2000, BECo's cost-recovery for one-third of BECo's capital investment in Pilgrim during the outage and one-third of the Company's share of any post-outage capital additions and O&M, would be put on a performance basis. The performance factors are similar to those used for the 1989-1992 period (i.e., capacity factor and management performance indicators), and are specified in the settlement. All other pilgrim costs (i.e., the remaining two-thirds of the costs incurred since the outage, and all costs prior to the outage) would continue to be collected.

7. None of the pre-1989 capital additions to Pilgrim would be subject to disallowance on prudence grounds.

Source: Author's Compilation

The four core parties signatures on the settlement is indicative of their belief that the settlement represented a better resolution of the issues in the cases from their individual perspectives than they would have expected from a DPU decision. If they believed otherwise, it is not likely that they would have signed. When asked to rank how well the settlement satisfied their underlying interests, all four parties gave it high marks (7 to 8 on a scale of 1 to 10) and expressed a high degree of satisfaction.[18] Even after three years, the parties still feel extremely positive about the overall settlement, and each only suggested a couple of relatively minor issues they might have changed if they could have better predicted certain future events such as the economic downturn, and the rapid growth of utility DSM programs in Massachusetts.

The settlement promised to remove a huge uncertainty regarding the content of the DPU's final order in both cases. More importantly, the settlement allowed the parties to act proactively in designing tolerable penalties and incentives. From BECo's perspective it averted yet another potentially hostile DPU order. Also, settling such important cases with its traditional adversaries was an invaluable harbinger for the new executive team with ramifications (both inside and outside of BECo) beyond the immediate issues at hand (May Interview). From the NUPs perspective, they gained major financial concessions from the Company, in way that did not threaten BECo's economic viability. In addition, the NUPs got many unexpected things including direct control over the Company's DSM effort, and the tying of cost-recovery to general performance requirements including health and safety indicators. All parties also avoided the need for contentious rate-case litigation with each other during the next three years.

The settlement is important because it managed to resolve some extremely difficult issues in the context of a contentious case with a great deal of creativity and innovation. For instance, instead of rebating customers for the replacement power costs that BECo had collected from ratepayers during the outage, the parties agreed to allow the Company to keep that money and provide $75 million dollars in DSM to its ratepayers (without recovery in rates) through programs approved by the parties to the settlement.

Another important example of the parties' innovation was the decision to tie rates during the following three years to Pilgrim's actual performance. The Pilgrim Settlement's inclusion of additional health and safety performance factors was unique in the nation. In theory, the inclusion of these factors could provide additional incentive to maximize long-run performance, while reducing the incentive for a utility to manage a plant solely to maximize its capacity factor in the short-run (Nogee Interview).

Finally, another important innovation was the parties decision to tie cost-recovery on one-third of any incremental investments made in Pilgrim since the outage began and into the future to Pilgrim's performance between 1992 and 2000. Although two other nuclear facilities, Diablo Canyon in California and Fort St. Vrain in Colorado, had been similarly "cut loose" from traditional cost-plus ratemaking (except that those two plants had 100 percent of their costs tied to performance), Pilgrim was the only plant where performance was tied, at least in part, to health and safety indicators.[19]

DPU Approval

The settlement was submitted to the DPU for review and approval on October 3, 1989. The settlement was signed by the core negotiating group and all of the other parties to the cases, except for the Massachusetts Bay Transportation Authority which did not raise any objections. In the accompanying cover letter, the parties indicated that:

> ...this Settlement Agreement is far-reaching in effect, and achieves the Department's goals of performance-based ratemaking and investment in cost-effective DSM programs. The value to all interested parties of this global settlement is very substantial. It permits the parties and the Department to put these disputes behind us and focus our collective efforts on better serving the public in the future (Settlement Cover Letter, p. 3).

Since a Commission can not delegate its authority to make the final decision on adjudicatory affairs, it is obligated to carefully review settlements prior to approval and make a finding that the settlement is essentially "just and reasonable and in the public interest":

> Thus, a settlement agreement among the parties, however, well wrought, does not oust the Department's jurisdiction nor absolve the Department of its statutory obligation to conclude its investigations with a finding that a fair outcome will result (D.P.U 88-28, 88-48, 89-100 (October 31, 1988), pp. 8-9).

Obviously, to come to such a conclusion in cases as complicated and controversial as these, the DPU must determine a reasonable range of acceptable outcomes. Since the settlement discussions started after the hearings and the DPU was obligated to issue an order in the rate case by January 23, 1990 or BECo would legally be entitled to its entire rate increase request, the DPU had already had substantial internal discussions on the cases, and was preparing a draft order (Werlin Interview).

However, rate case orders are rarely issued before the last day of the suspension period in Massachusetts, and significant issues are often not resolved until the waning hours. Therefore, although the Commissioners may have had a general notion of the direction and rough magnitude of how they wanted to resolve these cases, specific numbers had not been finalized when the settlement was received. Lastly, given the uncertainty about the DPU's legal authority to order the Company to (1) tie Pilgrim cost recovery to its performance, or (2) link performance to health and safety indicators; or (3) order the Company to invest in DSM expenditures without charging ratepayers, it can not be presumed that the DPU was contemplating taking such actions on its own initiative.

After careful scrutiny, the Department approved the settlement on October 31, 1988 concluding that:

> The benefits to BECo customers envisioned by the settlement agreement are consonant with reasonable findings, taken as a whole, had the cases taken the customary course (D.P.U 88-28, 88-48, 89-100 (October 31, 1988), p.10).

In addition to finding that the settlement "fairly repairs the harm to ratepayers that Boston Edison's decisions during the outage may reasonably be said to have caused", the Department praised the settlement for its innovative performance features (id.).

Still, the DPU spent nearly half of the eighteen-page order chastising the Company for its actions during the outage (id., pp. 11-17).

> The information before us shows a pattern of inadequate planning and chaotic execution of major projects that persisted well into 1987...the Company's resource planning continued to suffer from failure to assess all reasonable alternatives, failure to conduct cost-effectiveness and feasibility analyses before embarking on major investments, (etc.) (id., p. 12).

In doing so, the DPU was clearly informing the parties and the public of its predisposition to require major disallowances in the absence of the settlement. Still, the Order ends on a positive note, praising the Company for the settlement and hoping that it may be a symbol of a brighter future for the Company and its ratepayers:

> Indeed, the settlement agreement itself may be the bellwether of a change in practice and attitude from one of confrontation to one of conciliation, a recognition by the Company that the consequences of its own actions must be squarely reckoned with, resolved, and put behind it (id,. p.16).

Post-Settlement Era

Since the Pilgrim Settlement was adopted, several events have occurred which together provide additional insight. These issues include the emergence of opposition to the settlement, Pilgrim's actual performance, the fate of the plans laid out in the Settlement under New England's economic downturn, and the trials and tribulations of the DSM Settlement Board. Each of these factors are explored in this section.

Outside Opposition

Although the signatories, the Department, and the press were positive about the settlement, representatives of some local citizens groups and the NRC voiced opposition. The day the settlement was approved by the DPU, representatives of local citizens' groups faxed the Department a letter claiming that there could be "serious consequences to the health and safety of the public" if the settlement was approved, and asked the Department to stay its decision and allow for additional public input (Nickerson et.al. Letter 1989). The NRC's criticism came later in public speeches and direct contact with the Department (Werlin and Shimshak Interviews).

Ironically, although one of the settlement's self-proclaimed strengths was the linkage it established between health and safety at Pilgrim on the one hand and BECo's economic return on the other, health and safety issues were central to the opposition by these seemingly disparate groups. The local citizens, who were primarily interested in shutting Pilgrim down, worried that the performance incentives -- particularly the capacity factor incentives -- would encourage BECo to run the plant unsafely to maximize their bonuses (Patriot Ledger 11/27/91). The criticisms, particularly from the local citizen groups, really stung given the NUPs obvious concern over health and safety issues at Pilgrim (Nogee Interview).

The NRC was not receptive to the idea of linking health and safety indicators directly to economic returns. It had successfully opposed a proposal in New York to link nuclear plant performance to financial management incentives,[20] arguing that utilities should strive for safe plants for their own sake. The NRC was concerned that the performance formulas would provide incentives for BECo and other utilities to run plants to maximize their scores with respect to the indicators, and might also provide incentives that could undermine accurate logging of the health and safety indicators that the NRC required them to track.

Pilgrim Performance

One of the NUPs' primary objectives in crafting the settlement was to create a system of incentives that would force BECo to turn Pilgrim into one of the best run plants in the country or retire it. However, as Nogee describes, the NUPs remained skeptical that BECo could turn Pilgrim around:

> Our bet was they couldn't do it, and were likely to have to shut the plant down. No plant in the country had made the kind of turnaround Boston Edison projected (Patriot Ledger, 11/27/92, pp.1,16).

During the first two years after the settlement, as Nogee points out in the same Patriot Ledger article, Pilgrim's performance has shown overall improvement compared to its historic record. In both years, BECo earned bonuses, albeit small ones, in accordance with the performance formulas. During the first year BECo earned $470,000 in bonus money over the $20 million base component. It earned $142,000 in bonus money over the $42.5 million base during the second year.

Pilgrim's historic capacity factor of approximately 57 percent increased to 68 percent during the first year and fell slightly to 64 percent during the second year:[21] --

both landed in the neutral band width (60-76 percent) which provides neither bonus nor penalty. Table 4.7 shows how Pilgrim did with respect to all of the indicators tracked in the settlement. During the first year, Pilgrim was in the neutral zone in 4 categories and the bonus zone in 3 others. In the second year, the performance slipped slightly -- in the neutral zone in 3 categories, the bonus zone in 2 categories and in the penalty zone in 2 categories (safety system failures and collective radiation exposure). There also appeared to be little consistency in the indicators between the first two years since only the capacity factor remained in the same category (e.g., neutral) in both years.

Table 4.7
Pilgrim Performance Indicators

Indicator	Neutral Zone	First Year	Second Year
Capacity Factor	60 - 76%	68% (N)	64% (N)
SALP	1.6 - 1.8	1.70 (N)	1.57 (B)
Automatic Scrams While Critical	1 - 3	2 (N)	0 (B)
Safety System Failures	2 - 4	3 (N)	7 (P)
Safety System Actuations	1 - 2	0 (B)	1 (N)
Collective Radiation Exposure	345 - 575 (Person - Rems)	221 (B)	578 (P)
Maintenance Backlog (More Than 3 Months)	49.4 - 59.4%	41.2% (B)	52.4% (N)

Notes: First year is 11/89 - 10/90. Second year is 11/89 - 10/90.
Slightly different time periods were used for some indicators.
(N) Indicates in neutral zone, (B) bonus zone, (P) penalty zone.
The neutral zones for some factors float over time to track industry-wide performance.

Source: Pilgrim Settlement Agreement, October 3, 1989
Personal Correspondence From Tom May, BECo

Still, Rachel Shimshak of EOER claims "Pilgrim has made a miraculous turn-around" (Shimshak Interview). Moreover, the NRC which in the mid-1980's considered Pilgrim one of the five worst plants in the country, now considers it "above average". However, it is probably premature to determine whether Pilgrim is cured of the problems that have plagued it. While operating better than previously, Pilgrim's capacity factor hovers in the lower-to-mid range of the neutral zone (i.e., 64-68 percent). Since, as BECo maintains, Pilgrim is only economic above a 60 percent capacity factor (given its base case assumptions)[22], it may remain only marginally cost-effective in the long-run. Table 4.7 also indicates that Pilgrim continues to experience some health and safety problems (e.g., during the second year there were seven safety system failures and collective radiation exposure was above the neutral range defined in the settlement).

Also what role, if any, the settlement has played in Pilgrim's improvement is unclear. Obviously, at either extreme, BECo stands to gain or lose tens of millions of dollars per year from the performance incentives. However, around the neutral zone the incentives probably provide little financial motivation.

At least three other factors have occurred besides the settlement which probably contributed to Pilgrim's improvement. First, as discussed previously, significant changes occurred in BECo's upper management and both the management and operation practices of the plant prior to the settlement. Second, throughout the outage the NRC continued to vigilantly oversee Pilgrim's improvements and it continues to monitor operations since it came back on-line (as it does for every other nuclear facility in the country). Lastly, it is hard to imagine making hundreds of millions of dollars of improvements in Pilgrim and not have its performance improve!

Perhaps the greatest benefit of the performance factors in the near-term is that they are being more closely scrutinized by the public and the regulators, which may be more effective than any direct financial impact. Probably because of the NRC and some local citizen group's outspoken concern about performance incentives, the Company appears reluctant to publicly acknowledge that it pays much attention to them. Recently, George Davis, the chief executive at Pilgrim claimed that plant managers do not base decisions of the state bonus system, saying "we do not allow ourselves to even consider it" (Patriot Ledger 11/27/91).

The Economy Sours

When the parties signed the settlement in 1988, none of them suspected that the Massachusetts economy was about to sour. However, soon after the settlement, BECO's sales growth plummeted with the Massachusetts economy. In 1990 the Company experienced its first negative sales growth in over 20 years (May Interview). However, BECo was precluded by the settlement from requesting a rate increase (i.e., to spread its fixed costs over the smaller sales volume) for three years. The Company's unanticipated loss, which conversely was ratepayers' unexpected gain, may be on the order of tens of millions of dollars.

Tom May claimed that, had BECo realized the economy would worsen, it probably would not have agreed to a three year rate freeze in the settlement, or would have insisted on the inclusion of an accounting mechanism that would make the Company whole regardless of sales volume.[23] But ironically, as May agrees, the rate freeze may prove to be one of the most healthy things that happened to the Company. Not only did it allow the Company "three years of peace with respect to rate case litigation", but it forced BECo to substantially cut Company' costs. Since all the other Company's in Massachusetts have had rate increases during this period, BECo, which had some of the highest retail rates in Massachusetts, now has rates that are among the lowest. For example, while its residential rates are still approximately 10 cents/kwh as they were in 1988 when BECo had the highest residential rates in the state, only one Company now has lower rates. A similar pattern can be found in its commercial and industrial rates.

Largely as a result of BECo's cost cutting initiatives and low rates in the wake of the settlement and the economic downturn, BECo's stock prices have risen sharply during the past year. In addition, BECo's top 22 executives received substantial bonuses worth $2-3 million during 1991 (Patriot Ledger, 11/12/92).

DSM Settlement Board

The original purpose of the Settlement Board was to make sure that the $75 million BECo agreed to spend on DSM without recovery from ratepayers was spent wisely, and that one-third of the DSM was distributed to the "hard-to-reach" sectors (e.g., low-income). In fact, BECo will spend the $75 million it agreed to in the settlement and much more -- projecting to spend $48 million on DSM in 1992 alone and $214 million during the 1990 - 1994 period (BECo et.al. 1990). In addition, the Board is responsible for initiating numerous program design innovations, especially in BECo's residential programs.

Despite these apparent successes, the participants I interviewed agreed that the DSM Settlement Board has proven to be the most frustrating part of the settlement implementation process. It has turned out to be time-consuming and contentious. The Company claims that the NUPs are trying to micro-manage it, and the NUPs claim that the Company is being recalcitrant and withholding important information.

Some issues, such as designing an appropriate cost-effectiveness tool to screen DSM measures have engendered a two-year debate between the Company and the other Board members.[24]

Notably the same parties who were able to forge a creative and comprehensive settlement during the Pilgrim cases, appear to be stumbling over relatively small DSM issues. There appear to be three possible reasons why this consensual process in the post-settlement implementation phase has faltered. First, whereas the Pilgrim settlement was time-constrained since a settlement had to be reached in a matter of months or the DPU would decide the cases, the three-year duration of the settlement Board has allowed many issues to remain unresolved. Many of them were policy-related disputes, which in hindsight most of the parties claimed should have been brought to the DPU for resolution early-on.

Second, concurrent with the Settlement Board's oversight, there has been a DSM collaborative process which has also been designing DSM programs for BECo (See DSM Collaborative Case which is the second case in this chapter). The parties to both processes were almost identical and the NUPs on the Settlement Board intended to allow most program design issues to be resolved in that collaborative. However, they occasionally added additional program elements -- often to the consternation of BECo and sometimes even the Conservation Law Foundation (who were instrumental in the Collaborative but not part of the Settlement Board). Also, the NUPs often found themselves spread too thin by their Settlement Board commitments on top of their other substantial work loads to participate effectively. Finally, to the degree that the settlement precluded BECo from collecting additional financial incentives associated with their DSM programs besides the $75 million in direct costs, BECo's enthusiasm for

DSM programs may have been less than other Massachusetts' utilities which participated in DSM Collaboratives but were not constrained from earning such incentives.[25]

Third, shortly after the Settlement Board began, in May 1990, BECo filed plans with the regulators to build a 306 MW, gas-fired, combined-cycle generating unit known as Edgar Station (Edgar). The AG, MASSPIRG, and CLF intervened in the cases before the Energy Facility Siting Council (EFSC) and DPU to oppose Edgar. Since the primary justification for the plant was a projected need for power that hinged in part on the amount of available DSM, the parties were suddenly litigating many of the same issues they were trying to more peacefully resolve at the Settlement Board. But instead of a few million dollars worth of DSM riding on the Settlement Board's decisions, the parties now also felt they had the fate of a major new supply-side plant in tow.

Conclusions

I begin this concluding section by addressing whether the Pilgrim settlement saved process-related resources compared to the traditional adjudicatory process. I then examine whether the settlement was successful in terms of enhancing the legitimacy of the adjudicatory process and the practicality of the end results. Finally, I conclude by highlighting the unique features of the settlement process itself.

Saving Resources in the Adjudicatory Process

As discussed in Chapter 3, using settlement and other consensus-building methods within the adjudicatory process is often touted as being able to save substantial time and resources. At first blush, it is difficult to imagine drawing such a conclusion in cases like these that required over 90 days of evidentiary hearings.

However, the proper framework for analysis is to compare the resources used in the settlement process with the likely resources that would have been expended had the DPU resolved the cases. The enormous amount of time and money spent on the case prior to the inception of settlement discussions should be considered a sunk cost with respect to this question.

In both cases, when the settlement discussions began, the hearings had concluded and all that remained was for the parties to write legal briefs. The preparation of briefs in cases like these, in which the parties explain why their positions should be upheld and their opponent's rejected based on the record, would undoubtedly have cost the parties substantial time and effort. Still, such an effort probably would not have required as much resources as the intensive three months of settlement negotiations. All those I interviewed claimed it took more than half of their own time and substantial resources from their respective organizations.

In theory the Pilgrim settlement should also be credited with savings from reduced litigation had the DPU's decision been appealed. Placing a value on this requires estimating both the probability of such a challenge and its likely cost. Certainly in cases as controversial as these, appeals are fairly common -- particularly if a PUCs' Order leans heavily towards one party or the other. At the same time, according to Tom May, given BECo's overwhelming desire to put Pilgrim behind it and make peace with both the intervenors and the regulators, the Company's tolerance in these cases would have been much higher than it had been historically. Since appeals can be costly (though usually much less than the original litigation), despite perhaps a low probability of appeal, the Pilgrim settlement certainly should be afforded some positive benefit in this area. However, it is probably not enough when combined with the additional resources incurred during the settlement process itself to conclude that the settlement saved process-related resources.

If there were any process-related savings from the settlement, they will probably occur during the implementation phase. Having crafted the settlement themselves, there is a greater likelihood of enthusiastic implementation than if the DPU had ordered comparable changes. Therefore, the result should be less regulatory oversight and litigation. Clearly, if the settlement had not frozen BECo's rates for three-years, given the economic down-turn, the parties would have engaged in additional and costly rate case proceedings before now.[26] The DSM Settlement Board is the one place where the implementation of the settlement may actually be sapping more resources than if there had been no settlement. The Board has been more time-consuming and frustrating than any of the parties had anticipated. However, these costs must be compared to accomplishing similar results through costly litigation. (See DSM Collaborative case for further discussion of this last point).

On balance it appears that the Pilgrim Settlement did not save resources related to the adjudicatory process itself in the short-run, but may save resources in the future by avoiding or deferring future litigation. Moreover, by improving participant relations, as everyone interviewed claimed, potential savings might occur in other, subsequent proceedings between BECo and the intervenors. However, the proceeding analysis, which focuses only on the process-related savings vis-a-vis traditional litigation is incomplete, since it does not represent a net benefit analysis. A more complete and important analysis must focus on how successful the consensus-building supplement was in enhancing the legitimacy of the traditional process and improving the practicality of the final results.

Legitimacy

PUCs can occasionally craft orders in the wake of contentious adjudications that are able to satisfy the wide range of interests in a case. More often, litigation like in the Pilgrim cases, push parties to take extreme positions and the PUCs' final decision has a "split-the-baby" quality.

In the Pilgrim settlement process, parties were forced to get beyond the extreme positions taken during the cases to probe each others' underlying interests. For example, during the cases, the primary focus was on the parties' positions with respect to an appropriate level of compensation or disallowance for BECo's past decisions. However, during the settlement discussions, the parties were forced to deal directly with their true underlying interests -- the future of Pilgrim and the utility's DSM plans, and the Company's overall viability and reputation. Without recognizing where these underlying interests -- converged and diverged -- a settlement would not have been possible.

The fact that consensus was reached between BECo and the intervenors is testimony to the enhanced perception of the legitimacy of the settlement process by the participants compared to the range of likely outcomes had the DPU decided the cases. As mentioned, all of the parties I interviewed felt that the settlement was extremely successful in satisfying their underlying interests. Although the implementation phase, most notably with the DSM Settlement Board, has sometimes been frustrating, all the parties I interviewed retain great enthusiasm for the original settlement which they created.

The DPU's approval and praise of the settlement further enhances its legitimacy, as does the absence of any appeals. There were, however, two blemishes related to this enhanced legitimacy. First was the discontent voiced by some of the local citizen groups who felt their health and safety concerns over Pilgrim's continued operation were ignored. Second, was the NRC's concerns over the legitimacy of tying cost-recovery to performance-based approaches generally and to the NRC's own health and safety indicators specifically.

With respect to the local groups, it is difficult to sustain an argument that their concerns were ignored, since those groups were members in the MCSE, one of the signatories of the settlement. Also, the citizens' interests to see Pilgrim preferably shut down but otherwise made safer were obviously shared by the NUPs. Since the DPU did not have the authority to shut the plant down on health and safety grounds, these parties would probably not have been satisfied by the likely range of DPU decisions in the absence of settlement. Furthermore, the addition of health and safety indicators to the performance formulas was an obvious improvement to using capacity factors alone. Lastly, the local groups total opposition to the use of performance indicators in the settlement is surprising since Senator Golden's original petition on behalf of the local citizens' was to move all of Pilgrim out of rate base and on to a performance basis (rather than the relatively small portion moved out in the settlement).

The NRC's concerns, though couched in language that appear to question the legitimacy of the Pilgrim Settlement and the DPU Order approving the settlement, are really about the practicality of linking performance to cost recovery. According to the NRC, performance incentives could cause nuclear plant operators to jeopardize safe operation for short-term economic gains. Adding health and safety indicators did little to allay their fears. However, while raising important empirical issues, the NRC's worries seem somewhat unfounded given their own continuing obligation to oversee health and safety at Pilgrim and other nuclear facilities. In the end, the NRC's concern has more to do with the conflicting jurisdiction between the state and federal government on regulatory issues related to nuclear power plants, than on the legitimacy of the settlement itself.

Practicality

The Pilgrim Settlement seems to have developed superior remedies that were both more implementable and effective then what may have been expected from a DPU order. If the decision had been left exclusively to the DPU, while probably well-reasoned and judicious, it would most likely have focused largely on an appropriate level of disallowance for BECo. It may have laid out certain expectations with respect to BECo's future performance. However, the Order probably would still have focused primarily on BECo's past actions. It is unlikely that the Department would have formally linked Pilgrim's cost-recovery directly to its performance, particularly to health and safety indicators, nor would it have included anything on DSM expenditures. These linkages were unlikely in large part because they were not articulated in the case record, and thus would not necessarily have been prominent in the minds of DPU staff and Commission. However, even if the Commission was considering comparable options, problems regarding its legal authority could have constrained them. This may have precluded the Commission from such experimentation, despite their obvious sympathies for what those changes represented.

The members of the core settlement group were much freer to explore alternatives to resolving the contentious issues in the case. They ultimately also agreed on a de facto disallowance range. However, they were able to package it in a way that better satisfied their interests. All the parties agreed that the settlement they signed more creatively and practically resolved the outstanding issues than could have been expected from a DPU order. Even the NUPs were clear that a major DPU disallowances alone, without any formal incentive structure for future performance, would not have served their interests well even though that is exactly the remedy they were formally seeking in the cases.

Rather than force the DPU to make a prudence determination, in large part on unknowable future projections of variables that would determine the cost-effectiveness of Pilgrim, the settlement ties BECo's cost-recovery directly to Pilgrim's future performance. The settlement added six health and safety performance indicators to counterbalance concerns that this tying could provide BECo perverse incentives to operate the plant unsafely. This addition was the first in the country.

Perhaps even more impressive than the overall structure of this performance approach is its detailing. Not only did the parties agree on the appropriate indicators for the performance approach, but they agreed on explicit formulas for each of them. These formulas specify the band-widths in which the Company would earn neither bonus nor penalty, and the value for each bonus and penalty step outside that neutral band-width. Formulas of this detail would have been extremely difficult for the Department to derive on its own, even if it had been so inclined, and would have never emerged consensually in the contested hearings process.

Another example of the creative practicality embodied in the Settlement is found in the combined treatment of the replacement power and the DSM issues. The parties agreed to provide BECo's customers with $75 million of essentially free DSM services rather than refund a portion of the replacement power monies collected during the outage to BECo's ratepayers, as the AG originally requested. This quid pro quo allowed BECo to save face by avoiding the perception that it imprudently overcollected money from its ratepayers during the Pilgrim outage, and in fact gave BECo the opportunity to bolster its image by actively promoting DSM. The NUPs felt that it still allowed them to show their constituencies that they secured something tangible. In addition, by establishing a DSM Settlement Board, the NUPs gained more control over the shape of BECo's DSM programs than it otherwise would have.

However, the DSM Settlement Board has been the source of some friction among the parties during implementation. Much of that friction is being driven by issues other than those anticipated in the settlement itself, such as the possibility of a large, new supply-side facility whose future is partially hinged on the amount of DSM available. Nonetheless, even here the Settlement Board has fulfilled its obligation to oversee the spending of $75 million on DSM; and the Board, despite much bickering, has even managed to produce several important program design innovations.

Together all these practical innovations distinguish the Pilgrim Settlement from typical rate case orders on the one hand, and more narrowly construed traditional rate case settlements on the other. However, whereas the concepts and directions established during the settlement appear to have practically resolved many of the thorny Pilgrim-related issues, it is still early to tell how they will actually work. While Pilgrim's overall performance has improved; it has been uneven (i.e., the capacity factor is up but it was penalized in 1991 for continuing to expose some of its workers to radiation as well as other safety problems). Also, several other factors besides the settlement including new management, vigilant regulatory oversight, and large capital investments have occurred concurrently.

In theory the settlement should provide financial incentives for BECo either to improve the operation of Pilgrim or retire it and replace it with less expensive alternatives. However, the magnitude of the incentives, the portion of Pilgrim's embedded and future costs exposed to the performance requirements, or both may be too small to ultimately motivate the Company.

Process Evaluation

In many respects the Pilgrim Settlement was an extension of a traditional process used to resolve rate cases and other adjudicatory matters before state PUCs. Although the frequency differs from state-to-state, rate case settlements are not uncommon. However, traditional rate case settlements are usually narrowly focused on selecting essentially a few numbers such as the magnitude of the change in the cost-of-service or the rate-of-return. Occasionally the settlements venture into more complicated areas such as cost allocation and rate design.

The uniqueness of the Pilgrim settlement rests in large part on its success in resolving a broad array of contentious and complicated issues in one fell swoop. More importantly, its uniqueness derives from the parties' use of consensus-building techniques to craft a solution that enhanced the final resolution of those issues; rather than merely serving as a convenient substitute for the DPU's judgment on more narrowly-defined questions (e.g., selecting an appropriate level of disallowance).

It is important to emphasize why the parties chose to settle the case before reviewing the process itself. Despite over 90 days of hearings, the parties remained uncertain regarding what the Department would ultimately order. More importantly, the reasonable range of likely outcomes from the Department, given precedent and other legal constraints, was not really attractive to any of the parties because it was unlikely to satisfy their underlying interests. For both these reasons, the parties chose to act proactively by seeking a mutually agreeable settlement on their own.

Several features of the settlement process itself helped the parties achieve what in the end must be considered a fairly successful settlement. First, all the participants put forward competent and senior personnel -- BECo's new Chief Operating Officer, for example, attended all the settlement discussions. Second, the participants were able to make room in their busy schedules to participate fully in the settlement process -- spending, on average, half their time over a three-month period. Third, the negotiations were clearly timely and time-constrained since the Department was required to decide the case itself and issue an order by the end of the six-month suspension period.

Fourth, the non-utility parties acted as a coalition, with a core sub-group of the original intervenors working out any minor discrepancies among themselves separate from the direct negotiations with BECo. The coalition-approach helped to further streamline the meetings between the Company and the intervenors. The only short-coming of the representative, coalition approach, was that even though all the parties ended up signing the settlement, some of the neighborhood groups behind Senator Golden's original petition felt that they had not been adequately represented and were not happy with the final settlement (even though Senator Golden himself supported the settlement). Better communication within the strict confines of protecting the confidentiality of the settlement negotiations themselves should have been possible.

Several features of the negotiation strategy are worth highlighting. First, the parties gained by their decision to initially focus on key principles from which a subsequent settlement could be molded, rather than continuing to haggle over the appropriate level of disallowance. Once they agreed on several major principles and objectives, though the negotiations were never easy, the focus shifted to how to best reach the agreed-on objectives. In this way the difficult distributive questions, which were the exclusive focus of the contested hearings, were temporarily suspended so that parties could identify areas where integrative bargaining could occur. Second, once integrative bargaining began, the parties did not try and solve each issue sequentially. Rather, they recognized from the beginning the value of packaging proposals in ways that allowed them to take advantage of their different relative valuations of particular issues right up until the end. Finally, and perhaps most importantly, the parties took advantage of their freedom to reach beyond the confines of the narrow questions addressed in the contested cases (i.e., How much money should BECo be given or denied?). By grasping innovative remedies that made sense vis-a-vis the parties true interests, like focusing on Pilgrim's future performance and BECo's DSM plans, the parties were able to find fertile ground for trading.

In closing, it is worth pondering for a moment whether the settlement could have occurred earlier in the contested case process -- sparing everyone considerable expense and aggravation. Although some of the hearings could have probably been circumvented, it is unlikely that in these cases a settlement would have been possible or productive early-on. Parties needed the opportunity to present their own and probe each others' cases. This ventilating was probably necessary to get numerous facts and opinions on the table, and to allow the parties to more realistically assess their relative strengths in the cases. In this regard, the Department's own information requests and cross-examination, although not definitive with respect to the

Commission's ultimate intentions, also helped parties to reassess their strengths and weaknesses.

All of those I interviewed were skeptical about the usefulness of having initiated settlement discussions much earlier in the process. Alan Nogee articulately captured this commonly-held view:

> A settlement would not have made sense either prior to or early in the hearings. We needed to get all the information out on the table. Otherwise, the settlement would have become a back room deal, and not a creative solution based on the evidence and the parties' different expectations of the future. Until we had developed the case on paper, we would not have known how to set all the parameters in the settlement, and it would have been rather arbitrary (Nogee Interview).

While I agree with the parties' assessment that it was critical for them to have thoroughly ventilated the issues prior to settling, I question whether that ventilation really necessitated so many days of evidentiary hearings. Perhaps the use of technical sessions during the cases could have helped establish the facts more quickly and completely. More importantly, such sessions may have allowed parties to understand each other's underlying interests faster than the highly contentious and positional hearings allowed. There may have even been other, more direct, ways for the Commission to convey its concerns to the parties such as the use of an expanded prefiling conference.

These suggestions along with other possible improvements to adjudicatory consensus-building including mediation are explored in more detail throughout this dissertation. The next case on a DSM collaborative process, specifically examines the use of a settlement process prior to the initiation of a contested case.

Endnotes (Chapter 4, Pilgrim Case)

1. The Massachusetts DPU has traditionally interpreted Massachusetts' Open Meetings Law (Chapter 30) to allow it to deliberate on and decide rate cases in closed-door executive sessions. Internal memos leading up to such decisions as well as discussions among Commissioners and staff during these sessions are considered confidential and not for disclosure. Although it is conceivable that some of these internal memos could be obtained through the Freedom of Information Act, without making a formal request (which would certainly be challenged by the DPU) those documents are not available for direct quotation by present or former DPU staff.

2. Also, a study by the Massachusetts Department of Public Health found that people who lived within 10 miles of Pilgrim between 1972 and 1979 were four times more likely to develop adult leukemia than residents from elsewhere in 22 communities near the plant. However, direct causality to Pilgrim has not been substantiated and continues to be contested particularly by BECo (The Boston Globe 10/10/90).

3. Exhibit AG-4 in Massachusetts D.P.U. 88-28. NRC Letter to BECo President Staszasky. January 16, 1982.

4. Although there is on-going dispute with respect to the similarities between Chernobyl and plants similar to Pilgrim, the heightened concern in the U.S. regarding reactors like Pilgrim is undeniable. In June 1986, for instance, Harold Denton, NRC's top safety official publicly stated that GE's Mark I nuclear containment, which was the design used at Pilgrim and 24 other U.S. plants had "something like a 90 percent probability" of failure in a severe accident (Nogee 1988, quoting <u>Inside N.R.C.</u>, June 9, 1986).

5. Stephen Sweeney remained as CEO until 1989. Reportedly Sweeney left only after Reznicek threatened to leave if he was not promoted as promised, and former Senator Paul Tsongas who was on BECo's Board of Directors intervened on Reznicek's behalf (Boston Globe, 2/15/92).

6. Massachusetts Energy Facilities Siting Council, <u>Boston Edison Company</u>, 15 DOMSC 287 (1987).

7. The NRC ultimately rejected MASSPIRG's "show cause" petition, and the courts refused to reverse that rejection. However, the petition received a great deal of press attention and was the subject of several Congressional hearings (Shimshak Interview).

8. It is worth noting that Pilgrim's original price tag was between $200 and $250 million in 1972 when it first came on line. Although in real 1986 dollar this is certainly equivalent to more than $500 million, the outage capital and O&M costs are substantial and may have exceeded the original cost of the plant.

9. Massachusetts, like many other states, uses a fuel charge to pass the fuel and purchased power costs associated with power generation -- regardless of whether they go up or down -- directly to ratepayers. Although the fuel charges are adjusted quarterly, the hearings associated with the adjustments are generally perfunctory, and the pass-through virtually guaranteed. In Pilgrim's case, BECo had been allowed to pass-through the replacement power costs subject to future refund.

10. An independent study by the Nielsen-Wurster Group funded by BECo, concluded that 41 days of the outage could have been avoided by BECo. This translated into approximately $7.6 million of the replacement power costs which BECo decided not to seek recovery on (or really retain since they had already collected it), although BECo maintained that it did "not believe all 41 days were avoidable" (Letter from BECo's Deputy General Counsel, Douglas Horan, to the DPU on 9/15/88).

11. The Pilgrim-related items included (1) a return on $332 million of capital expenditures made in Pilgrim (i.e. the $221 million during the outage and $111 million of capital improvements made prior to the outage but after the previous rate case had been filed in December 1985), and (2) $101 million of incremental O&M (i.e, the O&M expenditures that were more than the expected test year levels established in the prior rate case) which BECo proposed amortizing over five years.

12. While there were other intervenors in the cases, EOER and the Attorney General were the only parties who sponsored testimony, and along with MASSPIRG were the only parties who actively participated in the cases.

13. In Massachusetts, DPU staff typically serve only as advisors to the Commission. Staff did not act as advocates as occurs in many other states where the advocacy staff puts on a case in much the same way as other parties. In Massachusetts, at the time, technical staff would sit on the bench with a hearing officer and question the witnesses for the DPU.

14. The results indicated that in order to be economic, Pilgrim would need to operate at a capacity factor greater than 60 percent when measured from the end of the outage, and at greater than 68 percent if measured from the beginning of the outage. The historic capacity factor was 57 percent.

15. The new rules required that any capital investments over $250/KW be subject to preapproval. BECo's $332 million investment probably exceeded that threshold.

16. According to Alan Nogee, prior to Reznicek's call to Shannon, MASSPIRG and the Company had engaged in exploratory discussions regarding the possibility of settling the case. While these discussions occurred with senior managers within BECo, they did not involve the senior executives. Everyone I interviewed agreed that the official starting point of the settlement discussions began with Reznicek's call to Shannon.

17. Mike Meyer, a consultant to EOER, also participated in all the negotiations. Donna Sorgi, Director of the Regulated Division of the Attorney General's Office at the

time, attended settlement meetings on occasion, and briefed Attorney General James Shannon weekly on the negotiations (Dean).

18. The results were: Shimshak 7, May 7-8, Nogee 7.5, Dean 8. All commented that they considered these rankings extremely high, and both Nogee and Dean mentioned that anything higher than an 8 would be unrealistic if not impossible.

19. In the other two cases, both plants still had to comply with state and federal health and safety requirements but their economic recovery was not directly linked to their performance as in BECo's case.

20. NUREC-1256, Vol.1, p.40.

21. The second year included a refueling outage which BECo claims accounts for the drop in capacity factor (May Interview).

22. BECo, Pilgrim Analysis. EFSC 90-12/12A, Exhibit BE5, Vol.IV, 5/1/90.

23. Mechanisms such as California's ERAM attempt to hold a utility's revenue collection constant (i.e., to meet fixed costs) regardless of whether sales increase or decrease due to unanticipated results.

24. For example the parties have been debating the proper way to handle administrative costs for over two years. The utility argues that administrative costs should be assigned to each measure prior to screening, while the NUPs argue that administrative costs should be included only when screening the cost-effectiveness of the entire program rather than for each measure.

25. The financial incentives included both a lost revenue adjustment mechanism and a positive financial bonus for successful DSM implementation. The former compensates utilities for any revenue losses associated with reduced sales that result from DSM programs that were unanticipated in the prior rate case. The latter refers to financial bonuses (or shared-savings) given to a utility above reimbursement for direct expenditures on DSM or lost revenue.

26. On April 15, 1992, after the stay-out provision of the Pilgrim Settlement expired, BECo did file for a rate increase of approximately 7 percent (Massachusetts D.P.U. 92-92).

Massachusetts DSM Collaborative Case Study

Introduction

Purpose

This case study analyzes the way consensus-building is used among traditional adversaries to design comprehensive demand-side management (DSM) programs for utilities outside the traditional adjudicatory process. Since 1988, six Massachusetts have been involved in unique collaborative processes with four non-utility parties (NUPs) including: the Conservation Law Foundation (CLF), the Office of the Attorney General (Attorney General), the Massachusetts Division of Energy Resources (DOER), and the Massachusetts Public Interest Research Group (MASSPIRG). These utilities are Boston Edison Company (BECo), Cambridge and Commonwealth Electric Companies (together COM/Electric), Fitchburg Gas & Electric (FG&E), Eastern Edison Company (Eastern -- the Massachusetts retail company of EUA Utilities Associates), Nantucket Electric Company (Nantucket), and Western Massachusetts Electric Company (WMECo -- the Massachusetts retail company of Northeast Utilities (NU)).

After an initial phase when all the organizations worked together to develop a generic set of program designs and tried to resolve underlying policy issues, the NUPs worked with individual utilities. A separate but parallel DSM Collaborative, which is also covered in this case study, occurred between the New England Electric System (NEES) (including its largest retail company the Massachusetts Electric Company (MECo)) and CLF.[1]

The collaborative processes used to develop these DSM programs differed significantly from historic litigation strategies in which the NUPs intervened in virtually every case before the Massachusetts Department of Public Utilities (DPU) to force utilities to improve their DSM efforts. The DSM Collaboratives which occurred in the wake of a history of litigation, had at least three unique features. One was their attempt to settle contentious issues prior to litigation rather than at the end of a litigated case as is the general rule with traditional settlements. Second was that the utilities agreed to provide over $3 million in funds for the NUPs to secure outside technical experts. Finally, unlike traditional settlement processes which generally end when the case is resolved, some of the sub-collaboratives with individual utilities have already lasted more than three and a half years.

I explore whether these collaboratives represent an improvement to the traditional adjudicatory procedures previously used to resolve these issues, and whether they produced superior results. I conclude that despite significant variability and room for improvement among the individual sub-collaboratives, the DSM Collaboratives have helped the utilities' DSM programs become more practical while enhancing the legitimacy of the adjudicatory process.

Research Methods

When preparing this case I reviewed relevant documentation including orders issued by the DPU, written testimony, transcripts of hearings, utility filings, speeches by participants and journal and newspaper articles. In addition, I conducted 31 (primarily face-to-face) interviews with 28 representatives of the utilities, the NUPs, former DPU Commissioners, and other intervenors during the Summer and Fall of 1991.[2] The interviewees are listed in Table 4.8 along with their affiliations and titles. I originally conducted these interviews as part of a larger study on DSM collaboratives entitled <u>Public Involvement in Integrated Resource Planning: A Study of Demand-Side</u>

Management Collaboratives (Raab and Schweitzer 1992) which was funded by the US Department of Energy and published by Oak Ridge National Laboratory.[3] Some key findings from that cross-collaborative analysis, which included nine cases involving 24 utilities and approximately 50 NUPs in 10 states, are woven in to this analysis.

Table 4.8
Interviews for Massachusetts and NEES Collaboratives

Utilities:	
John Cagnetta	Northeast Utilities, Senior Vice-President for Corporate Planning and Regulatory Relations
Al Destribats	NEES, Vice-President for Planning
Peter Flynn	NEES, Director of C&LM
L. Carl Gustin	Boston Edison, Senior Vice-President Customer Savings, Marketing, and Corporate Relations
Elizabeth Hicks	NEES, Director of Demand Planning
Kathleen Kelly	Boston Edison, Manager Evaluation and Monitoring
Lydia Pastuszek	NEES, President Granite State, (former Director Demand Planning)
John Rowe	NEES, President and CEO
Richard Sergel	NEES, Treasurer, (former Director of Rates)
Earle Taylor	Northeast Utilities, Director Conservation and Load Management
Ben Tucker	Boston Edison Company, Technical Assistant to L. Carl Gustin
Wendy Watts	Nantucket Electric Company, Director of Conservation
Carol White	EUA Services Corporation, Supervisor of Demand-Side Planning and Evaluation
Mort Zajac	COM/Electric, Manager of Demand Program Administration
Non-Utility Parties:	
Steve Burrington	CLF, Attorney
Joseph Chaisson	Consultant, Lead Coordinator of NUP Consultants
Susan Coakley	Consultant, Coordinator of NUP Consultants for BECo, COM/Electric, and EUA Collaboratives (Former Staff DPU)
Armond Cohen	CLF, Senior Attorney
Stephen Cowell	Conservation Services Group, Inc., President (Former Lead Residential Consultant)
Douglas Foy	CLF, Executive Director
Alan Nogee	MASSPIRG, Energy Program Director
Jerrold Oppenheim	Massachusetts Attorney General's Office, Assistant Attorney General

Rachel Shimshak	Massachusetts Division of Energy Resources, Director of Policy and Planning
Regulators:	
Susan Tierney	Secretary for Environmental Affairs (former Commissioner Department of Public Utilities)
Robert Werlin	Attorney, Private Law Firm (former Commissioner and Chair Department of Public Utilities)
Mary Kilmarx	Rhode Island Public Utilities Commission, Director of Energy Policy & Planning
Janet Besser	New Hampshire Public Utilities Commission, Manager of Energy Planning
Other Intervenors:	
Andrew Newman	Attorney, for Lighting Retailers, and Large Industrial Consumers

Finally, as the lead staff person responsible for questioning witnesses and drafting orders for the DPU on the Massachusetts utilities' DSM programs during most of the period covered by these cases, I was a "participant-observer" to the Collaboratives.[4] As such, my observations regarding both the external collaborative process, the hearings, and the internal DPU decisionmaking process helped shape my perspectives on this case.

I also circulated earlier drafts of these collaborative efforts to select interviewees. Their corrections and comments have been incorporated into this final case study as appropriate.

Organization of Case Study

I begin the case with a description of the contentious history between the utilities, the NUPs, and the DPU over DSM issues. I follow this with an analysis of the genesis of the DSM collaboratives, including the decision by NEES and CLF to pursue their own collaborative. After examining the structure and accomplishments of the first phase of the Massachusetts Collaborative in which all the utilities except for MECo and the NUPs worked together, I compare and contrast four of the individual collaboratives that followed (BECo, COM/Electric, WMECo, and MECo). I also include an analysis of the preapproval cases before the DPU where the collaborative designs were scrutinized by the regulators, and other intervenors who were not privy to the negotiations.

In the concluding section, I evaluate whether the collaborative processes saved more process-related resources than a fully adjudicated alternative, and whether the collaboratives have produced a better process and superior results. I end with a brief process evaluation in which I highlight some of the unique features of the DSM collaboratives, and identify several areas of possible improvement.

Background

During the mid-1980's none of the Massachusetts utilities viewed DSM as a significant resource. Programs tended to focus on (1) load management, (2) research, or (3) audits related to implementing federal and state statutes (e.g., Residential Conservation Services) (Cohen and Chaisson 1990). Unlike the California utilities which collectively spent hundreds of millions of dollars on DSM in the early-to-mid-1980's, ramping down their expenditures during the late 1980's (Raab 1991, Raab and Schweitzer 1992), electric utilities in Massachusetts spent relatively little. Not until 1987 did several of the utilities begin to offer systemwide programs with limited financial incentives, largely in the form of rebates. That year, as indicated in Table 4.9 (on the next page) the Massachusetts utilities still spent less than $18 million on DSM -- representing less than 1 percent of their total revenue.

Beginning back in 1984, virtually every time that a utility filed a rate case at the DPU, parties such as the AG and DOER would protest the Company's inadequate

DSM efforts. The cases became rather acrimonious, and resulted in a series of orders with increasingly stronger language, in which the DPU chastised the utilities for not aggressively pursuing DSM resources.

Table 4.9
Massachusetts Utilities' DSM Expenditures in 1987

Utility	DSM Expenditures ($ Million)	Total Revenue ($ Million)	DSM/Revenue (Percent)
BECo	5.2	$1,181	0.4%
COM/Electric	0.8	361	0.2%
MECo	9.4	1,086	0.6%
WMECo	2.4	295	0.8%
Total	$17.8	$2,923	0.6%

Note: Eastern, FG&E, and Nantucket essentially had no DSM programs in 1987 except for the federally-mandated RCS residential audit program.

Source: All Numbers Provided by Utilities

In 1986, in a case that received much local and national public attention the DPU penalized BECo's rate-of-return primarily for not adequately pursuing DSM (D.P.U. 85-271-A/86-266-A, pp. 10-15 (1986)). Other utilities also received harsh criticisms and penalties for not aggressively pursuing DSM.[5] According to John Cagnetta, Senior Vice-President for Northeast Utilities, WMECo's parent Company:

> During this period, the DPU carefully probed our DSM programs and continuously questioned the underlying economic, policy, and technical assumptions. The cases were highly contentious with a lot of intervenors, and were extremely burdensome for all (Cagnetta Interview).

However progress was slow despite increasing litigation and pressure from the DPU including financial penalties and requirements for the utilities to run specific DSM pilot programs. Robert Werlin, former DPU Commissioner, describes the DPU's frustration:

> While we required various pilot programs, the DPU didn't really know what would work. The companies remained unenthusiastic, and up through the 1986-1987 period, while we continued to operate in an action-reaction-action mode, there was really no significant movement towards pursuing DSM (Werlin Interview).

Meanwhile, the New England region was in a capacity-tight situation, and the prognosis for the future was not hopeful (New England Governors' Conference 1986). In 1986, the DPU opened a generic docket (D.P.U. 86-36) to explore options for utilities to recover supply-side resource costs in ways that might encourage resource development while better protecting ratepayers. Before new rules could be promulgated,[6] a series of brownouts occurred in Massachusetts in the Summer of 1987.

With constrained supplies, highlighted by the brownouts, the pressure for utilities to more aggressively pursue DSM continued to mount. After an investigation of the brown-outs prompted by petitions from the AG and DOER, the DPU reiterated that each utility was obligated to pursue all cost-effective DSM (D.P.U. 87-169, (1988), p. 72).

Formation and Approval

The Birth

In July 1987, the New England Energy Policy Council ("NEEPC"), consisting of twenty-six environmental and consumer groups, released a study on potential energy conservation savings in New England entitled <u>Power to Spare: A Plan For Increasing New England's Competitiveness Through Energy Efficiency</u>.[7] The study claimed that total projected electricity demand in 2005 (i.e., existing demand plus utility projections of approximately 2 percent per year) could be cut by 37-to-57 percent by adopting technically-feasible DSM measures. While the utilities and others disputed the magnitude of some of the numbers, no one disputed the overall thrust of the study -- that there existed a large reservoir of untapped DSM.

Half a year later, in February 1988, the Connecticut PUC ordered Connecticut Light and Power (the Connecticut retail Company for NU and WMECo's sister retail company) to increase its DSM expenditures and undertake a collaborative process with several intervenors. This collaboration, which came at the end of a contentious rate case during which parties pressed for more DSM, was the first full-scale "DSM Collaborative" (Raab and Schweitzer 1992). Its presence in a neighboring state, ultimately influenced Massachusetts' utilities, intervenors, and regulators to undertake a similar Collaborative.

In the spring of 1988, hearings were held in Massachusetts on DSM and least-cost planning issues in an expanded and bifurcated rulemaking process (D.P.U. 86-36).[8] Douglas Foy, Executive Director of CLF, who followed a panel of national experts,[9] asked the DPU to order the eight private electric utilities in the state to do the following: (1) enter into a joint planning process with the NEEPC, (2) implement the results of such a process, and (3) provide the NEEPC with funds to hire outside experts (Tr. 5/10/88, D.P.U. 86-36).[10]

The NUPs viewed collaboration as an alternative to litigation for accomplishing their common objective of having the utilities procure comprehensive, cost-effective DSM as expeditiously as possible. Douglas Foy explains why an alternative was necessary:

> Our guerilla warfare was not working well on DSM. We could stop new supply-side projects and we could show the inadequacy of existing DSM programs in litigation, but we neither had the in-house expertise nor the funding to tell regulators about better DSM programs (Foy Interview).

Uncertain about its authority to order a funded collaborative effort, the DPU requested written comments from interested parties on the legal findings necessary to require the utilities to comply with CLF's request. The NUPs filed comments claiming that no new findings were necessary. The utilities, however, argued against CLF's request for various reasons including: (1) the DPU's lack of authority to order a collaborative in a rulemaking proceeding (as opposed to an adjudicatory proceeding); (2) the DPU's lack of authority to order intervenor funding; and (3) the fact that several utilities were considering volunteering to work with the NUPs.

During another hearing in the generic rulemaking proceeding, with the DPU still deliberating on the fate of CLF's request, John Cagnetta of WMECo volunteered to participate in a collaborative process and coordinate the utility parties.[11] While encouraging Cagnetta, the DPU staff posed numerous issues for the parties to address in designing a voluntary collaborative process regarding: representation, scope, deadlines, and the role of the DPU. On July 19, 1988, a proposed collaborative agreement was jointly submitted by CLF, DOER, AG, MASSPIRG and seven of the eight private electric utilities in the Commonwealth.

MECo, the second largest utility in Massachusetts (based on revenue), decided not to join the Massachusetts Collaborative but to engage in a separate but parallel DSM collaborative through NEES (its parent, holding Company) with CLF alone. MECo decided not to join the Massachusetts Collaborative for two reasons. First, it maintained that it's programs would be slowed down because they were further along then the other utilities. Second, although 75 percent of its retail sales were in Massachusetts, it's programs still had to pass muster in New Hampshire and Rhode Island (Destribats, Pastuszek and Rowe Interviews).

CLF also favored keeping the collaborative with NEES distinct from the other utilities because NEES was likely to go the furthest, the fastest, and do the best job -- thus being the "flagship" for the other utilities to emulate (Foy Interview). Their decision not to include the other NUPs in the NEES Collaborative was also based on a fear that they too would slow down the process (Chaisson Interview). Not surprisingly, the two organizations' decisions did not sit well with the other utilities or NUPs, or necessarily with the regulators. The resulting tensions and other problems within both collaboratives are discussed below.

Participants and Their Interests

But while the Massachusetts Collaborative may have been more inclusive than the NEES-CLF Collaborative, other parties with interests in the outcome of the process were not invited -- most notably the energy service companies (i.e., deliverers of DSM services) (ESCos) and the industrial customers. At one point, an ESCo actually petitioned the DPU to be admitted into the Massachusetts Collaborative and numerous other ESCOs expressed interest in participating at some level.[12] From the NUPs perspective, despite some differences, they saw themselves as essentially a residential consumer and environmental coalition with a common perspective on the role of DSM in the utility industry. In their opinion, the differently-focused interests of the ESCOs and industrial intervenors could not easily be accommodated within a collaborative which was largely structured as a two-party negotiation (i.e., the utilities and the NUPs). In the interviews some of the NUPs agreed that they could have done a better job soliciting input from others: although none wanted to admit them as full parties to the collaborative. The utilities, in contrast, with the possible exception of NEES, generally regretted omitting others and were more interested in getting direct involvement from representatives of their other customers (i.e., non-residential) and ESCos in the future.

The parties' different perspectives on representation largely reflected their underlying reasons for participating in a collaborative process in the first place. As mentioned, the NUPs primary motivation was to expeditiously procure all cost-effective DSM. The NUPs differed only slightly in the relative importance of certain common interests underlying their strategic objectives like environmental preservation, reducing ratepayer bills, and avoiding outages while delaying the need for new supply-side resources. Strategically, the NUPs hoped to procure the best technical expertise on DSM in the country and help the utilities forge state-of-the-art programs.

In contrast, the utilities' primary reasons for participating were more political. Though interested in honing their technical competence and designing better programs, they wanted to engage in a process that could improve their relationships with the NUPs and the regulators, and dampen future litigation. Most of the utility representatives I interviewed felt the NUPs and the regulators in prior proceedings had unfairly judged and misunderstood their DSM efforts, and hoped that better communication would help in the future (Cagnetta, Gustin, Rowe and Zajac Interviews).

It is noteworthy that while the utilities were interested in securing better financial treatment for their DSM resources, they were more motivated to avoid future disallowances of DSM expenditures and penalties on their rates-of-return. The notion of providing positive financial incentives for superior DSM performance such as shared-savings was not explicitly on the table as it has been in subsequent DSM Collaboratives across the country (Raab and Schweitzer 1992), or in later phases of the individual Massachusetts collaboratives.

Phases and Funding

The Massachusetts Collaborative agreement proposed structuring the collaborative process in two phases. During Phase I, which was expected to commence on July 18 and end December 15, 1988, all parties would work together to design a generic portfolio of comprehensive DSM programs. An optional Phase II would comprise the NUPs working with individual utilities to tailor the generic program designs to their circumstances. (In the NEES Collaborative, the parties proposed refining NEES's existing programs and supplementing its current portfolio with new programs from the start.)

As part of the agreement, the utilities consented to provide the NUPs with money to secure outside technical expertise. In the Massachusetts Collaborative, for example, the utilities agreed to provide the NUPs with $385,000 for a technical assistance fund for Phase I to be managed by CLF. Contributions were divided among utilities in proportion to their relative size. NEES also agreed to provide substantial monies for CLF to secure similar expertise. None of the monies provided by any of the utilities, however, were for the NUPs internal staffing needs, and the utilities retained veto power over the NUPs' proposed consultants.

These funds have been made available in the Connecticut Collaborative and most other DSM collaboratives (Raab and Schweitzer 1992). They have been critically important to the NUPs' ability to effectively participate in the collaborative processes.

They allowed organizations which had the political interest in pursuing a DSM agenda but not the in-house technical expertise an opportunity to more effectively participate in the regulatory process.

Approval of the Collaborative Agreement

The Commission was relieved that it was not forced to decide CLF's original motion (particularly with respect to ordering utilities to provide funding for the NUPs consultants which it considered comparable to intervenor funding),[13] and hopeful that the proposed collaborative process could be successful in accelerating the Massachusetts' utilities DSM efforts in ways that the DPU itself had not succeeded. The DPU approved the Massachusetts Collaborative Agreement on August 4, 1988 (DPU 86-36-D).[14] According to former DPU Commissioner Susan Tierney:

> All of us [Commissioners] were frustrated because we were doing a lot of hammering on the utilities to do more DSM, and we were still not getting sufficient cost-effective DSM. We were willing to give the collaborative process a try, recognizing that even if it failed the Commission would still have greater leverage to try other regulatory approaches (Tierney Interview).

However, unlike many other DSM Collaboratives where the regulatory staffs were present as full parties or as observers (Raab and Schweitzer 1992), the DPU staff did not participate. As discussed in the Pilgrim case, the absence of an advocacy staff at the DPU limited its ability to have staff participate in rate case settlements. Since the DSM Collaboratives were viewed as front-end supplements to potential future adjudicatory proceedings on the utilities DSM programs, the Commission determined that staff could not participate in the collaborative and then advise them in subsequent related proceedings.

The DPU obviously had strong feelings and some in-house expertise regarding DSM issues. Its inability to participate directly in the collaboratives meant that the participants were forced to second-guess its interests. The DPU meanwhile tried to make its expectations clear wherever possible. For instance, in the Order approving the Massachusetts Collaborative, the DPU expressed numerous concerns and directives.[15] Later in this case study I will show how participants' consistent lack of access to DPU perspectives resulted in some settled issues that were unacceptable to the DPU and could have been avoided through better linkages.

Phase I

Structure

Phase I of the Massachusetts Collaborative had an Oversight Committee, as well as a Working Group with five sub-groups focused on (1) residential programs, (2) commercial and industrial programs (later split into two groups), (3) load management and rate issues, (4) data base and monitoring issues, and (5) policy issues. The utilities and the NUPs were represented on the Oversight Committee and were part of the Working Group and its sub-groups. The Oversight Committee only met once at the beginning of the process, while the working groups met regularly throughout Phase I.

In many ways, the structure of the Phase I Collaborative resembled that of a two-party rather than a multi-party negotiation. By design, the utilities and NUPs each acted as separate coalitions -- reaching internal consensus on issues prior to negotiating between the coalitions. At both the working group level and in each sub-group a pair of utility and non-utility representatives coordinated all activities and co-facilitated the meetings. Outside neutrals were not used at all during Phase I.

Among the NUPs, CLF clearly played the lead role, not only in initiating the Collaborative, but in managing the day-to-day operations as well. CLF was responsible for identifying the consultants and overseeing their work. The other NUPs signed off on the consultants prior to hiring and reviewed the consultants' major work products. Some tensions arose during Phase I between CLF and the other NUPs regarding CLF's dominant role within the NUPs. Specifically problematic were CLF's efforts to simultaneously represent its own interests while being the "shuttle diplomat" between the NUPs and the utilities on the one hand and the NUPs and the consultants on the other.

In subsequent phases of the Collaborative, while the NUPs continued to support CLF's management of the process given their greater resources and their skills in that area, several changes were made. In addition to hiring separate NUP coordinators for each of the utility-specific Collaboratives, the internal NUP process was revised to provide the non-CLF NUPs with greater access to the consultants, as well as more direct access to the utilities. This reduced CLF's role as shuttle diplomat and alleviated some of the friction that developed among the organizations.

In the NEES Collaborative, where CLF was the only NUP, a hierarchical oversight structure was also used. However, the structure consisted of three successively senior pairings of representatives from NEES and CLF, ending in John Rowe, the CEO of NEES and Douglas Foy, the Executive Director of CLF. Most problems were resolved at the lowest level of oversight involving the CLF Coordinator and the NEES DSM Manager, but occasionally, on issues of great importance (e.g., the appropriate incentive level for the Company, environmental externalities, and fuel switching), the issues were bumped all the way up to the top. As shown later in the case, the

NEES/CLF structure worked well for the parties, and they achieved a high degree of consensus throughout their joint effort.

Early in both collaboratives, participants spent a majority of their time in detailed technical discussions between the NUPs' consultants (most of whom were from the Pacific Northwest where aggressive DSM programs had been run by utilities in the mid-1980's) and the utilities' technical staff. This joint fact-finding phase was used both to familiarize the NUPs with the utilities' programs, and to update everyone on the strengths and weaknesses of DSM programs being implemented elsewhere in the country. According to everyone I interviewed, this period was technically enlightening and strategically critical, as it allowed the utilities and NUPS to begin to build constructive relationships.

Developing Programs and Grappling With Controversial Issues

The main goal of the Massachusetts Collaborative during this first Phase was to design a set of comprehensive programs that could subsequently be fine-tuned to fit the particularities of the individual utilities during Phase II. Ultimately the parties were able to reach consensus on a portfolio of 25 separate DSM programs that covered most end-uses in new and existing buildings and facilities. This consensus was a major accomplishment in its own right, given the long history of litigation and animosity between the NUPs and the utilities. Moreover, the scope of the consensus included a portfolio of programs that was far more comprehensive than any of the efforts offered by the individual utilities at that time. Finally, it was obvious that the program designs utilized the best available information from around the country and offered numerous innovative design features.

Phase I of the Massachusetts Collaborative had relatively little trouble ironing out broad-brushed program designs. However, it was less successful at reaching consensus on many details that relied on underlying policies. A brief analysis of some of the more controversial issues is useful to gain perspective on the relative strengths and weaknesses of the DSM collaborative process. Table 4.10 on the next page lists a spectrum of issues that were at least touched on in Phase I of the Massachusetts Collaborative. The relative ranking of the issues, which are arranged from the least difficult to the most difficult to reach consensus on, was found to hold across the broader range of collaboratives studied in the ORNL project (Raab and Schweitzer 1992).

The utilities and the NUPs exchanged position papers on various policy-related issues early in the Phase I Collaborative, but made little headway in finding common ground. The two most controversial and time-consuming policy debates involved selecting an appropriate cost-effectiveness test for screening DSM measures and programs, and designing an appropriate cost-recovery method for utility investments in DSM.[16] There was as much controversy among the NUPs as there was between the NUPs and the utilities on cost-recovery issues (Cohen, Nogee, and Oppenheim Interviews). The intra-NUP disagreement turned on whether utilities needed and deserved additional financial incentives for pursuing DSM resources.

Table 4.10
Spectrum of Issues Addressed by DSM Collaboratives

Least Difficult to Resolve

1. Identifying potential DSM technologies and inefficient end-uses
2. Designing research and development efforts
3. Packaging measures into programs and designing marketing and delivery strategies
4. Screening measures and programs for cost-effectiveness (using previously adopted cost-effectiveness test)
5. Designing evaluation and monitoring plans
6. Choosing customer incentives for programs
7. Detailing cost-effectiveness tests for measure and program screening (including method for determining long-run avoided cost)
8. Selecting annual budgets for individual DSM programs and overall DSM effort
9. Ratemaking and cost-recovery issues (also in ascending order):
   A. Allocating DSM expenditures to rate classes
   B. Expensing vs. amortizing DSM expenditures
   C. Recouping lost revenue caused by DSM savings
   D. Other utility incentives (i.e., shared-savings, bounty)
10. Environmental externalities
11. Fuel switching

Most Difficult to Resolve

Source: Raab and Schweitzer 1992

On November 30, 1988, a month before the parties completed Phase I, the DPU issued an interim Order (D.P.U. 86-36-F) as part of its on-going rulemaking proceedings. In the Order, the DPU defined an appropriate cost-effectiveness test for comparing resources including DSM and provided some guidelines for DSM-related cost-recovery. While the DPU's Order did not resolve all the policy issues bogging-down the Phase I Collaborative, it provided sufficient definition with respect to a cost-effectiveness test to allow the program design process to continue.[17] It also provided adequate assurance with respect to the DPU's willingness to guarantee cost-recovery to allay some of the utilities' biggest fears about being required to pursue aggressive DSM agendas without compensation.[18]

According to Kathleen Kelly, Manager of Evaluation and Monitoring at BECo:

> Although we [the utilities] did not completely agree with all the policies in D.P.U. 86-36-F, we were somewhat relieved when it came out because it appeared that the collaborative was not going to come to agreement on most of these policy issues. The Order at least set a direction that we all had to live with (Kelly Interview).

However, the collaborative continued to attempt to iron out a cost-recovery proposal that was consistent with the DPU Order but more specifically met the needs of the parties. Parties were unable to reach consensus on such a proposal prior to the Phase I filing, apparently in large part because of the AG's and MASSPIRG's reluctance to commit to providing utilities with lost revenue and positive financial incentives (Cohen and Oppenheim Interviews).

Fuel switching (i.e., changing electric end-uses such as electric water and space heating to alternate, potentially less costly fuels such as gas as a DSM measure), which has been the bane of many other collaborative DSM processes, was not on the table for long in either the Massachusetts or NEES Collaboratives. The utilities made clear from the outset that they were not interested in discussing fuel switching and that little else would get resolved if it was made part of the collaborative agenda (Kelly, Taylor and Chaisson Interviews). According to Douglas Foy, the NUPs decided not to push the issue in these collaboratives since there was a big enough reservoir of DSM opportunities to pursue without factoring in fuel switching. He claimed, "you can't eat the elephant all at once" (Foy Interview).[19]

Environmental externalities were similarly relegated to a second tier issue in both collaboratives until the DPU Order (D.P.U. 86-36-F) which required that externalities be included in cost-effectiveness calculations. But instead of promulgating a method or set of values, the DPU chose instead to take advantage of the collaborative spirit and directed all interested parties to work together to propose both a method and specific values if possible. In April 1989 (after the Phase I filing), the collaborative and other parties along with NEES joined together in a mini-collaborative to explore environmental externalities. In June 1989, the mini-collaborative disbanded after an impasse over several issues. The most central was whether externalities needed to be priced before they could be included in resource comparisons.[20]

By the end of December 1988, the Massachusetts Collaborative had accomplished its primary objective for Phase I -- agreement on a portfolio of technically-sophisticated program designs. Many of the more contentious policy-related issues spilled over into Phase II Collaboratives and into the on-going NEES Collaborative. Some of the issues were resolved by the parties during subsequent rounds of collaboration. Other issues that were not resolved by the DPU in its interim Order (D.P.U. 86-36-F) or by the collaboratives themselves, were addressed in Orders issued at the end of the Department's "DSM preapproval" reviews following the adjudicatory proceedings in subsequent phases of the collaboratives. Other policy issues remain unresolved as of this writing (e.g., fuel switching) while some are being reexamined by both the DPU and the parties (e.g., environmental externalities, customer incentives, program budgets).

Filing at the DPU

The generic portfolio of DSM programs designed during Phase I was completed on schedule and filed at the Department on December 23, 1988. All eleven parties (i.e., seven utilities and four NUPs) agreed to these preliminary program designs as well as a set of minimum guidelines on program monitoring and evaluation. The future of a collaborative with all the utilities except with NEES, which was involved in an on-going collaborative with CLF, was somewhat unresolved at the time of the Phase I filing. Participants agreed that workplans for Phase II would be submitted by Companies that wished to continue with Phase II Collaboratives on or before June 19, 1989, instead of with the Phase I filing.

In January 1989, the DPU held a public hearing on the Phase I filing, and agreed to provide comments but not to issue an Order as the filing was deemed an informational filing. On March 22, 1989 the DPU staff provided a letter to all interested parties. They said they were "impressed by the success of the collaborative process to date", and then went on to emphasize several areas of DPU concern that needed more attention during Phase II.[21]

Still outside of the collaborative process, the DPU could only send signals regarding its interests and concerns through occasional orders and letters. These messages were often considered cryptic or ambiguous by the participants, and in any case, were incapable of addressing all the subtleties that come up when policies are transformed into implementation details. On April 4, 1989, the DPU Commissioners hosted a rare technical session on its ratemaking policies with respect to DSM program costs in an attempt to clarify its policies (which had been causing some confusion despite its interim Order) and to solicit feedback.

This half-day session, which was facilitated by someone outside the DPU,[22] successfully created a useful dialogue distinctly different from the traditional hearing and order-writing process. The use of facilitation freed the Commissioners and staff from running the sessions and allowed them to focus more attentively on the substantive issues. In hindsight, the DPU could have effectively used more technical sessions throughout the DSM Collaboratives to stay informed about the process, and to informally provide feedback on contentious issues. However, as discussed in the conclusions of this dissertation, such sessions need to be designed carefully to avoid ex parte contacts and other potential improprieties.

Phase II

Introduction

The primary objective of Phase II was to take the generic portfolio of programs agreed to during Phase I and adapt them to the particularities of individual utilities. Although the participants considered Phase II voluntary, as Table 4.11 on the next page shows, the utilities all entered into separate collaborative processes with the NUPs except for FG&E which decided not to engage in further collaboration, and MECo which simply continued its collaborative through NEES with only CLF.

The Phase II Collaboratives were similarly structured. Each had an oversight group consisting of the utility and a representative from each of the four NUPs. Each also had four or five working groups focusing on commercial and industrial programs, residential programs, evaluation and monitoring and other areas which included both NUP consultants and utility staff. The utilities continued to provide funds for the NUPs to secure outside technical expertise. Some of the utilities also hired their own consultants, particularly the smaller ones which did not have adequate in-house expertise.

Table 4.11
Phase II Timeline: Agreements, Filings, and DPU Orders

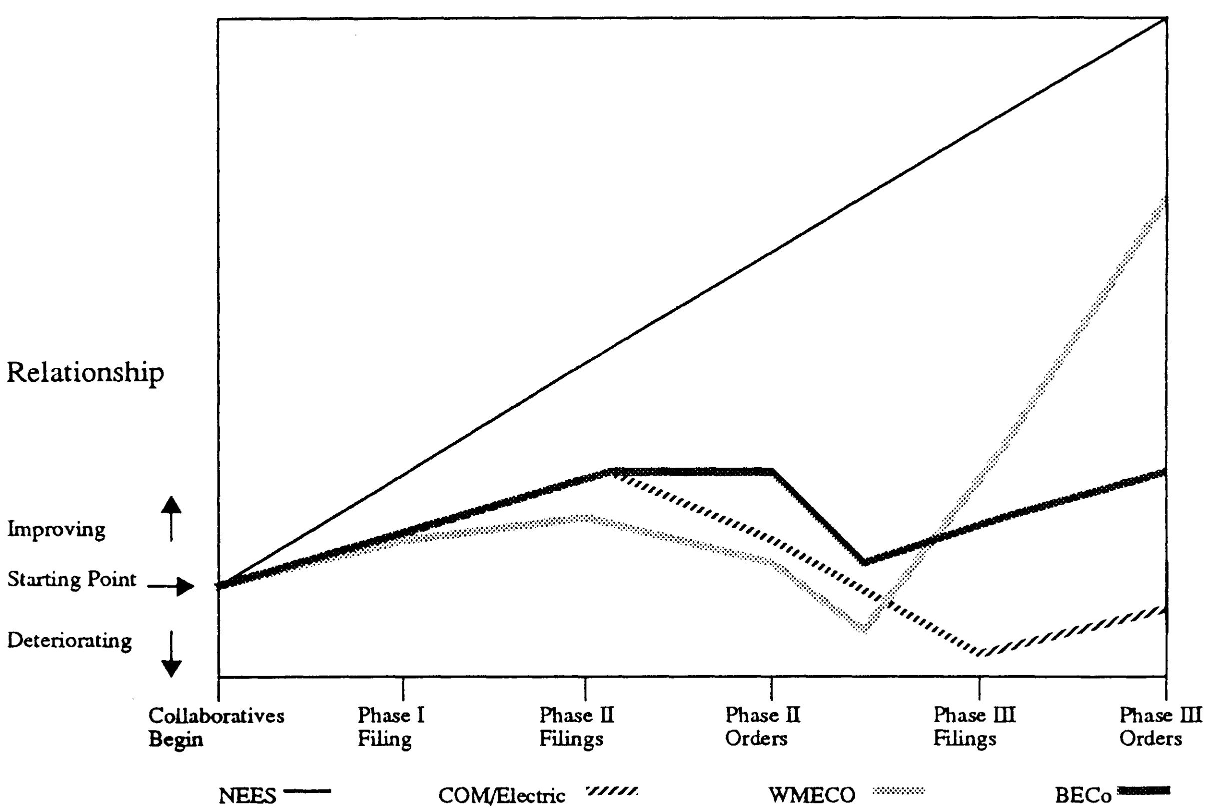
Utility	Agreement	Filing	DPU Order
BECo	June 1989	March 1990	na
COM/Electric	March 1989	November 1989	July 1990
Eastern	June 1989	March 1990	na
FG&E	na	na	na
MECo	na	September 1989	March 1990
Nantucket	September 1989	May 1991	December 1991
WMECo	March 1989	September 1989	June 1990

Notes: FG&E did not enter into a Phase II agreement.
MECo did not have a distinct Phase II agreement separate from original agreement signed August 1988.
BECo and Eastern filings were informational only, and no DPU action was ever taken on either of them.
The Nantucket Collaborative ended before the Phase II filing.

A NUP coordinator was hired for each collaborative to oversee consultants' work and act as a liaison between the process and the NUPs. The coordinator was also a liaison between the NUPs and the utilities -- often working through technical issues directly with the utility coordinator who was generally a senior staff person. Only BECo hired outside consultants to coordinate its internal staff, but this did not work well and was terminated after several months (Coakley Interview). Again, no outside mediators were used in any of the collaborative processes.

Despite similar structures and common agendas, the collaboratives rapidly took on their own distinct characters. Some succeeded where others failed. Figure 4.0 (on the next page) provides a basic road-map of the four individual collaboratives that are explored in the following few sections. The map traces the historic relationships between the NUPs and the utilities from when the collaboratives began in mid-1988 through the end of 1991. As can be seen, each collaborative took on a distinctly different character, indicative of their unique set of problems and accomplishments. During periods when the figure shows strong or improving relationships, consensus-building was at its best, while during periods of low or deteriorating relationships, the collaboratives were marked by contentiousness.

Figure 4.0
Relationship Between NUPs and Utilities
August 1988 - December 1991



Source: Author's Personal Assesment

The NEES Collaborative is the only one with steadily improving internal relationships overall. The WMECo collaborative, in contrast, was virtually shut-down after a contentious case before the DPU following Phase II, but was revitalized and strengthened after a brief hiatus. COM/Electric's Collaborative was somewhat counter-cyclical to WMECo's: it filed a consensus plan at the end of Phase II, but fell apart shortly thereafter. The BECo collaborative, while following a rocky road throughout, did not have the radical swings experienced in the COM/Electric and WMECo collaboratives. But, nor did it experience the steady improvement that occurred in the NEES Collaborative.

Massachusetts Electric Company

The collaborative between NEES (MECo's parent, holding company) and CLF, which began prior to any of the other Phase II collaboratives, was less contentious than the others in part because intra-NUP squabbles evident in Phase I of the Massachusetts Collaborative were absent (since there was only one NUP - CLF), and in part because of a good relationship that developed early-on between NEES and CLF (including CLF's consultants) (Chaisson, Cohen, Destribats, Pastuszek Interviews). Still, each conservation program took months of joint fact-finding and program-design negotiations. Apparently it was also much easier for NEES and CLF to reach agreement on new programs for commercial and industrial customers, than it was in areas where NEES had preexisting programs which they were often reluctant to change (Chaisson Interview).

NEES and CLF ultimately agreed on a portfolio of ten programs that would cover all customer sectors, for both new and existing structures. The consensus between the two parties included many significant innovations. For instance, most of the programs were designed around the concept of "direct investment" in which NEES would purchase DSM resources from its customers by paying, in most cases, the full incremental cost of the measures. This approach differed conceptually from most of the utility programs across the country during the previous decade which used partial rebates and low-interest loans.

Another major innovation from the NEES Collaborative was the provision of an actual financial incentive for NEES to aggressively pursue DSM based on the concept of shared-savings. Shortly after John Rowe became CEO at NEES in February 1989, he made clear to his staff that he could not continue to support DSM unless they found a way to make it profitable (Pastuszek, Rowe Interviews). Since Douglas Foy of CLF concurred with Rowe's assessment that "the rat must be able to smell the cheese" (explaining why utilities needed incentives), the two organizations were able to forge a creative incentive approach.[23] Prior to their effort, such an approach while touted in the literature (Moskvovitz 1989) had not been adopted and, as mentioned earlier, was controversial among the NUPs.

Through MECo, NEES became the first utility in Massachusetts to file for preapproval of its programs in the Commonwealth. MECo proposed spending $37 million in Massachusetts in 1990. CLF filed jointly with MECo in complete support of its programs and its cost-recovery proposals. The AG, however, who had not been invited to participate in the collaborative intervened to protest MECo's incentive proposal and what it considered poorly designed and inadequately-funded residential DSM programs. The Energy Consortium, a group of large industrial users, also intervened primarily to get MECo to reduce its proposed incentive. Finally, a group of lighting vendors argued that having the Company distribute lights for free in many of its programs would violate anti-trust law.

Western Massachusetts Electric Company

In March 1989, WMECo became the first utility to sign an agreement to begin a Phase II Collaborative with the NUPs. In the first six-months of their collaborative they were able to hammer-out most of the program details. However, several issues remained unresolved and highly contentious. The most contentious revolved around the pace at which WMECo pursued DSM. The NUPs argued that the Company should pay the full incremental cost for DSM measures and run its DSM programs at full throttle (i.e., not cap the annual DSM budgets, but allow "maximum exploitation of conservation opportunity...subject only to constraints of C&LM infrastructure availability" (CLF Initial Letter Brief, 4/11/91, p. 2). The Company, meanwhile, facing an over-capacity situation (due primarily to the start-up of its nuclear power plant, Millstone III) wanted to proceed slowly in acquiring DSM resources and wanted to find ways for the customers receiving the services to pay as much of their cost as possible.

Evaluation and monitoring plans and DSM cost-recovery were also highly contentious issues. The NUPs proposed using end-use metering and traditional statistical sampling techniques for measuring savings. The Company found this unreasonably expensive and proposed an alternative but untried approach.[24] With respect to cost-recovery, the NUPs disagreed among themselves and with the Company about whether WMECo deserved to recover lost revenue associated with its DSM programs and earn an additional positive financial incentive.

Despite a lack of consensus, WMECo filed for preapproval in September because it feared disallowances on its preexisting DSM programs (Cagnetta Interview). The

NUPs did not jointly file with the utility in support of its programs, as CLF had done with MECo. Instead, CLF and the AG intervened to express their concern that WMECo's investment posture did not reflect the maximum commitment to pursuing all cost-effective DSM over the next few years, and that the future of the collaborative seemed uncertain.[25] The only other intervenor was the Energy Consortium which argued that portions of the DSM programs were anti-competitive.[26]

In an effort largely to appease the NUPs prior to the start of hearings, WMECo unilaterally increased its proposed 1990 DSM budget from $4.7 million to $6.1 million and agreed to do more DSM if possible (Cagnetta Interview). While generally appreciated by the NUPs, the mid-course changes came too late to be adequately reviewed before the hearings. According to Joe Chaisson, the NUP Coordinator, the NUPs inability to review the changes on time was partially due to the lateness of the changes, and partly because the NUPs were stretched too thin to respond in a timely fashion (Chaisson Interview). The result was a relatively confusing and contentious hearings process that lasted 8 days. During this time, the DPU staff, attempted to ferret out the details of the Company's revised proposals as well as the evolving positions of CLF and the other NUPs.

In the end, the NUPs still maintained that WMECo's filing did not commit to fund conservation to the maximum extent feasible (NUP Letter, April 11, 1990, pp.7-8). DOER, the AG, and MASSPIRG recommended against providing WMECo with any positive financial incentive because their "preliminary" review of the filing "does not permit the conclusion that the Company proposes exemplary or above-average performance" (id.). CLF, however, split from the other NUPs, and decided that, despite the short-comings in WMECo's filing, it would support WMECo's request for recovering its direct DSM expenditures, any lost revenue associated with those expenditures, and a financial incentive (CLF Letter Brief, 4/11/90, p. 3).

COM/Electric

In contrast to the WMECo Collaborative, the Phase II COM/Electric Collaborative went relatively smoothly, ending in a virtual consensus filing in November 1989. CLF intervened in support of the Companies proposal as it had done in the MECo case.[27] While the AG also intervened, it did not get too involved because it considered COM/Electric's DSM plans and projections a "shining star" among the utilities (Oppenheim Interview). The Company requested preapproval for 16 programs at an estimated cost of $11 million for 1990.

However, the filing was made in the midst of a snow-balling ratepayer revolt sparked by recent rate increases made by Commonwealth Electric (as approved by the DPU). These were unrelated to DSM but doubled the bills of some electric heat customers.[28] On January 11, 1990, after the DSM preapproval request was filed but prior to the hearings, in an unprecedented move, the Massachusetts Legislature with Governor Dukakis's blessing, overturned the DPU's rate case order for Commonwealth Electric by reallocating costs and reinstating the previous rate design, including "discounts" for electric space heating.

While customers generally praised most other utilities for proposing aggressive DSM programs, two residential ratepayer groups, IRATE and RATEBUSTERS, intervened in COM/Electric's DSM preapproval case to protest against the Company's attempt to raise rates for DSM. In addition, they accused the Company of falsely advertising that it would deliver DSM to its customers for "free" while in fact, they argued, it had every intention of recovering those costs through rates.

COM/Electric requested direct cost-recovery for its DSM expenditures in the year that the monies were spent like other utilities. But unlike WMECo, COM/Electric did not request any compensation for lost revenue nor did it request a positive financial incentive as both MECo and WMECo had done.[29]

Boston Edison Company

The BECo Phase II Collaborative started later than the COM/Electric and WMECo Collaboratives for two reasons. First, both the Company and NUPs were preoccupied with other proceedings (e.g., the Pilgrim nuclear outage cases discussed in the previous case study in this Chapter). Also BECo was somewhat ambivalent about continuing with the collaborative process (Kelley Interview). When it finally began, the BECo Collaborative was slower and more contentious than the others. In large part this was caused by bad blood between the utilities and the NUPs as a result of nearly a decade of vitriolic litigation over BECo's Pilgrim nuclear power plant, its commitment to DSM, and the management of the company generally.

Also, the NUPs were less willing to defer to CLF on many of the decisions as they were in the other Collaboratives. Here they were involved in every detail. This involvement was partly because of the NUPs historic interest in BECo which is the largest utility in Massachusetts regulated by the DPU,[30] and partly because the NUPs had already cut-their-teeth in the other Phase II Collaboratives which had begun earlier (Nogee and Shimshak Interviews). In some ways BECo appears to have been held to a higher standard than the other utilities during Phase II.

In October 1989, the non-CLF NUPs gained additional incentive to focus on the BECo Collaborative when the DPU approved the Pilgrim Settlement (described in detail in the previous case study). The Settlement required BECo to spend $75 million on DSM without recovering the costs from its ratepayers and to set up a DSM Settlement Board including the AG, DOER and MASSPIRG (but not CLF who was not a party to the Pilgrim cases) to oversee the spending.

Whereas WMECo and COM/Electric concluded their Phase II Collaboratives and filed for preapproval in the fall of 1989, BECo did not conclude the second Phase of its collaborative until March 1990. Although the parties had completed the bulk of their effort the previous fall, they continued to seek agreement in several elusive areas -- most notably the role of performance contracting in BECo's commercial and industrial programs, and the Company's cost-effectiveness screening tool (Gustin and Coakley Interviews). The participants had not agreed to all the final details when BECo finally filed its programs in March 1990. However, since the Company was obligated to provide $75 million worth of DSM without reimbursement from the ratepayers, the March filing did not seek the DPU's preapproval and no formal review was ever conducted.

Phase II Preapproval Cases

Most of the Phase II Collaboratives ended in requests for DPU preapproval.[31] As mentioned, several parties intervened in the MECo, WMECo and COM/Electric cases; and, despite a considerable degree of consensus within the respective collaboratives, the cases were all fairly contentious. Parties outside the Collaboratives raised many of these issues; however, some were also raised by the NUPs themselves.

The cases followed traditional adjudicatory procedures used in rate cases including discovery, testimony, hearings, and the filing of legal briefs. Over half a dozen days of evidentiary hearings transpired during which parties cross-examined each other and the DPU staff questioned everyone.

The DPU's tasks during the hearings were two-fold. First, it needed to resolve contested issues raised by intervenors. Second, the DPU was obligated to guarantee that the resultant rates would be just and reasonable and the settlement was consistent with the DPU's DSM policies. Therefore it had to scrutinize all the other settled issues. This task was tantamount to making sure that the DPU's own "interests" and the "interests" of ratepayers were accommodated by the settlement.

Unlike most traditional rate case settlements in which PUC's are generally required to accept or reject the entire settlement, no such restriction was placed on the DPU by the parties to the Collaboratives. The DPU ultimately approved the majority of the details submitted in the DSM preapproval filings and generally praised both the process and the results. However, it also required significant changes in all three cases. In fact, the Massachusetts DPU required more substantial changes than any other state PUC that has reviewed a DSM Collaborative to date (Raab and Schweitzer 1992). (In contrast, the Rhode Island and New Hampshire portions of the NEES Collaborative filing were resolved in traditional, post-filing settlements including the advocacy staffs of the PUCs. These settlements were in turn approved by the Commissions without any substantive changes.)

The changes required by the DPU fall into two broad categories of issues: program design and ratemaking. With respect to program design, the DPU actually rejected two of WMECo's and three of COM/Electric's programs for not meeting the DPU's cost-effectiveness criteria.[32] The DPU also refused to approve at least one of the collaboratively-designed programs for each of the utilities because it concluded that they were not complete in all their details.

The DPU often required modifications on the programs it did approve. For instance, it ordered WMECo to enrich the customer incentives in its commercial and industrial programs (i.e., to reduce the buy-down from a three year simple payback to two years for large customers and to provide full funding for small customers). Generally, the DPU required the utilities to accelerate the implementation of many of their programs and include additional, potentially cost-effective measures. In one instance, it ordered WMECo to include motors and building shell measures in addition to lighting measures in its small commercial retrofit program. The DPU also ordered the Companies to examine DSM opportunities in entirely new areas that were not covered by the collaboratives such as streetlighting, and voltage reduction on the distribution systems. Finally, the DPU ordered all three companies to improve their monitoring and evaluation plans which it considered an integral part of program design.

Whenever the DPU ordered modifications, it essentially returned the issues back to the collaborative participants for further resolution and improvements. The DPU either ordered the utilities to resubmit new programs or program revisions in interim compliance filings, or to wait until the utility's next preapproval filing the following year.[33]

The DPU also ordered substantive changes on ratemaking issues. It significantly modified MECo's cost allocation proposal and MECo and WMECo's financial incentive proposals. Although MECo's original cost allocation proposal was to spread DSM costs equally over all energy sales (i.e., on a per kwh basis), the DPU decided that the costs should first be divvied among the customer classes eligible to participate in each program and then spread equally within them on a per kwh basis.[34]

MECo's request for a financial incentive was one of the most contentious issues in the proceeding, and was also controversial within the DPU. According to former Commissioner Robert Werlin:

> The incentive that MECo proposed represented a fundamental break in the way rates were set. We had three commissioners with three different views on the strengths and weaknesses of the original proposal. Eventually we were able to come to a consensus that if the Company does a good job, it would be o.k. for it to make a little more money (Werlin Interview).

However, the Commission required several major changes including (1) halving the requested incentive amount plus requiring a threshold that would only allow bonus recovery on savings exceeding 50 percent of projected savings; (2) scrapping MECo's proposed shared-savings-based incentive formula and replacing it with a fixed cents/kwh and $/kw bonus; and (3) requiring that savings be based on after-the-fact measurement rather than prespecified estimates.[35]

The DPU also approved a bonus incentive for WMECo but required it to pass a higher threshold of achievement prior to payment than it had required of MECo. MECo was required to meet 50% of its targeted savings prior to earning a bonus on all additional savings, while WMECo was required to meet 75% of its targeted savings before it could earn comparable bonus on all additional savings. The more stringent bonus hurdle was justified primarily because of the Commission's finding that although WMECo's proposed DSM efforts showed substantial improvement over prior efforts, it appeared less aggressive than MECo's (D.P.U. 89-260, p. 123). The DPU's decision turned largely on the testimony of the NUPs since it had little other than the MECo case to use as a benchmark.

Through its preapproval Orders, the DPU finally had direct input into the collaborative program designs and ratemaking proposals of the utilities and the NUPs. The DPU's directives occasionally reinstated objectives relinquished by the NUPs during the negotiations. In other instances, all the collaborative parties felt somewhat disdainful of the DPU's strong intervention.[36] If the DPU had directly participated in the collaborative processes it is likely that some of the collaborative programs and ratemaking proposals would have been designed to better reflect the regulators' interests, or the DPU would have been more receptive to the collaborative designs as submitted, or both.

Phase III

Phase III of the DSM Collaboratives began immediately after the Phase II processes ended for BECo and MECo. The WMECo process restarted after a brief hiatus, while the COM/Electric Collaborative never restarted. Each of these efforts are described in this section.

MECo: Growing Stronger

The collaborative process between NEES and CLF intensified and improved after what both parties perceived as major victories. These victories occurred not only in Massachusetts but also before the Rhode Island and New Hampshire PUCs where even fewer changes were made to their collaborative-filings, and where almost all issues were settled with the PUC Advocacy staffs and other intervenors after the filing but prior to a Commission ruling. NEES and CLF worked together during Phase III to (1) formulate the compliance filing in Massachusetts, particularly in the design of an evaluation and monitoring plan which had not been filed prior to the 1990 preapprovals, (2) work through the myriad of details necessary to implement the approved programs, and (3) begin to refine the programs and budgets in preparation for the 1991 preapproval filing.

In October 1990, NEES and CLF jointly filed a 1991 proposal for review in the three states which represented a consensus on all issues. The Company proposed increasing its expenditures in all three states to $85 million which represented a 30 percent increase over its $65 million 1990 budget (and 20 percent over the $71 million that was actually spent in 1990). The $85 million represented almost 5 percent of NEES's gross revenue and was among the highest expenditures by any utility in the country (Moskovitz et.al. 1992).[37] It is also important to point out that NEES agreed to increase the budget despite its calculation that the souring New England economy would result in the leveling of its load-growth for the foreseeable future.

MECo and CLF jointly filed their consensus proposals at the DPU. Again the Energy Consortium (i.e, large industrial users) intervened. This time they pushed for an energy service charge that would effectively reallocate DSM expenditures directly back to the actual recipient of the DSM service. The AG did not intervene, but Boston Gas Company did to press MECo to include fuel switching in its DSM programs. The DPU decided to bifurcate the preapproval proceeding and put the controversial fuel switching issue on a separate track. As of this writing, the fuel switching proceeding has not been resolved although more than 20 parties intervened (including CLF in support of fuel switching and opposition to MECo's position) in what turned into a costly and heated adjudication.

WMECo: Hiatus and Rejuvenation

After the DPU's Phase II Order, the collaborative between WMECo and the NUPs screeched to a halt. The parties stopped talking to each other for several months

(Chaisson Interview). According to Earle Taylor, WMECo was disappointed with the lack of support it received from the NUPs in the hearings:

> We were extremely upset over the NUPs' stance during the hearings. The NUPs had been pushing us to pay 100 percent of the cost of DSM and to run our programs at more aggressive levels. We finally gave in at the 11th hour and agreed to run our programs full throttle, although we didn't give in on the customer incentive payment issue. Still the hearing process was more contentious than we wanted, and we felt somewhat betrayed by not getting more support from the NUPs. We started to feel like we got little out of the collaborative (Taylor Interview).

At the same time, the NUPs were frustrated with the Company for making many changes without consulting them or giving them sufficient time to review the changes prior to the hearings. More importantly, they continued to be frustrated over WMECo's lack of movement on customer incentives and several other issues.

Apparently the collaborative of WMECo's Connecticut sister retail company, Connecticut Power and Light, which had also stopped during this period, was revived after the PUC Chair, Peter Boucher, called all the parties together and pressured them to reconvene the collaborative. The CP&L Collaborative brought in an outside mediator to help with this task. The reasons and mechanisms behind the resurrection of the WMECo Collaborative, which happened subsequent to the Connecticut revival, are less clear-cut (e.g., the DPU did not pressure the parties nor was an outside mediator brought in). However, NU's CEO, William Ellis apparently pushed to reconvene the group prior to the next preapproval filing (Taylor and Chaisson Interviews). A new NUP coordinator and CLF attorney were brought on board, both of whom had substantially more time to invest in the process than their predecessors, and a new WMECo coordinator was selected.

Once resuscitated, the WMECo Collaborative progressed smoothly and the second preapproval filing was the first fully consensual filing that included all the NUPs in Massachusetts (Chaisson Interview).[38] In sharp contrast to the 1990 preapproval case, CLF, DOER, and the AG all intervened before the DPU in support of WMECo's entire preapproval package. The AG and MASSPIRG, who had previously refused to support positive financial incentives or even lost revenue adjustments for any utility, signed off on both for WMECo. In contrast to his comment after the first preapproval case, WMECo's Taylor was far more sanguine about the collaborative after the second time through:

> We were very happy to have their endorsement in the second preapproval. It would've been extremely hard on us if their support or testimony was either absent or negative. As a result, we have decided that it's worth the price over the next few years to get the NUPs "good housekeeping" seal of approval (Taylor Interview).

COM/Electric: The Unravelling

While the WMECo Collaborative went from contentiousness in Phase II to creative, consensus-building in Phase III, the COM/Electric Collaborative moved in the opposite direction. Despite a relatively harmonious and productive Phase II Collaborative between COM/Electric and the NUPs, the parties were unable to even reach an agreement to engage in subsequent collaboration. According to Mort Zajac of COM/Electric, both the NUPs proposed level of oversight and the price seemed unreasonably high:

> The NUPs proposal for on-going collaboration included what we considered to be an unreasonable level of oversight and micromanagement. We felt that they were proposing a continuous level of review -- equivalent to the IRS sitting here everyday waiting for you to do your taxes. We felt that it would paralyze the staff. In addition we found their proposal too expensive, and didn't feel that

> some of the experts they proposed to use were as proficient as our own staff (Zajac Interview).

The Company's reluctance to engage in subsequent collaboration with the NUPs was rooted in frustration and dissatisfaction with certain aspects of the Phase II Collaborative. Specifically, the Company maintained that it had been difficult to get the NUPs' focused attention, or to reach a consensus on certain issues (Zajac Interview).[39]

The NUPs acknowledged that they had some internal problems during Phase II of the COM/Electric Collaborative including the fact that some of its consultants were tardy, and some of its members, most notably the AG and MASSPIRG, were more focused on the BECo Collaborative. However, all the NUPs were still interested in pursuing an on-going collaborative with COM/Electric, and were frustrated by COM/Electric's unwillingness to go forward at a level of engagement comparable to the Phase II effort (Chaisson and Coakley Interviews).

The parties never did reach agreement, and no collaboration occurred after Phase II. Instead COM/Electric hired its own consultants, and filed for preapproval unilaterally in March 1991. It proposed to limit its DSM expenditures to $23 million for both its companies and to run only four programs.[40] Its proposal did not include several programs previously ordered by the DPU, nor did it include three programs that were preapproved in 1990, at the parties request, for immediate implementation.

CLF intervened to make the unprecedented request that the DPU find COM/Electric's implementation of its prior preapproval contract and its 1991 DSM preapproval proposal imprudent, and that the Company's entire DSM effort be placed under the direction of an outside receivership.[41] COM/Electric defended its decision as part of its need to restrict its DSM effort in the face of mounting public opposition to rate increases of any sort and severe limitations on its ability to retain the additional staff necessary to run new programs. However, it pointed out that despite this decision, the programs it did run were successfully implemented.[42] Finally, COM/Electric maintained that given its current financial condition it needed to continue to streamline and prioritize its programs and maintain a budget cap in the future.

Other intervenors, in what turned out to be an acrimonious proceeding, included: the AG, DOER, Massachusetts Executive Office of Economic Affairs, Energy Engineers Task Force, City of Cambridge Public Schools, IRATE, Cape United Elderly, Inc., and an industrial ratepayer group called Save our Regional Economy (SORE). More discovery requests were served on the parties (over 300) and more hearings were held (three days of public hearings and fourteen days of evidentiary hearings) than in any other DSM-related case that had ever come before the DPU.

After the hearings, but prior to the DPU issuing its Order in the case, the parties representing a diverse group of interests, were able to forge a settlement resolving many of the most contentious issues. The most significant features of the settlement included: (1) setting up a formal Task Force comprised largely of the parties to the settlement to work with COM/Electric on improving its DSM programs and its relations with its ratepayers; (2) setting aside $250,000 to hire an independent DSM expert to provide on-going scrutiny of COM/Electric's DSM efforts, to provide advice, to act as a liaison to the Task Force and the DPU, and even to mediate disputes when necessary; and (3) minimizing future rate impacts through cost caps and the amortization of expenses, while expanding the scope of its programs. The settlement left certain issues for the DPU to decide such as the prudence of COM/Electric's past DSM activities.

BECo: Same As It Ever Was?

Much of the debate during Phase II, particularly with respect to policy ramifications of the screening tool, continued in Phase III. In fact, the issues intensified substantially, after the company informed the DPU and the Massachusetts Energy Facility Siting Council (Siting Council) of its intent to construct a 306 MW gas-fired combined-cycle generating facility at a site Edgar Station (Edgar) a retired BECo plant known. The amount of cost-effective DSM available to the Company was a central issue in the Edgar case.[43] The intervention of CLF, the AG, and MASSPIRG to oppose Edgar at the DPU and the Siting Council was not well-received by the Company, and further strained an already-stressed Collaborative.

Although Edgar seemed to reopen old wounds among the participants, they continued to try and settle remaining DSM issues such as the screening tool and the evaluation and monitoring protocols, and help the Company ready its new DSM programs for implementation (Coakley Interview). Concurrently, the Company was working through the details of its programs with the DSM Settlement Board established in the Pilgrim case, creating additional coordination problems despite the fact that both the collaborative and the Board contained many of the same members.

In an attempt to gain greater control over the process, the Company insisted that when the NUPs' consultants visited BECo that they brief BECo's Senior Management on their findings prior to reporting back to the NUPs (Gustin Interview). This request caused an uproar with the NUPs who did not want the Company to control their consultants. The final resolution was to hold "exit interviews" where the consultants briefed the Company in the presence of the NUPs. This change apparently helped the process. It allowed the parties to work from the same information-base thereby accelerating the transfer of information from the consultants to all parties, and provided the Company and the NUPs with greater face-to-face interaction (apparently prior interaction was often through CLF or the NUP coordinator).

In March 1991, BECo filed its revised programs with the DPU for preapproval. This time, since the Company's projected 1991 expenditures exceeded the DSM it promised to deliver at no cost to its ratepayers under the Pilgrim Settlement, the Company sought preapproval on the incremental investment including recovery of lost-revenue and a financial bonus. The parties had reached consensus on virtually all issues, with the NUPs filing a joint brief supporting BECo's filing. However, the NUPs raised concerns regarding the Company's load management programs and other matters that were not directly part of the collaborative effort (id.).

Phase III Preapproval Decisions

Table 4.12 shows the filing and order dates for the Phase III Collaboratives.

Table 4.12
Dates for Phase III Filings and DPU Orders

Utility	Filing Date	Order Date
BECo	April 1991	April 1992
COM/Electric	March 1991	January 1992
MECo	October 1990	January 1991
WMECo	March 1991	July 1991

Notes: The COM/Electric filing was not a collaborative effort.
The BECo Order was expected in April -- after the final write-up of this case for this dissertation.

With its Phase III Preapproval Orders, the DPU continued to inject its own concerns and interests into the DSM activities of the utilities despite substantial consensus in the MECo and WMECo Collaboratives and the settlement of the COM/Electric case.[44] Nowhere was this more apparent than the MECo Order where even without the AG's intervention, the DPU continued to (1) push the Company to make its programs as comprehensive as possible (i.e., pursue all cost-effective measures rather than merely the most cost-effective measures), (2) offer them to all its customers as quickly as possible, and (3) cover enough of the measure costs through direct investment to guarantee high participation and measure acceptance (D.P.U. 89-260 (June 1990)).[45] In contrast to the DPU's continued push for pursuing all cost-effective DSM, the Rhode Island PUC had just approved a settlement crafted by its staff that pushed NEES to go after the most cost-effective programs and measures within programs rather than comprehensive treatment spread over all customer classes (Kilmarx Interview, Kilmarx and Wallis 1992). This different direction is important to note because it highlights the non-homogeneity of the regulators themselves, and underscores the need for including them in the process.

In the MECo case, the Massachusetts DPU rejected the Appliance Labeling and Multi-family programs submitted by the collaborative for not being cost-effective. The DPU also ordered MECo to refine its cost-effectiveness analysis in several important respects,[46] lowered its financial bonus from $6.1 million to $5.4 million, approved its evaluation and monitoring plans with some modifications, and granted the Company a preapproval for one year instead of the five it had requested (id.). Overall, despite the changes, the DPU continued to find that if MECo met its targets as modified by the Department's Order, it would be doing an "exemplary" job.

Even in the COM/Electric case, while ultimately approving the fairly comprehensive settlement, the DPU issued a 146-page order in which it thoroughly analyzed, and made findings on every aspect of the case. The DPU went through each program and provided guidance to COM/Electric and other parties to the settlement on the Department's expectations.

In stark contrast to the order at the end of Phase II, the DPU's Phase III WMECo Order was extremely supportive of the unanimous settlement reached by the Company and the NUPs. Although it rejected the energy service charge notion raised by the Energy Consortium in its intervention, it only made several minor modifications to the Collaborative' proposals. This positive Order, with its lack of DPU-required modifications, was due primarily to the settlement of the issues between WMECo and the NUPs in a way that was responsive to past DPU directives.[47]

On-Going Collaboratives

More than three and a half years after the DSM Collaboratives began in the Summer of 1988, the BECo, MECo, and WMECo Collaboratives continue. The COM/Electric, Eastern, and Nantucket Collaboratives have been terminated. However, the on-going collaboratives' focus has changed from program design, to implementation oversight and program refinement. Since the utilities are offering programs that are on the cutting edge of those offered nationwide, the NUPs' consultants earlier role of bringing in the experiences of other utilities is less relevant today.

All three remaining utilities have committed to a funded-collaborative in 1992. However, the future of these collaboratives remain uncertain. Both BECo and WMECo continue to question the benefits they receive compared to the costs they incur (Taylor and Gustin Interviews). Neither Company is interested in having the NUPs continuously looking over their employees' shoulders and expressed the desire for greater control (id.). BECo also expressed a desire during the interviews to expand the process to include more of its consumers as well as DSM service providers, but to concurrently restructure the process so that it's more like an advisory board than a consensus-based collaborative.

The NUPs also believe that the collaboratives can and should wind down over the next several years. However, they are not particularly interested in an advisory board structure where they would have much less influence (Chaisson and Nogee Interviews). In California, where the utilities set up advisory boards directly after the conclusion of the collaborative, most of the NUPs expressed extreme dissatisfaction and frustration over the change (Raab 1991, Raab and Schweitzer 1992). While advisory boards can undoubtedly play an important role in utility DSM programs, they do not appear to be a substitute for a consensus-based collaborative.

The only collaborative which does not show major fatigue despite various stresses is the NEES Collaborative which continues to involve only CLF. After submitting its third consensus DSM preapproval filing (this time for 1992), MECO and CLF were able to settle the case with all the intervenors including a newly formed DPU advocacy staff (D.P.U. 91-205).[48] Armond Cohen of CLF expressed confidence that the two organizations, which now agree on everything except environmental externalities, fuel switching and perhaps program scale would continue their collaboration for the foreseeable future. Unlike the other utilities, the collaborative seems truly ingrained at NEES. John Rowe, NEES's CEO speculated about its future:

> If our collaborative is now 70 percent for political legitimacy reasons and 30 percent for substantive reasons, that's a good combination. Since the need for legitimacy and good ideas will never change, I expect that the collaborative will continue. In fact, I hope that we can expand it to other areas like environmental externalities (Rowe Interview).

Conclusions

I begin this concluding section by addressing whether the DSM Collaboratives saved process-related resources compared to an entirely litigated approach. I then examine whether the collaboratives successfully enhanced the legitimacy of the adjudicatory process and the practicality of the end results. The section ends by highlighting the unique features of the settlement process which contributed to the successes and failures of the DSM collaboratives.

Saving Resources in the Adjudicatory Process

The collaboratives required extensive commitments of time and resources from all parties. While Phase I of the Massachusetts Collaborative process only took half a year; the NUPs have been actively engaged in negotiations with WMECo, BECo, and MECo for over three and a half years as of this writing. They were also involved for almost two years with COM/Electric, Eastern, and Nantucket before those collaboratives ended. As Table 4.13 on the next page shows, over $3 million was spent by the utilities to hire DSM experts to advise the NUPs during the first three years. During this period, the utilities spent an additional $2-3 million to cover their own staffing and consultant needs (Utility Interviews). Each of the NUPs also estimated dedicating approximately a 1/3 to 1/2 FTE of a staffperson's time to the collaboratives with CLF dedicating significantly more (NUP Interviews).

Table 4.13
Massachusetts Utilities' Expenditures for NUP Consultants
August 1988 – September 1991

Utility	Phase I ($1,000)	Phase II & Beyond ($1,000)	Total All-Phases ($1,000)
BECo	215	729	944
COM/Electric	66	368	434
Eastern	42	323	365
FG&E	7	na	7
MECo	na	696	696
Nantucket	1	36	57
WMECo	54	583	637
Total	$385	$2,735	$3,120

Notes: BECo only through 5/31/91. MECo through 4/30/91. All expenditures for MECo shown in Phase II. MECo estimated at 75% of NEES expenditures. FG&E did not engage in a collaborative after Phase I.

Source: Expenditures from D.P.U. 91-80 (IR-2-11).

Virtually all those interviewed concluded that while the collaboratives were extremely resource-intensive, having to litigate all the issues would have probably required even more resources in total. This possibility appears substantiated by both the historic DSM-related litigation prior to the Collaboratives, as well as the contentious post-collaborative DSM-related litigation such as the recent COM/Electric case[49] and the on-going adjudications over fuel switching in Massachusetts. Also, unlike traditional settlements which usually occur at the end of a contested case, these collaboratives are unique in that they represent pre-filing settlements. As such, they have a greater potential to save resources associated with litigation than a traditional settlement.

Some short-term process-related resources may have been saved. However, several important factors mitigate this conclusion. First, not all the collaboratives consistently resulted in full consensus filings. When filings occur without consensus, such as in WMECo's first filing, the litigation process can be intensive. Second, even where the collaboratives did reach consensus, since they did not include all interested parties, a litigated case was always put on by outside intervenors. The intervention by the AG after the first consensus filing by only MECo and CLF is a prime example of this phenomenon. Last, even where there was a consensus and little or no third party intervention, as was the case in WMECo's and MECo's second preapproval filings, given the DPU's lack of direct representation in the collaboratives and its intense interest in DSM, both cases required over a week of hearings. Also, final DPU orders in virtually all the DSM preapproval cases were not issued until the end of the DPU's self-imposed deadline regardless of how controversial the cases were. Thus little, if any, time was saved in the approval process itself. In collaboratives in other states where consensus was achieved among a broader range of parties including the regulatory staff and where no self-imposed decision deadlines were in effect, more litigation before the PUCs was usually avoided than in Massachusetts (Raab and Schweitzer 1992).

As discussed in Chapter 3, a careful analysis of the process-related savings must look beyond the immediate PUC process to embrace the appeals and implementation processes as well. Monsanto Company unsuccessfully appealed the PUC's decision to allow a provision in one of WMECo's DSM programs that restricted industrial self-generation (as a condition for participation), as a violation of state antitrust law and as discriminatory.[50] This was the only appeal regarding the DPU's decisions on the collaboratives, and it was a rather narrow appeal of a design feature of a single program which could have been waged against many non-collaboratively designed DSM programs with similar elements. Therefore, it should not be inferred that the collaboratives increased process-related costs associated with appeals. On the other hand, since appeals of DSM-related issues in Massachusetts happened rarely, if ever, prior to the DSM Collaboratives,[51] the DSM Collaboratives may not have saved significant resources in terms of avoiding future appeals.

To the extent that programs have been implemented more rapidly, at a greater scale, and more comprehensively than they might have otherwise, the collaboratives probably avoided some long-term litigation. At the same time, the litigation that has occurred when the collaboratives have gone astray (e.g., WMECo after Phase II, COM/Electric after Phase III), has been conducted at a level of exhaustive detail that would be unlikely if not inconceivable had the collaboratives never transpired in the first place. On balance, the collaborative processes will probably save some long-term, process-related resources compared to an approach that used only litigation.

However, it is worth noting that if the NUPs were forced to litigate every DSM issue, they probably could not afford as comparable a level of involvement as they were able to muster for the collaboratives. Their limited resources would have required them to be more selective in picking their battles. In addition, if everything was litigated, they most certainly could not have afforded all the outside technical expertise the utilities funded during the collaboratives. Therefore, although the overall process-related resources from a societal perspective may have increased through a purely litigated path, the NUPs' dedicated resources may have actually decreased while the utilities' and the DPU's may have increased.

More importantly, even if the NUPs did pursue litigation and were able to afford the requisite outside technical expertise, regardless of whether it cost more or less than collaboration, litigation may never have been able to produce qualitatively comparable results to what the collaboratives produced. To the extent the process was perceived as fairer, and better DSM programs resulted from the collaboratives, total net benefits were probably positive (and potentially substantial) regardless of whether the process-related costs were slightly more or less than traditional litigation. A comparative analysis to explore these critical points is provided in the next two sub-sections.

Legitimacy

As discussed, DSM issues in Massachusetts have historically been vehemently contested in rate cases and other proceedings before the Department and other agencies (e.g., the Energy Facilities Siting Council), rarely leaving any of the participants I interviewed with positive feelings about the regulatory process or its results. Despite some on-going battles within the DSM collaboratives, the parties frequently reached a surprisingly high degree of consensus on program design and program scale issues. For example, Phase I of the Massachusetts' Collaborative, Phase II for COM/Electric, Phase III for both WMECo and BECo, and all phases of the NEES Collaboratives were essentially consensual filings. These agreements are no small feat, and they potentially enhance the legitimacy of the traditional adjudicatory proceedings used to resolve these issues by better satisfying the participants' interests.

The few cases where consensus fell apart prior to a utility filing (e.g., the WMECo Phase II filing and COM/Electric's Phase III filing), raise some concerns about the sustainability of this legitimization process. Nonetheless, the fact that WMECo was able to recover from its hiatus after its contested case in Phase II, and come to the first fully consensual filing in Phase III (which included all the NUPs) is testimony to the potential long-term benefits from collaboration in this area. Even in the COM/Electric Phase III case, which was strongly opposed by the NUPs and other intervenors in the most contentious DSM case ever to come before the DPU, a settlement was reached after hearings but prior to a Department-issued Order.

Still, the collaboratives did not make an effort to include all potentially interested parties. In the NEES Collaborative, only CLF was included, and the AG, an active member in the other collaboratives, intervened against MECo in its first collaborative filing. All the collaboratives experienced intervention by other parties like energy service companies, industrial consumers, and residential ratepayer groups. By not adequately representing the interests of these groups within the pre-filing collaboratives themselves, some of the legitimization that the collaboratives generally enhanced were definitely compromised. Attempts to garner that support through other means such as advisory groups could not take the place of more active involvement through the actual collaboratives.

Unlike in many other states, the Massachusetts DPU staff did not participate in the collaboratives primarily because it was not an advocacy staff (Raab and Schweitzer 1992). The DPU's lack of direct involvement may ironically have compromised the legitimization of the process to some degree both by inadequately inoculating the collaborative participants with the DPU's interests, and by not giving the DPU the direct benefit of the substantive knowledge learned during the collaboratives or the difficult tradeoffs made while building consensus. Instead of direct DPU involvement in the collaboratives, the Department's interests were conveyed with each successive order. Ultimately the DPU required many modifications to the collaborative-filings -- sometimes even when the parties had reached consensus.

In the end, however, the DPU's overall enthusiastic support for most of the collaborative agreements contribute to a conclusion that the collaboratives helped enhance rather then hinder the legitimacy of the DPU's adjudicatory processes. In a recent article in Public Utilities Fortnightly entitled "Collaborative Approaches to Conservation" (March 1, 1992), a heretofore unlikely duo -- former DPU Chair Bernice McIntyre and BECo's CEO Bernard Reznicek, wrote:

> Today, just five years later [after the collaboratives began], few would argue that the Massachusetts commission lost control when it created the opportunity for dialogue. In fact, many might argue that the commission, the utilities, and the advocates became more informed and were better able to define and offer solutions to problems.[52]

The lack of appeals, except for one in the WMECo case in which the Massachusetts Supreme Judicial Court upheld the DPU's decision, can be construed as further testimony to the success of the collaboratives in satisfying the various interests of society, and working within the confines of regulatory and judicial reality. Also, where collaboratives were on-going, the implementation problems were resolved much more expeditiously and productively (e.g., MECo) than where the collaboratives had disbanded (e.g., COM/Electric). Finally, the improvement of interpersonal relationships among most of the collaborative participants, as many I interviewed reported, is likely to have positive spillover into subsequent regulatory procedures related to DSM and other matters. These spillover effects may in the long-term be the most important testimony regarding whether the DSM Collaboratives enhanced the legitimacy of the DPU's adjudicatory procedures.

Practicality

The DSM Collaboratives seemed to produce many practical improvements to utility DSM programs which may not have surfaced from the continuation of a purely litigated path. I will explore this contention by examining both the scale and design of DSM programs, and the resolution of related policy issues, where the collaboratives did not do as well.

Program Scale

The DSM programs of the electric utilities in Massachusetts have increased substantially since the inception of the DSM Collaboratives in the summer of 1988. As Table 4.14 on the next page indicates, the annual expenditures on DSM for the utilities have increased approximately ten-fold between 1987 and 1991, from $18 million to $174 million (in nominal dollars). Measured as a percentage of revenue, the increase represents approximately an eight-fold increase in expenditures from 0.6% in 1987 to 4.7% in 1991. As columns E and F indicate, those expenditures resulted in an approximately five-fold increase in annual energy and capacity savings. By the end of 1991, the utilities' total investments during the 1987-1991 period have resulted in the installation of approximately 350 MW of DSM capacity in Massachusetts. (See Appendix 1 for data on the individual utilities between 1987 and 1991.)

Table 4.14
Massachusetts Utilities' Annual DSM Spending and Savings
1987 – 1991

Year	DSM Expenditure ($ Million)	Operating Revenue ($ Million)	Expenditure As Percent Of Revenue	Incremental Installed MWH	Incremental Installed MW	Cumulative Installed MW
1987	$17.8	$2,923	0.6%	52,837	46	69
1988	$30.2	$3,020	1.0%	143,061	72	98
1989	$55.6	$3,291	1.7%	238,792	122	190
1990	$117.7	$3,490	3.4%	322,088	179	274
1991	$174.2	$3,701	4.7%	389,470	188	346

Notes: Includes BECo, COM/Electric (except for cumulative KW), MECo and WMECo
Does not include data from FG&E, Eastern, or Nantucket
Incremental Installed MW and MWH represent annualized numbers (i.e., if all measures were installed on January 1 of the year).

Source: All data supplied by utilities. 1991 data estimated in most cases.

The increase in spending and projected savings that has occurred since the collaboratives' inception is real and measurable, and the increases in projected future expenditures and savings also appear significant. However, the credit that the DSM Collaboratives deserve for these accomplishments is more often debated. Even without the collaboratives, all of the utilities DSM efforts would undoubtedly have increased -- possibly substantially. For over half-a-decade prior to the collaboratives, the Massachusetts DPU had been increasing its pressure on the utilities directly through its rate orders to accelerate and deepen their DSM efforts. Penalizing BECo on its rate-of-return, in large part for inadequately pursuing DSM, was perhaps the most extreme example of the Commission's willingness to spur the utilities into action. Other companies were also receiving harsh words and increasing directives with respect to DSM from the DPU. With the DPU's initiation of a DSM inquiry within its Integrated Resource Management rulemaking proceeding just prior to the initiation of the Collaboratives, the DPU was likely to increase their pressure to pursue DSM more aggressively.

Yet, despite the DPU's willingness to pursue a fairly interventionist course of action in support of DSM, the utilities' DSM programs would probably not have developed as far or as fast absent the collaborative process. Everyone I interviewed for this case, including the former Commissioners, concurred with this observation. For instance, even after several years of increasingly critical orders by the DPU on DSM issues, between 1987 and 1988 the Massachusetts utilities continued to increase their commitments to DSM, but at a much slower rate than after the collaboratives were in full swing.[53]

Given the limited resources and expertise at the DPU, it would have been extremely difficult, if not impossible, for the DPU to step in and micro-manage the utilities in a way that would guarantee that they implement the DPU's policy objectives. As former Commissioner Tierney points out, the collaboratives deserve significant credit for jump-starting the companies' DSM efforts:

> If there were no collaboratives, even if we wanted to push DSM, we simply didn't have enough staff to do so. Therefore the process would have been much slower with the Company making proposals, then the intervenors attacking them, then the Commission deciding, and then going through the entire process again and again. I think that without the collaborative there would have been a lot less DSM, and that the DSM that was done would not have been as comprehensive (Tierney Interview).

Lastly, some recent literature implies an alternative hypothesis that the utilities new-found ability to earn positive financial incentives on their DSM investments (e.g., shared-savings) deserves credit for recent enhancements to the utilities DSM efforts (Nadel et. al. 1992). This issue needs some sorting out, since in both of the individual

Massachusetts Collaboratives where financial incentives occurred (i.e., MECo and WMECo) they were awarded in the context of DSM collaboratives.

The shared-savings-based financial incentive mechanism should be seen largely as an innovation of the collaboratives themselves, since it emerged for the first time in the collaborative between NEES and CLF.[54] Also, without the collaboratives to help sort out the issue of when performance should be considered "exemplary", the Massachusetts DPU would probably not have been forthcoming with financial incentives which were controversial both inside and outside the DPU. Moreover, neither MECo nor WMECo were granted financial incentives until after they had agreed to extensive program design changes and the acceleration of program implementation. BECo and COM/Electric's efforts give further evidence that the collaborative processes and not just new-found financial incentives were behind utilities' increased willingness to scale-up their DSM investments. These efforts were comparable to MECo's and WMECo's in most respects although they did not request, nor receive, positive financial incentives.[55]

Program Design

The DSM-related experience and knowledge of Massachusetts' utilities and NUPs was augmented by hiring consultants with extensive experience running DSM programs. This guaranteed that the collaboratives had access to the best available information when designing DSM programs. Comprehensive and generally innovative program designs emerged as a result of this technical expertise in conjunction with the political agendas of the various participants in the collaborative processes. Innovative features of the programs included: (1) detailed market segmentation and target marketing; (2) the concept of direct investment in DSM (i.e., utilities paying up to their avoided cost of new supply to purchase DSM resources); (3) an emphasis on capturing lost opportunity resources (e.g., new construction and equipment replacement) and avoiding cream-skimming (e.g., not installing sub-optimal levels of insulation or doing only lighting retrofits when other measures are also cost-effective); (4) detailed monitoring and evaluation plans to, among other things, try to measure actual savings; and (5) creating mechanisms to link utility profits directly to DSM performance.

Most likely the DPU would not have anymore success pushing the utilities to adopt these innovative program design elements than it had in trying to accelerate program implementation. In fact, the DPU was largely hamstrung with respect to program design issues without the collaboratives. While the DPU could react to program details that it was asked to review, it would have greater difficulty pre-designing programs on its own in sufficient detail to direct the utilities to undertake specific efforts. The DPU tried this approach to program design with mixed-success when it previously ordered the utilities to pilot-test performance contracting programs in the pre-DSM-collaborative era.

At best, absent the collaboratives, the program detailing would have been subject to extensive litigation. Instead, despite some modifications ordered during each Company's preapproval cases, the DPU enthusiastically endorsed the program designs worked-out by the utilities and the NUPs in the collaboratives. Moreover, almost all the programs are in the field instead of tied-up in potentially endless litigation.

Though still evolving, most collaboratively-designed programs have resulted in higher than expected levels of participation. Furthermore, the program designs are recognized nationally as state-of-the-art, and the participants of the Massachusetts

Collaboratives have been key presenters at every major conference on DSM since the collaboratives began.

Resolving Policy Issues

The collaboratives successfully resolved a multitude of technical issues necessary to design DSM programs and generally operationalize the DPU's DSM-related policies. However, they have not been nearly as successful in resolving related underlying but unresolved policy issues. For instance, during Phase I, attempts to reach agreement on an appropriate cost-effectiveness test and on cost-recovery issues were extremely contentious and polarized. Difficulties arose both between the utilities and the NUPs, and among the individual NUPs especially on cost-recovery issues.

Although the DPU's Order (D.P.U. 86-36-F), issued in the midst of the Phase I Collaborative effectively broke the impasse on many of the bigger policy questions, some that remained unanswered or that required a level of detailing beyond the DPU's Order, continued to elude consensus right through the end of Phase I, into Phase II and beyond. The DPU's DSM preapproval Orders, issued at the conclusion of Phase II and Phase III, continued to resolve critical underlying policy disputes among the parties on the appropriate cost-effectiveness test, customer incentives, program scale, and cost-recovery issues to name a few.

The parties' inability to agree to an environmental externality methodology through a separate mini-collaborative encouraged by the DPU, is another example of these collaboratives' difficulty resolving critical policy issues. Finally, the utilities considered the issue of whether electric companies should include fuel switching measures within their DSM programs so politically sensitive that they would not allow it to be discussed even in the collaboratives. As a consequence of the collaboratives' inability to resolve the environmental externality and fuel switching issues, as well as a host of other DSM-related policy issues, those issues are likely to be decided by the DPU through further adjudicatory proceedings.

The DSM Collaboratives may not have done a great job resolving the underlying policy issues that often touched on important distributional issues and philosophic underpinnings. However, their attempts were not necessarily unheeded. Debates on cost-effectiveness testing and even environmental externalities highlighted important technical information and clarified parties' interests and positions. By the time these policy issues were presented to the DPU for resolution, they were much more finely honed than they may have been without the benefit of the debates during the collaboratives. This focusing helped the DPU make more informed (and therefore hopefully more practical) decisions.

Process Evaluation

One major difference between traditional settlement and the DSM collaboratives, is that the collaboratives began prior to any specific adjudicatory proceeding, and not after discovery, hearings or the filing of legal briefs as is usually the case in traditional adjudicatory settlements in rate cases. By focusing consensus-building during the pre-filing rather than the post-filing period, there was a greater potential for process-related savings. More importantly, since parties' positions were not yet publicly staked-out as they usually are in traditional adjudication (i.e., filing of testimony early-on, and briefs after hearings), there was more flexibility to explore creative settlements that better satisfied everyone's interests.

The use of these prefiling settlement processes appeared particularly well-suited for the prospective nature of formulating the utilities' DSM programs. Historic facts were not really at issue here. Instead, the immediate focus was to formulate the best strategy for procuring cost-effective DSM resources in the future.

Both Phase I of the Massachusetts Collaborative and the NEES Collaborative began with a joint fact-finding effort in which the parties developed a technical data base and explored program design options. This was particularly important because it pulled together the technical information that was essential for ultimately shaping the program designs. It also allowed parties to create program design options without having to make final decisions about funding or incentive levels which were reserved for Phase II. Finally, the joint fact-finding effort gave these traditional adversaries an opportunity to begin to build interpersonal relationships and trust where little had previously existed.

Another important and unique feature of the DSM collaborative process was the funding that was provided by the utilities for the NUPs to secure their own independent technical expertise. As discussed earlier, over $3 million has already been spent to this end in Massachusetts. The outside experts provided state-of-the-art technical knowledge for the collaboratives -- particularly in the early phases where information about the experience of other programs from across the country was critical. Unlike traditional adjudication where technical knowledge is often used as a weapon, the experience and recommendations of the outside consultants were readily shared in the collaboratives, and often served as a starting point for further negotiations.

Moreover, the funding for outside experts allowed the NUPs, who had a political interest in the utilities' DSM efforts but varying degrees of technical expertise, to more effectively participate in the collaborative processes. In this regard, the funding of outside experts helped to further empower the NUPs.

Despite these extensive resources, several of the individual collaboratives suffered because the NUPs and their consultants were spread too thin. The parties acknowledged that this problem was at least partially responsible for the tensions that arose around WMECo's first preapproval filing, and COM/Electric specifically mentioned it as a major frustration. The problem was in part due to the consultants being so over-committed that they could not deliver technical work-products in a timely fashion. There were also bottlenecks within the NUPs' respective organizations who took a long time to review documents and reach decisions.

Of course, there were also instances when the utilities themselves proved to be the laggards. Still, the collaboratives may have benefitted from increased resources, particularly to help fund the NUPs' own internal staffing needs. However, the NUPs consider it problematic to secure money from the utilities (and hence from the ratepayers) for internal staffing purposes (with the only exception being when CLF secured money from BECo to retain an attorney) and the utilities might consider such funding comparable to intervenor funding which they have always opposed. This poses a hurdle to sustaining on-going collaborative efforts -- particularly where the same NUPs are involved in more than one effort simultaneously.

Unlike traditional settlement processes which often must contend with all the intervenors in the case, the participants in these voluntary collaboratives were carefully self-selected. Despite the presence of four NUPs in each of the collaboratives (except for the NEES collaborative which included only CLF), all were structured more-or-less as two-party negotiations with the NUPs acting as a coalition -- hiring a single NUP coordinator and a single set of consultants. This structure was possible because of the NUPs common interest in seeing more aggressive DSM programs implemented as soon as possible. Other typical intervenors such as industrial consumers were not viewed as allies by the NUPs and were not invited to participate.

This selectivity worked well for the parties in the short-run allowing them to stay focused, and to often reach creative agreements on complex matters in relatively short time-periods. However, the failure to directly embrace all interested parties within their collaboratives resulted in subsequent intervention by non-participants and contentious litigation before the Department in every case. Still, it is not apparent that less exclusivity in these collaboratives would have automatically improved the end results. The ORNL study on DSM collaboratives, for instance, found that some collaboratives that were more inclusive did quite well (e.g., the California collaborative with 15 parties covering the full spectrum of stakeholders still reached substantial consensus) while others had serious problems (e.g., New York State Electric and Gas Corporation which included industrial intervenors who were not supportive of developing utility DSM programs) (Raab and Schweitzer 1992).

The process would have needed a different structure if additional parties were included in the Massachusetts Collaboratives, since it is unlikely that they would have been compatible with the NUPs. A single NUP coordinator or set of consultants may not have sufficed.

It is worth reiterating that the DPU staff also did not participate in the Massachusetts Collaboratives either as a full party or even as an observer, in contrast to many other states where advocacy staffs from PUCs often actively participated and advisory staffs occasionally observed (Raab and Schweitzer 1992). Massachusetts did not at the time have an advocacy staff, and the Commission determined that its advisory staff should not participate even as observers.[56] The DPU's absence from the process resulted in some collaborative agreements that were ultimately rejected by the Department, and some stalemates within the collaboratives themselves, particularly on policy-related issues, that may have been avoidable.

Greater access to the DPU staff and Commissioners either on a formal or informal basis may have succeeded in clarifying past decisions and revealing current perspectives, so that the process did not get bogged-down or unnecessarily polarized. The DPU attempted to do this with some success when it held a facilitated informal session on DSM ratemaking issues. More technical sessions on a regular basis, at least with the DPU staff, may have been appropriate and useful.

The DPU may also have been able to play a greater mediatory role on policy issues by hearing policy disputes, and issuing interim rulings. Alternatively, the collaboratives may have benefitted from the services of an outside mediator to help participants resolve policy disputes, or even to help the processes accommodate a broader range of interested parties. However, as discussed in the concluding chapter, any such changes particularly with respect to greater DPU involvement must be done with an eye to ex parte and other legal restrictions.

To the extent that DSM Collaboratives occur prior to a utility filing, they do not preclude the use of more traditional settlement processes between the time when the programs are filed but before a PUC order is issued. In this respect, pre-filing settlement processes not only supplement traditional adjudication but they can supplement traditional settlement processes as well. This scenario is exactly what occurred in both Rhode Island and New Hampshire where the DSM agreements between NEES and CLF were settled with the advocacy staffs of the PUCs and other intervenors subsequent to the collaborative filings. In the third phase of the COM/Electric collaborative, a diverse group of parties were able to reach a settlement after the collaborative had broken down and an extremely vitriolic, contested-case proceeding had ensued. In this way, the prefiling settlement process expands both the points of opportunities for settlement and the timeframe during which a settlement can be forged.

A final distinguishing characteristic of the DSM collaborative processes studied here is that many are on-going. In contrast to traditional settlement procedures which rarely last more than several months, the NEES, BECo and WMECo Collaboratives are all approaching four years. Although the collaboratives have operated in phases with discrete products delivered at the end of each phase (e.g., filing at the DPU), and although there have been brief hiatuses from time-to-time (e.g., several months), these processes have been on-going. These rather unprecedented relationships have for the most part been extremely fruitful in developing programs, and then in jointly reviewing monitoring and evaluation results and refining the programs as necessary (i.e., in accordance with evaluation and monitoring data and changing circumstances such as the downturn in the New England economy). However, it is not clear whether these collaboratives will or should continue indefinitely, even though they continue to mature.

Endnotes (Chapter 4, DSM Collaboratives)

1. MECo is responsible for 75 percent of NEES's retail sales. NEES also has retail companies in both New Hampshire (Granite State Electric Company with 5 percent of retail sales) and Rhode Island (Narragansett Electric Company with 20 percent of retail sales). Although this case study attempts to analyze the entire collaborative between NEES and CLF, it emphasizes the experience of the collaborative results in the Massachusetts regulatory process -- the primary focus of this case.

2. All interviews were face-to-face except Besser, Burrington, Chaisson, Pastuszek, Watts and White which were done by phone. Chaisson, Cohen, and Werlin were interviewed on two separate occassions -- once for the Massachusetts Collaborative and once for the NEES Collaborative.

3. In the ORNL study, the NEES-CLF and Massachusetts collaboratives were researched and described separately, but have been combined here into one case. All the work on the two original cases were done by me.

4. My tenure at the DPU began in May 1988 as a Senior Economist and ended in January 1991 as the Assistant Director of the Electric Power Division. In January 1989, I became the lead staffperson responsible for DSM.

5. In June 1987, the DPU severely chastised WMECo for its lackluster DSM efforts (D.P.U. 86-280-A).

6. D.P.U. 86-36 ultimately resulted not only in new resource "preapproval" regulations, but also in DSM cost-recovery and ratemaking rules, an environmental externality methodology and a new all-resource bidding process. The formation of these rules are discussed in detail in the Integrated Resource Management Rule case study in the following chapter.

7. Though not formal members of the NEEPC, the AG and the DOER representatives attended many of the coalition's meetings and supported the process.

8. The expansion and bifurcation of the generic investigation was largely in response to a request by the AG, DOER, CLF and other members of the NEEPC.

9. The Panel of experts included Arthur Rosenfeld (Lawrence Berkeley Labs), Thomas Foley (Northwest Power Planning Council), Joseph Chaisson, Nancy Benner (Portland Energy Conservation, Inc.), Stephen Cowell, Paul Chernick (PLC Inc.), H.Gil Peach (Pacific Power & Light), and Armond Cohen. The experts were sponsored by CLF, MASSPIRG and seven other members of the NEEPC, and were funded by DOER.

10. CLF had been an active participant in the initial litigated case and the subsequent DSM collaborative in Connecticut.

11. Cagnetta had lead responsibility in NU's participation in the DSM Collaborative in Connecticut as well. It's also notable that Cagnetta had previously taken a course on "principled negotiation" from Roger Fisher author of Getting to YES. See Chapter 3 for discussion of nexus between dispute resolution literature and electric utility consensus-building experiments.

12. Sentinel Energy Services Company, which was involved in residential performance contracting sent the DPU a letter protesting the exclusive nature of the Collaborative. The NUPs decided not to expand the process, but the parties held a meeting with 16 people representing nine ESCOs and energy consulting firms to review the programs being developed and to solicit recommendations. The DPU did not order the parties to expand their membership, primarily because it considered the process voluntary.

13. The DPU had never previously allowed the funding of intervenors in rate cases or other proceedings, and did not believe that it had the authority to do so, despite frequent requests by intervenors to allow it.

14. The Order was silent on the NEES-CLF Collaborative which the Department was never asked to approve.

15. In D.P.U. 86-36-D (1988) the Department issued the following directives: (1) Programs should be implemented as soon as they are ready (i.e., utilities should not wait until the following summer after Phase II); (2) Parties should address other hard-to-reach sectors (besides low-income) including (a) rental housing, (b) small commercial establishments; and (c) public buildings and facilities, to "spread the direct benefits" of DSM; (3) All interested parties should be directly or indirectly invited to participate in the process; (4) Parties should not come to the Commission to resolve collaborative disputes on a regular basis; (5) Utilities should consider the $385,000 for the NUPs experts allowable as a legitimate DSM development cost; and (6) Parties should focus on program design and implementation issues rather than policy issues.

16. With respect to the appropriate cost-effectiveness test, the debates included (a) Whether a utility revenue minimization test or a societal test should be utilized? (b) How, if at all, environmental externalities should be internalized? and (c) How, if at all, DSM measures and DSM programs which include bundles of measures should be evaluated differently? With respect to cost-recovery, the debates included (a) Whether utilities should expense or amortize their DSM investments; (b) Whether utilities should be entitled to any lost sales revenue associated with the pursuit of DSM; and (c) Whether any additional incentives beyond recovery of direct costs and lost revenues was justified?

17. In the end, the Phase I program designs did not use any cost-effectiveness test to screen the program designs -- leaving that level of detail for Phase II (Phase I Report, p. 4).

18. With respect to cost-effectiveness testing, the Order required that utilities use a societal test that includes both customer and utility costs as well as environmental costs and any other significant non-energy costs and benefits (D.P.U. 86-36-F, pp. 19-

24). With respect to cost recovery, the Order indicated its willingness to entertain proposals either to expense or amortize direct DSM expenditures, as well as proposals to recover lost revenue (id., pp. 31-36). The Order further indicated that substantial DSM programs could be submitted for "preapproval" just as supply resources could (i.e., utilities could commit to providing DSM at a certain price in exchange for the DPU essentially finding the programs "prudent" and "used and useful" ex ante rather than through ex post reviews as was traditionally done in Massachusetts and most other states) (id.). The Order did not grant the utilities any additional incentives such as shared-savings.

19. CLF did, however, push fuel switching in its collaboratives with utilities in Vermont from the start. Largely because of the controversy on that issue, those collaboratives were extremely contentious and slow-moving although they eventually settled the fuel switching issue with all the utilities (Raab and Schweitzer 1992). Meanwhile, as of this writing, fuel switching issues are still being heavily litigated in Massachusetts after Boston Gas intervened in MECo's DSM preapproval case in 1991, and over twenty additional parties followed suit.

20. On August 31, 1990, absent a consensus, the Department issued its final rules in its on-going D.P.U. 86-36 investigation. In the Order, the Department adopted a series of environmental adders for different pollutants recommended by the DOER, which were the highest adopted values by any state at the time (D.P.U. 89-239, pp.51-85)

21. The DPU staff's concerns included (a) making sure the cost-effectiveness tests were consistent with those outlined in D.P.U. 86-36-F; (b) addressing all hard-to-reach sectors including rental housing in 1-4 unit structures and institutional facilities; (c) avoiding lost opportunities and cream-skimming (e.g., the letter warned against using the proposed appliance labeling program); and (d) retaining performance contracting as an option.

22. David O'Connor, Executive Director of the Massachusetts Office of Dispute Resolution (then called Massachusetts Mediation Services), provided facilitation. At the time, David O'Connor was also facilitating a series of technical sessions for the Department in its Integrated Resource Management rulemaking process. His role, and the use of outside neutrals are discussed in detail in the DPU rulemaking case in the next chapter.

23. The NEES-CLF incentive proposal was actually a two-part incentive. The first part rewarded the utility for each kwh saved at a fixed price (i.e., maximizing incentive), while the second part rewarded the utility based on a percentage of the difference between NEES's avoided cost and the cost of DSM (i.e., efficiency or shared-savings incentive). In theory, the maximizing incentive was to guarantee that the utility pursues all cost-effective DSM (i.e., less than NEES's avoided cost) and not just the cheapest DSM, while the efficiency incentive was so that the Company would deliver its programs as efficiently as possible.

24. The Company proposed using the model-based statistical sampling (MBSS) technique. In the MBSS technique, the error ratio is used in place of the more familiar coefficient of variation of the target variable. The advantage of the MBSS technique according to WMECo is that it allows sample size to be reduced substantially below conventional sampling techniques.

25. MASSPIRG and DOER did not intervene in the case, and all the NUPs including the Attorney General let CLF represent their interests on most issues in the case. However, the DPU did solicit the testimony of all the NUPs (even those not formally in the case) on WMECo's programs.

26. Specifically the Industrial Intervenors (Kimberly-Clark Corp., Meade Corp., and Monsanto Co.) argued that provisions in the Large Commercial and Industrial program violated anti-trust law by precluding self-generation as a precondition for participating in the Company's DSM programs (D.P.U. 89-260 (June 1990).

27. CLF only challenged one aspect of COM/Electric's proposal -- the sole-sourcing of audits in the Electric Heat Program.

28. The increases were caused by a combination of factors including (1) increasing costs for Commonwealth Electric combined with not having had a rate case since 1982, (2) the elimination of discounted electricity prices for space heating customers, (3) the movement to marginal cost-based pricing generally, and (4) a dramatic increase in the fuel charge almost immediately after the rate increase went into effect.

29. COM/Electric maintained that due to all the controversy over its rates, it would not be wise to push for incentives or even lost revenue at that time (Zajac Interview).

30. MECo, the only other utility in Massachusetts of comparable size, essentially volunteered to have its DSM programs regulated by the Commonwealth instead of FERC. Also, the Collaborative with MECo involved only CLF.

31. Under Massachusetts' unique preapproval rules, originally designed for major supply-side investments, utilities could have their resources approved ex ante as opposed to ex post. However, preapproval requires that the resource is anticipated to be cost-effective, and that cost-recovery is tied to performance (D.P.U. 86-36-E and F (1988)).

32. The DPU clarified and refined its cost-effectiveness screening criteria in the Orders in these preapproval cases (e.g., free-rider, free-driver, and administrative cost issues were addressed for the first time in these cases). In doing so it helped further resolve most of the controversy that continued to surround this issue in the collaboratives. However, in doing so, some of the programs that appeared cost-effective previously were no longer cost-effective and vice versa.

33. The DPU approved the programs for one year instead of on an indefinite basis -- as other PUCs have done. The DPU's decision was in part because MECo, the first

utility through the process, requested only a one year approval, and in part because of the DPU's desire to continue to keep the utilities' DSM programs on a short-leash.

34. The DPU concluded in making its cost allocation decision that "fairness dictates that customers who are prohibited from participating in a program because their class has not been offered that program should not have to see their bills rise to pay for it" (D.P.U. 89-194/195, p. 212 (1990)). This decision hinges on an important question (which was discussed in Chapter 3) regarding whether DSM is a resource, or a customer service, or both. If one views it purely as a resource it should be allocated as MECo proposed. However, if it is viewed solely as a customer service it should probably be allocated directly back to the participating customer as Cicchetti and Hogan and others have proposed (Cicchetti and Hogan 1988). Ironically, despite a long history of the utilities in Massachusetts viewing DSM primarily as a customer service and the DPU arguing that it was a resource, the DPU's final decision cuts a middle course between the two approaches. Al Destribats of NEES, in our interview, acknowledged that his Company later concluded that the DPU's cost allocation decision was a wise one which better served the interests of MECo's customers as well as its own interests than its original proposal.

35. In actuality the savings must only be measured for the first two years. Life-time savings, which is what the incentive payments are based on, are calculated by multiplying the annual measured savings by prespecified measure lives for each measure. It should also be noted that MECo and CLF volunteered to use after-the-fact measurement in Massachusetts in the course of the hearings after sensing the DPU's interest from staff's questions and knowing about the AG's interest (Hicks Interview).

36. A good example of this issue was the DPU's rejection of an appliance labeling program that all the parties had agreed on in all three cases. The DPU was not convinced that the program was cost-effective. More importantly, the DPU thought that a rebate program might be more effective and ordered the Companies to reevaluate their programs -- to all the participants' chagrin.

37. According to this recent study, only two other utilities spent more on DSM as a percent of revenue than NEES in 1991 (Seattle City Light spent $15 million which represented 6.2 percent of revenue, and Sacramento Municipal Utility District spent $42 million representing 6.4 percent). Also, only two other utilities spent more than NEES in absolute dollars, although neither spent more as a percent of revenue (Southern Cal Edison spent $108 million representing 1.4 percent of revenue, and Pacific Gas & Electric spent $154 million representing 1.7 percent).

38. MECo's preapproval filings also represented a consensus but only between the Company and CLF. As discussed, in the 1990 case the AG intervened against parts of MECo's preapproval request.

39. Mort Zajac of COM/Electric maintained that the NUPs would constantly want to renegotiate issues that had been agreed to after they were revisited in the BECo Collaborative, which he maintained absorbed most of the NUPs focus.

40. The four programs included (1) Residential Hot Water/General Use Program, (2) Residential Electric Heat Program, (3) Direct Investment Program (for small/medium commercial and industrial customers, non-profit organizations, and other non-residential customers that lease), and (4) Customized Rebate Program (for larger commercial and industrial customers, and schools).

41. CLF justified its punitive request on the basis that the Company had proved it was incapable of running successful DSM programs and had no plans to carry out the DPU's policies of pursuing all cost-effective DSM opportunities from its customers (CLF Brief). CLF also asked the DPU to order COM/Electric to develop and implement various programs not part of its proposed portfolio (e.g., new construction), to develop detailed evaluation and monitoring plans, and to change its cost-effectiveness screening tool (id.).

42. For instance, COM/Electric argued it gained a much higher absolute participation in both its Small Commercial and Industrial program and its Electric Heat program than any other utility in Massachusetts in 1990 (despite its relatively small size). It also argued that it had spent more money on its overall DSM effort in 1990 when measured as a percent of revenue than any other utility in Massachusetts.

43. The Company argued that even if it pursued and acquired all the cost-effective DSM opportunities as agreed to in the Collaborative it still needed Edgar. The AG, MASSPIRG and CLF argued, among other things, that the Collaborative agreement only covered five years and that more DSM should be available making the plant virtually unnecessary for the foreseeable future.

44. The DPU's BECo Order was not out as of the final writing of this case, and is therefore not incorporated in this brief section.

45. The DPU's directives in this regard included (1) approving the increase in rebate levels for Energy Initiative and Design 2000 programs; (2) putting the Company on notice that its Small C&I program must include non-lighting measures in 1992 to be considered for approval; (3) ordering MECo to increase expenditures in its Home Energy Management (residential load management) program from $2.9 to $4.5 million; (4) ordering the Company to go systemwide with its Residential Lighting program in 1991, and to offer compact fluorescent lights with electronic ballasts in 1992 unless the Company could prove they would be detrimental to the system; (5) requiring quarterly tracking of Company performance with respect to residential programs because of poor performance in 1990 (i.e., residential expenditures were down 45% from budget while C&I expenditures increased 15% from budget); and (6) ordering MECo to study and implement all cost-effective voltage reduction opportunities on the system.

46. The DPU ordered MECo to include evaluation and monitoring costs and any projected bonus in the cost-effectiveness analysis of each program. It also directed MECo to use the Department's externality numbers from D.P.U. 89-239 (1990).

47. It is also possible that the complete change in Commissioners and the senior DPU staff responsible for DSM immediately after the Phase III MECo Order (and hence also after the previous WMECo DSM order) also played a role. The new leadership at the DPU may be willing to provide more deference to settlements on DSM and other issues than the prior Commission and staff.

48. The settlement also included the Energy Consortium and the City of Worcester. The settlement largely accepted the filing as submitted and did not require any major modifications to program design or budget. In a rather unique approach to settlement, two of the DPU advisory staff who cross-examined the witnesses, switched to advocates in order to settle the case after the close of hearings.

49. This litigation apparently cost CLF over $100,000 for its own staff time and for purchasing the services of outside, expert witnesses (Coakley Interview).

50. In Monsanto Co. v. Department of Public Utilities, the Massachusetts Supreme Judicial court concurred with the DPU's conclusion that "the program design submitted by the Company appears to be consistent with the clearly articulated and affirmatively expressed policies of the Department", and that therefore neither State nor Federal antitrust acts were violated (412 Mass. 25 (1992)).

51. Henry Yoshimura, Director of the Electric Power Division at the DPU, does not recall there ever being another appeal on a DSM-related decision in the eight years that he has been with the DPU.

52. The symbolism of the former Chair of the DPU and BECo's CEO writing an article together must be noted as nothing less than impressive given the long history of confrontation between the two entities.

53. For example, there was only a $2 million, 25% increase between 1987 and 1988, as opposed to the doubling that occurred between 1988 and 1989, and the redoubling that occurred between 1989 and 1990.

54. Prior to the NEES-CLF proposal, the shared-savings concept was only discussed in theory in the literature (See Moskovitz 1989).

55. Both COM/Electric and BECo were constrained from applying for financial incentives by factors essentially external to the Collaborative itself. For COM/Electric it was the threat of a ratepayer revolt which precluded it from asking for any more cost-recovery than absolutely necessary. It is possible that COM/Electric's recent back-pedalling of its DSM commitments may in part be due to the lack of adequate financial incentives. For BECo it was the constraint of the Pilgrim Settlement which provided that its first $75 million of DSM expenditures be paid by its stockholders at no cost to the ratepayers. BECo immediately requested a lost revenue adjustment and positive financial incentives on its incremental investment from the DPU (with the NUPs' support) once the $75 million was exceeded.

56. The Commission's decision was in part based on their concern that staff could not fit the collaboratives in their preexisting work-load, and in part due to legal concerns that participation even as observers might violate ex parte rules (since the utilities would eventually request approval through adjudicatory proceedings).

Adjudication Chapter Summary

In this Chapter I evaluated two attempts to introduce supplemental consensus-building processes in traditional adjudicatory proceedings. The first used a settlement process at the end of extremely contentious litigation associated with expenditures made by Boston Edison Company during a 32-month outage at its Pilgrim Nuclear power plant. The second entailed a collaborative process between utilities and several non-utility parties to prospectively design comprehensive demand-side management programs during negotiations lasting over several years.

My analyses indicate that consensus-building can enhance the legitimacy of adjudicatory proceedings largely by giving stakeholders an opportunity to design remedies and plans that better satisfy their own interests. In the Pilgrim case, the mere fact that traditional adversaries were able to reach a consensus after one of the most contentious adjudicatory proceedings imaginable, suggests this possibility. PUC approval, lack of appeals, and several other factors bear this out despite several noteworthy problems. The effect that the DSM Collaboratives had on the legitimacy of their adjudicatory proceedings, while also positive, was somewhat more difficult to characterize definitively because it involved many sub-collaboratives which fluctuated between consensus-building and contentious litigation for several years.

Both cases also provide strong evidence that consensus-building can improve the practicality of final remedies and future plans in adjudicatory proceedings. Parties' creatively resolved thorny issues in the Pilgrim settlement by tying BECo's cost-recovery to the future performance of the plant (including operational, health and safety factors), and by having the Company deliver $75 million of DSM in lieu of refunding replacement power monies paid by ratepayers. The remedies were attractive to the DPU but probably would not have arisen from formal adjudications.

In the DSM Collaboratives, over $3 million have already been spent to hire consultants from across the country to bring state-of-the art information into the negotiations. The collaboratives have in-turn produced DSM efforts for Massachusetts utilities with many nationally-recognized program design innovations. Again, these practical plans probably would not have emerged from traditional litigation anytime soon.

However, the consensus-building processes have been relatively resource-intensive. The Pilgrim Settlement required an entire summer of negotiations among the parties, and occurred after virtually all the litigation was completed. The DSM Collaboratives have required enormous investments of time and money over several years. Yet, the DSM agreements were still all litigated before the DPU despite these collaborative efforts. I conclude that short-term process related resource savings are not guaranteed in adjudicatory settlements. However, long-term net benefits appear to be positive and significant compared to traditional adjudication, once the actual improvements to the remedies and plans are factored into the analyses.

Chapter 5: Rulemaking

Introduction

I begin this chapter by differentiating agency rulemaking from adjudication (the subject of Chapter 4). I then trace the history of agency rulemaking from its introduction at the federal level in 1946. The short-comings of traditional agency rulemaking are highlighted, and the promise of alternative, consensus-based rulemaking processes is introduced. In the second and third part of the chapter, I analyze two case studies. The first case entails the use of facilitated, technical sessions used to develop Integrated Resource Management rules in Massachusetts. The second focuses on a negotiated settlement process used to develop resource bidding policies in New Jersey.

Differentiating Agency Rulemaking From Adjudication

Decisions in agency adjudications, though often considered precedential, are not formally binding on persons who are not parties to the case. Rules on the other hand, legally apply to all parties under an agency's jurisdiction. Agencies theoretically use rulemakings to act proactively by formulating policies that are applied prospectively, and adjudications to apply (and necessarily interpret) preexisting rules to individual cases retrospectively. Because of this important distinction, rules are generally more appropriate for resolving industry-wide policies.

The courts have historically afforded agencies a great deal of latitude in choosing to resolve policy matters through either process.[1] However, over the past decade all branches of government have increasingly expressed a preference for rulemaking for creating broad policies. Still, agencies frequently use adjudication for these purposes (Shapiro 1965, Breyer 1982, Burns 1988, Strauss 1989).

Agency rulemakings also differ procedurally from adjudications in theory. The procedural differences stem from the basic premise that agency adjudications are "quasi-judicial" while rulemaking is essentially a legislative function. In the former, agencies must make every effort to act as an impartial judge; in the latter, neutrality is neither assumed nor expected. In adjudications the agency is required to make decisions based on the facts in a particular case as presented by the parties. In rulemakings, agencies are generally less restricted by court-like, due process constraints. As such, requirements for agencies to build a detailed record, to justify their final decision, and to avoid ex parte communications are supposedly more relaxed.

However, in practice many of the procedural distinctions between agency rulemaking and adjudication have been blurred by both the courts and the legislatures. Court-like restrictions have been layered on to the rulemaking process over time (Harter 1982, Strauss 1989). The next section briefly explores the evolution of these changes and presents an analysis of the current dilemmas faced by agency rulemaking. Since state rulemaking practices generally follow federal practice, and because describing the history and practice of rulemaking in each state would be difficult, the primary focus of the ensuing discussion is on federal agencies. I will analyze deviations from federal rulemaking with respect to state PUCs in a subsequent sub-section.

The Evolution of Agency Rulemaking

In 1939, James Landis, then Dean of the Harvard Law School and formerly one of the first commissioners on the Securities and Exchange Commission, published a seminal book entitled The Administrative Process. In it he criticized agencies' use of adjudication, and proposed that they be allowed to promulgate rules (McCraw 1984; Burns 1988). Landis argued that agencies needed to be able to formulate policies to pursue their mandates separate from adjudicatory proceedings:

> For that [administrative] process to be successful in a particular field, it is imperative that controversies be decided as "rightly" as possible, independently of the formal record the parties themselves produce. The ultimate test of the administrative [process] is the policy that it formulates; not the fairness as between the parties of the disposition of a controversy on a record of their making (Landis 1938, pp. 38-39).

Landis's persuasive call was instrumental in the passage of the federal Administrative Procedures Act (APA) in 1946 (McCraw 1984). Besides codifying existing adjudicatory procedures used by agencies, the APA created rulemaking procedures allowing federal agencies to promulgate rules. Known as informal or "notice-and-comment" rulemaking,[2] the APA required that agencies (1) give notice of a proposed rulemaking in the Federal Register, (2) provide interested parties with an opportunity to participate in the process via written comments, and (3) publish a final rule, generally 30 days before it was to go into effect.[3] The requirements for informal rulemaking were extremely permissive and did not even require agencies to conduct hearings except when mandated by Congress under special statutes and in specific circumstances, or when agencies decided to do so on their own.

The same year that the federal APA was adopted (1946), the Conference of Commissioners on Uniform State Laws promulgated a model state APA that was virtually a carbon copy. Adoption of the model state APA is voluntary; however, almost every state has either copied it verbatim or with minor changes (Davis 1972, Bonfield 1986, Burns 1988).

Although the APA's rulemaking requirements directed agencies to offer the public a chance to participate in the process, the new laws approached the agencies as "expert guardians" and relied heavily on their knowledge and experience (Harter 1982). Since the advent of agency rulemaking in 1946, administrative rulemaking has accelerated greatly -- perhaps far beyond the original expectation of its architects. One need only look at the explosion of administrative rules on health, safety and the environment which cropped up beginning in the 1970's to understand this trend. At the same time, Congress and the courts have tried to make agencies more accountable and to provide even greater opportunities for public participation. However, they have tried to bolster the legitimacy of the rulemaking process by layering additional procedural requirements on the scant rulemaking requirements found in the original APA.

Congress, for instance, in passing the Freedom of Information Act in 1969 and the Government in Sunshine Act in 1976, altered rulemaking practices by respectively bringing much of the internal documentation related to agency rulemaking and more of the decisionmaking process itself into public view (Strauss 1989). They also tried to increase agency accountability by passing the Federal Advisory Committee Act of 1976, which placed restrictions on the ad hoc committees often used by agencies to help develop policies and rules (Harter 1982). Finally, Congress has increasingly required administrative agencies to promulgate rules using procedures that are stricter than required by the APA to implement numerous new substantive statutes.[4]

For the federal courts' part, several significant cases have contributed to the refinement of the procedures that govern Agency rulemaking. Beginning in 1971 in Overton Park, Inc. v. Volpe, the Supreme Court required agencies to conduct thorough, probing and careful reviews that would enable the courts "to see what major issues of policy were ventilated by the informal proceedings and why the Agency reacted to them as they did."[5] This case contributed to administrative agencies increasingly embracing "paper hearing" procedures whereby an agency would carefully document all the information it used in reaching a decision and would respond to important comments made by interested parties (Strauss 1989). In 1977, in Home Box Office Inc. v. FCC, a lower court appeared to interpret the Overton decision to (1) extend strict ex parte restrictions to rulemaking procedures (i.e., make it impermissible for regulators to have private, off-the-record conversations with interested persons as is typical for legislators), and (2) to allow an opportunity for adversarial comment (i.e., allow interested parties to cross-examine each other in court-like fashion) (id.).

The courts later receded from some of the specific suggestions made in Home Box Office. In fact, in Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc. in 1978 the U.S. Supreme Court unanimously decided to forbid the lower courts from requiring agencies to follow more stringent procedures than those included in the APA.[6] However, although the sweep of the Vermont Yankee decision is often debated, today's administrative rulemaking process has undeniably adopted more of the trappings of adjudicatory proceedings than was originally envisioned in 1946 when the APA was first promulgated. Current law does not require strict ex parte rules, adversarial hearings or an exhaustive record that includes everything an agency knows or has heard. However, agencies are required to develop elaborate public records that include all the documents received during the rulemaking process and to respond to all comments made (Strauss 1989).

The current administrative process is often referred to as "hybrid rulemaking" to reflect the gradual judicialization (i.e., formalization) of the informal, notice-and-comment process resulting from the actions taken by Congress and the courts (Harter 1982, Susskind and McMahon 1985). Philip Harter in his seminal article "Negotiated Rulemaking: a Cure for Malaise" published in 1982, observes that many of these rulemaking requirements are appropriate given the significant impact of rules on our society. However, he argues that the requirements have contributed to a "malaise" whereby "parties complain about the time, expense and legitimacy of the administrative decisions reached through the hybrid process" (Harter 1982, p. 6). He argues that agencies are no more capable of resolving what are essentially political questions in a way that is considered legitimate, than they were prior to the judicialization. Susskind and Morgan go somewhat further in claiming that increased judicialization may paradoxically be aggravating the malaise:

> We are facing something of a paradox. Many of the steps taken to enhance the legitimacy of decisionmaking have caused substantial delay and inefficiency -- undermining the very credibility they were meant to enhance (Susskind and Morgan 1986, p.24) .

The rulemaking process itself has become more adversarial, and the appeal rate of agency decisions has increased dramatically. For instance, William Ruckelshaus, former federal Environmental Protection Agency (EPA) Administrator, claims that in the early 1980's more than 80 percent of EPA's rules were appealed and approximately 30 percent were changed as result of the litigation (Susskind and McMahon 1985).

Four of every five EPA decisions continue to be appealed in the 1990's, according to EPA's current Administrator, William Reilly (New York Times, 9/23/91). This situation is not unique though the appeal rate of rules vary among federal agencies (Elliot and Schuck 1991, Harter Interview).[7]

It is important to point out, however, that while the judicialization of the rulemaking process may be increasing, it is not the root cause of the crises of legitimacy that the process is currently experiencing. At the heart of the crises is a growing inability of agencies, and the public generally, to resolve increasingly more technical and controversial issues. In this respect, over reliance on agency "expertise" seems neither feasible nor prudent. At the same time, attempts made by Congress and the courts over the past two decades to transform agencies acting in their rulemaking capacities from experts to "umpires", albeit active ones and to guarantee the public greater influence on agency rulemaking, also appears to be failing (Harter 1982, Susskind and McMahon 1985). Susskind and McMahon describe the dilemma:

> If all regulations had a clearly determinable factual basis, arguments about the exercise of agency discretion would be moot. Agencies, however, must also make policy choices in situations where either the desired facts are not available or the "facts" are contested. In such instances, the agency exercises considerable discretion as it interprets inconsistent facts, balances various and often competing interests, and ultimately makes subjective policy choices with very real economic and political ramifications. In this context, an agency can expect opposition to almost every rule it develops (Susskind and McMahon 1985, p. 135).

Alternative Rulemaking Procedures

In Harter's seminal work, he proposes curing the malaise by introducing an alternative rulemaking procedure based on negotiations between interested parties including the agency.

> Thus, an alternative, more direct way to make the inherently political decisions [of agencies] would be to adapt the legislative process itself to the development of regulations. Such a process would enable representatives of the competing interests, including the relevant agency itself, to thrash out a consensus on the policy instead of making a pitch to the umpire. A form of negotiation among the affected parties by a proposed rule would be such a process (Harter 1982, pp. 28-29).

Although Harter was not the first to suggest the possibility of improving agency rulemaking through negotiations,[8] he was the first to thoroughly detail what such a process might look like.

Harter's proposal, often referred to as "reg-neg",[9] contains the essential steps shown in Table 5.0 (on next page). Harter's and Susskind and McMahon's work contain other important recommendations on specific details of negotiated rulemaking (e.g., the creation of a resource pool to fund participants and outside experts, and the use of mediation); however, the above represents the major stepping-stones of the process (Harter 1982, Susskind and McMahon 1985). Consultation with the Office of Management and Budget (OMB) is the only step missing from the table with respect to federal negotiated rulemaking. Given OMB's substantial powers to oversee agency decisionmaking for cost-effectiveness and other purposes, OMB is supposed to be consulted early and often in a negotiated rulemaking process (EPA 1991, Pritzker Interview).[10]

Table 5.0
Negotiated Rulemaking Steps

1. An outside convener, selected by the agency, helps assess whether a rule is appropriate for negotiation (i.e., there is a reasonable likelihood of achieving consensus), and identifies and helps solicit representative stakeholders.

2. If the rule is considered appropriate for negotiation and parties are willing to participate, an agency gives notice of its intention to negotiate a particular rule in the Federal Register.

3. Once final participants are selected, negotiations commence. Agency staff participate as full parties. The process works by consensus.

4. If and when consensus is reached, the agency publishes the consensus rule as the agency's proposed rule in the Federal Register.

5. Comments are received, and the agency publishes the final rules in the Federal Register either without change or with minor revisions, at least 30 days before the rules take effect. (If the comments reveal major flaws an agency may choose to send the rules back to the original negotiating group, or develop a new proposed rule of its own.)

6. There is a period after the final rules are published during which interested persons (outside of those who negotiated the rule) can appeal the final rules to the courts.

Source: Author's List Based on Literature (Harter 1982, Susskind and McMahon 1986)

What is of critical importance is that the process has been designed to supplement the traditional rulemaking process, rather than replace it. The negotiation process is essentially used in formulating an agency's proposed rule. Once this rule is developed, the rulemaking process takes its normal "notice-and-comment" course. As such, the addition of negotiation at the front-end is not inconsistent with the APA's rulemaking requirements, which is virtually silent on how agencies develop their initial proposed rules.

If all interested parties were involved in the settlement, comments on the proposed rule (i.e., the settlement) should be minimal. In theory, this type of process should result in rules that have much broader acceptance and are, therefore, more legitimate. As such, appeals should be minimized and the rules implemented as designed rather than resisted at every turn. Also, the literature claims that this should lead to a more efficient process -- saving time and money for the parties and the agency itself (Harter 1982, Susskind and McMahon 1985). Finally, the rules should be more practical to the degree that the less-adversarial process can produce better information and more realistic remedies.

Even if consensus is not reached, proponents claim that the process of negotiation can improve rulemaking. Susskind and McMahon explain why:

> In some respects, negotiated rulemaking cannot fail. At the very least, conflicts can be clarified, data shared, and differences aired in a constructive way. Even if full consensus is not achieved, the negotiations process may still have narrowed the issues in dispute (Susskind and McMahon, p.159).

Since Harter's article in 1982, at least eight federal departments and agencies have used negotiated rulemaking.[11] The EPA for instance, has completed at least ten reg-negs through the end of 1991 -- the most of any federal agency (EPA 1991, Pritzker Interview). Of the ten, six reached a complete consensus and three others reached agreement among most of the participants (EPA 1991).[12] However, even when a full consensus was not reached, the process significantly helped to shape EPA's final rules (Pritzker 1990).

Only two of EPA's rules that went through the "reg-neg" process were appealed, although neither on procedural grounds, and the courts upheld EPA's decisions in both instances (Pritzker Interview). Still, despite "reg-negs" support in the courts thus far, there has been some concern in the literature with respect to how well "reg-negs" will fair in the courts over time (Wald 1985).[13] However, many argue that the process itself should obviate the necessity of the courts taking a "hard look" at the results (Susskind and McMahon 1985, Harter 1986, Sturm 1991).

A complete evaluation of the federal experience with "reg-neg" is beyond the scope of this inquiry. However, it is worth noting that lead staff at the EPA and others consider the reg-neg process successful in creatively resolving thorny issues in a way that added to the practicality of the rules and helped to better legitimize both the process and the results (Fiorino 1988, Fiorino and Kirtz 1985, Susskind and McMahon 1985, Pritzker 1990). It is also worth reiterating at this juncture that on November 29, 1990, President Bush signed into law the Negotiated Rulemaking Act (Public Law 101-648) which encourages federal agencies to pursue negotiated rulemaking whenever possible and details the rulemaking process to be followed.[14] The passage of this Act is testimonial to the positive impression that negotiated rulemaking has made on federal agencies, Congress and the Administration to date.

Before turning briefly to state PUC rulemaking practices and the introduction of the cases, it must again be emphasized that "reg-neg" is not the only supplement to traditional rulemaking procedures which can begin to address the malaise of current rulemaking practices described by Harter and others. Negotiated rulemaking is perhaps the most visible and celebrated consensus-building technique on the federal level. However, it stands at the top of a pyramid of other supplemental, consensus-building procedures. Such procedures include policy dialogues, advisory committees, workshops, round-table discussions, and technical sessions. All of these alternatives serve to provide parties, including the agency staffs, with the potential for greater understanding of issues, proposals, and the interests and perspectives of others. They also provide opportunities for consensus-building, although "reg-neg" is perhaps the most formal and aggressive in this regard. As such, all of these techniques have the potential to make rules both more practical and more legitimate.

State PUC Rulemaking

Under American federalism, each state regulates its own administrative procedures. As mentioned previously, the National Conference of Commissioners on Uniform State Laws adopted a Model State Administrative Procedures Act (MSAPA) in 1946 to provide states with the opportunity to implement the federal APA procedures at the state level. The National Conference has updated those procedures in 1961 and again in 1981.

According to a study by the National Regulatory Research Institute in 1988, over 80 percent of the states have adopted some version of the MSAPA (Burns 1988).[15] However, the same study found that PUCs in only about half the states are actually required to comply with the MSAPA. The remaining PUCs either have received an explicit exemption from their state's APA or their state never adopted the MSAPA in the first place (id.).[16] These facts are not necessarily of major significance since all PUCs, even those that are exempted from their state's APA, have rulemaking rules that rarely deviate much from the federal APA requirements.

Of greater significance, is the NRRI report's finding that state PUCs do not regularly use rulemaking proceedings to make major industry-wide policy decisions. While this differs from state-to-state, apparently many PUCs still tend to set industry-wide policy by precedent through adjudicatory proceedings (Burns, 1988).[17] For instance, even the Massachusetts PUC, which initiated several significant rulemaking proceedings during the 1980's as discussed later in this chapter, recently chose to revisit its environmental externality policies and to explore creating fuel switching policies (i.e., requiring electric utilities to pay for their customers to switch from electricity to gas and other fuels as a DSM measure) through adjudicatory proceedings (D.P.U. 91-131 and D.P.U. 90-261-A, respectively). Over the past decade, as mentioned in Chapter 4, the DPU has only initiated two rulemakings on electricity issues (Yoshimura Interview).

The reasons that state PUCs appear to be embracing rulemaking more slowly than federal agencies is not completely clear. This difference is probably connected to a greater procedural inertia at state PUCs caused by a longer history than most other state and federal agencies -- and one that until recently, has been exclusively focused on adjudicatory proceedings. Nonetheless, many PUCs have begun to promulgate rules on issues of major structural and regulatory import such as least-cost integrated planning, resource bidding, DSM incentives, preapproval ratemaking, environmental "adders", avoided cost calculations, and marginal cost pricing.

Rulemaking will begin consuming an increasing proportion of PUCs' dockets as the industry and its regulatory environment continues to change rapidly. For the most part, this is happening voluntarily as PUCs recognize the virtues of trying to resolve inherently subjective, public policy disputes through rulemaking rather than adjudication. However, state legislatures, administrations and even the courts are increasingly pressuring state PUCs to pursue industry-wide policies through rules, as is happening at the federal level.

When state PUCs do make rules, they have often experienced many of the same criticisms as federal agencies. The rulemakings are often both time-consuming and contentious. The only notable difference between PUC and other state agency rulemaking and federal agency rulemaking, is that state rules appear to be appealed less frequently. Though I have no hard data to confirm this as fact, those experts I queried on this subject during my interviews concurred with this observation (Burns, Harter, Miragliotta, Oppenheim, Pritzker Interviews). The less frequent appeal rate makes some intuitive sense. First, each federal rule has a greater impact on national interest groups than state rules. Second, appeals are more affordable at the federal level relative to the resources of those interest groups. Finally, the success rates of appeals at the state level where courts may have historically shown greater deference to agency decision making may be lower.

A lower appeal frequency does not necessarily imply that state PUCs or state agencies in general, are somehow more competent rulemakers and that the rules are ultimately more practical and palatable. However, to the extent that parties, particularly the regulators themselves, are motivated to experiment with consensus-building techniques as a means of avoiding lengthy appeals, that motivation may be somewhat diminished at the state level. Yet, appeals are not uncommon on the state level and may grow as PUCs and other state agencies rely more on rulemaking and the rules become more sweeping, controversial, or both. More importantly, as mentioned previously, high appeal rates are just one impetus among many for trying to improve rulemaking practices.

Introduction to Cases

The case studies explore what benefits, if any, consensus-building processes including negotiated rulemaking can add to traditional rulemaking at state PUCs. The first case shows how the development of Integrated Resource Management rules in

Massachusetts successfully used a structured technical session process over several years with the assistance of outside facilitation. The second case examines the formation of New Jersey's Bidding policies through a negotiated settlement process that resembled a "reg-neg" process in many respects.

Endnotes (Chapter 5, Introduction)

1. SEC v. Chenery Corp., 332 U.S. 194, 198, 203 (1947).

2. Notice-and-comment rulemaking is otherwise known as "informal" rulemaking to distinguish it from "formal" rulemaking which was also discussed in the APA. Informal rulemaking is the norm among most agencies and is the only type of rulemaking referred to here. Formal rulemaking occurs when Congress requires a special set of formal rulemaking procedures in a particular application (Pritzker and Dalton, 1990, p. 49).

3. Section 553 of the Administrative Procedures Act of 1946 (5 U.S.C. §§551-559).

4. See footnote number 18 in Harter's seminal work on "Negotiating Regulations" in the Georgetown Law Journal, 1982. Here he cites numerous statutes where Congress has required stricter procedures than required by the EPA including the National Highway Traffic Safety Act of 1976, the Consumer Product Safety Act of 1976, and the Toxic Substances Control Act also of 1976.

5. Overton Park, Inc. v. Volpe, 401 U.S. 402 (1971).

6. Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc., 1978. 435 U.S. 519.

7. Harter observed during our phone interview that rules from certain federal agencies such as the FDA and FAA are appealed less often than rules from EPA, DOT, and OSHA.

8. In footnotes 157 and 158 of Harter's original treatise, he cites several earlier works by Dunlop 1975, Reich 1981, Schuck 1979, and Stewart 1981 which contained earlier references of the possibility of alternative rulemaking procedures including negotiations. See also two articles by Henry J. Perritt, Jr. (1986 and 1987) for additional discussion of evolution of negotiated rulemaking.

9. The term "reg-neg" is a bit of a misnomer since it only refers to negotiated rulemaking, although "regulation" is made up of rulemaking, adjudication, and other regulatory functions. Perhaps "rule-neg" would have been a more appropriate coinage.

10. Although OMB has not been a direct participant in negotiated rulemakings thus far, the lead agency is supposed to work closely with them throughout the process. In EPA's guidelines for contractors, it claims OMB must be consulted prior to the negotiations regarding the appropriateness of the subject and the recommended committee members. OMB must then received all documents throughout the negotiations and be briefed on an on-going basis. OMB attendance is encouraged.

11. The Federal Departments and Agencies that have attempted negotiated rulemaking include: Department of Transportation, Environmental Protection Agency, Department of Labor, Department of the Interior, Federal Trade Commission, Nuclear Regulatory Commission, Department of Education, and the Department of the Interior (ACUS 1990, pp. 327-343).

12. The five reg-negs that reached consensus were: (1) Nonconformance Penalties under Sec. 206 (G) of the Clean Air Act (1985); (2) Emergency Pesticide Exemptions under Section 18 of the Federal Insecticide, Fungicide, and Rodenticide Act (1986); (3) New Source Performance Standards for Woodburning Stoves (1988); (4) Fugitive Emissions from Equipment Leaks (1991); and (5) Oxygenated and Reformulated Fuels (1991). The other reg-negs where most parties agreed and EPA's final rules were close to that agreement included: (1) Resource Conservation and Recovery Act Permit Modifications(1988); (2) Asbestos Containing Materials in Schools (1987); and (3) Underground Injection of Hazardous Wastes. Two other reg-negs did not end in consensus rules and no rules have been promulgated by EPA (1) Worker Protection Standards for Agricultural Pesticides; and (2) Recycling of Lead Batteries.

13. Wald argues that "negotiation typically does not eliminate court involvement altogether; instead it changes the nature and scope of the judicial role" (Wald 1985, p.17). Specifically she argues that judges will need to decide thorny issues such as the development of legal standards for identifying relevant interest groups, assessing the extent of their participation, and checking-up on the negotiating "process" itself.

14. See endnote number 17 in Chapter for fuller discussion of the Negotiated Rulemaking Act.

15. Of thirty-seven states that responded to the survey, five claimed the state had not adopted the MSAPA and two were uncertain (Burns 1988, p. 3-4).

16. According to my interview with Robert Burns of NRRI, PUC exemptions from state APA requirements appear driven by a PUC's desire to be relieved from the APA's adjudicatory requirements rather than its rulemaking requirements. Exemptions are usually granted as a way of grandfathering PUCs' ratesetting rules that generally preexisted the APA, and in recognition of some of the unique characteristics of ratesetting compared to other forms of adjudication.

17. In addition to the NRRI study, many of those I queried on this point during my interviews concurred (Burns, Harter, Miragliotta, Oppenheim, Pritzker Interviews).

Massachusetts IRM Rulemaking Case Study

Introduction

Purpose

The purpose of this case study is to analyze the innovative rulemaking process used by the Massachusetts Department of Public Utilities (DPU) and the Energy Facilities Siting Council (EFSC) between 1988 and 1990 to develop rules which greatly effect the way electric utilities plan for and procure resources. Known as Integrated Resource Management rules (IRM), these had two overarching objectives. First, that electric utilities conduct a solicitation process approximately every other year to procure resources to meet their power needs. Second that both supply- and demand-side resources regardless of ownership (i.e., utility or non-utility) be considered under one consistent, competitive solicitation framework.

The process used to develop these rules differed from a more traditional "notice-and-comment" rulemaking process by including a series of ten technical sessions hosted by the agencies (8 by the DPU and 2 by the EFSC) over two years. These sessions were attended by over 130 people from 71 organizations, and staff from both agencies. Independent facilitators were used in all the sessions.

The case explores whether the addition of these consensus-building processes allowed for greater public participation and ultimately improved the final rules themselves. I conclude that they helped make the rules both more practical and more legitimate even though no consensus was ever sought or achieved. They also helped improve the regulatory climate with positive benefits beyond the IRM rules themselves.

Research Methods

I combined several methods in developing this case. First, I was one of the lead staff at the DPU responsible for the development of the IRM rules and the design of the supplemental technical session process. As such, I was a participant-observer throughout both the external public hearing and technical session process and the internal DPU process of drafting the actual orders and rules. In addition to direct observation, I had the benefit of a long paper trail including both public documents and confidential internal memorandum. Also, after each of the two rounds of technical sessions, I administered a detailed questionnaire survey to the participants to solicit their feedback on the strengths and weaknesses of the technical sessions (See Appendix 2 for Survey and Data Compilation). This case write-up includes the results of 53 completed surveys after the first round of sessions and 41 completed surveys after the second. Finally, I conducted face-to-face, structured interviews with the following 14 participants in the rulemaking process shown in Table 5.1.

Table 5.1
Interviews for Massachusetts IRM Rules

Utilities:	
Al Destribats	New England Electric System, Vice-President For Planning
Robert Fratto	COM/Electric, Manager of Demand Program Administration
Richard Hahn	Boston Edison, Vice-President For Marketing
Government:	
Jerrold Oppenheim	Massachusetts Attorney General's Office, Assistant Attorney General
Robert Shapiro	Department of Public Utilities, General Council (Former Executive Director, Energy Facilities Siting Council)
Robert Werlin	Attorney, Private Law Firm (Former Commissioner and Chair, Department of Public Utilities)
Mary Beth Gentleman	Attorney, Private Law Firm (Former Assistant Secretary for Policy, Executive Office of Energy Resources)

Third Party Providers:	
Stephen Cowell	Conservation Services Group, Inc., President
Sherif Fam	Thermo-Energy Systems Corporation, Manager of Regulatory Affairs (former President, New England Cogeneration Association)
Rolly Rouse	Conservation Conversions, Inc., President (former Chief Operating Officer, Citizens Conservation Corporation)
Environmental and Consumers Groups:	
Armond Cohen	CLF, Senior Attorney
Alan Nogee	MASSPIRG, Energy Program Director
Other:	
David O'Connor	Massachusetts Office of Dispute Resolution, Executive Director (facilitator for technical session process).
Harvey Salgo	TELLUS Institute, Manager Least Cost Utility Planning (represented the Executive Office of Energy Resources in the IRM proceedings).

Organization of Case Study

I begin the case by describing the regulatory and procedural background from which the IRM rulemaking emerged. Next I analyze the strengths and weaknesses of the more traditional rulemaking process that Massachusetts used to formulate its preapproval ratemaking rules which immediately preceded the IRM rules. The preapproval rulemaking serves as a backdrop to better highlight the procedural changes initiated in the IRM rulemaking.

I then examine at length the substance and the process of the IRM rulemaking and explore the decision to use technical sessions and delay the issuance of proposed rules to gain greater public input. Next, I describe and analyze the structure and the process of the technical sessions themselves including the use of focus groups, the role of the staff and the Commission, and the use of outside facilitation. The case then turns to an analysis of the substantive contribution of the technical session process by examining areas of substantive agreement and areas where participants remained divided. Before turning to the conclusions, I explain how the output from the technical sessions was integrated into the formal process, and how the substantive issues in the case were ultimately resolved.

In the final section, I explore the overall success of the IRM rulemaking process. Specifically, I analyze the issues of resource savings, legitimacy and practicality are analyzed. A brief process evaluation appears at the end of the concluding section.

Background

Prior to proposing actual rules, both federal and state administrative agencies often undertake generic investigations or inquiries during which questions are posed to the public on a particular issue and information is gathered through hearings, written comments, or both. The IRM rulemaking process grew out of such a generic investigation. However, the original intent of the investigation, which was initiated in February 1986 on the Department of Public Utilities' own motion, was to examine an important but much more narrow question regarding the appropriate pricing and ratemaking treatment to be afforded to new, utility-owned electric generating facilities.

This more narrow ratemaking investigation followed on the heels of the DPU's issuance of a proposed rule in a prior investigation. That proposed rule contemplated requiring electric utilities to conduct an annual competitive bidding process to implement the federal Public Utilities Regulatory Policy Act (PURPA) by procuring electricity from Qualifying Facilities (QFs).[1] The QF rule (220 CMR 8.00), finally adopted in August 1986 (D.P.U. 84-276-B), constituted the first statewide PURPA-related rule in the nation to rely on bidding.[2] The key innovation was its attempt to stimulate a QF market while harnessing competitive forces to set a market price for power. This approach was an attempt to stimulate the market by guaranteeing QFs long-term contracts at or below each utility's full avoided cost of power, while avoiding the problems that California utilities experienced.[3]

The generic investigation undertaken in 1986 in Massachusetts to look at the ratemaking treatment for utility owned and operated resources was in part an attempt by the Massachusetts' Commission, chaired by Paul Levy, to examine whether the concept of market-based pricing from the QF regulations could somehow be infused into the traditional cost-of-service ratemaking process typically applied to utility investments.[4] As this generic investigation commenced, three important things were happening. First, in the face of a vibrant New England economy, forecasters were predicting significant increased power needs for the foreseeable future (New England Governor's Conference 1986). Second, in the wake of major cost overruns on several new utility-owned generating facilities (most notably nuclear power plants) coupled with substantial cost-recovery disallowances by state regulators, utilities were reluctant to build new facilities. Third, even absent disallowances (or the threat of disallowances), utility investments in several large, costly construction projects (e.g., Seabrook 1 and 2, Millstone 3, Pilgrim 2) left them in a weak financial condition making it extremely difficult to attract additional capital to finance future construction projects.

With the 1984 addition of a "used and useful" standard in Massachusetts to the existing prudence review, utilities and others were maintaining that the regulatory promise of cost recovery for their investments had been broken (Kalt 1988). Under the "prudent, used and useful" standard, utilities could only recover a return <u>of</u> prudently-incurred investments and a return on investments prudently-incurred and economically-useful. To be economically-useful, the power was required to still be "useful" (i.e., cost-effective) and actually "used" (i.e., operational) regardless of whether it was projected to be economic and needed when the decision to construct the plant was initially made.

The Commission perceived that a lack of a vibrant QF market coupled with the utilities' reluctance or inability to undertake new power plant construction threatened to leave the region short on power, or faced with rising power costs as utilities purchased expensive power elsewhere, or both. Having resolved the QF situation to their satisfaction (at least in theory), the Commission turned their attention to ratemaking issues associated with utility resources. However, during the early phases of the generic ratemaking investigation, many participants filed comments emphasizing that the Commission should also consider other alternatives to new utility-owned supply-side investments. Most notably, they suggested the need to look at demand-side management (DSM) opportunities and purchases from independent power producers (IPPs) including QFs,[5] and stressed the need to integrate all demand and supply options under one comprehensive regulatory framework (See D.P.U. 86-36-B (1987)).

Recognizing the validity of these comments, a new Commission Chaired by Bernice McIntyre[6] decided to broaden the investigation:

> The Department finds...that it should consider in this docket ways in which the regulatory structure can encourage electric utilities to consider on a systematic, equitable, and integrated basis all supply and demand options and to implement those measures that will result in providing reliable service in a cost-effective manner (D.P.U. 86-36-B).

With the issuance of this order on November 3, 1987, the generic investigation was effectively bifurcated into parallel tracks with the ratemaking issues associated with utility generation in one set of proceedings and the integrated resource planning and procurement issues in another. The primary reason for the split was to fast-track the ratemaking portion of the proceeding.

The Traditional Process (Formation of Preapproval Rules)

When the investigation into the ratemaking treatment for new utility-owned generation commenced in February 1986, the DPU described its intentions as follows:

> This proceeding has been structured as a generic rulemaking case so as <u>to allow a full exchange of ideas</u>, unencumbered by specific project circumstances, on the wide range of issues pertaining to the impact of various ratemaking alternatives on utility investment (emphasis added) (D.P.U. 86-36, p. 2).

As mentioned, the DPU wished to explore possible alternatives to its "prudent, used and useful" standard which many considered too onerous, and potentially inconsistent with the more market-based pricing embodied in the QF regulations.

The procedures the DPU used to pose questions, solicit input, and formulate regulations essentially followed the traditional "notice-and-comment" rulemaking process as illustrated in Table 5.2 on the next page. This process generally typifies the way administrative agencies such as state PUCs traditionally conduct rulemaking processes. However, it includes several steps that go beyond the minimal standards required by the federal Administrative Procedures Act (APA) and the APA requirements adopted by most states. First, it is legally permissible to initiate a rulemaking process with proposed rules (i.e., Step 5) rather than with a fact-finding investigation. Second, the issuance of an interim order (Step 3) which digests what has already been submitted and asks for further information, is not necessarily typical. Rather, regulators often propose actual rules directly after an initial fact-finding process. Lastly, while hearings are usually held as a matter of course, they are generally not required unless an interested party specifically requests them. The DPU, for instance, accepted written comments after issuing its interim order, but did not hold a second round of hearings prior to issuing proposed rules.

Table 5.2
Steps Used For Developing Ratemaking Preapproval Rules

Step 1:	Announce Opening of Investigation, Pose Some Questions (D.P.U. 86-36, February 1986)
Step 2:	Hold Formal Hearings, Receive Written Comments
Step 3:	Issue Interim Order Which Discusses Comments Received, Reviews Options, Poses Additional Questions, and Requests Further Comments (D.P.U. 86-36-A, April 1987)
Step 4:	Receive Written Comments
Step 5:	Issue Proposed Rules, and Request Comments (D.P.U. 86-36-C, May 1988)
Step 6:	Hold Formal Hearings, Receive Written Comments
Step 7:	Issue Final Rules (D.P.U. 86-36-E, October 1988)

Source: Author's List

The initial order opening the investigation was a concise statement of the problem(s) the DPU believed needed to be addressed (D.P.U. 86-36). After receiving comments and holding hearings, the DPU issued an interim order that discussed several alternatives for addressing the problems, and expressed its inclination to pursue a "preapproval" approach (D.P.U. 86-36-A). Under a preapproval cost-recovery system, the utilities and the ratepayers would sign a contract prior to plant construction for a certain amount of power at a given price. In addition to guaranteeing a market for the power, the DPU, and through the contract the ratepayers, would agree not to second guess the decision to build the plant through future proceedings. In return, the utilities would agree on a cost-recovery cap on construction costs and a linkage of actual recovery to the operating performance of the new plant. Different risks would be borne by ratepayers and utility shareholders.

In the interim order, additional questions were posed and comments requested from everyone except the utilities who were actually ordered to file responsive comments (id.). After receiving comments, but without holding hearings, the DPU issued proposed rules based on the preapproval concept (D.P.U. 86-36-C). These rules would apply both to new utility supply resources and to existing utility-owned supply resources where expenditures were anticipated to 1) exceed $250/KW, 2) extend the life of the plant, or 3) expand the capacity of the plant (D.P.U. 86-36-C, p. 103). The DPU further proposed that the risks associated with various changes unanticipated at the time of signing the preapproval contract be divided between the utility and its ratepayers as in Table 5.3 on the next page. According to the order accompanying the proposed rules, the preapproval cost recovery policy became effective as of May 12, 1988 -- the day the proposed rules were issued but prior to their final adoption.

After the proposed rules were issued, a single public hearing was held to "accept comments". Four parties testified (the Attorney General, the State Energy Office, and the two largest utilities), and seven additional parties provided written comments. Of the total eleven parties -- a modest number for rules of such import -- only one commenter, the Massachusetts Public Interest Research Group (MASSPIRG), was not representing a utility, state agency, or legislator. Although the final rules (220 CMR 9.00) clarified some issues and established a preapproval review time of 8 months, no other substantive changes were made from the proposed rules despite continued criticism (D.P.U. 86-36-E (1988)).

Table 5.3
Division of Risks of the Proposed Preapproval Ratemaking Rules

Risks Shouldered by Utilities:

1. Construction costs (including inflation)
2. Operation and maintenance costs
3. Unforeseen government regulation (e.g., environmental, safety, and health)
4. Plant performance
5. Cost of capital

Risks Shouldered by Ratepayers:

1. Decreased demand
2. Fuel price volatility
3. Decreased cost of alternative energy resources

Source: Author's List Based on D.P.U. 86-36-C (1988)

The proposed preapproval rules represent a significant substantive departure from traditional ratemaking practices, and with their adoption Massachusetts headed into territory unchartered by other state PUCs. Though receiving general support from many parties, the rules have become increasingly controversial since they were adopted.[7]

Despite the few embellishments to the minimal legal rulemaking requirements used to formulate the preapproval rules, the process remained fairly traditional. I note several potential short-comings: First, although the DPU initiated the rulemaking by claiming that the purpose was "to exchange ideas," the exchange remained extremely formal with the DPU issuing orders and posing questions, and commenters responding. While both the DPU's and participants' positions were given some room to evolve through an iterative process of orders and comments, no real dialogue ever occurred. Questioning of the participants on the record by the Commissioners and staff during the formal hearings, did not really constitute a dialogue. Certainly any discussions that may have occurred were bilateral (i.e., between the DPU and a single participant) and no free-flowing discussion between the DPU and the interested parties, or among the parties occurred. But even the formal questioning was limited since no hearings were held between the interim order and the proposed rules. Furthermore, given the importance of the rules, a surprisingly limited number of parties, including only one public interest group, participated in the rulemaking process.

No real effort was made in the preapproval rulemaking to build consensus on either the main thrust of the rules or specific implementation details. While informal comments are permitted in rulemaking (i.e., interested parties speaking directly to staff or Commission), my interviews and my own observations substantiate, little of this occurred.[8] Given that, (1) the Commission delivered its final decision to implement a preapproval approach in the proposed rules rather than the final rules; and (2) virtually none of the detailing changed between the proposed regulations and the final regulations despite numerous critical comments; the Commission apparently made up its mind by the time proposed rules were promulgated.

Most of those interviewed on the IRM case who also participated in the preapproval rulemaking, maintained that the preapproval rules could have benefitted from infusing technical sessions, or other consensus-building supplements to the rulemaking process. They suggested that such processes could have helped in conceptualizing the overall framework as well as fleshing out the detailing;[9] and that such supplemental sessions may have clarified several issues which are being litigated in recent cases involving the application of the preapproval rules (e.g., Boston Edison Company's Edgar Station).

Overview of IRM Rulemaking Process

The process used to develop the IRM regulations is shown below in Table 5.4.

Table 5.4
Massachusetts IRM Rulemaking Steps

Step 1:	Announce Opening of Investigation, Pose Questions (D.P.U. 86-36-B, November 1987)
Step 2:	Six (plus) Days Formal Hearings, Receive Written Comments (December 1987 - June 1988)
Step 3:	Issue Order Including Some Final DSM Policies and Proposal For IRM Structure, Pose Questions on IRM Proposal (D.P.U. 86-36-F, November 1988)
Step 4:	Four, Half-Day Technical Sessions (December 1988 - February 1989)
Step 5:	Three Days Formal Hearings, Receive Written Comments (February - March 1989)
Step 6:	Issue Proposed Rules, and Request Comments (D.P.U. 86-36-G, December 1989)
Step 7:	Four, Half-Day Technical Sessions (January 1990)
Step 8:	Four Days Formal Hearings, Receive Written Comments (March -May 1990)
Step 9:	Issue Final Rules (220 CMR 10.00, D.P.U. 89-239, August 1990)

Source: Author's List

The process included several significant modifications to the more traditional rulemaking process used to develop the preapproval rules. First, rather than moving directly to formal comments and hearings after issuing an interim order, the DPU sponsored four, half-day technical sessions to discuss the proposed regulatory framework with interested parties (Step 4). Second, after holding formal hearings and issuing proposed rules, the DPU again sponsored four, half-day technical sessions this time to discuss the proposed rules with interested parties (Step 7). Lastly, although both the preapproval and the IRM rulemaking process issued interim orders which are not generally required in rulemaking proceedings, the IRM interim order went further than the preapproval order by including a detailed description of a potential new regulatory framework which it wished to use as a starting text for further discussion and comment (Step 3, D.P.U. 86-36-F). These three modifications further supplemented the traditional rulemaking process.

Substantive Overview of IRM Proposal

Prior to the issuance of the interim order, D.P.U. 86-36-F in November 1988 (Step 3), the DPU held over a half-dozen days of formal hearings on energy planning, competitive bidding, and DSM issues. Many of the parties sponsored expert witnesses from across the United States to enter a broad range of information and experience into the record. Within the context of providing comments in the proceeding, the Executive Office of Energy Resources (renamed the Division of Energy Resources in 1990 (DOER)), the state's energy office which had been instrumental in formulating the DPU's QF regulations, presented a detailed proposal for IRM rules for the DPU's consideration. The DPU concurred with many of DOER's proposals. However, it differed in some respects, most notably on the role of the utility in a new regulatory structure (i.e., DOER did not want the host utility to participate in an all-resource bidding process, while the DPU was more inclined to let them), and decided to issue its own proposals.

The DPU attempted to address three primary objectives with its proposed regulatory framework. First, it wanted to see all resources -- both demand and supply, and utility- and non-utility-owned resources -- better integrated in utility resource decisionmaking. Second, it wanted to build on its QF regulations and proposed preapproval regulations by fostering greater competition for electricity resources, and market-based pricing. Together these first two objectives are often called attempts "to level the playing field" between utility supply-side resources and other resource options. Lastly, the DPU wanted to further expand the criteria on which resources were selected by more formally including factors other than direct cost, most notably environmental externalities.

The DPU's proposed regulatory structure contained four phases as delineated in D.P.U. 86-36-F (1988) and abstracted in Table 5.5:

Table 5.5
Four Phases of Proposed IRM Structure

Phase I:	The utility submits to the DPU and EFSC for review and approval its: 1) demand forecast; 2) inventory of committed resources (i.e., existing and planned); 3) technically-feasible, uncommitted DSM resources; 4) potential viable plant life extension; and 5) an all-resource RFP solicitation proposal.
Phase II:	The utility issues its approved all-resource RFP solicitation, receives bids from third-parties, submits bids itself, ranks all the projects, selects a final portfolio of projects and submits it to the DPU as its integrated resource plan for review and approval.
Phase III:	The DPU reviews the utility's integrated resource plan to make sure that it properly applied the approved RFP criteria, and that there was no self-dealing (i.e., the utility unfairly favored its own projects). A preapproval investigation regarding the cost recovery terms of any utility project in the final mix would also be conducted.
Phase IV:	The utility negotiates final contracts with resource providers, and submits them to the DPU for review and approval.

Source: Author's List, Abstracted From D.P.U. 86-36-F (1988)

Under this proposed new regulatory structure, each utility would conduct an all-resource solicitation every other year, and the entire process -- from the initial filing in Phase I to the approval of individual contracts in Phase IV -- was slated to last seventeen months. Despite staggering the utilities solicitations to facilitate its reviews, the DPU specified that meeting this ambitious schedule would necessitate securing additional staff resources.

It is worth mentioning at this juncture that the DPU's proposed regulatory structure represented a significant departure from the prevailing modes of resource decisionmaking and regulation used across the country. First, whereas most utilities that engaged in what is often called Least Cost Integrated Planning (or Integrated Resource Planning) in other jurisdictions focused on a "planning" model, the DPU's proposed approach focused more on a "market-driven" model. Both approaches begin similarly with a determination of need based on projections of demand and committed resources. However, the "planning" model relies on the utility to identify a combination of specific or generic project types that could best meet the projected need. The identification and procurement of resources, while often rigorously conducted under the "planning" model is somewhat ad hoc as it relies on a utility's skills in identifying alternatives. The Northwest Power Planning Council and the utilities in Wisconsin have been leaders in applying this approach. In contrast, the DPU proposed to use a "market-based" all-resource bidding process as a means of identifying and procuring needed resources.

Second, the DPU's proposed all-resource solicitation process also differed from bidding processes that utilities were implementing in other states. Although utilities in other states were beginning to expand their QF bidding process to include bids from independent power producers (IPPs) and demand-side management (DSM) providers (e.g., Central Maine Power, and several New York and New Jersey utilities), no one else was proposing that utilities participate in their own solicitation processes. Concerned that a true least-cost portfolio could not be achieved unless utility resources competed head-to-head with the resources of third-party suppliers, the DPU's proposed structure allowed utilities to participate in their own solicitation. In fact, the DPU's proposal actually required the utility to bid a portfolio of projects that would cover the entire need, based on the utilities "obligation to serve", just in case better projects did not emerge from the solicitation process.

In addition to the proposed IRM structure, the interim order also included policy statements and findings with respect to DSM. Table 5.6 outlines the major DSM policies annunciated in D.P.U. 86-36-F. Unlike the proposed IRM structure which would eventually be reformulated, first into proposed and then final rules, the DSM policies were adopted as DPU policy as of the issuance of the order on November 30, 1988.[10]

Table 5.6
DSM Policies In D.P.U. 86-36-F

1. Utilities must use a "societal" cost-effectiveness test when evaluating resource decisions including DSM. Such a test must include environmental externalities and, for DSM, any additional costs and benefits to the customers.[11]

2. Utility DSM programs must attempt to capture all potential lost opportunities, avoid cream skimming, and pay particular attention to hard-to-reach sectors (e.g., rental housing, small commercial businesses).[12]

3. Utilities must file an annual status report on its DSM programs with the DPU.[13]

4. Large utility DSM programs are eligible for preapproval under the preapproval rules developed for utility supply-side resources.

5. Utilities have the option to either expense, or amortize with a return their DSM expenditures. Utilities can also apply for compensation for any unforseen revenue lost between rate cases as a result of their DSM programs.[14]

Source: Author's List, Abstracted From D.P.U. 86-36-F (1988)

Decision to Use Technical Sessions

As discussed, the Commission could legally have simply issued proposed IRM rules, taken public comment, and then issued final regulations. Instead, they chose to issue an interim order which contained a description of a potential new regulatory framework and to hold technical sessions prior to receiving formal comments. Both decisions stemmed from the same objective -- to provide parties with a greater opportunity to participate in and contribute to the process of formulating the regulations.

The interim order represented the Commission's disposition at the time based largely on the evidence in the proceeding thus far. However, the Commission it was well aware that it was proposing a major restructuring of the industry that needed substantial public review and debate. As evidenced both by the tone of the interim order and the six, single-spaced pages of questions at the order's end, the DPU sought feedback on all aspects of its proposal which clearly contained many unresolved, or partially resolved issues. Specifically, it sought input on the issues that represented the greatest changes to the existing regulatory structure and which it correctly suspected would engender the greatest controversy. These issues included:

1) Whether utilities should participate in their own solicitations;

2) How much flexibility utilities should have in selecting resources once they are identified (i.e., should they adhere to a strict self-scoring system, or be allowed to pick and choose according to a more subjective evaluation?);

3) Whether demand-side resources and supply-side resources should be integrated into a single solicitation, and if so, how;

4) Whether existing and planned resources should be considered committed, or whether they should be eligible for replacement through the IRM process;

5) Whether utilities should be allowed to procure any resources outside of an IRM solicitation process;

6) Whether the seventeen month timeframe for the process was workable (i.e., short enough so that projects would not be stale, but long enough to allow for adequate review);

7) How environmental externalities associated with electric generation should be valued and included in IRM; and

8) How public involvement in the IRM process itself could be enhanced.

Later in the proceeding, the DPU would also query participants regarding whether utilities needed additional financial incentives to better guarantee their diligent pursuit of IRM objectives.[15] In addition to all of these broad policy questions, the interim order also included many specific questions on implementation details.

The Commission explored a range of options with staff to enhance public involvement in the IRM rulemaking process, and decided to pursue a highly structured technical session process. Bernice McIntyre, Chair of the Commission, described their goals in adding technical sessions to the traditional rulemaking process in her opening remarks at the first technical session:

> Our decision not to proceed immediately with proposed regulations, and to use facilitated technical sessions is an attempt to give all of you maximum input into these crucial regulations. We hope that we can accomplish several objectives during these sessions: First, we want to make sure that all of you fully understand the regulatory framework that we have outlined in D.P.U. 86-36-F. This includes both the details of the most recent Order, and the rationale behind all aspects of

> our proposed regulatory framework. Second, we want to hear from all of you about the parts of our proposed regulatory framework that you support and those parts that you do not. Third, we would like to examine - together - any suggestions you may have for improving the proposal. Lastly, we expect that the formal public hearings that will begin shortly after these technical sessions conclude, will be even more focused and productive than usual as a result of our efforts here (McIntyre Speech).

Several points regarding the Commission's decision to use technical sessions need to be underscored. First, although technical sessions had been used at the DPU on prior issues, the ones proposed here were significantly more ambitious in many respects, most notably their number and size, and their use of outside facilitation. Second, although the Commission hoped to accomplish much during the sessions, they were viewed as a supplemental enhancements to the formal hearing and subsequent comment process. Lastly, although the Commission hoped that the sessions would reveal areas of general agreement and disagreement with respect to its proposed rules, it did not view them as a formal attempt to reach consensus among the parties.

At the staff's suggestion, the Commission considered more active consensus-building processes such as negotiated rulemaking, but rejected them in favor of a technical session process. Former Commissioner Werlin explained during our interview that the Commission was skeptical that a consensus could emerge from a more from negotiated rulemaking given the complexity and controversial nature of the proposed IRM structure, and was afraid that if one did emerge, it might be unacceptable to them.

Use of Technical Sessions

Altogether ten, half-day technical sessions were used in the course of finalizing the IRM rules for both the DPU and the EFSC.[16] Four were held between December 1988 and February 1989 to consider the proposed regulatory framework described in the interim order, D.P.U. 86-36-F. An additional four were held in January 1990 to consider the DPU's actual proposed regulations, D.P.U. 86-36-G, and finally, the EFSC hosted two sessions in August 1990 to consider its proposed regulations covering its portion of the IRM structure (i.e., the approval of the demand forecast, committed resources, and resource need) (EFSC 90-RM-100). Since the DPU's rulemaking is the focus of this case study, the following discussion of the technical sessions exclusively examines the eight sessions hosted by the DPU, unless otherwise noted.

Structural Overview

The DPU's technical sessions differed somewhat between the first and the second round. During the first round, the participants spent most of their time in three groups of 25-30 participants. Each participating organization was invited to send two representatives, and the DPU staff preselected the small groups with an eye to balancing the different interests within each of them. Each group included a DPU staffperson and a professional facilitator from outside the DPU. On the first day, the groups brainstormed on the strengths and weaknesses of the DPU's IRM proposal. The entire group usually assembled at the beginning and end of each day to share information and ideas. The agendas for the remaining three sessions were based on the first day's discussions. Although the Commissioners opened the first session and returned at the end of the fourth, they were not present throughout.

The second round of technical sessions, which occurred after the DPU issued actual proposed rules, did not use small groups. Instead, a single representative from each organization sat around one enormous table during all four sessions and one facilitator was used. DPU and EFSC staff actively participated in the second round, although the Commissioners were not present. The agendas were essentially preset in the invitation letters mailed with the proposed rules, although some changes occurred in the course of the sessions.

The change in structure between the first round of technical sessions and the second underscored the slightly different purpose contemplated for each. The first round was clearly a time for participants to familiarize themselves with both the DPU's proposal and the interests and perspectives of other parties. It was also a time when the Commission was most interested in soliciting alternatives to its proposals. As such, small group brainstorming worked best to provide each individual with both maximum exposure and input. In the second round, the DPU and the facilitator believed that less time was needed for parties to understand the proposed rules or the interests and perspectives of others since much groundwork had been laid in the first round of sessions. At the same time, although the Commission was still not seeking a formal consensus from the group, it did hope to clearly identify areas of convergence and divergence, and to solicit any suggestions for fine-tuning the proposed regulations. It was determined that one group with representatives from the interested parties better served this final focusing process than three smaller groups.

Participation

Approximately 85 people, not including the DPU or EFSC staffs or the facilitators, attended one or more of the technical sessions in the first round. A majority of the participants attended all four of them. In the second round, following the issuance of the proposed rules, despite the fact that only one representative from each organization was allowed around the table (alternates were invited to sit outside the circle), approximately 110 people, attended at least one of the sessions. Again these participants did not include the DPU or EFSC staff. Table 5.7 lists the participating organizations by type and shows that 71 organizations attended at least one of the eight technical sessions (130 people altogether).

Table 5.7
Participants at the IRM Technical Sessions – By Type

Type	Number	Percent
Utilities	11	15%
Government	7	10%
Non-Utility Providers:		
Supply-side	25	35%
Demand-side	8	11%
Environmental and Consumer Groups	5	7%
Other*	15	21%
Total	71	99%**

Notes: *"Other" includes consulting firms, law firms, private citizens and academics.
** Does not equal 100% due to rounding.

Source: Author's Compilation

The 71 organizations greatly exceeded the 11 organizations that participated in the preapproval rulemaking that had immediately preceded the IRM process. Two factors of seemingly equal importance account for this. First, the preapproval rules, which on the surface only directly apply to utility-owned resources despite the fact that the rules could potentially greatly influence a utility's inclination to build its own resources vs.

buying from third party providers, only attracted a handful of non-utility parties and no one from the development community. In contrast, the potentially sweeping impact on energy planning and procurement practices in Massachusetts of the IRM rules were obvious to everyone from the outset.

Second, as many of those I interviewed mentioned, the technical sessions were a far more inviting and accessible process than the formal hearing and comment process -- particularly for organizations that do not regularly appear before the DPU. Whereas in the formal process, parties are merely noticed regarding the existence of hearings, the DPU actually included a formal invitation letter to the technical sessions.

Also, the technical sessions were conducted in a significantly different atmosphere from the normal hearing room process. The sessions took place away from the DPU's windowless hearing room with its uncomfortable wooden pews facing the elevated bench where the Commission and staff preside. Instead, the sessions were held in an old mansion owned by the Boston Adult Education Center in the Back-Bay section of Boston. People sat around one large table or met in small groups. The DPU staff, which generally had little informal contact with interested parties because of ex parte rules, actively participated in all the sessions.[17] Finally, the presence of facilitators and occasionally of the Commissioners differentiated the sessions from the normal course of affairs.

As Table 5.7 illustrates, a broad spectrum of interested parties attended the sessions. Reflecting the sentiment of the vast majority of those interviewed, Steve Cowell, President of Conservation Services Group, Inc., described the attendance as follows; "Everyone who was anything in energy in Massachusetts attended the technical sessions. It was an extremely well-endowed group" (Cowell Interview).

Despite the diverse participation, some of those interviewed lamented that more consumer groups (e.g., low-income, small commercial, large commercial and industrial) were not more directly represented although they were indirectly represented through several state agencies, citizen groups, and law firms. In addition, several of the environmental and consumer groups I interviewed mentioned that they felt at a disadvantage in part due to the overwhelming number of utilities and supply-side developers in attendance (over 50%), and in part because their own limited resources curtailed their ability to fully participate. Despite these legitimate concerns, which hint at ways to improve subsequent rulemaking processes, it is important to underscore here that the technical sessions used in the IRM rules represented a significant broadening of public participation compared to prior rulemaking and adjudicatory proceedings before the DPU.

The Role of Staff and the Commission in the Technical Sessions

DPU staff actively participated in the technical sessions. During the first four sessions a technical staff member was in each of the three small groups. In the last four sessions, the three technical staff members joined the other participants around the large table.[18] Their role was two-fold. First, in both the small groups and the large group, staff acted as an interpreter for the DPU, continuously describing to participants the DPU's proposals and perhaps more importantly the reasoning behind them. Second, staff acted as an emissary from the sessions to the Commission, bringing criticisms, observations and recommendations back to them after each session.

Staff opened most discussions with a brief presentation describing the DPU's proposals and posing one or more pointed questions to the group. Throughout the discussions, the technical staff clarified issues, reacted to suggestions, and assisted the facilitator in keeping the discussions focused on relevant issues.

All of those I interviewed felt that the staff's participation was essential to the success of the process for both of the reasons described above. The evaluation forms completed by participants after each round rated the effectiveness of staff's serving as a technical resource extremely high (mean of 5.1 out of 6 in both years). Of equal importance to staff's technical contribution during the sessions, however, was the exposure that they gained to the concerns of the participants and the real complexities of the business-side of resource development. This was invaluable to their subsequent efforts to assist the Commission in formulating rules that were more practical and more responsive to the diverse interests.

The Commission's direct participation in the technical sessions was rather limited. The Commissioners initiated the first session with a brief statement followed by an opportunity for participants to question them on the proposed regulatory structure -- a reversal of the normal course of affairs where the Commission questions parties from the bench. The Commission then returned at the end of the fourth session to hear comments first-hand, and to discuss the issues raised by the participants. The Commissioners did not attend the second set of sessions, but did participate in the EFSC's two technical sessions.

Although the Commissioners differed with respect to their interest in participating directly in the technical sessions, they ultimately decided that the potential benefits of their regular attendance did not justify the potential of stifling the free-flowing dialogue. Most of those interviewed concurred that the Commission's limited participation in the technical sessions was appropriate. Some, however, felt that the process would have benefitted from greater access to the Commissioners on the one hand, and greater exposure of the Commission to their views on the other.

Facilitation

The Commission found staff's argument for outside facilitation compelling and made arrangements with the state office of Mediation Services (which has since changed its name to the Office of Dispute Resolution) to secure facilitation services.[19] David O'Connor, the Executive Director of that office, was the lead facilitator throughout both the DPU and EFSC technical sessions. To facilitate the other two small group sessions in the first round of sessions, the DPU hired John McGlennon and Peter Schneider of ERM-McGlennon, Inc.. Both McGlennon and Schneider had experience mediating negotiated rulemaking processes sponsored by the EPA.

Given the large number of participants and complexity of the issues being discussed, facilitation was necessary to keep the sessions focused. Outside facilitation also freed staff to participate in the substantive discussions. In addition, the facilitators brought a level of expertise to the role that PUC staff do not generally possess.

In the formal evaluations after both rounds of technical sessions, participants claimed that the facilitators managed the sessions effectively (mean of 4.9 and 5.2 in 1989 and 1990 respectively). The follow-up interviews revealed overall enthusiasm for the use of facilitation in general, and David O'Connor's performance specifically. While some wished that he had more technical expertise, others felt that his level of technical expertise was adequate for acting as a facilitator and that he occasionally made insightful and useful substantive suggestions. With respect to consensus-building, some felt that O'Connor's natural inclination to push for consensus from his mediation work seemed inappropriate at times and actually hindered the free-flow of ideas. In contrast, others felt that they would have liked to see him more aggressively push for consensus.

Technical Sessions – Substantive Results

Table 5.8
Substantive Agenda of Technical Sessions[20]

<u>Sessions After Interim Order, D.P.U. 86-36-F:</u>		
First Session	(12/21/88)	Strengths and Weaknesses of Proposed Structure
Second Session	(1/4/89)	Role of Utilities in the Solicitation Process
Third Session	(1/18/89)	Integrating Demand and Supply Resources
Fourth Session	(2/1/89)	Intergovernmental Coordination, Timeline, and Transition Rules
<u>Sessions After Proposed Rules, D.P.U. 86-36-G:</u>		
First Session	(1/3/90)	Balancing Flexibility and Reviewability (Utility Projects, Self-scoring, Negotiation, Optimization)
Second Session	(1/10/90)	Other Structural Issues (Resource Selection Criteria, Prefiling Settlement Process, Committed Resources, Acquiring Resources Outside IRM)
Third Session	(1/17/90)	Environmental Externalities
Fourth Session	(1/24/90)	Transition Rules and Ratemaking Treatment

Source: Author's List

As Table 5.8 above reveals, a lot of ground was covered during the two rounds of technical sessions and the breadth was consistent with the broad scope of the emerging IRM rules themselves. The first round focused on the major theoretical and policy questions. The second revisited some of the issues but generally focused on critical implementation details. This evolution is not surprising as the proposed rules confirmed many of the Commission's predispositions hinted at in the interim order (e.g., the need to include the host utility in the solicitation process). The second round also addressed both environmental externalities and ratemaking issues in response to significant concerns raised by the DPU in the order accompanying the proposed regulations (D.P.U. 86-36-G (1989)).

The substantive discussions in the sessions were generally quite animated. However, while there was sufficient time to get a strong flavor of the issues including the range and intensity of participants' interests, there was insufficient time to explore or revisit issues in any depth. It is not surprising that 45 percent of the post-session survey respondents in 1989 and 27 percent in 1990 claimed that there was "too little" time allotted to the technical sessions, and that many of those interviewed lamented not having enough time to explore issues further. In contrast less than 10 percent each time felt that "too much" time was spent.

Convergence

The technical sessions were not a formal consensus-seeking process. No votes were ever taken nor was consensus otherwise rigorously tested. Nonetheless, a significant and surprising degree of convergence of opinion on many issues surfaced during the discussions. This convergence was noted by staff and facilitators during the course of the sessions, and was reflected in the participants' testimony and comments during the formal steps in the rulemaking. Finally, it was verified in my interviews. Table 5.9 highlights six areas of substantial convergence of opinion by participants that were first revealed during the technical sessions.

Table 5.9
Convergence of Opinion During the Technical Sessions

1. Support for the overall principles of increasing competition and of better integrating all resources.
2. Inclusion of a prefiling settlement phase preceding a utility's initial filing.
3. Allowing a utility to negotiate with providers after the initial ranking of projects.
4. Allowing a utility to make its final resource selections based on an analysis of its optimal portfolio of resources.
5. Preference for an environmental externality method that focused on impacts rather than on technologies.
6. The need for increased coordination between the DPU and the EFSC in overseeing IRM, and the acceptance of the need for increased staffing at the two agencies to implement IRM.

Source: Author's List

A brief discussion of these areas of convergence follows. First, while the notion of supporting the overall principles of increased competition and resource integration is fairly popular today, only a few years prior to the technical sessions many of the participants argued against pursuing DSM and QF resources in a serious manner. The general acceptance and approval of these concepts by all the participants in the sessions, despite disagreements on how to accomplish these goals, is not trivial.

Second, the DPU suggested the inclusion of an eleven-week prefiling settlement process at the front end of the IRM regulations during which interested parties could get together with the utility for purposes of trying to settle its demand forecast, committed resources, need for power, and RFP criteria for the first time in its proposed rules (D.P.U. 86-36-G). The proposal grew in part out of general discussions during the first round of technical sessions and formal comments regarding the need to streamline the process, and in part out of the DPU's increasing appreciation of the potential for greater use of consensus-building activities in implementing its policies in light of current rate case settlements, the DSM Collaboratives, and the technical sessions themselves. With the exception of MASSPIRG, who feared that a prefiling settlement process might further disadvantage resource-constrained public interest groups, everyone was supportive of the concept. However, most parties were rather skeptical that wholesale settlement could be achieved given the short timeframe and the complexity of the issues. They did believe, however, that it could narrow subsequent litigation and better prepare utilities and intervenors alike.

Third and fourth, the technical sessions revealed participants' virtual unanimity to provide utilities greater flexibility in selecting the final mix of resources in the IRM process by allowing them to renegotiate project details with developers and by basing their final selection on an optimized portfolio analysis. These changes marked a significant departure from the QF regulations in force at the time which required the awarding of contracts based on a strict self-scoring, ranking system. Everyone supported greater flexibility than the existing QF regulations afforded. However, participants differed about where to draw appropriate boundaries around a utility's ability to deviate from the original project ranking through negotiation and optimization, given markedly different concerns with respect to utility self-dealing. To a certain degree, parties support for added flexibility can be traced to persuasive arguments made during the technical sessions by Massachusetts Electric Company about the success of its negotiation approach to acquiring QF power,[21] and by the Energy Lab at MIT with respect to the need to optimize the resource mix by basing final selection on a portfolio analysis approach using a production costing model.[22]

Fifth, participants expressed a surprising amount of agreement during the sessions that including environmental externalities in IRM was reasonable. Even more surprising were participants unanimous rejection of a more simplified technology-based approach to environmental externalities proposed in D.P.U. 86-36-G (e.g., placing one level of environmental adder on a coal plant and another on a gas plant) in favor of impact-based externalities (e.g., a pound of SOx gets one adder and a pound of NOx gets a different adder). Although participants disagreed on how to derive such an impact-based approach (i.e., whether monetization was necessary, and whether the cost-of-control represented an adequate proxy for damage costs), they all clearly favored using a more complex and disaggregated one.

Last, everyone agreed that the IRM process would benefit if the DPU and EFSC's reviews were better coordinated. Parties also accepted the need for both agencies to increase their staff to implement IRM -- regardless of its ultimate form. Proof of the participants' support for increased staffing and agency funding came after the technical sessions ended but prior to the issuing of the final regulations. At that point, and in the midst of major budget cuts for virtually all other state agencies, the Governor signed a bill providing the DPU and the EFSC with approximately $1 million per year to increase their staffs to implement IRM.[23]

On-Going Controversies

While convergence on some issues during the technical sessions definitely occurred as described in the preceding section, other issues remained controversial and divisive. Table 5.10 highlights several issues where substantial disagreement persisted.

Table 5.10
Issues Where Substantial Disagreement Persisted

1. Whether utilities should be permitted to participate in their own solicitation processes.
2. Whether existing or planned resources should be considered eligible for displacement through the solicitation process or whether they should be considered committed resources.
3. Whether environmental externalities needed to be monetized to be included in the solicitation criteria, and if so, whether using the cost of control technology was the appropriate approach.
4. Whether DSM bidding should be included, excluded or phased into an all-resource solicitation process.
5. Whether the initial ranking of resources should be based strictly on a self-scoring system.
6. Whether the DPU's proposed seventeen month timeline was appropriate.

Source: Author's List

A brief discussion of these areas of continued controversy follows. First, despite the theoretical appeal of allowing the utilities to compete head-to-head with other providers in an all-resource solicitation, participants such as DOER and the Attorney General's Office (AG) remained unconvinced that adequate protection could be mustered against self-dealing. Second, the utilities and some of the developers voiced strong opposition to exposing their existing and planned resources to possible displacement through the solicitation process. They felt this way even if those units were not part of the least-cost mix, and even if they would be financially compensated. Third, although parties generally agreed on including externalities as part of the RFP evaluation criteria and rejected a simplified approach based on technology, they strongly disagreed about what constituted adequate impact-based methods and values. One group led by DOER, environmentalists, DSM providers, and Boston Gas Company proposed higher externality values than any other state had adopted to date, basing their values on the cost of pollution control. The electric utilities on the other hand, wanted to use a weighting and ranking approach and recommended much lower externality values. The disagreement between these two camps was not new, as the parties had reached the same impasse during an attempted collaborative process on the subject undertaken at the DPU's encouragement between April and June of 1989.

Fourth, the DSM energy service companies (ESCo's) were pushing hard for a fully integrated demand and supply side solicitation process. Meanwhile, the electric utilities and all four non-utility parties who were engaged in a collaborative process to design comprehensive DSM programs for the utilities (DOER, AG, CLF, and MASSPIRG), argued for providing the nascent utility DSM programs with a "safe harbor" from competition for the near future. The utilities and non-utility parties involved in the DSM Collaboratives claimed that an all-resource solicitation could undue their efforts in launching comprehensive DSM programs for each utility, and result in paying too much for DSM and in cream-skimming (i.e., getting the most cost-effective DSM, but leaving other cost-effective DSM untouched). The ESCos countered that all-resource bidding did not necessarily lead to expensive DSM or cream-skimming, but that the "safe harbor" proposal would effectively reduce competition and shut them out of the market by locking up all the DSM technical potential in the utility programs (Raab 1990).

Fifth, many participants maintained that the initial ranking should be based on a strict self-scoring formula, even though almost everyone was willing to provide the utilities a certain degree of flexibility in selecting an optimized final resource mix provided it did not result in self-dealing. Others argued against using a strict self-scoring approach in favor of an approach that gave the utilities greater flexibility in the initial ranking as well. Last, developers and utilities generally kept pushing for a tighter timeline to avoid the problem of projects becoming stale, while intervenors like the AG and MASSPIRG kept arguing that they needed more time for review and potential litigation than the current proposal allowed.

Despite the fact that there were still many issues involving major disagreements at the end of the technical sessions, the groups had reasonably aired the substantive issues. As a result, everyone came to understand the opposing perspectives more clearly, as well as the complex tradeoffs associated with changing any one aspect of the rules. As Harvey Salgo of TELLUS Institute, who represented DOER during the sessions, observed in our interview, "The most striking, and perhaps the only real, consensus reached during the technical sessions was a shared appreciation for the complexity of the issues". In the concluding sections I reflect on how a greater understanding of this complexity by the staff and the participants contributed to both more palatable and more practical rules, and a more successful rulemaking process generally.

Formal Rulemaking Process and Final Rules

At the end of the first round of technical sessions, comments were filed and 3 days of formal hearings were held. Nine months after the comments were received, the DPU issued proposed rules in December 1989. After the second round of technical sessions were held in January 1990, four days of hearings were held in March and April 1990 during which 20 interested parties testified, and written comments were received from 32 interested parties in May. Final rules were issued in August. At both rounds of hearings, the Commission heard all the testimony and questioned the commenters directly.

For both the proposed and final rules' staff met often with the Commission to help forge a rule that was responsive to the issues and concerns raised during the technical sessions and formal hearings and comments, and which all three Commissioners could support. Extensive meetings were also held between the DPU and the EFSC during these periods to work through coordination issues, and to assist each other in the development of the two agencies' respective rules.

Many of the technical session participants who I interviewed said that their formal comments were much more informed and focused as a result of the technical sessions. Former Commissioner Werlin, a recipient of those comments, concurred:

> The technical sessions were extremely helpful in providing us with better comments. The sessions provided an iterative process that successfully funneled the comments. Proposals that we were getting in the formal comments were already compromises. As such, we got a much better glimpse of the middle ground. A traditional rulemaking would've been much more positional, and we would have had to pull teeth in the hearings to try and separate the parties underlying interests from their positions (Werlin Interview).

It was much easier for staff to understand the comments and immediately identify any changes in perspective or new ideas, after having discussed all the issues and heard the parties interests expressed during the technical sessions (Author's Observation).

The DPU and EFSC did an enormous amount of work crafting both the proposed and final rules. They attempted to find the right balance between what often felt like disparate goals of stimulating competition, maintaining utility discretion, taking a societal perspective, and guaranteeing adequate reviewability. The issues discussed in the previous section, regardless of whether there was a convergence of opinion or not, could not be considered in isolation as they are all interdependent pieces of the IRM framework. Changing one piece of the puzzle often required rethinking numerous other pieces -- if not the entire structure.

Where convergence was revealed during the technical sessions and formal hearings, the final rules incorporated it in every case, despite the fact that the DPU was legally free to do otherwise. When there was no convergence, difficult policy choices were made by the Commission after careful consideration of the record established over the course of both the informal technical session process and the formal hearings and comments. In every case, the DPU understood the ramifications of its decisions much better than it would have without the benefit of the technical session process. Table 5.11 highlights the major changes and refinements to the IRM structure as they appear in the final rules D.P.U. 89-239 (1990) from what was originally proposed in the interim order D.P.U. 86-36-F (and delineated above in Table 5.5).

Table 5.11
Major Changes and Refinements in the Final IRM Rules

<u>Prefiling Settlement Process</u> (11 Weeks):

1. An eleven-week prefiling settlement process was added to the front-end of the process to help educate interested parties with respect to a utility's Phase I filing and parties' interests and concerns, to settle issues where possible, and to better focus subsequent litigation. The process is required to begin with a technical session.[24]

<u>Phase I</u> (5 Months):

1. In addition to filing its demand forecast, inventories of committed resources and uncommitted DSM resources, and an all-resource RFP solicitation proposal, the final rules require that the utility submit in some detail descriptions of each of the projects it intends to submit as its response to its own RFP. This requirement,

which was included as a means of diminishing concerns of self-dealing, does not however include the project price which is to be submitted concurrent with the other bids.

2. Utilities are required to include environmental adders in their RFP selection criteria based on impacts (rather than technologies). Specific adders, submitted by DOER and Boston Gas, based on the cost-of-control were adopted, and represent highest values adopted in country (see Appendix 3).

3. Greatly reduces possibility of considering existing and planned resources as uncommitted (i.e., decreases eligibility for displacement through the solicitation process) except in extraordinary circumstances.

4. Requires one joint filing for the DPU and EFSC instead of two separate filings.[25] Filings will be considered approved as submitted if DPU can not complete its review in time allotted.

Phase II (7 Months):

1. Requires that utilities allow for DSM bidding, but allows utilities to use either a combined, or separate solicitation process. Also, protects preapproved utility DSM programs in the near term by giving them status as committed resources.

2. Makes optional the use of a rigid self-scoring system for the initial ranking of projects, but requires that weights for each broad category of criteria (e.g., diversity, price) and a qualitative description of how each criteria will be evaluated be made explicit.

3. Allows the utility to deviate from the rank order of bid resources (actually the re-ranked order after negotiations) based on an optimized portfolio analysis of different groupings of projects in conjunction with its existing and planned resource mix.

4. Requires utilities to negotiate with projects representing 130% of need in rank order to improve the projects, and gives the utility the option to negotiate with additional projects.

Phase III (3 Months):

1. No major changes. DPU still reviews final resource mix to make sure that the utility properly selected resources based on the approved criteria (with modifications based on optimizing the entire portfolio) and that there was no self-dealing. Only modifications was decision to move preapproval process of successful utility resources to Phase IV which is the time that all other projects are negotiating final contracts.

Phase IV (5 Months):

1. No additional changes besides inclusion of utility preapproval process. Utilities negotiate final contracts with award group, and seek approvals from the DPU.

Other Highlights:

1. Overall Timeline -- The overall timeline of the process was changed from seventeen months originally proposed to twenty months (not including the prefiling settlement process).

2. Transition Rules -- DPU orders utilities to expand QF bidding process to include IPPs (but not DSM), and to apply environmental externality adders in any bid process or DSM program design during the transition period to IRM.

3. Incentive Ratemaking -- DPU approves the use of incentive ratemaking for utility DSM programs, as well as for the purchasing of non-utility resources (both supply and demand-side) but defers specifics to case-by-case basis.

Source: Author's List Based on D.P.U. 86-36-F (1988) and D.P.U. 89-239 (1990)

Conclusions

Saving Resources in the Rulemaking Process

The DPU's eight technical sessions cost approximately $15,000 for the DPU to hire the facilitators, rent the elegant but inexpensive meeting rooms at the Boston Adult Education Center, and to provide drinks and muffins at each session. Massachusetts Mediation Services contributed limited additional funds and services from its own budget to the facilitation pool for the first round of technical session. The technical sessions required approximately 600 person-days (a little more than two full-time person years) of time assuming an average of 75 people attended eight DPU-sponsored technical sessions for a full day for each session (i.e., attendance, travel, preparation and debriefing).

Notably, the vast majority of participants (i.e., over 90% in both rounds) claimed in the post-session surveys that the amount of time allotted to the technical sessions was "just right" or "too little", with a distinct minority claiming that "too much" time was spent in technical sessions (See Appendix 1). This survey represents at least an informal, "first-cut" indication by the participants that the benefits of the time and effort they dedicated to the technical sessions outweighed the costs.

Although the cost side of the equation is relatively straight-forward, estimating the gross and net benefits (i.e., benefits minus costs) is more complicated. In many respects, the formal portions of the rulemaking process proceeded in virtually the same way as they would have without the technical sessions, in terms of holding hearings, filing comments, and writing the orders and rules. In fact, without the technical sessions, the DPU probably would have skipped the interim policy piece (D.P.U. 86-36-F) and issued proposed rules directly. Unlike an adjudicatory proceeding, the time-consuming and expensive processes of issuing discovery, allowing parties to cross-examine one another, and writing briefs are not typical in rulemakings, and can not be counted as savings here (despite the assumptions to the contrary of many of those interviewed). However, as many of those interviewed pointed out, the formal testimony and written comments were more finely focused than they would have been without the technical sessions, and this in turn facilitated the Commission's decisionmaking and the drafting of the rules and orders. Since parties proceeded to write lengthy comments and the DPU wrote detailed orders, any savings that may have occurred in this regard were probably small.

It is also true that the IRM rules were not appealed to the state Supreme Judicial Court (SJC) and that the technical sessions may have contributed to parties' greater acceptance of the final rules. However, as discussed in the first part of this chapter, while appeal of administrative rules is fairly common in federal agencies, such appeals are much rarer at the state level. According to Jerrold Oppenheim, Assistant Attorney General in Massachusetts, "parties would generally be hesitant to appeal new rules here because they are well-aware of the SJC's inclination to defer judgement on technical issues to administrative agencies thus making a successful appeal of a rule such as IRM unlikely". Therefore, the avoidance of the cost of an appeal should probably not be credited to the technical sessions. In any case, appeals of this sort are usually made on fairly narrow grounds and while requiring some resources to prepare briefs and argue before the SJC, are not nearly as resource-intensive as a fully litigated case.

Another process-related benefit should be attributed if the technical sessions contributed to a better understanding and acceptance of the rules, and improved compliance while reducing costly future litigation associated with implementation. Although it is certainly too early to evaluate this issue, it is worth noting that the first utility to go through the IRM process, Massachusetts Electric Company, recently settled the case with a wide range of intervenors prior to the beginning of litigation.[26]

On balance, it is not clear that the technical sessions saved any resources related to the rulemaking process itself, although it may save process-related resources in the long-run. However, in addition to the process-related costs and benefits described above, as discussed in Chapter 3, it is also critical to assess whether the regulations themselves are better because of the supplemental process. If so, the net benefits to society are likely to be substantial given the relatively insignificant costs described above. In separate interviews, both Robert Werlin former Chair of the DPU, and Robert Shapiro former Executive Director of the EFSC, expressed their firm belief that because the sessions improved the final rules, their inclusion in the rulemaking process was a definite net societal gain. I explore these potential gains directly in the next two sections.

Legitimacy

I conclude that the addition of technical sessions and the decision to issue an interim order prior to releasing proposed rules enhanced the legitimacy of the traditional rulemaking process and made the final rules more palatable to the public. The mere fact that the process elicited the active involvement of more participants, representing a larger number and broader spectrum of society than any prior proceeding before the DPU (over 130 from 71 organizations) suggests this possibility. However, the critical advantage of adding the technical sessions to the traditional process was that the technical sessions provided the participants with a better forum for 1) understanding what was being proposed, 2) hearing the interests of other participants, 3) exploring the pluses and minuses of various alternative proposals; and 4) having an opportunity to try and persuade others to adopt their viewpoint. As Robert Fratto of COM/Electric explains, the sense of having been better heard because of the technical sessions added to the acceptability of the rules.

> The rules represented major policies that effect the entire way that utilities operate. However, the rules were much more palatable to a wider audience because more people had a real opportunity to provide input through the technical sessions, and the DPU was generally responsive to that input (Fratto Interview).

Consensus was not actively sought during the technical sessions. However, where a convergence of perspectives did emerge, it appeared in the final regulations. I disagree with skeptics who may argue that this convergence of opinion could have emerged just as strongly from the formal hearing and comment process. First, convergence happened only at the tail-end of lengthy discussions of particular issues (e.g., the issue of increased flexibility to negotiate and optimize). Second, in the formal process, parties tend to focus their comments almost exclusively on the issues of greatest concern to them, often completely omitting certain issues. The technical sessions ferreted out opinions on a broader range of issues than would likely have emerged in the formal process. Lastly, the technical sessions allowed the participants and the DPU staff to observe the range and intensity of comments in a way that was far more compressed in both time and space, and thus easier to understand, than in a formal process that's spread over days of hearings and mountains of written comments. As Rolly Rouse, former Chief Operating Officer of Citizens Conservation Corporation, aptly observed, "The technical sessions allowed everyone to see the entire picture all at once, thus avoiding the blind person and the elephant syndrome" (Rouse Interview).

The ability to see the whole picture at once, allowed some convergence of opinion and generally allowed the staff to propose alternatives to the Commission that it believed would better address the participants' diverse interests. The incorporation of any emerging consensus from the technical sessions and formal comments further legitimized the process.

Even in areas where differing perspectives were sustained throughout the technical session process and formal comments, participants still had a greater understanding of the opposing arguments and a respect for the Commission's difficult decisions, than if no technical sessions were used. This heightened sensitivity also added to the enhanced legitimacy of the final rules. Richard Hahn, Vice President at

Boston Edison Company describes this phenomenon that many of those interviewed mentioned:

> If nothing else, the technical sessions gave me a higher comfort level with the final regulations. I had a better understanding of the diversity of interests, and a greater appreciation of the difficult tradeoffs the Commission had to grapple with (Hahn Interview).

In the areas where major substantive disagreements persisted, the Commission made the final decisions. Though every issue had clear winners and losers, no single interest group considered itself to be a winner or loser on all issues. When asked to rank the DPU's balancing of the diversity and intensity of interests expressed during the technical sessions and formal comments on a scale of 1 to 10, ten of the twelve participants I interviewed thought it did extremely well scoring them in a range of 6.5 - 9. Only two parties did not concur -- giving the effort a 3. However, their reasoning perhaps suggests the Commission did better than the low scores imply. Both could not give the DPU a higher rating because they felt they had lost on two of their most important issues. However, while both were somewhat disappointed at the DPU's decision to let utilities bid in their own solicitation process, one was incredulous that the Commission did not further shorten the timeline of the process while the other was equally incredulous that the timeline was not lengthened -- both felt changing the timeline as they proposed would have better balanced the interests! Others were hard pressed to suggest ways that could have better balanced the interests of stakeholders.

Better balancing of interests in a rulemaking process where all interests are represented should lead to better rules. However, the key point here is that the overall perception that the final rules were fairly balanced despite continued controversy over many of the specific details, supports the argument that the technical sessions enhanced the legitimacy and acceptability of the final rules and the process itself.

The one issue that several of those interviewed claimed may have somewhat compromised the legitimacy of the IRM rulemaking process was the DPU's final decision to include the largest environmental externality adders adopted by any state in the nation. Al Destribats, former Vice President at NEES, for instance claimed:

> On a subject as complicated as environmental externalities, we needed much more discussion and expert opinion than the technical sessions and hearings allowed. It was basically handled too quickly and bothered a lot of people here at the Company (Destribats Interview).

On the one hand, it is tempting to dismiss this claim by pointing to the following facts: 1) the DPU had put parties on notice of its intent to include externalities two years before the final rules in its D.P.U. 86-36-F Order, and had in fact requested proposals; 2) an involved environmental externality collaborative process including all the utilities and many non-utility parties failed to reach consensus; 3) one entire technical session and much of the formal hearings were focused on externality alternatives; 4) the DPU specifically solicited supplemental comments on the adders it ultimately adopted prior to their adoption; and 5) the Commission acknowledged that the values were preliminary, and that alternative values could be established in future cases. However, the opposing facts that the specific adders adopted 1) were not in the proposed rules; 2) surfaced relatively late in the process (i.e., during the penultimate technical session and final hearings); and 3) represented essentially the largest numbers proposed rather than any type of compromise, lend credence to the criticism that the externality portion of the final rules were not as thoroughly mulled-over as most other portions.

In the end, although the process used to adopt the externality adders probably did not violate legal due process requirements, it may have compromised the legitimization process that the inclusion of technical sessions generally seemed to enhance. Further analysis and discussion of the externality adders might have changed the final numbers, or made the adopted numbers more palatable, or both. In any case, the adders themselves are being reexamined as of this writing through an involved and expensive adjudicatory proceeding that may have been avoidable.[27]

Practicality

The technical sessions contributed significantly to making the final rules more practical than originally proposed. Former EFSC Executive Director Robert Shapiro explains:

> In addition to better understanding how each issue effected different groups, I also could understand "real-world concerns" much better than I had previously experienced in formal proceedings. As a result, I believe the final regulations of both agencies are far more "practical" than they would've otherwise been (Shapiro Interview).

Former DPU Chair Robert Werlin concurs noting that, "originally, we inadvertently had things in our proposal that would've caused problems, and which we may have missed without the technical sessions" (Werlin Interview).

At least two factors contributed to the technical sessions' ability to infuse greater practicality into the rules. First, the process itself attracted business concerns such as supply-side developers and DSM providers to participate in the rulemaking, in a way that the formal process by itself may have precluded. As Mary Beth Gentleman, former Assistant Secretary of Energy Policy for the Commonwealth (currently representing cogenerators and DSM providers in private law practice) pointed out, the mere presence of these business folks added a critical "reality check" to the entire process. Second, throughout the course of the technical sessions, the practical concerns regarding project selection, timing, and financing issues were amplified in a way that is unlikely to have emerged from the hearings and written comments alone.

The feedback from the technical sessions and subsequent comments convinced the DPU and the EFSC to retreat in several areas they considered theoretically appealing, because they recognized that the solutions were untenable from a practical viewpoint. The most striking example of this was the two agencies' decision not to subject existing and planned units to displacement in the all-resource solicitation process. Both agencies believed strongly that an integrated planning framework should optimize the entire resource mix not just incremental new resources. However, as a practical matter they were convinced largely through the technical sessions that the rather limited opportunity for displacement (i.e., it's unlikely that operating plants could be displaced by unbuilt plants except when operating costs or environmental impacts of an existing plant are substantial), did not justify either the substantial work involved in putting every resource through the solicitation process each time, nor the potentially chilling effect that this would have on utilities and developers with respect to financing their projects.[28]

The technical sessions assisted the DPU in translating theory into practice on other issues like a retreat from self-scoring in favor of greater utility flexibility in selecting resources, and the relaxation of a fully integrated solicitation that would have subjected all supply and demand-side resources (including the utilities DSM programs) to compete head-to-head with the same evaluation criteria. Finally, in response to constant admonishments during the technical sessions to streamline the process and enhance inter-agency coordination, although the final rules do not cut the overall timeline (in fact the timeline increased from seventeen to twenty months) but did make several changes to enhance coordination and improve the chances for everyone to meet the ambitious timeline. Such enhancements included: 1) the addition of a prefiling settlement process; 2) the change from separate filings at each agency to a single joint-filing; 3) self-imposed deadlines for the agencies to issue orders by or the filings would be considered approved as submitted; and 4) a process whereby each agency agreed to incorporate the findings of the other agency into its own proceedings.

Process Evaluation

The IRM rulemaking process differed from traditional rulemaking procedures in at least two important respects. First, rather than issuing proposed rules early in the rulemaking process, the DPU issued an interim order that described a potential new regulatory structure and requested public comment on every aspect of its proposal. Second, rather than moving directly to formal comments and hearings after issuing the interim order and again after issuing proposed rules, the DPU sponsored a series of technical sessions. Both innovations were attempts to enhance public input into the rulemaking process.

The DPU held eight technical sessions over the course of the rulemaking process (two additional sessions were hosted by the EFSC in finalizing its portion of the rules). More than 130 individuals (not including DPU or EFSC staff) representing 71 different organizations, agencies, and private interests attended at least one of the DPU's technical sessions. Most of the 71 participating entities were represented at all of the sessions.

The number and diversity of participants was impressive and critical to success of process. All of the major players on electricity issues in Massachusetts were present. The process may have further benefitted by including additional stakeholders such as local governments or other ratepayer groups (e.g., residential, small commercial and industrial). However, the DPU would have needed to actively recruit these groups since they did not show up on their own and many of them are not regular parties before the DPU.

Holding the technical sessions away from the DPU hearing rooms in an informal setting was another important ingredient to the success of the technical sessions. This helped to more clearly differentiate the process from traditional proceedings. It also provided a more relaxed atmosphere to explore the issues and each others' underlying interests.

The sessions began after the DPU proposed an IRM structure in a policy order (D.P.U. 86-36-F) but prior to issuing actual proposed rules. The existence of an actual proposed structure served as an important starting-text and helped focus discussions. By not beginning with proposed regulations, the DPU sent an important signal that it sought public input. The process might have benefitted from some technical sessions even prior to the DPU's issuance of its policy framework, although the approach taken marked a substantial improvement over traditional "notice-and-comment" rulemaking.

DPU staff actively participated in all the sessions. Their role was three-fold. First they represented the Commission's perspective within the group. Second, they served as technical resources for the group. Third, they served as a conduit from the sessions back to the Commission and vice versa. All these roles were essential. Their presence helped inform the sessions and keep them focused on what the Commission needed. More importantly, the ideas gleaned from the sessions were immediately used to help the DPU reshape its proposals. The sessions would have been much less useful and productive without the staff's presence, as both the surveys and my interviews confirmed.

The Commissioners, however, decided not to maintain an on-going presence at the sessions, although they did attend small parts of two of the DPU's sessions and both EFSC-sponsored sessions. More direct involvement by the Commissioners might have been useful and appropriate to explain their proposals, and for them to hear the participants interests and opinions first-hand. However, with respect to exploring alternative proposals and building consensus; on balance, the Commissioners' presence might have dampened the free-flowing dialogue that occurred. Most of those interviewed concurred with this observation.

The use of facilitation was well received by the participants and at the Commission, and was considered by everyone to be an essential ingredient to the success of the technical sessions themselves. The facilitators level of technical expertise and lack of a more aggressive consensus-building posture were appropriate given their role as defined by the DPU. However, a more aggressive consensus-seeking process might have required more of a mediatory role and possibly more substantive knowledge of the issues.

Although the process resulted in substantial convergence of opinion on many issues, it stopped short of actively seeking consensus. The benefit of using technical sessions instead of a more aggressive, consensus-seeking process such as negotiated rulemaking, was that it allowed many more people to have direct input in the process. It also allowed for on-going brainstorming throughout the sessions. The disadvantage of not pushing for consensus, was that many issues were not resolved by the group, and the discussions remained at the broad policy level. There was neither the time nor the inclination to develop detailed implementation mechanisms or resolve the actual wording of the rules.

A more active consensus-seeking process, perhaps only in the second round of technical sessions, might have been appropriate and achievable. Using a negotiated rulemaking approach would have necessitated a more substantial resource commitment by participants and the DPU. It might also have required limiting participation to a representative sub-group, and perhaps securing mediation services. However, if such an approach further enhanced both the legitimacy and practicality of the rulemaking process and the final rules it probably would have been worth the effort.

Endnotes (Chapter 5, IRM Case)

1. The Public Utilities Regulatory Policy Act was signed into federal law in 1978. It requires that utilities buy power from Qualifying Facilities which are defined as electricity generators that are under 80 MW and use renewable resources, or cogenerators of any size or fuel type that meet certain efficiency requirements.

2. Central Maine Power voluntarily implemented a QF bidding system for several years. But bidding was not used by other Maine utilities nor required by the PUC.

3. California utilities suffered from both oversubscription (i.e., more power than was needed) and undue expense -- particularly in the face of falling world oil prices and reduced demand growth (Wiggins et. al., 1988).

4. Beginning in the early 1980's, the Levy Commission, which included Commissioners Robert Keegan and Bernice McIntyre (all three appointed by Governor Dukakis), also pushed utilities to implement marginal cost pricing.

5. Independent power producers (IPPs) represent all supply-side generation that is not built by a utility for its own use. Though IPPs are generally owned by non-utility entities, there is no legal prohibition against utility' or utility subsidiary' ownership of IPPs, although FERC often frowns on affiliated transactions. IPPs use all technologies and fuel types. Qualifying Facilities (QFs) are a subset of IPPs that is defined in federal law as defined above in Endnote 1.

6. Paul Levy left to head the Massachusetts Water Resources Authority. Robert Werlin, former General Counsel at the Department, took Chairwoman McIntyre's Commission seat. Several months, later Robert Keegan left and was replaced by Susan Tierney then Executive Director of the Energy Facilities Siting Council. After Governor Weld came into office at the end of 1990, all new Commissioners were appointed (Massachusetts is one of the only states which does not have staggered Commission terms). Susan Tierney was made Secretary of Environmental Affairs, and Commissioners McIntyre and Werlin joined private consulting and law firms respectively.

7. Boston Edison Company's Edgar preapproval request has resulted in contentious litigation with many parties. At the center of the litigation is whether Edgar is needed, and whether it represents the least-cost option.

8. I believe that this was largely due to the fact that both the parties and the DPU spent most of their time operating in an adjudicatory mode with strict restrictions against ex parte communications. As a result, the Commission and staff did not encourage informal dialogue, nor did many of the participants pursue this avenue.

9. It is notable that the rules were formulated almost entirely by the Commission and General Counsel without the assistance of the DPU's technical staff. Staff was only brought in after the fact-finding hearings were closed.

10. These policies were of immediate assistance to the electric utilities and four non-utility parties who were engaged in a collaborative process to design comprehensive DSM program for the utilities. The Department's policies helped to overcome an impasse in the collaborative negotiations over the appropriate cost-effectiveness test and ratemaking treatment for DSM resources. The Collaborative DSM process is described in detail in the Chapter 4.

11. The order specifically rejected the "no-losers" test which would limit utility investment in DSM to the difference between a utility's marginal avoided cost and average rates. The "societal" test requires utilities to pay up to the utility's full avoided cost plus any costs associated with environmental damages for DSM resources. However, while the DPU required utilities to include environmental externalities in their cost-effectiveness screening, it did not provide formulas or numbers do so. Instead, the order urged interested parties to work together to develop a proposal (D.P.U. 86-36-F (1988)).

12. "Lost DSM opportunities" means the failure to capture cost-effective DSM savings at the time when it is most practical and inexpensive to do so, like when a building is first constructed or when a customer replaces mechanical equipment. "Cream-skimming" is the act of only installing DSM measures with the highest benefit-cost ratio without capturing all other cost-effective DSM. Cream-skimming can often lead to lost opportunities since it may be uneconomic to return to a customer's premises at a later date. "Hard-to-reach sectors" such as low-income customers generally have greater market barriers that hinder their participation in DSM programs.

13. The annual DSM filing format was issued several months later by staff after conducting two, half-day informal technical sessions with the utilities and other interested parties to work through the Department's proposed format. The process was successful at developing common definitions for the terms, and smoothing out many, but not all, of the rough edges in the filing format.

14. In Massachusetts, D.P.U. 86-36-F gave utilities the clear option of selecting "expense treatment" for their DSM investment where they recoup their investment essentially in the year they are incurred but without return. Alternately they can select "amortization treatment" where they recoup only a portion of their expenses each year plus a return on the unamortized balance. Utilities can also recoup any lost revenue that may occur when DSM decreases energy sales below the anticipated sales used to determine rates in the prior rate case. It can therefore erode expected revenue and serve as a disincentive to the aggressive pursuit of DSM by utilities. It is an important historical note that additional positive financial incentives, such as shared-savings, were not mentioned in the order nor widely discussed at the time. Additional financial incentives were first approved by the Department in D.P.U. 89-194/195 (March 1990) in MECo's DSM preapproval case.

15. Specifically, the order accompanying the proposed regulations asked if incentives were needed to better guarantee utility enthusiasm for purchasing supply- and demand-side resources from third party providers, since under the existing ratemaking system there was only a strict dollar-for-dollar pass through to ratepayers with no

additional return (D.P.U. 86-36-G). The Order also requested comments on whether utilities needed positive financial incentives in addition to the other options (i.e., expensing, amortizing, preapproving, and lost revenue compensation).

16. The technical sessions all began at 8:30 in the morning and ended at 1:00 in the afternoon.

17. During adjudications, which comprise the vast majority of DPU proceedings, Commissioners and technical advisory staff are not allowed to have off-the-record discussions with litigants. Although some states have advocacy staffs that act as full parties and are permitted to discuss issues with parties during adjudications, the Massachusetts DPU only had advisory staff.

18. Representing the Department were (1) Henry Yoshimura, the Assistant Director of the Electric Power Division ("EPD") at the first session and becoming the EPD's Director by the last one; (2) myself, a Senior Economist at the EPD at the first session becoming the Assistant Director prior to the issuance of the final rules; (3) Susan Coakley, also a Senior Economist at the EPD, was present for the first four technical sessions, before leaving to help coordinate the Massachusetts DSM Collaboratives for the non-utility parties; and (4) Tim Woolf, was also a Senior Economist at the EPD and participated in the second round of technical sessions after leaving DOER where he had spearheaded that agency's earlier participation in the Department's IRM proceedings. In addition, other Department staff participated in the technical sessions both as scribes and in other administrative roles.

19. Massachusetts is one of six states with a state-sponsored offices of dispute resolution. The other states include New Jersey, Minnesota, Hawaii, Ohio, and Oregon (ACUS 1990, O'Connor Interview).

20. EFSC also held two technical sessions in August 1990 pertaining to its own proposed rules. The first session on August 8 covered demand forecasting and to the prefiling settlement process. The second session on August 16 covered committed resources, planned resources, and resource need.

21. In 1986 the Department approved an exemption from the QF regulations for MECo so that it could pursue a negotiation approach. MECo filed an annual report with the Department comparing its negotiation-based results to the bidding approach used by utilities in Massachusetts and elsewhere (MECo 1990). MECo's relative success was shared with participants during the technical sessions.

22. MIT Energy Lab was working with interested parties throughout New England in modeling various scenarios (Andrews 1990). Their findings were described during the technical sessions, and many participants were involved in MIT's research effort.

23. Governor signed into law (Chapter 150) bill providing DPU and EFSC $620,00 and $430,000 per year respectively to implement IRM. While the monies to fund IRM staffing were to come directly from utility assessments and developer contributions and therefore would not directly effect the state budget (D.P.U. 90-278 (November

1990)), the public perception of these agencies enrichment in the wake of the collapse of the "Massachusetts Miracle" was not taken lightly by anyone. The support of the utilities, who probably had the political power to delay if not undermine the funding legislation, without even seeing the final rules speaks to the support of increasing the staffing of the two agencies generally, and perhaps support for an IRM-type process specifically.

24. Discussions and positions taken by parties during the course of settlement negotiations will not be admissable nor subject to discovery during any adjudicatory proceeding, although facts disclosed during the process are discoverable. Any settlement, partial settlement, or contested settlement reached by the parties will be filed with the DPU and the EFSC as a component of the company's initial filing. 980 CMR 12.03 (4).

25. EFSC findings on the adequacy of a utility's demand forecast, committed resources, resource need and resource potential will be adopted by the Department, and reflected in its review of the utility's solicitation proposal.

26. Many factors contributed to the settlement including a projection of little or no need for power, and the uncertainty of the DPU's jurisdiction over a utility that is part of a regional holding company. However, this does not detract from the fact that a creative settlement was reached with many parties representing quite disparate interests. Even MASSPIRG's Allan Nogee who provided the most substantive criticism of the notion of a prefiling settlement process during the technical sessions (and continues to maintain that the process disadvantages resource-poor public interest groups) but who participated in the settlement, claimed in our interview that the it was "creative and reasonable". Although Nogee, and several other parties, did not sign the final settlement, they did not oppose it. The cases were Massachusetts Electric Company and New England Power Company. EFSC 91-24, and D.P.U. 91-114.

27. Boston Edison Company Edgar Station preapproval request, E.F.S.C. 90-12/12A and D.P.U. 90-117/118. Case had 20 intervening parties, 49 days of hearings, and over 1150 exhibits and record requests.

28. Though the issue of committed resources was discussed at length at the Department's technical sessions, it was also discussed at the EFSC's technical sessions which were attended by the DPU Commissioners.

New Jersey Bidding Settlement Case Study

Introduction

Purpose

The purpose of this case study is to analyze the innovative settlement process initiated by the New Jersey Board of Public Utilities (Board) in late 1987 to develop a set of policies to guide the state's electric utilities in their procurement practices with respect to alternative power producers (APPs) including Qualifying Facilities (QFs); non-QF, Independent Power Producers (IPPs); and Demand-Side Management resources (DSM). The process used to develop these policies differed from a more traditional "notice-and-comment" rulemaking in its use of settlement negotiations prior to the Board formalizing a set of policies. It differs from the Massachusetts IRM technical sessions described in the previous case study in this chapter because these negotiations actively sought consensus among the participants, whereas the effort in Massachusetts stopped short of this objective (focusing on education and open-discussion).

In the end, 11 of the 13 parties representing a broad-spectrum of interests signed a 52-page, comprehensive set of all-resource bidding policies after half-a-year of negotiations. If the Board had then published the settlement in the New Jersey register as its own proposed rule, received comments, and issued a final rule, this case would constitute a negotiated rulemaking. However, while the Board did embrace the settlement without change it decided not to go through a formal rulemaking process. That decision was appealed by three separate entities.

The case explores whether the infusion of a settlement process at the front-end of a policy- or rule-making process enhances public participation and improves the final policies or rules. I conclude that the use of a settlement process made the final New Jersey bidding policies more practical in many respects, while enhancing the legitimacy of the process. However, I also conclude that other factors, such as the decision not to formalize the settlement in rules and various implementation-related issues, have threatened to compromise some of these gains.

Research Methods

In preparing this case, I used a wide range of primary documentation such as Board Orders, written comments, agendas, correspondence, staff reports and internal Board memos. I also had the benefit of several secondary sources including comparative studies that analyzed New Jersey's bidding system, and an article written by one of the participants to the settlement that appeared in Public Utilities Fortnightly (Walker 1989).

In addition, I conducted lengthy telephone interviews with representatives of 8 of the 13 participating members of the settlement process. I selected a sub-set that included a representative, cross-section of the stakeholders in the negotiations (e.g., two of four utilities, and two of four QFs), and included representatives from both of the non-signatories. In addition, I interviewed four other individuals who did not participate in the settlement process, but provided invaluable background information on the rulemaking requirements in New Jersey, and on how the implementation of New Jersey's bidding process compares with other experiences in the country. A list of all those interviewed is shown in Table 5.12.

Table 5.12
Interviews for New Jersey Bidding Settlement

Utilities:	
Dennis Baldassari	Jersey Central Power & Light Company, Vice President of Rates, Materials, and Services
Harold Borden	Public Service Electric and Gas Company, Senior Vice President for External Affairs
Government:	
Michael Ambrosio	Board of Public Utilities, Bureau of Rates and Tariffs, Electric Division, Chief
Joe Bowring	Department of Public Advocate, Division of Rate Counsel, Chief Economist
William Potter	Partner, Private Law Firm (former Special Counsel, Division of Energy, Department of Commerce and Economic Development)
Alternative Power Producers and Industrial Consumers:	
Robert McNair	Cogen Technologies, Inc., Chairman and President
Michael Walker	Attorney, Private Law Firm, (represented Small Power Production Interests)
Harry Kociencki	Hoffman-LaRoche, Inc., Director of Corporate Energy Administration and Operation (represented Large Industrial Consumers)
Other:	
Anthony Miragliotta	New Jersey Office of Administrative Law, Assistant Director of Rules and Publications
Jim McGuire	Department of Public Advocate, Division of Rate Counsel, Attorney (former Director Department of Public Advocate, Center for Public Dispute Resolution)
Charles Goldman	Lawrence Berkeley Laboratory, Staff Scientist
Edward Kahn	Lawrence Berkeley, Laboratory, Group Leader, Utility Planning and Policy

Organization of Case Study

I begin the case study with a discussion of the period prior to the initiation of the settlement process between 1981, when the Board first adopted QF policies, and 1987 when the settlement process began. I then describe and analyze the settlement process itself, and highlight areas of compromise and creativity. This is followed by a discussion of the controversial aspects of the settlement which ultimately led to significant dissent and discontent among some participants.

I then turn to an analysis of the post-settlement process -- in particular the Board's decision not to formalize the settlement in actual rules and the appeals that ensued as a result. Next I evaluate the current experience of implementing the new bidding policies that were adopted by the Board in 1988. In the concluding section, I analyze the success of the New Jersey settlement process according to the criteria specified in Chapter 3.

Background

The Bidding Settlement approved by the Board in 1988 was a direct outgrowth of the Board's policies for QFs adopted in 1981 to implement the federal Public Utilities Regulatory Policies Act of 1978 (PURPA) (Docket No. 8010-687, 10/14/81). The Board's 1981 policies established guidelines for determining the rates that QFs were entitled to be paid for delivering electricity to the utilities, as well as a series of related issues (i.e., interconnection costs, standby rates, backup rates, and safety requirements). These QF policies were "rule-like" in their scope and content. However, they were formulated after a contested, adjudicatory proceeding rather than a formal rule-making.

In an effort to enhance QF development in New Jersey, the Board actually required utilities to pay 10 percent more than the utility's projected avoided energy cost, although PURPA only requires that QF's be paid up to a utility's full avoided cost (i.e., cost of the next available electricity supply option).[1]

> The Board is of the opinion that QF energy has a value in excess of the PJM billing rate (Pennsylvania, New Jersey, Maryland Power Pool) and that a figure of 10% above the billing rate is a reasonable and appropriate measure which reflects the excess value. We further believe that the setting of avoided energy cost at 10% above the PJM billing rate will help to adequately promote cogeneration and small power production in New Jersey and, at the same time, will yield long term benefits to utility ratepayers (Docket No.8010-687, 11/14/81, p.3).

In 1983, the Board issued an Order of Clarification which stated that all QF projects, not just those of 1 MW or less, as some had previously interpreted the 1981 Order, were entitled to receive these prices (Docket No. 8010-687, 12/7/83). The 1983 Order also explained that QFs were entitled to receive levelized payments for their electricity instead of prices that escalated over time. This levelization, which allowed for the front-loading of payments to QFs, was considered essential for nurturing the nascent QF industry.

Only a few contracts with small QFs were signed in New Jersey through 1985 despite having in place many essential ingredients necessary for a vibrant QF market (e.g., the Board's generous pricing and levelization requirements, a sizeable need for power by the utilities, and a large industrial base which provided numerous potential cogeneration sites). According to Michael Ambrosio, Chief of the Bureau of Rates at the Board, the primary reason for the inactivity was the protracted negotiations that were occurring between the QFs and the utilities over contract details.

In 1985, Jersey Central Power and Light Company (Jersey Central) became the first electric utility in the state to offer a standard offer, long-term contract for QFs over 1 MW. Previously this had only been available for small QFs. The contract, which was guaranteed to QFs on a first-come, first-served basis at the pricing terms required by the Board, was an immediate hit with the QFs compared to the preexisting negotiation process. Jersey Central's first 200 MW block was oversubscribed almost immediately (Staff Report, p. 15).

Both Jersey Central and Atlantic Electric reached settlements with Board staff that effectively institutionalized the standard offer approach by 1987. Subsequently, QF development in New Jersey began to flourish. By the end of 1987, the Board had approved 600 MW of QF contracts and an additional 1,500 MW were in the pipeline (i.e., final negotiating and signing stage or under review at the Board). A study conducted by Lawrence Berkeley Laboratory identified New Jersey as one of four states (along with California, Texas, and Maine) with "significant levels of QF development" during that time (Kahn et. al., 1989). Still, the other two utilities in New Jersey, Public Service Electricity and Gas (PSE&G) and Rockland Electric, which did not have standard offer contracts, signed-up relatively few QFs during the mid-1980's.

In May 1987, the Board released a report by its staff entitled: "An Assessment of Cogeneration and Small Production Policy in New Jersey 1981-1986". The report was required as part of the five-year review of New Jersey's QF policies as required in the original 1981 Order. The Board issued a cover letter with the report requesting public comments on it and related Board policies:

> The Board welcomes your comments on staff's report and is interested in hearing your views on any other ratemaking and regulatory issues related to cogeneration and small power production in New Jersey (Letter 5/20/87).

In its report, and during the hearings in September 1987, Board staff maintained that QF development was finally taking off in New Jersey after the advent of standard offer contracting and that the Board should "stay the course" with respect to its existing policies (Gabel 1987, p. 2). Staff did, however, recommend two things. One was to remove the 10 percent bonus to QFs from the avoided energy cost calculation which they saw as no longer necessary to jump-start the QF industry. The other was to include additional protection against potential utility self-dealing (i.e., the utilities contracting with their own QF affiliates).[2] Staff adamantly rejected the notion of replacing the standard offer contracting approach with a bidding system as several New Jersey utilities were suggesting:

> The concept of auctions or bidding systems should be rejected by the Board as an approach which will limit the growth of economic QF development in the State by slowing down the signing of contracts and giving the utilities an unfair, uncompetitive market advantage over QFs (Report, p. 40).

The other non-utility parties (NUPs) that provided comments on the staff's report and the Board's QF policies seemed to generally align with the staff's call for "staying the course". All the NUPs including the QFs, the Public Advocate, the State Division of Energy, and the Industrial Users wanted to see the continuation of a standard offer approach with prices set close to full avoided cost. The QFs and Industrial Users (who were cogenerators themselves), wanted to maintain the 10 percent bonus while the others did not.

The utilities, however, were dissatisfied with the emerging standard offer process and wanted to see major changes. Harold Borden, Senior Vice President for External Affairs at PSE&G explains:

> PURPA and the Board's Orders implementing it were unleashing a lot more cogeneration than we had anticipated. While we had some need to purchase QFs, we were concerned that we would have to buy more than we needed at prices that we considered too high (Borden Interview).

During the hearings, both PSE&G and Jersey Central offered testimony calling for the Board to scrap the standard-offer approach and initiate a bidding process. The utilities' viewed a bidding process as a way to provide them with greater flexibility in selecting QFs (i.e., it would no longer be a first-come, first-served process) while driving down the price they had to pay below full avoided cost to a competitive market price.[3]

Settlement Process

The procedural context in which the Board received comments and held hearings was unclear at the time. Specifically, it was not obvious whether a contested case, a rulemaking, or some other procedure would follow public comment. Without clarifying this important issue, but after hearing testimony and receiving comments, the Board determined that many valid arguments had been made on both sides of the bidding vs. standard offer debate. Subsequently, the Board directed its staff to convene settlement discussions with other interested parties, rather than move directly into litigation or rulemaking (Ambrosio Interview).

On December 4, 1987 Steven Gabel, then Director of the Division of Electric at the Board, sent a letter inviting interested parties to a conference to discuss the possibility of settlement. He justified his request as follows: "It is our opinion that the commonality of interest in the development of cost effective generation sources is sufficient to make settlement a reasonable possibility" (Gabel Letter). Although Board staff often settled adjudicatory proceedings such as rate cases, this constituted their first attempt to settle a case involving large policy issues outside the context of a contested proceeding.

Approximately 100 people showed up at the initial conference. The staff suggested a settlement working group of eleven interested parties including themselves, and gave those present an hour to select representatives. According to my interviews, everyone agreed on the negotiating representatives, and decided to allow the cogenerators to have three representatives instead of one -- supposedly to account for the diversity of interests they represented. Table 5.13 shows the make-up of the final thirteen representatives to the settlement group.

Table 5.13
Representatives to the New Jersey Bidding Settlement Group

Board Staff
Cogenerators (three representatives)
Department of Public Advocate, Division of Rate Counsel
Department of Commerce, Division of Energy
Independent Power Producers
Industrial Energy Users
Small Power Producers
Utilities (four representatives)

The only representatives from consumer groups were the Public Advocate and the industrial users (who apparently were more interested in their role as cogenerators than ratepayers). No environmental groups were present. According to those interviewed, no other environmental or consumer groups were active in New Jersey at the time, although several mentioned that in hindsight at least the state Department of Environmental Protection should have been recruited.

All interested parties were invited to attend the meetings, although only representatives of the settlement group were permitted to sit at the table. Several other groups, such as the "Clean Coal" developers, regularly attended the negotiating sessions. Commencing officially in early January 1988, bi-weekly negotiating sessions were held through July 1988 when most of the parties reached an agreement. Towards the end of the negotiations, participants began meeting more frequently -- up to several times per week. All negotiating sessions were held in a conference room at the Board.

The New Jersey bidding settlement process did not use an outside facilitator. Instead, the Board staff set the agendas, convened the meetings, and as the process progressed drafted each iteration of the settlement document. According to those interviewed, the tremendous amount of power which this gave the staff was not surprising given staff's preexisting clout with the Board. Staff's clout appears to have been a combination of their individual skills[4], and the structure of the agency itself vis-a-vis staff's relationship to the Board.

Unlike most other state PUC's, New Jersey is one of the only ones where the staff can act in both an advocacy and advisory capacity on the same case. Most other states, have either no advocacy staff at the PUC, a permanent separation between advocacy and advisory staffs (sometimes with the advocacy staff housed in another agency altogether), or a case-by-case separation of advisory and advocacy staff. The fact that the parties in New Jersey know that after staff negotiates a case as an advocate, they can often advise the Board on the outcome, gives the staff more power than is typically enjoyed by advocacy staffs across the country (i.e., where there is more formal separation between the advocacy staff and the Board or Commission). Couple this structure with a long history of the Board's heavy deference to staff judgement on most issues, as my interviews revealed, and you have a fairly formidable staff.

Given this influence, staff's decision early-on to switch their support from a "stay the course" approach that continued to rely on standard offer contracts to a bidding system, created quite a stir in the negotiations. Staff's reasoning for what interviewees viewed as a sudden change was explained by Michael Ambrosio:

> We changed our mind on the standard offer vs. bidding debate because we saw that with certain protections we could use a bidding process to prioritize projects and set price without squeezing out cogenerators. We realized that we couldn't close our eyes to the fact that bidding was being used throughout the country with apparent success, nor to the fact that getting the utilities to agree on a standard offer contract approach was unlikely. At the same time, if we didn't get the concessions we were looking for on the utilities' original bidding proposals, we would've returned to a standard offer approach (Ambrosio Interview).

From the utilities' perspective, as Dennis Baldassari, Vice-President of Rates, Materials, and Service at Jersey Central explained, "the group didn't convene meaningful discussions until staff said that they were willing to move towards a bidding system" (Baldassari Interview). However, all NUPs interviewed felt that once the staff announced this change, their influence on the outcome of the negotiations plummeted -- while the utilities' power soared. Some NUPs felt that they were forced to "concede turf on every point". Others, particularly the Public Advocate, felt that they were virtually ignored (Bowring Interview).

Despite the NUPs' perceptions, intensive negotiations continued for half-a-year. By mutual agreement, the original March 31 completion deadline was extended for four months. During the negotiations, the original two-page settlement proposal ballooned into the 52-page settlement that was ultimately signed by eleven of the thirteen representatives in July (Industrial Users and the Public Advocate did not ultimately sign). The decision to shift from a standard offer approach to a bidding paradigm was essentially a fait-accompli once the staff aligned with the utilities. However, the detailing of such a system was by no means settled early-on and engendered intensive debate and compromise.

During the negotiations, many creative compromises surfaced that may not have emerged through a traditional rulemaking. Other issues remained controversial and somewhat acrimonious. In the next sections I explore the settlement itself.

The Settlement

The final settlement signed by eleven of the thirteen parties represented a detailed set of bidding guidelines and policies that defined a whole new way of procuring non-utility power in New Jersey. Table 5.14 highlights the settlement's major components:

Table 5.14
Major Components of the New Jersey Bidding Settlement

1. Requires all electric utilities to conduct bids concurrently on an annual basis, whenever power need is projected (first round assumed to take longer).

2. All QFs, conservation projects greater than 400 kilowatts, and IPPs (at a utility's option) are eligible to respond.

3. Precludes utilities from participating in their own bids. Precludes utility subsidiaries from participating for at least the first three years.

4. Specifies a project ranking system consisting of three parts: (1) economic factors which can not be more than 55% of total weight; (2) project status and viability which can not be less than 25% of total weight; and (3) non-economic factors (e.g., fuel type, location, environmental benefits) which can not be less than 20% of scoring weight.

5. Prior to release, RFP submitted to Board and interested parties. Any objections raised by commenters are settled by Board staff (i.e., staff represents commenters and own position) and utility. If can not settle, or commenters do not agree with settlement, Board hears complaints at its own discretion.

6. Includes numerous minimum thresholds for participation by bidders regarding site control, fuel supply, thermal sales, permit identification and scheduling, milestone schedule, etc..

7. If bidder makes award group in two or more utility solicitations, each utility has option to bid against the other by offering to sweeten a bidder's original bid.

8. Individual contracts are reviewed by the Board -- there is no formal examination of the entire award group. There is no deadline for contract review and approval by the Board (2-6 months expected).

9. Establishes a liquidated damage fund where developers put money in at certain times and risk losing a portion of money whenever milestones are missed. Also requires security deposit if substantial front-loading of payments to APPs (i.e., greater than 20% of forecast avoided cost for oil/gas plants, and 35% for renewable and solid fuels).

10. Contains several non-bidding options: (1) Requires utilities to continue to offer short-run tariffed rates for QFs for energy-only, (2) Requires each utility to set aside a 5 year block of power (ranging from 25 MW (RECo) to 200 MW (PSE&G)) for small projects under 10 MW to receive long-term contracts at full avoided-cost rates, and (3) For three years, utilities required to sign long-run contracts with qualifying resource recovery facilities at full avoided-cost (after 3 years new facilities are required to bid).

11. Requires wheeling to in-state QFs on an average cost basis. Allows voluntary wheeling for IPPs, but no self-wheeling (i.e., from one industrial facility to another).

12. Utility bid process and all resulting power purchase contracts approved by the Board are deemed reasonable and prudent (unless discovered that utility has financial interest in facility).

13. Requires utilities to calculate their avoided costs over a 25 year period by using the differential revenue requirement method rather than the PJM method required by the 1981 Board Order.

14. The policies sunset after 5 years from date of Board approval unless renewed.

Source: Author's Compilation

Comparison With Massachusetts' IRM Rules

The settlement reached by the parties is no less comprehensive or complex than the Massachusetts' IRM rules described in the previous case. But while the two approaches to utility energy planning and procurement practices are similar, they are also significantly different. I present a brief comparison between the New Jersey settlement and Massachusetts' IRM rules as a way of expeditiously providing the reader with insight into the substance of the New Jersey settlement.

First, by including IPP power and DSM resources, both the New Jersey settlement and the IRM rules in Massachusetts expanded the bidding process that had been used by numerous utilities throughout the United States during the mid 1980's to secure QF resources.[5] However, despite being hotly contested in both states, the Massachusetts rules require utilities to participate in their own solicitations while the New Jersey settlement forbids utilities from directly participating and bans affiliates for at least three years.

Second, the project selection process in New Jersey relies on self-scoring and is probably less flexible but easier to review than in Massachusetts. The utilities in New Jersey are allowed less latitude to negotiate with projects, and less opportunity to reoptimize the final mix of projects to mesh with existing and planned resources.

Third, at least on paper, the New Jersey bidding cycle is more frequent (e.g., every year instead of every two-to-three years), and each bid from submittal of RFP to signed contract is slated to be completed within one year rather than 18 months as in Massachusetts. Fourth, the New Jersey settlement has a less formalized public review process but greater involvement from Board staff than the Massachusetts' proposal for both the review of the initial RFP and the final award group.

Fifth, while the New Jersey settlement changed the way utilities calculate avoided cost, the Massachusetts' rules virtually eliminated avoided cost calculations altogether. Sixth, while the Massachusetts' rules call for the inclusion of a liquidated damage fund and security when there is front-loading, the New Jersey settlement includes more detailed formulas for doing so. Lastly, although the New Jersey bidding criteria require looking at environmental externalities, the Massachusetts rules lay out a detailed set of externality "adders".

Compromise and Creativity

The New Jersey Bidding settlement included several noteworthy features which highlight the potential benefits of a negotiated approach to policy formation. The first is the way the settlement balanced the need to provide financial protection to ratepayers against failure of an APP to come on-line in a timely fashion (or at all for that matter) with the need to encourage APP development. Again, as a benchmark that is fairly typical in the country, the IRM rules in Massachusetts require all successful bidders to pay a fixed fee of $15 per kilowatt into an in-service security account within 30 days from contract signing. If the project comes on-line as scheduled, the money is returned to the developer. If it is delayed, the utility retains a percentage of the money based on a straight-line formula (the utility retains the entire fund if the projects fails).

In contrast, New Jersey's far more detailed liquidated damages fund is shown in Table 5.15.

Table 5.15
New Jersey's Liquidated Damage Fund for APP Developers

Milestone	Liquidated Damage Fund: Coal Project	Other Projects	Amount Forfeited if Milestone Missed
Bid Accepted by Utility	$2/KW	$4/KW	na
Environmental Permit Filed	$2/KW	$2/KW	$1/KW
Environmental Permit Received	$5/KW	$3/KW	$2/KW
Financial Commitment Received	$2/KW	$2/KW	$1/KW
Construction Commences	$7/KW	$7/KW	$4/KW
Total	$18/KW	$18/KW	

Source: New Jersey Bidding Settlement

The primary difference between the two remedies is that the New Jersey approach, while involving a slightly greater amount (i.e., $1.8 million for a 100 MW APP instead of $1.5 million), ramps-up payments into the fund to coincide with meeting each successive milestone instead of requiring a flat deposit at the outset. This innovation is an acknowledgement that at certain junctures the developer is willing to put up more money as the project becomes more real, while less potential damage is done to a utility and its ratepayers if a project fails early-on. New Jersey's liquidated damages fund also differentiates between coal which is much more capital-intensive and more difficult to permit than other fuels, and keys penalties to missed milestones.

All of those interviewed in New Jersey concurred that the degree of specificity and the resultant practicality of the liquidated damage fund would not have surfaced in a traditional rulemaking. Michael Ambrosio explains:

> No one would have suggested this approach in a rulemaking. The focus would have been on what bottom-line amount to require for liquidated damages.

> Extreme positions would have been taken, and the Board would have picked a number. Meanwhile, it took us 3-4 entire sessions to negotiate this solution. During the course of those negotiations we not only realized how complex the issue was, but more importantly, we eventually realized that there was actually a way to structure it that could satisfy both the utilities and the developers. While we still went back-and-forth on the actual numbers, in the end, it was a lot easier once we agreed on the principles. Everyone appeared satisfied with this part of the settlement when it was completed (Ambrosio Interview).

Two other features of the settlement were identified during the interviews as examples of creative and detailed approaches that are unlikely to have surfaced in traditional proceedings. The first is the security provisions that protect the utility and its ratepayers from the risks of providing front-loaded, levelized payments to APPs. Under the settlement, security is only required when front-loading is forecast to exceed the utility's avoided cost by 20% for oil and gas projects and 35% for solid fuel and renewable projects (Settlement, pp. 16-17). The second issue is the scoring system which not only specifies an array of factors that must be evaluated for each bid, but bounds the weights that the utilities can give each of the three major scoring categories (e.g., economic factors must be less than or equal to 55 percent of the score, project status and viability factors must be greater than or equal to 25 percent, and other non-economic factors must be greater than or equal to 20 percent) (id., p.13).

In both cases, participants in the settlement process spent several entire days negotiating these issues -- much more time than a traditional rulemaking process would ever allow. More importantly, by allowing for a full airing of the issues during the settlement discussions, the group was able to craft solutions which everyone could live with (even the non-signatories expressed support for these elements). This outcome would be unlikely if the Board had determined these elements on their own after brief exposure to everyone's positions through written comments, and hearings, if any.

Dissent and Discontent

The New Jersey Bidding settlement included a high degree of consensus among the parties on most issues. However, there was also a certain amount of dissent and discontent. As mentioned, two of the thirteen parties to the negotiations, the Public Advocate and the Industrial Users, did not sign the final stipulation of settlement. In fact, several people informed me that the Division of Energy signed the final settlement at the last moment, against the advice of its staff, and after "substantial arm-twisting".[6] The cogenerators signed the final agreement. However, they were basically dissatisfied with the overall thrust of the settlement (particularly the movement towards bidding) and many of the details, according to Robert McNair, President and CEO of COGEN Technologies and one of the three representatives of the Cogeneration Interest Group. In hindsight, McNair claimed that he should not have signed but taken the cogenerators concerns directly before the Board, despite a de facto moratorium on signing new QF contracts during negotiations which pressured cogenerators to settle the case (plus many cogenerators were reluctant to bite the hand that had been feeding them in any case) (McNair Interview).

Several issues were central to much of the dissent and discontent over the final settlement. The Public Advocate and Division of Energy remained opposed to involvement of a utility or a utility subsidiary in its own bidding process. Although a compromise was reached to delay involvement of utility subsidiaries for at least three years, apparently this was not sufficient to allay the fears of those two organizations (Bowring and Potter Interviews). They also remained bothered by the amount of discretion that the settlement seemed to leave the utilities in defining the amount of power they would solicit through the bidding process (i.e., the bid block) vs. the power that the utility could still pursue outside the bidding process through building its own projects and through other purchases from outside its service territory. As William Potter, who represented the Division of Energy throughout most of the negotiations prior to leaving for private law practice explained, the Division feared that the bidding policies would "create QF ghettos" that would not be properly integrated with the utilities entire resource mix (Potter Interview).

The Board staff's intention to minimize the potential ghettoization of QFs by spear-heading the review of both utility bidding and non-bidding proposals, apparently raised a series of other major process-related concerns for the Public Advocate and the Division of Energy. Under the settlement, instead of automatically providing the opportunity for interested parties to litigate a utility's RFP proposal, the Board staff is given the opportunity to settle with the utility any of its objections plus those raised by parties in written comments (Settlement, p. 40). If no settlement is reached, or parties remain disgruntled, the Board <u>may</u> choose to hear the case.

For both the Public Advocate and the Division of Energy, giving Board staff the authority to essentially represent the entire public interest, at least initially in the review process, raised questions both of due process and of competing jurisdictions (Bowring and Potter Interviews). While the Public Advocate maintained that it's job was to represent ratepayers before the Board, the Energy Office maintained that it's job was to review utility energy planning decisions. Both agencies apparently felt that the preeminent role of the Board staff in future reviews was not appropriate,[7] and that the right for parties to put on a contested case should not be compromised.[8]

As mentioned, the NUPs, except for the Board staff, were less than enthusiastic about embracing a bidding framework, and the APPs (including the Industrial Users) were upset about an apparent erosion in the price they would receive for future power. In addition, the Industrial Users were dissatisfied because they could not convince any of the other parties to let them wheel power from one industrial site to another via the utility grid (i,e., "self-wheeling"). Finally, the inclusion of DSM in the bidding process, which occurred literally within the last few weeks of negotiations at the Division of Energy's insistence, by all accounts was not adequately specified in the final settlement, leaving many unanswered questions. The parties I interviewed were not fundamentally opposed to DSM bidding. However, most would have preferred to defer discussion on the subject until a subsequent "Phase II" negotiation.

Post-Settlement Process

Several days after the settlement was signed, the Board released it for public comment. To the chagrin of the Industrial Users, neither the settlement document nor the request for comments mentioned that two parties to the negotiations had not signed (nor the reasons for their dissent). Also, while the Board referred to the settlement as containing new "guidelines and procedures", their intentions regarding New Jersey's formal rulemaking requirements were still not clear. Under New Jersey's Administrative Procedure Act, if the Board intended to adopt the settlement as a rule it needed to publish it in the New Jersey Register as a Board proposed rule, receive comments, hold a hearing if requested and deemed necessary, address the written and oral comments and publish a final rule in the New Jersey Register that reflected the public comment (N.J.A.C. 1:30).

Despite receiving comments from 12 parties including the Public Advocate, and several developers and large users -- most of which were critical of various aspects of the settlement -- the Board decided not to hold hearings on the settlement despite the criticisms. The Board also decided to adopt the settlement as Board policy without going through a formal rulemaking process. According to Michael Ambrosio of the Board staff, this decision engendered substantial debate within the Board both on legal and strategic grounds (Ambrosio Interview).[9] In the end, according to Ambrosio, the Electric Division staff's desire for greater future flexibility won out:

> Staff's primary interest was not to take a procedural short-cut on the adoption of the bidding policies themselves; rather, we wanted the ability to fine-tune the policies while they were being implemented without going through a six-month rulemaking process for each minor change. As such, we viewed a Board Order as providing us with much more flexibility than a formal rule (Ambrosio Interview).

On August 24, 1988 the Board adopted the settlement, and an Order to that effect was issued on September 28, 1988 (Docket No. 8010-687B, 9/28/88). In the Order adopting the settlement, the Board praised both the settlement process and the results:

> The Board believes that the Stipulation of Settlement was fairly negotiated, will impart substantial benefits to ratepayers over the term of the Settlement and will lead to the efficient development of future supplies of capacity and energy. The <u>new policy</u> should enhance the level of ratepayer benefit from APP development, improve the environment for APP investment and development by maintaining an ongoing, known market with adequate protection and will improve the system planning process of the utilities. (emphasis added)

The same day that the Board voted to adopt the settlement, William Potter, former negotiator for the Division of Energy and then representing Clean Coal, filed a Notice of Appeal with the Superior Court, Appellate Division. The next day he filed a "Motion for a Stay and for Reconsideration" at the Board (Potter 1988). Potter claimed that the Board had truncated the public participation for no apparent reason, and that the end result was a set of policies that were "neither fish nor fowl" since the Board had not followed either a rulemaking process nor a contested case proceeding (Potter 1988, Potter Interview). His Motion to the Board elaborates further:

> What the Board cannot do, absent serious risk of judicial review, is to proceed to conclude this docket through ad hoc procedures of its own...it is not enough to consider the Stipulation as neither a rule nor a contested case but rather as a mere "policy statement" or validation of a "contract" entered into by private parties...If characterized as a "policy decision," the Stipulation becomes a rule-making according to the A.P.A...If characterized as an order concluding a contested case, no stipulation which has not been signed by all parties or where interested parties object...can be approved in a summary manner (Potter 1988).

Both the Independent Power Coalition of America, Inc. (CICPA) and the Public Advocate also filed motions for rehearing and reconsideration regarding the Board's failure to follow requisite rulemaking procedures. In addition, the Public Advocate's motion protested the process included in the settlement for reviewing the RFPs of individual utilities and the resultant contracts. As discussed in the previous section, the Advocate had some serious reservation about the wisdom and the legality of the proposed review procedures.

In the written order issued on September 28, 1988, the Board rejected the parties' claims that its approval of the settlement violated New Jersey Law, and found that its actions were "consistent with proper administrative procedures...and are not inconsistent with our statutory authority" (Order Docket No. 8010-687B, 9/28/88. p. 7). The Board explains in the Order that it provided adequate notice, and a full opportunity for parties to provide feedback throughout the hearing, settlement and comment stages (id.,). On October 19, 1988 and March 22, 1989 the Board denied the motions for rehearing and reconsideration filed by the Clean Coal Developers and the CICPA respectively.

On September 13, 1989, the Public Advocate withdrew the last remaining appeal regarding the Board's decisionmaking processes associated with the adoption and implementation of the settlement. According, to Joe Bowring, Chief Economist at the Public Advocate, the Advocate withdrew its appeal as a quid pro quo for the Board's Order of Clarification issued on August 9, 1989 which effectively guaranteed them participation in the on-going review of utilities' bidding RFPs (Bowring Interview). With all the appeals withdrawn, the court never heard or ruled on these procedural issues.

Implementation Experience

Over three years have passed since the Board approved the bidding settlement. However, it is too early to gauge the implementation success of the new policies with any certainty. Only a few bid cycles have actually been completed, and no IPPs are scheduled to come on-line until 1993. However, some DSM resources secured after the first bidding cycle are in place (Ambrosio Interview). Still, several facts and observations are worth noting at this juncture.

Table 5.16 below summarizes the bidding experience to date. Utilities have not conducted annual bids as originally anticipated. This is partly due to what was probably an unrealistically tight timeline proposed in the settlement. However, it is also due to a perceived reduction in the need for APP power by the utilities. The portion of this reduced need that is due to a depressed Northeast economy is not heavily contested; however, the portion that is due to utilities continuing to pursue power options outside of the bidding process is controversial. For instance, Jersey

Central recently decided not to go out to bid for APP power but apparently is pursuing a 500 MW purchase power arrangement through its holding Company -- General Public Utilities.[10] Meanwhile, Atlantic Electric is seeking a certificate of need to construct its own 220 MW generating facility if necessary to meet its customers' demand, and PSE&G is pursuing major repowerings and expansion at two of its facilities equivalent to over 900 MW.[11]

Table 5.16
New Jersey Bidding Experience 1988-1991

Utility	Dates: Start	Completion	Bid Size	Response	Signed
JCP&L	1988	Dec. 1989	270 MW	768 MW (712/56)	261 MW (235/26)
PSE&G	1988	Dec. 1989	200 MW	700 MW (654/47)	257 MW (210/47)
Atlantic	na				
Rockland*	1988	Dec. 1989	200 MW	1412 MW (1395/17)	212 MW (195/17)
PSE&G	1991		85 MW		
JCP&L	1991		150 MW		

Notes:

1. Start Date when RFPs submitted for approval. Completion Date when award group named.
2. Numbers in () under "Response" and "Signed" headings refers to split between supply and demand-side resources respectively.
3. On-line represents installed capacity as of January 1992.
4. Atlantic Electric has not gone out to bid due to no projected power need through 2000.
5. Rockland bid was combined with Orange and Rockland bid in New York through an RFP that was approved in both states. Most of power (e.g, approx. 2/3) assigned to O&R in New York.

Source: Michael Ambrosio, New Jersey Board of Public Utilities

The utilities' decisions to aggressively pursue electricity options outside the bidding process, salt old wounds of the NUPs who during the settlement negotiations criticized giving utilities this flexibility. The situation puts the Board in the precarious position of having to administer a comparability test to make sure that a utility could not have done better by purchasing APP power through its own bidding solicitation. All the NUPs I interviewed expressed concerns that their biggest fears with respect to giving utilities too much discretion in selecting the bidding block size are being realized, despite giving the staff high marks for their attempt to devise such a test. Some of the NUPs also said they had difficulty getting access to the utility's submittals (including block size, avoided costs and the RFP) in a timely fashion, and had little meaningful input and influence into the Board's review process, which as mentioned previously is spear-headed by the Board staff in accordance with the settlement and Order of Clarification (Potter and Walker Interviews).

A second observation based on Table 5.16 and the interviews I conducted is that the responses to the bids have been relatively smaller (i.e., approximately 3:1 for PSE&G and Jersey Central combined) than responses to comparable integrated demand and supply bids by utilities outside of New Jersey where bid responses have averaged 9:1 (Goldman 1990). Several possible explanations may account for these phenomenon. First, with the advent of bidding, it is not as profitable for APP developers in New Jersey as before and some may have refocused their efforts on greener pastures. This reduced profitability is in part due to the removal of generous incentives offered prior to bidding (i.e., PJM rate plus 10 percent, plus the capacity deficiency charge). It was also posited that many of the best steam host sites in New

Jersey already had cogenerators installed during the successful standard offer contracting process (Ambrosio Interview).

However, Michael Walker, who represented the Small Power Producers, claims it is largely because utilities are suppressing their avoided costs (and thereby reducing the ceiling price available to developers) by inappropriately applying the methodology for determining their avoided costs that was agreed to in the settlement (Walker Interview). Walker believes that this is occurring largely because the settlement provided insufficient detail on how utilities were to make these calculations.[12]

Robert McNair of COGEN Technologies, Inc., one of the biggest APP developers in New Jersey, agrees with Walker's assessment (McNair Interview). He recently decided not to participate in the New Jersey bidding process he signed-off on in the settlement because of the low prices and small block sizes.[13]

Although Board staff's primary motivation for adopting the settlement through a Board Order instead of a formal rulemaking was to provide the Board with flexibility, they have not invoked that privilege often. In fact, the only changes to the approved settlement to date have been an enlargement of time for the bidding cycles, and the extension of the ban on utility affiliate participation in the bidding process for an additional year. In both cases, the changes were made by stipulation between the Board staff and the utilities. Other interested parties, including the other participants to the settlement itself, were provided an opportunity to submit written comments to the Board, but only after the stipulation was reached. The changes were not too controversial substantively. However, the fact that staff stipulated only with the utilities and provided only limited opportunity for input generally, aggravated those who already feared that the amendment process was unclear at best and possibly illegal (Bowring and Walker Interviews).

Finally, adoption of a new rule in 1991 on DSM resource planning and ratemaking incentives is relevant to the bidding case study both substantively and procedurally (N.J.A.C. 14:12). Among other provisions, the new DSM rules effectively reduce the importance of DSM bidding by encouraging a greater role for utility DSM programs and by allowing utilities to offer ESCO's a standard offer contract in lieu of including DSM in concurrent APP bids. Michael Walker believes that the adoption of this DSM rule was a "blatant disregard of the bidding settlement" because it compromised the inclusion of bidding as the settlement required (Walker Interview). Michael Ambrosio of the Board staff, however, argues that the DSM rules do not undermine the settlement but merely attempt to clarify important issues glossed-over in the bidding settlement (Ambrosio Interview).

On a procedural level, it is notable that the new DSM policies were adopted as rules, in compliance with New Jersey's rulemaking requirements. According to Michael Ambrosio, the Board decided to pursue a rulemaking in this instance because it was chastised by the courts on several occasions for not following rulemaking procedures. It also wanted to address the wishes of the new administration under Governor Florio which put all agencies on notice of its preference for pursuing rulemaking rather than adjudication whenever possible.

The Board chose not to use a settlement process in the DSM rulemaking because of its perception that the issues could not readily be settled.[14] Instead, the staff convened six, "round-table" discussions over the course of two years and numerous smaller focus groups. The round-tables were similar to the technical sessions used in

Massachusetts during the formation of the IRM rules, in the sense that they brought interested parties together to discuss the Board's proposals and explore alternatives.[15] Both the staff and the other round- table participants I spoke with considered the sessions informative and productive. However, they found the bidding settlement process to be more intense but ultimately more productive regardless of what they thought of the respective final policies.[16]

Future Revisions

The bidding settlement expires in 1993 -- five years from the date of the Board's approval.[17] The upcoming expiration provides the Board and stakeholders with an opportunity to change the policies. According to my interviewees, the NUPs will attempt to clear-up the ambiguities associated with determining the bid block size and the ceiling price. The parties will also revisit the appropriateness of continuing to use a rigid project self-scoring system for evaluating projects, and try to resolve the role of DSM in APP bidding in the wake of the new DSM rules. More fundamentally, they will revisit the question of the appropriate role of the electric utility and their affiliates in power production. Finally, it is likely that some parties will attempt to make APP development profitable for utilities, perhaps through a shared-savings mechanism similar to one recently adopted in New Jersey for DSM expenditures.

Given the multitude of old issues that need revisiting and new ones which need addressing, the Board will probably not simply extend the settlement for another five years (Ambrosio Interview). Rather, the bidding policies will likely go through a formal rulemaking process as did the recent DSM policies. In that case, the Board must decide whether to include a settlement process to develop the proposed rules. Alternately, they could use a technical session approach as they did to develop the

DSM rules and Massachusetts used for its IRM rules; or, they could simply revert to a traditional "notice-and-comment" rulemaking process without any front-end attempt at consensus-building.

Conclusions

Saving Process-Related Resources

The New Jersey Bidding Settlement negotiations were labor-intensive. Representatives from 13 organizations met bi-weekly over a 6-month period -- meeting more frequently towards the end. One member of the group, Robert McNair a cogeneration developer, flew in from Texas for every meeting.

The process-related benefits of the settlement are difficult to assess since the appropriate benchmark process is not obvious. The policies were never adopted through a formal rulemaking or even through an adjudicatory process. The settlement process was probably much more resource-intensive than a de minimis "notice-and-comment" rulemaking process. However, the resources invested may not appear so large if the alternative to the settlement was to thrash out the policies through a more involved rulemaking process (e.g., with several rounds of rule proposals, comments, and perhaps even technical sessions), or a lengthy adjudicatory process.

The Board's adoption of the settlement without subjecting it to a formal proceeding or making any changes resulted in the filing of several appeals with the state's Supreme Court. Although the appeals were ultimately withdrawn, if they had been pressed (particularly if the Board was ordered to conduct an entire formal proceeding), the settlement process itself may have precipitated some additional costs that a formal process may have avoided (i.e., traditional rulemakings are not routinely appealed to the courts at the state level).

It is still early to tell whether the settlement will produce process-related savings during implementation. On the one hand, things appear to be progressing as agreed to in the settlement, with several possible exceptions (discussed in next sections). When problems have arisen, the Board staff has settled them fairly expeditiously with the utilities. On the other hand, these recent settlements have engendered some discontent and potential future challenges by the NUPs who have felt unduly excluded.

On balance, it does not appear that the settlement saved process-related resources in the short-run. However, the benefits caused by improving the policies themselves may outweigh these short-run costs. I probe this conclusion in some detail in the next two sections.

Legitimacy

I conclude that despite numerous problems, on balance, the settlement process enhanced the legitimacy of the traditional policymaking process in New Jersey. The final settlement appears to have better satisfied the interests of most, if not all, of the participants than if the issues were resolved through traditional proceedings. A convincing example of this can be found by examining the interests and positions of the Board staff. The staff's primary interests were to avoid utility self-dealing, eliminate excessive payments to APPs without dampening the market, and increase their ability to oversee utility activity in this area generally. Meanwhile, their original position prior to the settlement was to "stay the course" by retaining the standard-offer contracting approach. Their decision during the settlement negotiations to switch to a bidding framework if certain checks and balances were included represented a major reversal of their position, and had a profound effect on the outcome of the settlement. If the resolution of these issues had remained in the traditional process, it is unlikely that the staff would have changed their position. Ironically, given staff's clout with the Board, their original position probably would have been adopted. But according to Michael Ambrosio, that scenario would have resulted in an outcome which Board staff now realizes would not have served their own interests as well as the final settlement (Ambrosio Interview).

The enhanced legitimacy of the policy-formation process produced by the addition of the settlement process is underscored by the fact that eleven of the thirteen participating groups, representing a broad spectrum of interests, signed the final settlement. That settlement was approved by the Board without change, and though three appeals were filed (primarily on procedural rather than substantive grounds), they were all ultimately withdrawn prior to being acted upon.

It can be argued that the presence of some dissent in terms of two parties not signing, and even discontent among some of those who did sign, may have compromised the legitimacy which the settlement process generally enhanced. However, most of the dissent and discontent were over major structural issues such as whether a bidding framework was better than a standard offer framework, or what the appropriate role of utility generation in a competitive marketplace should be. It is true that the settlement did not adequately resolve these issues to everyone's satisfaction. However, it is not clear that the dissatisfied parties would have preferred the outcome of a traditional rulemaking absent the settlement process.

The consensus of those I interviewed was that including supplemental settlement negotiations is preferable to a traditional rulemaking process alone. This was true even of those who did not sign the settlement or were otherwise discontent. One example is Harry Kociencki, who represented the New Jersey Pharmaceutical and Food Energy Users Group and did not sign the settlement. He explains:

> The settlement process gives people the opportunity to truly be heard and to negotiate. Despite the fact that we didn't do so well in the settlement process, I prefer to be in that type of forum than delegated a slot in a hearing...Although many of my primary interests (e.g., self-wheeling, and maintaining generous short-term, energy-only rates) were not satisfied, I felt the overall settlement did a fair job balancing the diverse interests at the table (Kociencki Interview).

Joe Bowring of the Public Advocate, the other non-signatory, also stated a preference for including a settlement process.

> I prefer the inclusion of a settlement process in rulemaking to rulemaking alone. Although we did not ultimately sign the bidding settlement, there were definitely changes to the settlement that addressed some of our interests because we were involved. This was not the case in the subsequent DSM rulemaking where there was no settlement process, we had no channel for meaningful input, and we were not satisfied with the outcome (Bowring Interview).

However, although the inclusion of the settlement process helped to better legitimize the overall policy-formation process, several other factors detracted from that sense of enhanced legitimacy. First, many of the participants were surprised and annoyed by the fact that the Board chose not to formalize the settlement in a rulemaking process, as appears to be required by the New Jersey Administrative Procedures Act. Three separate appeals on this issue were filed in the courts. Although the appeals were ultimately withdrawn for various reasons unconnected to the veracity of the allegations themselves, the issue continues to undermine the perceived legitimacy of the entire process.

Predicting court rulings with any certainty is always difficult. However, Anthony Miragliotta, Assistant Director of Rules and Publications in the New Jersey Office of

Administrative Law, concurred that the court probably would have concluded that the Board should have followed rulemaking procedures.[18] However, even if the Board had followed New Jersey's rulemaking procedures after the settlement was reached, perhaps subjecting it to greater public scrutiny, the final rules may not have differed substantively from the settlement. I conclude this because (1) the settlement had broad representation and involved extensive debate, (2) the Board, after hearing the substantive concerns raised by disgruntled participants and other interested parties, still chose to adopt the settlement as proposed, and (3) since the courts provide administrative agencies more latitude on substantive issues than procedural ones, they probably would not have ordered substantive changes if the Board was not inclined to do so.

However, by not subjecting the settlement to a formal rulemaking process, the Board succeeded in eroding some of the perceived legitimacy of the policies that the settlement process itself helped to bolster. Also, by not codifying the settlement in rules, the policies are more legally vulnerable to challenge, change, and even wholesale Board reversal. Ironically, New Jersey is the only state that I have found with negotiated rulemaking provisions in their Administrative Procedures Act.[19] However, Board staff were unaware of the negotiated rulemaking provisions which were codified in 1986 (Ambrosio Interview).[20]

A second feature of the settlement process and final results which may have compromised the perceived legitimacy are the provisions in the settlement allowing Board staff to spear-head the review of utility bidding RFP filings and resulting contracts. By providing staff with substantial leverage, these implementation review procedures supposedly streamline the process. However, deterring involvement of other interested parties, at best seems antithetical to the opening up of the public involvement process which the bidding settlement process attempted to embrace. At worse, this arrangement may violate due process rights, as the Public Advocate maintained in its appeal.

Lastly, the legitimacy of the settlement process has been called into question by those who believe that the utilities have not implemented the settlement in good faith. In particular, some of the NUPs I interviewed (both signatories and non-signatories), pointed to utilities' methods of determining their bid blocks and calculating their avoided costs. Allegedly the utilities have taken advantage of the ambiguities in the settlement to reduce both the block sizes and the avoided costs in ways which significantly diminish the importance of APP power and by implication the settlement itself. While they may not have violated the letter of the settlement, some feel that the spirit of the settlement has been compromised.

Practicality

The New Jersey Bidding settlement attained a degree of implementation savvy on many issues that almost certainly would not have surfaced through a traditional rulemaking process. Everyone that I interviewed agreed to this conclusion, even those who did not sign the final settlement or who signed despite being somewhat dissatisfied with the overall direction of the new policies (i.e., a bidding approach instead of standard offer).

The liquidated damages mechanism, which set up an insurance fund to provide compensation to the utility and its ratepayers if projects fail to meet certain milestones or come on-line, is a good example of the practicality of much of the final settlement. It appears to be a workable solution which embodies a creative balancing of the needs of the developers, utilities, and the public. This particular aspect of the settlement took three-four days to negotiate.

All those interviewed, agreed that this positive solution to a thorny problem would not have surfaced through a traditional rulemaking process. In a traditional rulemaking, the Board would have probably just taken testimony and then selected a single dollar/kilowatt figure somewhere in the middle of the range argued by the parties. The rich texturing embedded in the milestones with their differentiated payment schedules would have been lost.

To the extent that the liquidated damages fund better reflects the tradeoffs in the marketplace, the settlement can be credited for having infused greater practicality into the policies than may have occurred through a traditional rulemaking. Other areas that were settled after lengthy negotiations and the airing of different perspectives, such as the security provisions for front-loading and the RFP scoring system, also appear more practical because of the settlement process.

However, not every issue contained in the settlement received as much attention or detailing. Two examples include both the method for determining the highest price that can be paid to a prospective bidder (i.e., the price cap which is based on a utility's avoided cost), and the method for determining the bidding block size. In the case of the bid price cap, the settlement requires abandoning the old method and using a differential revenue requirements approach, but does little to specify this approach.[21] In the case of defining the bidding block, the utilities are required to bid out any incremental load but the settlement only lists factors the utilities must consider in determining such load. It does not specify how to make the tradeoffs between APP power and a utility's own construction plans or outside power purchases (Settlement, pp. 8-9).

In both cases, the ambiguity in the settlement has provided substantial discretion to the utilities, and this has been the source of much discontent among the NUPs (including those that signed the settlement). Some I interviewed claimed that the lack of specificity was due to a lack of time. Others claimed it was a strategic decision to preserve as much flexibility for the utilities as possible. It is also possible that parties did not recognize the potential problems associated with such ambiguity. Clearly, these issues could have been better fleshed-out in the settlement itself.

A skeptic might argue that the scrutiny of a formal rulemaking process would have better resolved issues like the methods for determining the bid ceiling price and bid block size. A formal rulemaking, for instance, may have forced the Board to definitively address these ambiguities. However, it is even more likely that a formal process would have made less headway producing practical solutions than the settlement did.

Process Evaluation

The use of a settlement process to resolve policy issues of this scope and complexity was unique and innovative. It constituted a more aggressive attempt at consensus-seeking than the technical session process used to formulate the IRM rules in Massachusetts. The New Jersey settlement also resolved many complex issues which the Massachusetts Department of Public Utilities did not believe could be settled when it decided to pursue technical sessions (e.g., whether utilities should be allowed to bid in their own solicitation).

The New Jersey Bidding settlement process benefited from its reliance on a core negotiating group. The 13 representatives of a broad spectrum of interested parties were selected by their peers. This representative approach kept the group to a manageable number (over 100 people showed up to the original meeting), and allowed the parties to proceed expeditiously. However, efforts were not made to solicit input from interest groups that did not normally appear before the Board at that time (e.g., environmental groups and agencies). Also, it does not appear that some of the individuals regularly conferred with those they purported to represent.

The settlement process effectively used the drafting of the settlement language itself as a focal point of the negotiations. Beginning with a two-page, single-text proposal formulated by the Board staff, six months and many drafts later, 11 of the 13 parties signed-off on a 52-page settlement document. Concentrating on the specific language of the policies helped keep participants grounded in crafting a tangible and workable product. It also forced them to resolve most issues at a level of detail rarely entertained in formal rulemaking proceedings. Such detail was not even attempted in the technical sessions used in Massachusetts during the development of its IRM rules.

Board staff chaired the meetings, drafted the text of the emerging settlement, and also actively participated as a full party. This gave them substantial control in guiding the process to meet their needs, and undoubtedly played a pivotal role in brokering the final settlement between the utilities, developers, and themselves. However, the Public Advocate, the Industrial Intervenor, and even the Division of Energy (which somewhat reluctantly signed the final settlement) felt shut-out of the process. Several parties protested the settlement before the Board, filed appeals to the courts, and have remonstrated against various events during the implementation phase as a result of their discontent with the original process and its results.

It is possible that the process could have been improved if staff did not try and play a dual role as both an active party and as a facilitator (or more accurately as a mediator). A professional third-party neutral may have helped parties find ways to bring everyone into the final settlement, and resolve some issues that were left rather ambiguous.

The process also seemed to suffer due to a lack of clarity regarding where the settlement would fit within the traditional regulatory structure. Most parties assumed the settlement would be adopted as Board rules. When it was not, numerous appeals were filed. Although the appeals were withdrawn for various reasons, the courts probably would have required the Board to put the policies developed in the settlement through a formal rulemaking process.

Although the Board did not adopt the bidding settlement as a rule but as a policy, they could have easily transformed it into a formal rule. They only needed to publish the settlement in the New Jersey Register as their own proposed rule, and then put the final rule in the Register after addressing any comments received.[22] If the Board had done so, this case would have provided a true example of a negotiated rulemaking, similar to the "reg-negs" conducted by the EPA. However, even without having gone through a formal rulemaking process, the New Jersey bidding settlement still constitutes a major innovation as one of the only examples in recent U.S. electric utility regulatory history where rule-like policies that apply across the industry have been formulated through a settlement process.

Endnotes: (Chapter 5, New Jersey Bidding Settlement)

1. The avoided energy component in the New Jersey system was to be determined by adding 10% to a utility's PJM billing rate projected over time. The avoided capacity component was the PJM deficiency charge for capacity (i.e., the cost of buying additional capacity from the pool, which is the average cost to a PJM member of a combustion turbine.)

2. There was a dispute between Board staff and Atlantic Electric over the utility's award of a contract to a subsidiary. The dispute was eventually settled. Staff had also lost a dispute with Public Service Electric and Gas on self-dealing (i.e., the Board did not find that self-dealing had occurred).

3. In contrast to the utilities' call for bidding in New Jersey, which in large part was to better control what they perceived as run-away QF development, the call for bidding in Massachusetts several years earlier came from the Commission and the State Energy Office as a way to stimulate QF development.

4. Staff representatives included Steve Gabel, Director of the Electric Division, Robert Chilton, Chief of the Bureau of Rates and Tariffs (in the Electric Division), and Michael Ambrosio, Chief Engineer of the Division. All three had been with the Board for some time, Gabel since before 1980, and all received substantial praise for both their intelligence and their savvy from all those interviewed.

5. Although IPP participation is at the utility's option in New Jersey, IPPs have been allowed into all of the bidding cycles thus far. On the other hand, while DSM bidding for large projects or programs is allowed outright in New Jersey according the settlement, in Massachusetts' IRM rules it is allowed only when it does not conflict with an existing utility DSM program.

6. Several people told me in no uncertain terms that the Division of Energy, until literally hours before end, was not intending to sign the settlement. Apparently significant pressure was brought to bear on them, although no one was sure (or willing to tell) whether the pressure came from within state government, from the utilities, or both.

7. Apparently turf battles between the Board and both the Public Advocate and the Division of Energy were intense at the time of the settlement discussions for numerous reasons, many of which were beyond the scope of this bidding settlement process.

8. Several of the due process concerns include: (1) the necessity of parties to file comments prior to discovery and cross-examination; (2) an inability for parties to try and settle their concerns directly with the utility; and (3) great discretion on the part of the Board and staff in determining if, and when, to adjudicate a utility's RFP. It should be noted that similar due process concerns were raised with respect to the review of the winning bidders.

9. The debate on whether or not to pursue rulemaking and the apparent last minute decision made by the Board is evidenced by the written speech delivered by Board President Christine Todd Whitman on the morning of the Board's adoption which was circulated to interested parties. In the speech, the words "for publication in the New Jersey Register" were deleted after the words "I recommend that it (the settlement) be approved".

10. Apparently GPU is planning to purchase 500 MW for Jersey Central from Duquesne Power -- 350 MW of system capacity and energy, and 150 MW interest in the existing Phillips coal plant.

11. Apparently Atlantic only plans to build the 250 MW facility if some of the APP power it's counting on fails. However this is still indicative of tensions between meeting incremental load with a utilities own resources or going back to the marketplace in a subsequent bid. PSE&G plans to replace and expand two of its facilities -- one in Bergen county and the other at Burlington.

12. For instance, Walker points out that there are many variables in the calculations which should be the same across all utilities but none were ever specified. He further points out that some utilities are inappropriately considering unprocured resources as committed. This effectively reduces the size of the resource block and reduces avoided costs.

13. McNair recently completed a 600 MW cogeneration facility at EXXON in PSE&G's service territory, but sold the power across the Hudson River (via an underwater cable built by his company) to Con Edison at prices significantly higher than he could have procured through the bidding process in New Jersey (McNair Interview).

14. According to Michael Ambrosio, the plumbers union were up-in-arms over the utilities running DSM programs which they believed would detract from their business. Apparently every meeting where DSM was discussed, many vocal plumbers (sometimes in the hundreds) showed up and protested. The Board did not think that settlement discussion would be productive in that environment.

15. The round-tables and the technical sessions differed in that the Massachusetts IRM technical sessions used outside facilitation, were more highly structured, and apparently made a greater effort to guarantee that all stakeholders participated.

16. An interesting postscript to the DSM rules is that they too have been appealed by the Public Advocate on procedural grounds. However, according to Joe Bowring, the appeal is not based on the rulemaking process, but on the implementation process which the Advocate is again claiming will compromise due process.

17. While the five-year expiration clause was part of the settlement, it is worth noting that even if it had been adopted as a formal rule it would have expired at the end of five-years as is required of all administrative rules under New Jersey law.

18. This assertion was based on his observation of the Court's treatment of similar cases (Miragliotta Interview).

19. Although the ACUS in its Negotiated Rulemaking Sourcebook (1990) also claims that Minnesota has negotiated rulemaking provisions, Roger Williams, Director of the Minnesota Office of Dispute Resolution maintained that was not the case during a phone interview. However, others states' rulemaking regulations would generally permit negotiated, settlement-type procedures for developing proposed rules as long as it then goes through the same rulemaking procedures afforded a rule developed through more traditional means (i.e., Commission develops proposed rule on its own perhaps after hearings, comments, or even technical sessions). New Jersey's rules actually set up a voluntary structure for negotiating a rule (N.J.A.C. 1:30-3.5).

20. The fact that staff was not aware of the "negotiating a rule" provisions is not surprising, since Anthony Miragliotta reported that though many agencies have enquired about the provisions, none have followed the procedures. Under the voluntary procedures, the Office of Administrative Law, at an Agency's request, acts as a convener and facilitator to the negotiations. The negotiations are limited to ten parties, and they attempt to complete the negotiations in ten days (longer if by mutual consent). If a settlement is reached, the Agency reviews it to determine if it wants to propose the rules. If it does, the formal rulemaking procedure is followed from then on. The voluntary use of the OAL, does not preclude agencies from pursuing other types of settlement-approaches, such as the one followed by the Board, to develop proposed rules.

21. The settlement provides only the following rather skimpy guidance:
The avoided costs will reflect the difference between: (i) the utility's best supply plan developed without additional APP capacity, and (ii) the utility's best supply plan changed to reflect, at zero cost, the "Avoided Cost Block." These supply plans should include the level of QF capacity commitments which are currently expected to be placed in service, but should not include previously contracted for capacity which is unlikely to develop (Settlement, p. 11-12).

22. The Board would also have been required to acknowledge and respond to all comments received on the proposed rule, regardless of whether it incorporated their suggestions into the final rules. If the Board was to go the rulemaking route, as it probably should have, it may also have needed to change some of the language of the settlement to make it more rule-like.

Rulemaking Chapter Summary

In this chapter I evaluated two attempts to introduce supplemental consensus-building processes in traditional rulemaking proceedings. The first used structured technical sessions with outside facilitators to develop Integrated Resource Management (IRM) rules in Massachusetts. The second used a negotiated settlement process to develop resource bidding policies for the state of New Jersey.

Together, the cases show the potential for improving the legitimacy of PUC rulemaking with consensus-building techniques. The IRM case shows that this can occur in the absence of formal consensus-seeking, while the New Jersey case shows that it can occur even when a complete consensus is not reached. Legitimacy was enhanced in both cases not because everyone suddenly loved the final rules and policies, which many did not, but because overall stakeholders preferred the process. They also took more direct responsibility for crafting the ultimate rules and policies, and came to better understand and appreciate the difficult tradeoffs that needed to made. However, both cases also showed how legitimacy can be undermined when some stakeholders are not accommodated, or the regulators make hasty decisions.

The processes also reached a surprising amount of agreement on structural issues and implementation details. This was more formally accomplished in New Jersey's settlement process than the technical session process in Massachusetts. However, it occurred in both locations. Overall these agreements produced practical improvements to the rules and policies which were unlikely to have emerged through the traditional processes.

The consensus-building processes were relatively resource-intensive. The Massachusetts IRM technical sessions required approximately 100 people to invest an additional 10 days of time over a two year period. The New Jersey settlement required a bi-weekly commitment from representatives of 13 organizations over six-months. Concurrent savings in the traditional processes are less clear-cut, but are probably small if any. However, long-term net benefits factoring in the improvements to the actual policies and rules appear to be positive compared to traditional rulemaking processes.

Chapter 6: Improving Electric Utility Regulation – Cultivating Consensus

I begin this final chapter by highlighting some of the major controversies facing society regarding the regulation of electric utilities. After revisiting the short-comings of past and current regulatory procedures, I conclude that the infusion of consensus-building processes into electric utility regulation can improve the resolution of these complex, and often contentious, disputes. Although settlements in electric utility regulatory cases are not uncommon today, use of consensus-building can be expanded and improved. At the end of the chapter I provide several recommendations on the design of consensus-building supplements to traditional regulatory processes for public utility commissions (PUCs), utilities, and others to consider.

Challenges Facing Society on Electricity Issues

The days are over when electricity issues were relatively non-controversial and utilities were routinely left alone to run their businesses as they saw fit. Beginning in the early 1970's, the real price of electricity began rising after more than half-a-century of declining costs. Since then utility decisionmaking has been constantly challenged by the public and by regulators. Intervention by outside groups in utility ratemaking and other adjudicatory proceedings, and interventionism by the regulators themselves, is now commonplace. Stakeholders also regularly participate in contentious rulemaking proceedings to consider sweeping changes in electric utility planning, management, and cost-recovery practices.

The contentiousness of electric utility-related disputes often goes to the core of how utilities' select and manage energy resources. For instance, although stakeholders agree that from a societal perspective, demand-side management (DSM) resources should be aggressively pursued whenever they cost less than new supply, they disagree about the appropriate role of the utility in purchasing them and delivering DSM services. This debate has intensified recently as some intervenors and regulators have called for utilities to include customer fuel switching measures in their DSM programs, and others have called for slowing-down utility' DSM expenditures to curb short-term rate increases. Cost-recovery issues associated with DSM expenditures have also been controversial.

Similar controversies have erupted regarding the appropriate role of utilities in providing supply-side resources. Despite a growing trend to open up the generation market to competition from non-utility generators, stakeholders continue to debate about how far and how fast this should be done. Moreover, they have extensive disagreements about the design of various mechanisms, most notably bidding systems, to encourage competition.

Environmental concerns also promise to remain controversial and challenging. Siting electricity-producing facilities of virtually any size or fuel type is extremely difficult. Recent attempts by regulators and other intervenors to have utilities consider potential environmental impacts alongside the direct costs of electricity when making resource selection and operation decisions have engendered substantial debate.

Proceedings to change the ratemaking system itself, to realign the incentives for utilities to pursue "least-cost" energy options through market-based pricing, shared-savings incentives, and decoupling sales from profits, are often controversial. Meanwhile, as the cost of electricity continues to rise, utilities and intervenors spend countless hours litigating how those increases should be allocated between customers and utilities, among customer classes, and between current and future generations.

Finally, federal and state entities and states themselves have significant inter-jurisdictional conflicts on electricity issues. The areas of conflict include the resource decisions made by multi-state holding companies, transmission access and pricing, utility mergers, authority over certain Qualifying Facility issues, and environmental issues.

Together these issues represent major challenges for society. Most of these challenges are likely to continue to intensify for the foreseeable future, and new challenges will surely arise. The electric utility industry and its regulatory environment are clearly at a number of complex, controversial and critically-important cross-roads.

Short-Comings of Current Regulatory Approaches: Interventionism Revisited

As described in Chapter 2, once electricity prices began to rise and environmental concerns moved to the foreground in the early 1970's, intervention in utility matters before state PUCs increased dramatically. Regulators, in turn, assumed much less of a lassiez-faire attitude towards their oversight role of electric utilities than they had in the past when prices were steadily declining. Tentative at first, many regulators began to use their new-found interventionism to spearhead numerous campaigns to change utility ratemaking and resource planning practices (Barkovitch 1989). Marginal cost pricing in New York, aggressive DSM programs in California, and substantial nuclear plant-related disallowances associated with "prudent, used, and useful" tests in several states are all examples of this interventionism.

Yet, beginning in the late 1970's and throughout the 1980's, problems with PUC interventionism, and the remedies produced after contested case proceedings more generally, began to surface. For instance, despite continued public support, California utilities did not sustain their aggressive DSM programs once PUC attention was diverted elsewhere. In Massachusetts, regulators and others feared that large nuclear plant cost disallowances under the DPU's "prudent, used and useful" test had scared utilities' away from building new generation at a time when it might be needed. These two examples point to the possibility that interventionism alone can lead to remedies that are not considered legitimate or practical by stakeholders, and can cause unintended or undesirable results.[1]

PUC interventionism is not likely to fare any better in the 1990's and beyond. Most of the contentious issues of the 1980's are still with us, and new issues which promise to be even more complex and contentious will probably emerge. Moreover, with increasing options for many customers (particularly large industrial customers) to buy alternative energy supplies, self-generate, or cut consumption through DSM, the utilities' monopoly on the distribution of electricity services is weakening. This in turn, partially undercuts regulators and other interested parties' ability to push their own agendas (e.g., environmental considerations, or aggressive DSM programs) because doing so might increase rates and further aggravate the bypassing of the utility system by customers (which could, in turn, aggravate rate increases on captive customers)

(Stalon and Lock 1990, Barkovitch 1989). Therefore, when bypass concerns are real and potentially substantial, interventionism may necessarily be tempered.

Meanwhile, utilities are repeatedly entangled by consumer and environmental intervenors with respect to almost any action they wish to take. Concurrently, environmental and consumer interests often conclude that despite winning many battles before state PUCs they are losing the war (i.e., they can often stop what they consider unacceptable utility decisions but can rarely precipitate more attractive options in their place). Litigation is usually resource-intensive and acrimonious, and regulators are forced to make decisions which often leave all parties dissatisfied. Appeals to the courts, and resistance to implementing remedies ordered by PUCs are common.

Finally, the opening-up of traditional utility generation to non-utility generators and to DSM resources, has made utilities (and hence ratepayers) much more dependent on others for providing resources than ever before. This growing interdependence renders interventionism without substantial consensus-building relatively ineffective. Remedies designed by PUCs alone in complex and controversial cases may be doomed for failure. Although this prediction may be more accurate when prospective issues and plans are the focus of attention (e.g., a utility's future DSM programs), I believe it is relevant for cases concerning past actions as well.

Benefits of Supplemental, Consensus-Building Processes

A wide range of consensus-building mechanisms can supplement traditional adjudicatory and rulemaking procedures including: technical sessions, advisory committees, case settlements, prospective collaboratives, and negotiated rulemakings. As the case studies in Chapters 4 and 5 revealed, such approaches can improve traditional adjudicatory and rulemaking processes in several ways. First, when traditional adversaries reach consensus in an adjudicatory or rulemaking proceeding, and that consensus is approved by the PUC (and upheld in the courts if appealed), the legitimacy of both the process and the results are generally enhanced. The settlements in the Pilgrim Nuclear Outage case and the DSM Collaboratives, satisfied the interests of the participants and the regulators (who did not participate in the settlement) better than contested case proceedings usually do. Even in the New Jersey Bidding case, where not all the parties joined the final settlement, the parties agreed that the settlement process represented a positive improvement over the traditional process (i.e., parties who did not sign the final settlement believed their interests would not have been any better served through a contested case proceeding or rulemaking alone).

The second major finding from the cases in Chapters 4 and 5, is that consensus-building can also enhance the practicality of remedies, plans and policies in ways that should improve implementation and reap greater benefits for society. Several noteworthy illustrations from the cases include: (1) tying BECo's cost-recovery to Pilgrim's performance, (2) detailed insurance-related provisions in the New Jersey Bidding settlement, and (3) various program design innovations and financial incentives in the DSM Collaboratives.

At least four positive attributes of consensus-building account for these substantive improvements:

- The best technical information was sought and shared, instead of being selectively pursued and used as a weapon as in traditional contested cases.
- The parties own concerns and experience were more directly reflected in the proposed solutions.
- The parties were able to reach beyond the confines of precedent and other potential legal restrictions that a PUC might have faced, to find more workable and efficient solutions that better met their needs.
- The parties could work out their solutions at a level of technical detail that would be extremely difficult, if not impossible, in a contested case or rulemaking proceeding.

Even when a formal consensus is not actively sought, as was the situation in the Integrated Resource Management (IRM) Rulemaking case in Massachusetts, a facilitated technical session process helped identify areas of convergence and numerous practical improvements to the proposed rules. Where disagreements on issues persisted, the informal sessions still focused the controversies in ways that greatly assisted the Massachusetts Department of Public Utilities (DPU) in its decision making. Although not everyone was completely satisfied by the final rules, virtually everyone found the technical sessions invaluable. No one I interviewed believed their interests would have been better satisfied without them.

The last major finding is that, contrary to conventional wisdom, resources associated with the processes themselves are not necessarily saved in the short-run. Consensus-building usually requires extensive time and expense from participants compared to the resources avoided in the traditional processes. Even the IRM technical sessions, which were the least resource-intensive of the four cases, still required participation in ten additional days of technical sessions without compensatory reductions in the traditional hearing and comment process.

However, stakeholders should realize process-related resource savings over a longer time horizon from avoided appeals, reduced future litigation, and greater implementation compliance. More importantly, when the long-term potential benefits associated with enhancing the legitimacy and practicality of PUC decisions are considered, net benefits to society can be positive and substantial even if the process-related cost savings are negative.

Cultivating Consensus

Barbara Barkovitch concludes in her book on regulatory interventionism in the utility industry that regulatory interventionism will not end but will shift its focus in significant ways over the next decade (Barkovitch 1989). Specifically, she predicts that regulators will focus on areas that minimize utility revenue requirements (in order to protect customers who have no bypass options), but will shy away from areas that shift costs and benefits among customer groups and between current and future generations (i.e., cost allocation and rate design) (id.). But I do not believe that regulators should only focus their attention in areas where they have clout. PUCs must ultimately make decisions that run the whole gamut of issues. More importantly, for reasons discussed in this dissertation, even in areas where PUCs supposedly maintain substantial leverage, interventionism without simultaneous consensus-building has had only limited success.

I therefore conclude that a paradigm shift is necessary. PUCs must seek to improve utility regulation by cultivating consensus among interested parties. In areas where PUCs still retain considerable leverage, supplemental, consensus-building can help gain greater legitimacy for their decisions, while producing practical improvements that may not have surfaced otherwise. In areas where PUCs' authority has been weakened by industry restructuring and other factors, or where rules and policies are being formulated in new areas, consensus-building seems imperative. Regulators can no more "go-it-alone" in today's complex and controversial environment than can utilities. I agree with Philip Harter that when administrative agencies, like state PUCs, embrace consensus-building processes they should be seen as a "positive means of resolving important issues, not as a second best alternative to the real thing" (Harter 1987).

This paradigm shift must not begin and end with PUCs. Utilities and other intervenors must also change their modus operandi. Settlement and other consensus-based processes are not new to electric utility regulation in most states. However, their uses can be expanded and improved. Utilities and other intervenors can and should seek to increase the use of consensus-building supplements to traditional adjudicatory and rulemaking procedures on their own.

However, as the gatekeepers of the formal regulatory processes, it is both appropriate and necessary for PUCs to play an active role in shaping these processes. PUCs can help cultivate consensus on policy matters by sponsoring policy dialogues or technical sessions, or by initiating formal negotiated rulemaking processes. In adjudicatory proceedings, PUCs can hold prefiling conferences and post-filing technical sessions. PUCs can also encourage parties to settle issues. Finally, PUCs can promulgate settlement guidelines, rules, or both.

Yet, a PUC's role in cultivating consensus should not be confused with that of a mediator whose job is to help parties better satisfy their interests, but who is not supposed to bring their own substantive agenda to the negotiations. PUCs have both quasi-judicial and quasi-legislative responsibilities and are therefore in many ways both party and final arbitrators (unless, of course, appeals are filed with the courts). Even in adjudicatory proceedings where they are required to act as neutral judges, most PUCs have either internal or external advocacy staffs who are given full-party status and often indirectly represent the PUC's interests in the proceedings.[2] Given this dual role, PUCs should take a leadership role in initiating and structuring consensus-building processes, while also participating in them to the extent allowed by their quasi-judicial responsibilities and staff resources.

Principles for Designing Consensus-Building Processes to Improve Electric Utility Regulation

In this section I provide eight principles for designing consensus-building processes to improve electric utility regulation. These principles, which are shown in Table 6.0, are derived from my case study analyses, the dispute resolution literature, and my personal experience. They are not meant to represent formal rules or guidelines for settlement negotiations. Instead, these are issues that PUCs and others who design such rules or guidelines, or design consensus-building processes in specific instances, should consider. While not exhaustive, I believe that these are the main ingredients necessary to improve traditional adjudicatory and rulemaking processes.

Improving regulatory processes does not by itself guarantee better regulation. However, it represents a critical step in that direction.

Table 6.0
Eight Principles for Consensus-Building in Electric Utility Regulation

1. Initiate Consensus-Building as Early as Possible
2. Include All Stakeholders
3. Secure Direct Involvement of the PUC Wherever Possible
4. Provide Adequate Resources
5. Do Not Exclude Contentious or Sensitive Issues From Consensus-Building Efforts
6. Consider Assisted Negotiation
7. Structure Consensus-Building Processes to Supplement Traditional Adjudicatory and Rulemaking Procedures
8. Modify Traditional Procedures to Better Accommodate Consensus-Building Opportunities

Initiate Consensus-Building as Early as Possible

Consensus-building processes should be initiated as early as possible to expand the opportunities for stakeholders to reach consensus and to influence the utilities' and, ultimately, the regulators' decisions. Early commencement also increases the potential for saving resources associated with traditional proceedings.

In adjudicatory proceedings, consensus-building processes can occur even prior to a utility filing a rate case or resource plan. This approach was used quite successfully in the DSM Collaborative cases. In rulemaking proceedings, consensus-building can be initiated prior to the release of proposed rules. In the development of IRM rules in Massachusetts, the first round of technical sessions occurred prior to the release of proposed rules but after the DPU released a policy paper which served as a starting-text for interested parties. The settlement negotiations in the New Jersey Bidding policy case, also occurred prior to any formal rulemaking or adjudicatory proceeding.

Consensus-building processes initiated either prior to, or relatively early in, formal proceedings need not, and in some cases should not, jump immediately to active settlement discussions. Formal consensus-seeking may often need to wait until sufficient information has been revealed for parties to better understand the issues, and for each party to better assess the relative strength of their respective cases (i.e., if the PUC were to decide the case without settlement). Workshops, technical sessions, and other joint fact-finding processes can productively precede formal settlement negotiations by helping to establish facts and identify potential remedies.

Given the complexity of the Pilgrim Outage case, it is unlikely that settlement discussions either prior to BECo filing its case, or even early in the proceedings, would have been particularly productive. However, other consensus-building supplements like technical sessions should have allowed parties to establish the information necessary to begin settlement discussions in less than the 90 days required to hear the case. Moreover, technical sessions may have done a better job revealing the parties' underlying interests and building trust than the contested proceedings -- which appeared to do just the opposite. The DSM Collaborative cases and the New Jersey Bidding case also included some joint fact-finding in the early stages of their negotiations.

Include All Stakeholders

Participants should strive to include the full-spectrum of stakeholders in consensus-building processes. The broader the support for a negotiated remedy, plan, or policy, the less likely it will be challenged before the PUC or in the courts. Also, excluding legitimate stakeholders, increases the possibility that practical improvements may be overlooked that would have rendered the final resolution both more implementable and more efficient.

In adjudicatory proceedings, settlements are generally restricted to only those parties that have formally intervened in a case. It is therefore important to encourage and support broad representation in adjudicatory proceedings from the start.[3] However, when broader participation in adjudicatory proceedings has not occurred, parties can still try and bring those interests into a consensus-building process indirectly through such mechanisms as advisory boards. The Pilgrim Outage settlement suffered substantial criticism from local citizen groups that might have been tempered had the participants more directly addressed their interests. As part of a third party mediator's job, they can bring the concerns of unrepresented interests into the process (mediation is discussed in more detail under a later principle).

In prospective collaborative processes and rulemaking proceedings, parties have much more flexibility to embrace all stakeholders and should do so as much as possible. No automatic ceiling on the number of parties that can be accommodated in a consensus-building process exists; rather, it depends on the particulars of the situation and the structure of the process itself. The facilitated technical sessions used in the IRM rulemaking in Massachusetts were completely open to all interested parties (although parties were asked to send no more than two representatives per organization) and as many as 100 people actively participated in some of the sessions.[4]

To facilitate settlement discussions or negotiated rulemakings, it may be necessary for stakeholders to work with a sub-group of interested parties to attain a manageable group. If a sub-group is necessary, parties should make sure it is representative of the larger group, and that formal linkages between representatives and their cohorts are established. The New Jersey Bidding settlement applied this approach fairly successfully -- using a self-selection process within interest groups to pare down the 100 parties that showed up at the initial meeting to 13 representatives.

Phasing negotiations is another potential way to include all interested parties when the number of parties is large or the interests are considered too divergent to be accommodated in one fell swoop. Under a phased approach, a core group of participants attempts to settle among themselves, and then negotiate with the remaining interested parties. To a degree, the DSM Collaboratives studied here used this phased approach. However, all of the collaboratives resulted in substantial litigation before the DPU by parties that were not part of the initial core group. The collaboratives might have ultimately benefitted from the inclusion of these other interested parties from the start. A phased-approach may therefore generally represent only a second-best option to either direct involvement of all interested parties or a representative approach.

Secure Direct Involvement of the PUC Wherever Possible

PUC staff, and possibly even the commissioners, should participate in consensus-building processes wherever permissible and appropriate to do so. This can provide an opportunity for the PUC's own interests to be better accommodated in any settlement that may emerge from the process. It also provides an excellent opportunity for the PUC's representatives to explore technical issues and gain insight into the underlying interests of the various parties in ways that formal proceedings generally can not.

Staff Involvement

Where the goal of a particular supplemental, consensus-building process is not actual settlement (i.e., workshops, technical sessions, and policy dialogues), it is appropriate and, I would argue, necessary for PUC staff to participate. As was shown in the IRM rulemaking case, the staff's involvement in the technical sessions was critical to their success, and the success of the entire rulemaking process. Not only were staff able to make invaluable contributions to the sessions by interpreting the Department's proposals and the reasoning behind them, but the sessions helped to educate the staff and the commission (primarily through the staff's role as emissary but also through improved comments in the formal proceedings).

It is also permissible and advisable for a representative of a PUC's advocacy staff to be a party to the development of an actual adjudicatory settlement or negotiated rule. The simplest way for staff to participate in these processes is for them to sign any negotiated agreement in a way that binds the advocacy staff, but not the Commission.[5] The settlement must then be reviewed and endorsed by the Commission itself, after providing an opportunity for public comment.[6] This approach was taken in the New Jersey Bidding case where the policies settled by the Board's staff were circulated for comment prior to the Board's adoption.

When PUCs have advocacy staffs, they should play an active role in settlement discussions. However, in both the Pilgrim settlement and the DSM Collaborative cases, staff from the Massachusetts DPU did not participate directly in the settlement processes. As an advisory staff to the commission they had to preserve their ability to advise the Commission on the cases. Particularly in the DSM Collaborative cases, staff's absence from the settlement processes caused some short-comings in the final agreements from the DPU's perspective. These might have been avoided had the DPU had an advocacy staff that could have participated in the collaboratives.[7]

Unlike adjudicatory proceedings, where the advocacy staff is forbidden from conferring directly with a commission, it would be permissible and advisable in rulemaking negotiations for the staff to confer with their commissioners throughout the settlement negotiations. However, if a PUC's open meeting laws forbid commissioners from congregating in a closed executive session, such conferences may either have to take place during public meetings, or with the staff meeting with individual commissioners.

Commissioners' Involvement

The direct participation of commissioners in supplemental, consensus-building forums other than formal settlement discussions, is generally legally permissible in rulemaking proceedings, and possibly even in adjudicatory proceedings if precautions are taken not to violate ex parte rules.[8] However, while commissioners direct involvement is advantageous to have for some reasons, their presence can have a chilling effect on the exploration of parties' interests and the development of even rudimentary consensual agreements. Parties are often either inhibited or positional before commissioners -- generally much more so than before the PUC staff. During the IRM technical sessions in Massachusetts, the Commission decided to appear only at the beginning of the first technical session to answer questions and at the end of the last session to get feedback. On balance, commissioners direct involvement in consensus-building processes, even where settlement is not part of the immediate agenda, should be used selectively and with caution (particularly in adjudicatory proceedings).

Commissioners can not, in any state that I am aware of, directly participate as a party in actual settlement negotiations in adjudicatory proceedings. It does appear legally permissible, however, for commissioners to directly participate in negotiated rulemakings. But, despite several possible advantages to commissioners participating in negotiated rulemaking (e.g., substantive knowledge of a particular commissioner, or an added sense of importance to the negotiations), there are several significant drawbacks. First, since commissions have to be free to make the final decision on a rule after receiving formal comments (including comments from those not present at the settlement negotiations or simply not in agreement with the negotiated rules), direct participation in the settlement process may unnecessarily compromise the appearance of fairness.[9] Second, a commissioner's participation only makes sense if the entire commission intends to formally ratify a settlement prior to signing, since binding one commissioner to a settlement has no real meaning. Third, as discussed previously, commissioners direct presence in the negotiations may have a chilling effect on creative problem-solving. Lastly, commissioners may have less expertise on the subject matter for a particular rulemaking than their staff. Therefore, on balance, I do not generally recommend direct participation in negotiated rulemakings by commissioners, although there may be instances where their participation is appropriate and workable.

However, even if commissioners do not directly participate in adjudicatory or rulemaking settlement negotiations, every effort should be made to communicate their interests and concerns to the participants. Obviously, prior orders on related questions can be the first place to look for commissioners' concerns and views. In addition, much can be accomplished through their staff. But commissioners can also communicate more directly. In rulemakings, where they have more procedural flexibility than adjudications, commissioners can hold periodic policy dialogues with all stakeholders to discuss various issues. In adjudicatory proceedings, commissioners can meet with interested parties prior to a utility filing to discuss PUC policies and possible issues that may arise in a forthcoming case. Also, when a commission issues an order opening a docket on a case, it can identify issues it believes are important for the parties to address. Commissioners can also hold discussions on the record about issues they would like to see addressed in a settlement. Similarly, when a settlement is first proposed, commissioners can issue an order delineating issues they believe must be addressed for them to fully consider the final settlement.[10]

Provide Adequate Resources

Consensus-building can require participants to devote a substantial commitment of time and financial resources. Securing adequate resources can often be problematic -- particularly for non-utility parties (NUPs). Although the occasional technical session can probably be accommodated, the NUPs may require financial assistance for more intensive and protracted efforts such as proactive collaboratives, negotiated rulemakings, and other complicated settlement negotiations. PUCs may also need more resources to effectively participate.[11]

Utilities (and therefore indirectly ratepayers) are the most logical source for such funding. Consensus-building processes are voluntarily pursued as a means of better satisfying everyone's interests (including the utilities). Thus utilities should not consider financial assistance as equivalent to intervenor funding and should not oppose it automatically. In the Massachusetts DSM Collaboratives the utilities voluntarily provided over $3 million during on-going negotiations for the NUPs to secure supplemental technical expertise from outside their respective organizations. The outside consultants served as a critical resource, not just for the NUPs, but for the utilities too. Without the funding, the collaboratives would have been much less fruitful, and might not have been possible at all.

However, even in the DSM Collaboratives, the NUPs did not receive resources to help defer costs associated with their own in-house and extensive participation in the processes. They did not request such funding because several feared it would not sit well with their constituents; and it would probably have been rejected by the utilities in any case. Without the funding, the processes suffered somewhat, as the NUPs spread themselves too thin, and appeared unresponsive at times. The other cases studied in this dissertation did not use supplemental funding for the NUPs (neither for in-house staff nor outside experts), although all the cases may have benefitted from funding (e.g., for additional joint fact-finding).

Future consensus-building efforts must address this potential constraint. If direct funding from utilities is not forthcoming, PUCs and intervenors should explore other avenues. One possible approach would be to establish a general consensus-building fund that is replenished with small, but regular assessments on utility bills and administered by the PUC or some other appropriate entity (e.g., in Massachusetts the State Office of Dispute Resolution would be a possible alternative). PUCs must carefully determine eligibility requirements for distributing funding so that expenditures are not excessive and are allocated fairly among legitimate stakeholders. Other sources of funding, such as foundations, may be appropriate for start-up or unique processes, but are probably not sustainable or reliable for repeated, and on-going efforts.[12]

Do Not Exclude Contentious or Sensitive Issues From Consensus-Building Efforts

All issues, regardless of how contentious or potentially sensitive, should be considered for inclusion in consensus-building efforts. Even issues that seem intractable may prove resolvable when parties focus on underlying interests. One of the reasons that the Massachusetts' Commission pursued a technical session process instead of a negotiated rulemaking was its belief that the parties would never agree on whether utilities should bid in their own solicitation processes. However, in the New Jersey Bidding Settlement, parties were able to agree to keep utilities and their affiliates out for at least three years. In the DSM Collaboratives in Massachusetts, parties decided that fuel switching was too controversial to settle and chose to exclude it from the processes and litigate it before the DPU (where, two years later, it is still not resolved). In contrast, DSM Collaboratives in Vermont included fuel switching issues, and despite some contentiousness, eventually settled the fuel switching issues as part of comprehensive DSM agreements.

Excluding particular issues a priori can unnecessarily erode fertile ground on which parties can make trades on a broader range of issues that may ultimately benefit all of them. Since parties retain veto power in a consensual process, and a PUC can reject settlements that it does not find to be in the public interest, neither parties nor commissioners should feel threatened by inclusion of particularly controversial issues.

Some PUCs, however, either dissuade or do not allow parties to settle certain issues such as cost allocation and rate design because they fear participants may dump costs on unrepresented parties. But if efforts are made to include all stakeholders in negotiations, or the PUC staff looks out for the interests of unrepresented parties, or both, such restrictions seem unnecessary and counterproductive (particularly since the PUC itself gets a chance to review every settlement). As discussed, the New York Public Service Commission recently withdrew its own proposed ban on negotiating rate design and rate of return issues from its new settlement guidelines after being persuaded that their exclusion could stifle rate case settlements.

Parties may wish to delay negotiations, particularly on certain contentious issues, until a later phase so that they can agree on other issues (thus building positive momentum) without sacrificing opportunities for mutual gains in the near-term. As discussed in the next section, parties may also want to consider using mediators or settlement judges to assist with particularly contentious disputes.

Even if parties do not reach consensus on difficult issues, consensus-building efforts can help to inform the debate while narrowing its scope; thereby facilitating the decision making process for PUCs. This was the case with a mini-collaborative effort on environmental externalities in Massachusetts which did not end in consensus, but did help crystalize the issues for the DPU.[13]

Consider Assisted Negotiation

Participants in a consensus-building process should consider whether facilitation or mediation services can be beneficial in their particular circumstances. Facilitation can help parties by allowing a neutral third party (or parties) to take responsibility for the myriad of details necessary to make such processes work smoothly (e.g., arranging meetings, compiling minutes) -- details which can sap energy from participants' involvement in the substantive negotiations. More importantly, facilitators can help moderate discussions and make sure they remain focused and on-schedule. Mediation generally includes all of the functions of facilitation, but connotes an intensification of the substantive involvement of the neutral. Mediators often work with individual participants outside the larger group meetings, and generally take a more active role in helping parties' shape actual agreements. Neither facilitators nor mediators impose solutions on participants who must agree to any consensus that emerges from an assisted negotiation. Any resultant settlements meanwhile must still withstand the scrutiny of the PUC, and the courts if appealed.[14]

Adversarial parties do not always need outside assistance to reach agreements in consensus-based processes. The Pilgrim Outage case is an example of an extremely creative settlement among parties with a long history of animosity without the use of outside assistance. Most settlements in electric utility cases today do not use any assistance.[15]

Still, in many circumstances assistance could be beneficial like when issues are particularly contentious or when many parties are involved in a process. For instance, it is unlikely that the technical sessions the Massachusetts DPU used in formulating its IRM regulations would have been as successful without the use of experienced, outside facilitators. Given that as many as 100 parties showed up at some of the sessions, it is hard to imagine how the technical staff of the DPU could have both managed the process and actively participated in the discussions.

The dispute resolution literature concludes that mediation can be beneficial for resolving the types of public disputes encountered in electric utility regulation (Harter 1987, Susskind and Cruikshank 1987). None of my case studies included a third-party mediator. However, both the New Jersey Bidding settlement process and the DSM Collaborative processes, may have benefitted from such outside assistance because despite their many accomplishments, they had numerous unresolved or partially resolved issues. Mediation could have been beneficial throughout the processes, or just for particularly difficult parts.

If parties in a particular dispute decide to secure outside assistance, they must make at least three important decisions. First, they need to decide if they are looking for facilitation, or mediation services. For technical sessions and other processes where the goal is to create a dialogue, a facilitator may be sufficient. A mediator is probably preferable for adjudicatory settlements, proactive collaboratives, and negotiated rulemakings where a consensus is actively sought.

Second, parties must decide whether they want to secure an outside professional facilitator or mediator, or use a settlement judge (or other staffperson) from within the

PUC itself. As long as any individual selected (1) is perceived as neutral by the participants, (2) has adequate skills and experience in providing facilitation or mediation assistance, and (3) has sufficient technical expertise if called on to mediate; an inside or outside neutral can be used.[16] If inside settlement judges are used, however, they should be different than the individuals who preside over the formal cases. Whether inside or outside assistance is sought, participants should be involved in their identification and selection as much as possible.[17]

Third, parties must decide who will pay for the facilitation or mediation services. As I concluded in the discussion about providing resources for participants, utilities (and therefore ratepayers) should be the primary source. However, other state and private funding options can also be pursued.

Structure Consensus-Building Processes to Supplement Traditional Adjudicatory and Rulemaking Procedures

Consensus-building processes must be structured to supplement -- not supplant -- traditional adjudicatory and rulemaking processes. PUCs can not delegate their decision-making authority, and must make the final decisions on adjudicatory settlements and negotiated rules before they can take effect. Consensus-building processes must also be careful not to violate preexisting regulatory and statutory requirements with respect to ex parte contacts, open meeting laws, and other applicable matters.

On a practical level, if a settlement is reached either in an adjudicatory or rulemaking proceeding, parties must have an opportunity to comment prior to a final PUC ruling. When adjudicatory settlements are contested, parties may need the opportunity to conduct cross-examination and to file written (and possibly oral) comments. All of the DSM Collaboratives in Massachusetts have necessitated extensive hearings, although the Pilgrim Outage settlement, which had unanimous support, did not.

After a settlement in a negotiated rulemaking, PUCs must, at a minimum, put the settlement out for public comment as proposed rules. However, if the settlement is not unanimous or some parties were not part of the negotiations, the PUC should solicit comments and hold hearings prior to releasing the negotiated settlement as its proposed rule.

In PUC regulation it is helpful but not sufficient that litigants have reached a consensus (unlike settlement in civil cases before the courts where it is also sufficient). In making its final decision with respect to a settlement, a PUC must also independently determine that the settlement is in the public interest. PUCs should require participants to file supporting documentation to provide an adequate record to make such a determination. Supporting documentation should include both factual background information and testimony from parties supporting the settlement (or contesting it if there are any non-signatories). The earlier in a formal proceeding that a settlement occurs (e.g., before the close of hearings, or even prior to a utility' filing) the more critical the supplemental information becomes, since little or no formal record will have been previously established.

When parties use technical sessions or other processes in which settlement is not the primary focus but valuable information or convergence of opinions surface, mechanisms are needed to feed that information directly into the formal proceedings.

This can be done by entering documents produced during the informal negotiating process directly (or a verbal summation by one or more party) into the record. PUCs should afford all parties an opportunity to explore this material further in the formal proceedings.

Modify Traditional Procedures to Better Accommodate Consensus-Building Opportunities

Traditional adjudicatory and rulemaking processes can be modified, or in some cases merely clarified, to provide a more supportive environment for consensus-building to occur. For instance, rather than rejecting settlements outright or even making substantial modifications unilaterally, PUCs should return settlements they cannot accept back to the parties for further work. If time constraints do not allow for renegotiation, parties should at least be given the opportunity to comment on any modifications or rejections proposed by the PUC prior to final adoption. As discussed above, commissions should also communicate their interests and concerns to participants in a consensus-building process as early and directly as possible.

PUCs must seek ways to provide adequate time for consensus-building. A perennial problem with settlements in rate case proceedings is that states often have a fixed suspension period (e.g., six months) after which the rates are approved as originally proposed if no decision is issued by the PUC. Obviously, this provides substantial pressure on participants and the PUC for settlements to occur quickly and for the formal litigation process to stay on schedule. Litigants can agree to extend suspension periods in many states (or in some cases by unilateral action by a utility).

More research is needed to determine how PUCs can stop the litigation clock when settlement discussions appear promising.

PUCs can also foster consensus-building by clearly and proactively developing policies which protect the participants' rights. For instance, PUCs should make clear that matters discussed in the course of settlement procedures (e.g., admissions, concessions, or offers to settle) are not subject to discovery, or admissable in any hearing unless all parties agree to do so. PUCs should consider requiring parties to provide notice of the initiation of settlement negotiations to all parties in a proceeding. Although parties must ultimately be allowed to settle with whomever they please (after weighing the cost and benefits of leaving any particular party out), all legitimate stakeholders should be invited to participate in settlement discussions. This requirement should not, however, preclude sub-groups either from meeting prior to the beginning of actual settlement negotiations for exploratory discussions, or from caucusing during the course of settlement negotiations.[18] When settlement discussions begin prior to a docketed case, and hence parties have not formally identified themselves, notice should be provided to all potentially interested parties including those who have intervened in a utility's last few cases.

PUC policies on settlement and other consensus-based processes should be institutionalized through the adoption of guidelines, rules, or both. Currently only few states have done this, although the Staff Subcommittee on Administrative Law Judges of the National Association of Regulatory Utility Commissioners (NARUC) recently adopted model settlement guidelines for states to consider.[19] There are two important reasons why states should formalize their settlement procedures and policies. First, it makes the policies explicit so that everyone is playing by the same rules. Second, it elevates consensus-building processes such as settlement to a stature comparable to traditional adjudication and rulemaking procedures which have enjoyed clearly articulated guidelines, rules or both for some time.

Parting Comment: One State's Evolution

When I first began working at the Massachusetts Department of Public Utilities in 1988, consensus-building processes were not used extensively. Although the Commission had encouraged and approved many rate case settlements, the Department did not have settlement guidelines or an in-house advocacy staff to participate in settlement discussions. Also, technical sessions were rarely initiated by the Department. When the Commissioners were approached by myself and others about using more alternative dispute resolution mechanisms, while not hostile to the notion, they expressed numerous concerns about the delegation of their authority, the appropriateness of staff participation, and the use of outside facilitation.

Over the course of my three-year tenure at the Department, I witnessed many substantial changes in this area. Much of the initiative for change came from utilities and intervenors outside the Department through such creative settlements as the one forged in the Pilgrim Outage case, and through the formation of the innovative DSM Collaboratives. Some of the innovation, however, came from within the Department. In particular, the successful use of facilitated technical sessions in conjunction with the formation of its new IRM regulations, helped allay many of the Commissioners' fears about using supplemental consensus-building techniques. It also pointed at new possibilities for future applications. By the time I left the Department in 1991, the IRM rules had been finalized (and even included a required prefiling settlement process)[20], technical sessions were commonplace, settlement guidelines had been issued for settling water cases, and an advocacy staff charged with representing the Department in settlement negotiations had been created and had even settled its first few cases.

In some ways, I believe the Massachusetts DPU's recent embrace of consensus-building processes represents a spiraling-back to the regulatory approach pioneered by Charles Adams at the Massachusetts Railroad Commission in the 1870's. Adams believed that regulators should cultivate consensus while still pushing forward their own agendas (McCraw 1984). Adams' use of consensus-building was in part philosophic and in part a result of not having the authority to order the railroad companies to do what he wanted. The Massachusetts DPU's use of consensus-building represents a recognition that, despite its extensive powers to intervene in utility matters, interventionism without consensus-building in this complicated and ever-changing world of electric utility regulation faces a high risk of failure.

The Massachusetts DPU along with the utilities and other intervenors that appear before it, are not alone in this realization. Settlements, DSM Collaboratives, and other consensus-building processes are springing-up with increasing frequency across the country. I hope my case study analyses, theoretical discussions, and recommendations will help guide those efforts.

Endnotes (Chapter 6)

1. Another good example of interventionism run amiss is the problem with California utilities' oversubscription to relatively expensive power from Qualifying Facilities because of long-term standard offer contracts required by the PUC in the 1980's.

2. I note that there is a broad array of arrangements between PUCs and their advocacy staffs -- ranging from complete and constant separation, to staff members rotating between advisory and advocacy roles. Obviously the closer the staff is to the Commission on a regular basis the greater the likelihood that we will understand and try and represent their interests in settlement negotiations.

3. One way to encourage broader representation is to make funding available to support the intervention of outside parties that would not otherwise have the resources to participate. Such an approach has often met with substantial resistance by many utilities and PUCs, and must be done carefully to avoid free-riders on the one hand, and disingenuous interventions on the other.

4. In the first round of four technical sessions, three smaller, facilitated groups were interspersed with larger plenary meetings to provide everyone a chance to discuss their views. In the second round of four sessions, only one group was used, with one representative from each organization sitting around a large table and their alternates sitting in an outer circle.

5. This could be more difficult at PUCs that do not have advocacy staffs. Staffs that normally act only in an advisory capacity (i.e., do not put on a case during adjudications) may need additional authority from their commissions to negotiate and bind themselves to a settlement.

6. In an adjudicatory proceeding, comments are generally limited to participants in the formal proceedings. In rulemaking proceedings, PUCs are not so restricted, and must, in fact, solicit comments from the broader public.

7. Subsequent to these cases, when the Massachusetts DPU procured additional staff to implement its IRM rules, a rotating advocacy staff was established (i.e., the same staff person may serve as an advocate on one case and an advisor on another.)

8. Ex parte rules which preclude commissioners from interacting with parties off-the-record in adjudications generally do not apply in rulemakings. In rulemakings, despite increasing judicialization, Commissioners still have the flexibility to act in a legislative mode, and discuss issues freely. Even if ex parte restrictions do extend to PUC rulemakings in some states, the types of forums discussed here, where all interested parties are invited to attend, should be permissible

9. Although commissioners do not have to maintain impartiality as in adjudicatory proceedings, they still need to maintain a certain degree of independence, which direct participation in a settlement -- as opposed to technical sessions -- could appear to compromise.

10. These recommendations and others were recently included in New York PSC's "Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines" (Opinion No. 92-2, March 24, 1992). The New York order also points out that if commissioners disagree on issues, dissenting opinions can also be offered to participants.

11. Some PUCs can shift staff workloads to accommodate additional involvement in consensus-building processes, while others will need new resources. The ease of acquiring new resources will vary from state-to-state. The settlement of the NEES-CLF Collaborative with the Rhode Island PUC included a provision that NEES provide the advocacy staff with an additional $25,000 per year so that it could hire the necessary expertise to participate in future collaborative efforts.

12. Funding for participation of environmental and consumer groups in many DSM Collaboratives across the country has often come from foundations such as the Pew Memorial Trust. This funding, while having substantial impact for those groups on DSM issues, is neither available for a wider-range of intervenor groups nor a broad range of contested case or rulemaking issues.

13. In some ways the entire IRM technical sessions served this function of both informing and focusing issues for the DPU. In other ways, the DPU's decision to use a technical session process instead of a negotiated rulemaking process conveyed a sense that the DPU either did not believe that the issues could be (or perhaps more accurately -- should be) settled. In contrast, the New Jersey Bidding policies, which covered similar territory as the IRM rules in many respects, did rely on a full-blown settlement process.

14. See Susskind and Cruikshank's Breaking the Impasse: Consensual Approaches to Resolving Public Disputes, Basic Books (1987), for a detailed discussion of the advantages of using assisted negotiation and the differences among various approaches. Susskind and Cruikshank also discuss non-binding arbitration as another option to facilitation and mediation, but one which has had little field-testing in resolving public disputes. As such, it is only flagged here as an area for further investigation and consideration.

15. FERC used settlement judges in only 10-20 percent, and NY in less than 10% of all cases settled. Outside mediators, rarely, used.

16. Some might argue that PUC settlement judges should not be considered neutrals. Others might argue that it is unlikely that outside, professional neutrals would have the substantive knowledge necessary to effectively mediate a contested electric utility dispute. However, I believe it depends on the particulars of the dispute and the individuals being considered.

17. In technical sessions or rulemakings with large numbers of participants it may be impractical to get all parties together and in accord on the need for a neutral, let alone the identification and selection of one. In such circumstances, it might be appropriate for the PUC itself to select an individual or individuals that meet the three criteria outlined in the text. However, if participants have strong objections to the selection, PUCs should be willing to find acceptable alternatives.

18. The confidentiality and notice recommendations draw heavily from the New York Public Service Commission's new settlement rules and guidelines (Opinion No. 92-2, "Opinion, Order and Resolution Adopting Settlement, Procedures and Guidelines", March 24, 1992). However, I am not convinced by their requirement which precludes utilities from caucusing with individual non-utility parties without first noticing all other parties and providing them with an opportunity to attend. I believe that this might be overly restrictive, and that the broader settlement process along with the PUCs ultimate oversight should provide sufficient protection against potential abuses.

19. California, New York, and Maine were identified as having formally adopting settlement policies. Massachusetts only has settlement guidelines for water cases. Although more states may have such guidelines at least two other surveys (one by the New York PSC and one by NARUC, both in 1991) and my informal inquiries have not identified any as of this writing. NARUC's model settlement guidelines were issued in April 1991.

20. The final IRM rules in Massachusetts (D.P.U. 89-239, August 1990) require that a utility (1) circulate a draft IRM filing several months prior to the actual filing date; (2) host at least one technical session to review the document with all interested parties; and (3) enter into settlement discussions with interested parties.

Appendices

Appendix 1
Massachusetts Utilities' DSM Expenditures and Savings (1987 - 1991)

Boston Ediston Company

(A) Year	(B) DSM Expenditures ($ Million)	(C) Operation Revenue ($ Million)	(D) Expenditures as Percent of Revenue	(E) Incremental Installed MWH	(F) Incremental Installed MW	(G) Cumulative Installed MW
1987	$5.2	$1,181	0.4%	14,022	23	23
1988	$7.3	$1,203	0.6%	27,284	37	41
1989	$13.8	$1,269	1.1%	50,911	80	91
1990	$29.5	$1,259	2.3%	105,940	120	134
1991	$40.4	$1,259	3.2%	93,887	112	147

COM/Electric

(A) Year	(B) DSM Expenditures ($ Million)	(C) Operation Revenue ($ Million)	(D) Expenditures as Percent of Revenue	(E) Incremental Installed MWH	(F) Incremental Installed MW	(G) Cumulative Installed MW
1987	$0.8	$361	0.2%	1,524	0.1	23
1988	$1.5	$359	0.4%	41,187	na	na
1989	$6.3	$441	1.4%	84,942	na	na
1990	$25.2	$465	5.4%	81,870	17	na
1991	$27.8	$465	6.0%	107,745	17	na

Massachusetts Electric Company

(A) Year	(B) DSM Expenditures ($ Million)	(C) Operation Revenue ($ Million)	(D) Expenditures as Percent of Revenue	(E) Incremental Installed MWH	(F) Incremental Installed MW	(G) Cumulative Installed MW
1987	$9.4	$1,086	0.9%	21,393	21	21
1988	$18.4	$1,140	1.6%	65,417	33	54
1989	$31.0	$1,232	2.5%	92,196	40	94
1990	$53.4	$1,391	3.8%	110,257	38	131
1991	$90.0	$1,559	5.8%	134,738	51	182

Western Massachusetts Electric Company

(A) Year	(B) DSM Expenditures ($ Million)	(C) Operation Revenue ($ Million)	(D) Expenditures as Percent of Revenue	(E) Incremental Installed MWH	(F) Incremental Installed MW	(G) Cumulative Installed MW
1987	$2.4	$295	0.8%	15,898	2	2
1988	$3.0	$318	0.9%	9,173	2	3
1989	$4.5	$349	1.3%	10,743	2	5
1990	$9.6	$375	2.6%	24,021	4	9
1991	$16.0	$418	3.8%	53,100	8	17

Note: All numbers were provided by the utilities. 1991 numbers are estimates in most cases. MECo assumed to equal 75% of NEES.

Appendix 2
Massachusetts DPU IRM Technical Sessions Evaluations for 1989 and 1990

I. How Effective Were the Technial Sessions In:	Year	Ineffective 1	2	3	4	Very Effective 5	6	Mean
A. Furthering Your Understanding of DPU Proposals	1989	0%	11%	9%	30%	45%	5%	4.4
	1990	0%	2%	5%	17%	56%	20%	4.9
B. Eliciting Alternatives to DPU Proposals:	1989	2%	4%	17%	30%	35%	13%	4.4
	1990	0%	7%	27%	44%	20%	2%	3.8
C. Improving Your Understanding of Others' Perspectives:	1989	0%	0%	0%	26%	49%	25%	5.0
	1990	0%	0%	7%	15%	56%	22%	4.9
II. How Effective Were:								
A. Outside Facilitator(s) in Managing Sessions:	1989	0%	0%	14%	22%	25%	39%	4.9
	1990	0%	0%	2%	17%	34%	46%	5.2
B. DPU Staff in Serving as a Technical Resource:	1989	2%	2%	2%	13%	42%	38%	5.1
	1990	0%	0%	2%	12%	56%	29%	5.1

III. How Would You Evaluate the Amount of Time Alloted to the Technical Sesssion?

	Too Little	Too Much	Just Right
1989	45%	6%	49%
1990	27%	10%	63%

NOTE: On Table I-III Above Sample for 1989 was 53 and for 1990 it was 41.

IV. If You Attended Both 1989 and 1990 Technical Sessions, Compare 1990 to 1989:

Less Successful	Same	More Successful
9%	36%	55%

Note: There Were 22 In Sample Who Were Both at 1989 and 1990 Sessions.

Source: Author's Compilation

Appendix 2 (Continued)
Technical Session Evaluation Form

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 86-36
TECHNICAL SESSION EVALUATION FORM
February 1, 1989

1. How effective were the technical sessions in furthering your understanding of the Department's regulatory framework as proposed in DPU 86-36-F?

Ineffective					Very Effective
1	2	3	4	5	6

2. How effective were the technical sessions in eliciting alternatives to elements of the Department's proposed regulatory framework?

Ineffective					Very Effective
1	2	3	4	5	6

3. How effective were the technical sessions in improving your understanding of other parties' perspectives on all resource solicitations and least-cost planning in general?

Ineffective					Very Effective
1	2	3	4	5	6

4. What aspects of the Department's proposals in 86-36-F do you think should not be changed? (Please List)

5. What aspects of the Department's proposal should definately be changed? (Please List)

6. What did you like most about the technical sessions? (Please List)

7. What did you like least about the technical sessions? (Please List)

8. The Department chose to use outside facilitators to manage the technical sessions. How effective were the facilitators in carrying out this role?

Ineffective					Very Effective
1	2	3	4	5	6

9. The Department assigned staff to serve as a resource in each small group. How effective were the staff in carrying out this role?

Ineffective					Very Effective
1	2	3	4	5	6

10. For purposes of reviewing the Department's proposal, how would you evaluate the the amount of time allotted (i.e., four, half-day sessions)? (circle one)

    Too Little   Too Much   Just About Right

11. For what, if anything, should the Department use technical sessions such as these later in this proceeding as well as in other future regulatory proceedings (e.g., rate cases, review of QF RFP's, generating unit performance reviews, promulgation of regulations, etc.)? (Please List)

12. What suggestions do you have for improving any future technical sessions that the Department may convene in this proceeding or otherwise? (Please List)

13. Which days did you attend the technical sessions? (circle each one that applies)

    December 21   January 4   January 18   February 1

14. Which small group were you in? (circle one)

    Red   Green   Blue

15. Which group most closely reflects your professional affiliation? (check one)

_____Utility
_____Supply Developer
_____Academic
_____Other (specify ______________________________)
_____Government Agency
______C&LM Provider
______Environmental/Consumer

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Supplemental Interviews

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All Supplemental Interviews Conducted Between September 1991 and May 1992.
* Indicates Those Interviewed on Several Occassions.