THE REGULATORY TREATMENT OF EMBEDDED COSTS EXCEEDING MARKET PRICES: TRANSITION TO A COMPETITIVE ELECTRIC GENERATION MARKET

A BRIEFING DOCUMENT FOR STATE COMMISSIONS

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EXECUTIVE SUMMARY

Introduction
Embedded Costs Exceeding Market Prices (ECEMP): What Is the Regulatory Task?

Many electric utilities today face three key facts:

1. they have incurred costs pursuant to a regulatory or contractual obligation;
2. the costs are reflected in cost-based rates; and
3. the cost-based rates may exceed the price of alternatives in the marketplace.

These utilities have, in a phrase, embedded costs exceeding market prices (ECEMP). The regulatory treatment of ECEMP is the subject of this document. We have chosen the phrase "ECEMP" because it is objective. Some describe ECEMP as "imprudent" costs and argue for disallowance on that basis. That argument is incorrect. By definition, if the costs are in rates, they have been found to be prudent. Others describe the costs as "unmarketable" and urge their disallowance on that basis. Whether unmarketability translates into disallowance depends on the interpretation of the "compact" between the particular utility and its regulators. Some interpret the compact as guaranteeing recovery of all prudent costs. The courts have rejected this view.

To disallow prudent costs, however, requires a legal theory. A regulator should be able to point to a pre-investment understanding about how the market risks were to be shared. Alternatively, there should be a indicia of post-investment action, such as utility claims for a risk premium added to the authorized return on equity, to compensate the utility for market risk. Otherwise the utility may be entitled to recovery.

It is not unusual for regulators to share the risk of an uneconomic plant between ratepayers and shareholders. There are sound policy bases for such assignments, including the idea that by requiring shareholders to bear some economic risk management will make the best decisions. Another theory for sharing is that the "compact" is silent, or the quid pro quos are not clear. In that situation, regulators might decide to share the cost among stakeholders

50-50. This 50-50 answer should be the end product of the analysis, not a means to avoid the analysis.

That leaves the category of "stranded" costs. This phrase is used most appropriately to describe situations where there is a violation of a quid pro quo; i.e., where (a) the utility was compelled (by contract or franchise) to make an investment and (b) a customer for whom the investment was intended avoids its cost responsibility for that investment.

The regulatory questions: The first regulatory task is to determine whether ECEMP should be recovered. The correct decision requires regulatory consistency. Whatever the regulators stated in the past as to who should bear which risks, the regulator must adhere to that position after the costs have been incurred.

The second question is, if the costs should be recovered, how should they be recovered? Recovery devices can affect prices and therefore participant behavior and market structure. The proper recovery devices are the ones which have positive effect (or the least negative effect), on economic efficiency. These questions will be discussed in Chapter IV. The FERC NOPR proposes a specific recovery device -- an adder on transmission prices -- which is discussed in Chapter V.

Jurisdictional Rationality: A key element in a national strategy on ECEMP must be jurisdictional rationality. The relationships among regulators must be set up so that their actions, taken in combination (which is how the market experiences them), produce economic efficiency and regulatory consistency. Players should not be able to "forum-shop" to avoid the outcomes imposed by economic efficiency or regulatory consistency.

Part One

Under What Circumstances Should Embedded Cost Exceeding Market Prices Be Recovered By Utilities? The Requirement of Regulatory Consistency Or Quid Pro Quo

II. Regulatory Consistency: Legal Foundations and Jurisdictional Implications

In a competitive, non-regulated industry, the problem of ECEMP is not new. Where there is a buyer-seller contract, the solution is in the contract. In the regulated world, contracts play a limited role. The substitute for contracts is regulatory clarity and, most importantly, regulatory consistency.

The requirement of regulatory consistency, or quid pro quo, is simply a rule of symmetry. Where a utility's investments contributing to ECEMP were made to carry out obligations imposed by regulation, regulation has to be prepared to pay the utility, consistent with risks undertaken by the utility. In the case of retail customers, the compact is embodied, legally, in a franchise agreement subject to State or local law. For wholesale transactions, the compact is usually a contract or tariff subject to FERC jurisdiction. The retail arrangements are discussed in more detail in Chapter II.C. The wholesale arrangements are discussed in Chapter III.

We stress the concept of regulatory consistency and quid pro quo because it differs from other proposed responses to the problem of ECEMP. Some have argued that regulators, in addressing "stranded costs," should "spread the pain," or "balance the interests," or "make the transition smooth," or "make a deal," or "protect utilities' financial integrity." These terms are subjective. They ask regulators to legislate, instead of applying neutral principles to proven facts. Regulatory consistency is the key principle. Whatever deal was struck, if it can be discerned, is the deal that now applies.

There is a strong argument that if the regulatory compact is binding on utilities, it also must be binding on individual customers. Any other rule would produce cross-subsidies among customers. Some industrial customers say they should not be responsible for investment "stranded" by their shopping because they "had no obligation." This argument assumes the question away. The question is what obligation does a customer have to balance the obligation the utility has. Under the customer's argument, the obligation to pay is determined by the customer. Under the law, the obligation to pay is determined by the regulator.

Regulators may find that the "compact" does not speak clearly on the precise question of who was obligated for what. In this situation, contract law principles are available. These principles suggest that contract gaps should be filled in a manner that serves the broader public interest; i.e., in a manner that is consistent with the development of more efficient and competitive markets.

III. Regulatory Consistency In the Wholesale Context: A Review of the FERC NOPR

In the electric industry, wholesale relationships are determined largely by contracts and tariffs. Exclusive jurisdiction over these contracts, if they address the sale of electric power in interstate commerce, is with FERC.

The pending FERC NOPR addresses, among other things, the question of recovery of ECEMP through wholesale contracts. Chapter III of this document analyzes that component of the FERC NOPR relating to whether ECEMP should be recovered through FERC-jurisdictional contracts.

For over 30 years, the courts consistently have held that a contract, once approved by FERC, cannot be changed except according to its terms. In short, the government cannot release companies from their bargains, except under circumstances of "unequivocal public necessity."

The FERC NOPR offers utilities an opportunity to seek FERC modification of these contracts. The Approach does not seem consistent with the contractual quid pro quos. Nor is there clear legal support for the NOPR's view that disappointed "expectations" justify cost recovery. The Mobile-Sierra doctrine protects contracts, not expectations. Moreover, although FERC does have jurisdiction over termination of service, that jurisdiction does not give it jurisdiction to change a contract. Finally, the wholesale contracts problem does not appear to have the type of drastic effect that rises to the level of "unequivocal public necessity."

Part Two
Assuming ECEMP Must Be Recovered, How Should It Be Recovered?

IV. Recovery Devices: Economic Efficiency and Jurisdictional Considerations

Assuming that the utility is to recover some or all of the ECEMP, what recovery device is appropriate? Chapter IV analyzes 10 such devices, from the perspective of regulatory consistency, economic efficiency and implementation difficulty.

V. A Return To the FERC NOPR: The Competitive and Jurisdictional Implications of Recovering ECEMP Through an Adder On the Transmission Price

Transmission or distribution service has become a much-discussed possibility for stranded cost recovery. The most prominent example of such a proposal is the FERC NOPR. The NOPR suggests that FERC has exclusive jurisdiction to set rates, terms, and conditions for the transmission of retail electricity in interstate commerce. The NOPR further suggests that if FERC has exclusive jurisdiction over the price of retail electricity, it can use that jurisdiction to order the recovery of "stranded" costs.

Under Alternative 1, if the utility is providing unbundled retail or wholesale transmission service to the departed retail customer, the utility may file at FERC to recover the costs through that transmission rate. This option would be available if one of three conditions is met:

1. the State is silent on "stranded cost" recovery;
2. there is a "conflict among authorities in a State"; or
3. there is "conflict" among States.

Under Alternative 2, recovery would be unavailable at FERC. The NOPR indicates there could be "exceptions" to this rule, but does not describe them.

The NOPR posits that FERC could award recovery of retail generation costs (i.e., ECEMP costs) if the recovery is part of a retail transmission rate. In opposition to this statement, one might offer two rationales: statutory and policy. Under the statute, FERC has no authority over retail generating costs. No one would suggest that FERC has jurisdiction to determine the treatment of the uneconomic capacity in the absence of a retail wheeling proposal. A retail wheeling transaction adds no facts to this equation. In terms of policy, if jurisdiction over uneconomic capacity as between States and FERC depends on the existence of a retail wheeling transaction, then utilities could "shop" for the FERC forum by inviting the customer to instigate a retail wheeling transaction.

FERC has a "strong preference" that States act on the quantification and recovery of stranded investment costs incurred for retail customers. But, if State action is not "adequate," the FERC may assert jurisdiction and act. There is no support in the Federal Power Act for this appellate role. There may be justification for a federal forum when States are in conflict and neutral party is necessary. A regulatory solution to ECEMP will not be rational if the treatment varies with the transactional event. The FERC NOPR commits this error.

A rationale allocation of responsibility: To allocate regulatory responsibility rationally, one first should define the responsibilities to be allocated. This paper has distinguished two regulatory responsibilities:

1. The determination of whether ECEMP should be recovered by utilities: Responsibility should lie with the jurisdiction which created the legal obligation to incur the costs. Thus:

    a. If the costs were incurred for a retail customer, the State should determine whether the costs should be recovered.

    b. If the costs were incurred for a wholesale customer, FERC should determine whether the costs should be recovered.

2. The determination of what recovery device should be used: If the device affects the efficient operation of markets outside a particular State, jurisdiction should lie with FERC. Otherwise jurisdiction should lie with the State commissions.

The error of the FERC NOPR is to combine these functions. Distilled, the FERC NOPR says:

1. We have jurisdiction over a device: transmission of wholesale and retail power.

2. Because we have jurisdiction over this device, we have jurisdiction over whether costs should be recovered; but, in the case of retail costs, only when the proponent of recovery proposes to use this recovery device. Otherwise we do not have jurisdiction over whether the costs should be recovered.

3. Where costs were incurred for retail customers, we prefer that States handle the problem. But if a State does not handle the problem "adequately," we will have jurisdiction to handle the problem. Thus we have jurisdiction not only over retail costs, but over whether retail costs are handled adequately by the State jurisdictions.

4. A challenge to the "adequacy" of a State action may be brought by a utility complaining of unrecovered costs, but not by a customer complaining of having to pay costs.

The easiest approach for FERC is to abide by the Federal Power Act. The FPA authorizes FERC to set the price for wholesale sale of electricity and for the transmission of electricity in interstate commerce. The recovery of costs incurred for retail electric service is not the wholesale sale of electricity or the transmission of electricity in interstate commerce. There is no authority in FERC to address the issue the way it has.

VI. Conclusion
Harmonizing Regulatory Consistency, Economic Efficiency and Jurisdictional Rationality

The treatment of ECEMP requires two distinct decisions. The first step requires a decision on whether ECEMP should be recovered by the utility. Chapter II explains that the whether question should be answered by reference to the historic quid pro quos, and Chapter III analyzes the FERC's NOPR from that perspective.

The second decision concerns how ECEMP should be recovered, if the regulator answers "yes" to the first question. The regulatory decision must harmonize the three major themes in this document: regulatory consistency, economic efficiency and jurisdictional rationality. It is the implementation of the recovery where these three themes meet. Ten recovery devices, using the criteria of economic efficiency, consistency with the quid pro quos and implementation difficulty. Chapter V analyzes the FERC NOPR from that perspective.

Cooperation and coordination to produce efficient regional electricity markets requires state-state and state-federal cooperation and coordination of transmission pricing, access (including retail or direct access), transmission siting, and ECEMP policies. It also requires consistent state-federal regulation that assures that electricity markets are operated by independent comptrollers who clear short-term, and long-term transactions by maximizing the value of those transactions on the transmission grid.

The goal must be to have the level of jurisdictional cooperation necessary to achieve this harmonization between regulatory consistency, economic efficiency and jurisdictional rationality. We are unaware of such cooperation today, and none is proposed in the FERC NOPR on Stranded Costs. However, in the FERC Notice of Inquiry on Alternative Power Pooling Institutions Under the Federal Power Act, there is some recognition that institutions can be set up that have the potential to resolve or mitigate the stranded costs from net generation savings and that greater federal-state cooperation and coordination might be necessary for the proper regulatory oversight of new alternative institutions that can make dynamically efficient competitive markets a reality.

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FOREWORD

This is a briefing document on the issue of embedded costs exceeding market prices in the electric industry. This document was commissioned by the Committee on Electricity of the National Association of Regulatory Utility Commissioners (the "Electricity Committee"), with funding from the U.S. Department of Energy and The National Regulatory Research Institute.

At approximately the time this document was commissioned, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) on this issue. "Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," 67 FERC para. 61,394 (June 29, 1994). Because the NOPR had implications for State commission decisionmaking, the Electricity Committee at its July 1994 meetings asked that an analysis of the NOPR be included in this report.

This document therefore attempts to fulfill two requests of the Electricity Committee:

1. to assist State commissions in addressing, at the State level, the problem of ECEMP; and

2. to assist State commissions in interpreting and responding to the FERC Notice of Proposed Rulemaking ("NOPR") on this subject.

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I. INTRODUCTION

EMBEDDED COSTS EXCEEDING MARKET PRICES (ECEMP): WHAT IS THE REGULATORY TASK?

A. Definition of ECEMP

Many utilities today face three key facts:

1. they have incurred costs pursuant to a regulatory or contractual obligation;
2. the costs are reflected in cost-based rates; and
3. the cost-based rates may exceed the price of alternatives in the marketplace.

These utilities have, in a phrase, embedded costs exceeding market prices (ECEMP). The regulatory treatment of ECEMP is the subject of this report.[1]

1. Sorting Out the Phrases: "ECEMP" vs. "Imprudent" Costs vs. "Unmarketable" Costs vs. "Disallowed" Costs vs. "Costs Without a Customer" vs. "Stranded" Costs

We have chosen the phrase "ECEMP" because it is clearer, and more objective, than other phrases. For example, some define the problem as "imprudent" costs and argue they should be disallowed on that basis. That argument is incorrect. By definition, the costs are in rates (otherwise the customer would have no complaint). All costs, when in rates, are "prudent" costs because otherwise they would not be in rates.[2] To argue for the

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[1] One might argue that there is a fourth fact: some retail customers have asserted a right, or at least a wish, to shop for the lower-priced alternatives. We have not listed this fact separately because, as argued later in the text, it should not, by itself, affect the regulatory treatment of ECEMP. We will argue that embedded cost exceeding market prices is an issue for regulators, regardless of whether a mobile customer makes it an issue.

[2] In order to be included in the rates of a regulated utility, all costs must be prudently incurred. Prudently incurred costs are those operating expenses or investments undertaken by the utility on behalf of its ratepayers that were reasonable under the circumstances at the time the decision was made or action undertaken. See Robert E. Burns et al., The Prudent Investment Test in the 1980s (Columbus, OH: The National Regulatory Research Institute, 1985); Gray and Rodgers, "State Commission Treatment of Nuclear Plant Cancellation Costs," 13 Hofstra L. Rev. 443 (1985).

disallowance of these costs on the grounds of "imprudence" would relitigate a point already decided.[3]

Others describe the costs as "unmarketable" and urge their disallowance on that basis. Prudent costs can be "unmarketable" costs, when they produce rates which exceed market prices. But unmarketability does not translate necessarily into disallowance. Whether it does depends on the interpretation of the "compact" between the particular utility and its regulators.

Some interpret the compact as guaranteeing recovery of all prudent costs; i.e., assigning the full risk of unmarketability necessarily to ratepayers. The courts and regulators have found that assignment of unmarketable costs to ratepayers is not a Constitutional requirement.[4]

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[3] It might be possible to find in retrospect that operating expenses were imprudently incurred if the cost of alternatives for the utility or its ratepayers were less than the prospective, out-of-pocket costs of the plant in question.

[4] In Duquesne Light Company v. Barasch, 109 S. Ct. 609 (1989), the United States Supreme Court addressed this issue in the context of abandoned generating facilities. The Pennsylvania Public Utilities Commission had allowed Duquesne Light Company and Pennsylvania Public Utilities Company to recover the sunk costs of abandoned nuclear plant, whose initiation and abandonment were deemed to be prudent. The Pennsylvania Supreme Court reversed, citing a State law prohibiting recovery of investment not "used and useful." On appeal to the United States Supreme Court, the utilities argued that disallowance of cost recovery of funds prudently invested deprived them of their property without due process of law, and resulted in an unconstitutional taking in violation of the Confiscation Clause.

The Supreme Court rejected this argument and held that so long as the end result of the ratemaking process is a rate of return that is not so low as to be confiscatory, the specific treatment of particular components of that process did not raise constitutional issues. Therefore, there is no Constitutional guaranteed recovery of all prudently incurred costs, whether or not they are marketable. There is merely a Constitutional guarantee that the end result of ratemaking will be an opportunity to earn a rate of return that is not so low as to be confiscatory.

The reasoning in Duquesne rested largely on that of Federal Power Commission v. Hope Natural Gas, 320 U.S. 591 (1944).

Others argue that the full risk of unmarketability should fall on utility shareholders under all circumstances. They would argue that customers have always had means to avoid responsibility for costs incurred on their behalf, through such actions as conservation, moving, closing down a business, municipalization of service territory that was formerly part of the utility's own territory and self-generation. The argument is that the utility knows about these risks and is compensated for them through its authorized rate of return.[5]

This position finds support in the U.S. Supreme Court's decision in Market Street Railway v. Railroad Commission. There the Court held that a regulator has not acted unlawfully by failing to set rates which make a utility financially viable, where the existence of competitive alternatives meant that the utility could not remain viable under any set of rates. As the Court stated (at 554):

> [I]f there were no public regulation at all, this appellant would be a particularly ailing unit of a generally sick industry. The problem of reconciling the patrons' needs and the investors' rights in an enterprise that has passed its zenith of opportunity and usefulness, whose investment already is impaired by economic forces, and whose earning possibilities are already invaded by competition from other forms of transportation, is quite a different problem.[6]

Depending on the application of these principles to a particular situation, "unmarketable" costs can either become "disallowed costs" or "costs without a customer."[7] The disallowance of costs requires a legal theory. One "theory" has been the so-called "used and useful" theory. The used and useful test traditionally has been applied to capacity, which was disallowed from rates when in excess of need. On at least one occasion, the used and useful concept was used to

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[5] With respect to municipalization, one could respond that in the early days of the industry, municipalization might change the ownership of the local distribution facilities but would not necessarily change the customers' source generation. That is, if the new municipal system become a full requirements customer of the utility, the utility therefore would not be at risk of unrecovered costs. Today, in contrast, "municipalization" connotes not only a change in distribution system ownership, but an effort to shop for other power supply alternatives. This phenomenon is not new, however. As discussed in Chapter III.D.1 below, municipal systems have sought alternative, competitive generation sources for over two decades.

[6] Market Street Railway v. Railroad Commission, 324 U.S. 548 (1945).

[7] The underlying investment itself does not generally become unmarketable. The investment is still capable of providing utility service at some price, but perhaps not at the embedded cost price.

disallow not only "excess physical capacity" but also "excess economic capacity."[8]

A danger with the "used and useful" concept is that it can become merely a label attached to a regulatory disallowance of costs which are "simply too high." To disallow prudent costs, a regulator should be able to point to a pre-investment understanding about how the market risks were to be shared. Alternatively, there should be a post-investment action, such as utility claims for a risk premium added to the authorized return on equity, to compensate the utility for market risk. Absent such indicia of risk assignment, it is difficult to identify a valid legal theory for assigning prudent but uneconomic costs to shareholders.

It is not unusual for regulators to share the risk of an abandoned plant between ratepayers and shareholders.[9] There are sound policy bases for such assignments, including the idea that by requiring shareholders to bear some economic risk management will make the best decisions (because it will not be "playing with other people's money").

Another theory for sharing is that the "compact" is silent, or the quid pro quos are not clear. In that situation, regulators might decide to share the cost among stakeholders 50-50. This 50-50 answer should be the end product of the analysis, not a means to avoid the analysis.

There also is the concept of "voluntary risk." An investor can choose to build capacity voluntarily, without legal obligation and without any customer commitment. Where such a speculative builder fails to recover the costs, the result is not "stranded investment;" it is "risked but lost" investment. Consider a utility which builds new plant to serve an existing wholesale customer in 5 years, where the utility has no obligation to serve that customer after 5 years, is such a voluntary risk-taker. It has not incurred an obligation and it is not entitled to receive a quid pro quo.

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[8] See Kansas Gas and Electric Co., Docket No. 84-KG&E-197R (Kansas State Corp. Comm. Sept. 27, 1985), aff'd, Kansas Gas & Electric Co. v. State Corp. Comm'n, 239 Kan. 483, 720 P.2d 1063 (1986). The case was appealed to the U.S. Supreme Court but settled before the Court heard the case.

[9] See Burns et al., The Prudent Investment Test, for a survey of state public service commission treatment of plant cancellation and see New England Power Co, 42 FERC para. 61,016 (1988) modified, 43 FERC para. 61,285, rehearing denied, 43 FERC para. 61,285 (1988).

That leaves the category of "stranded" costs. We believe the phrase is used most appropriately to describe situations resembling the dictionary definition of "stranded." Where a customer has a legal obligation to bear certain costs, and finds a way to avoid that obligation, the costs are truly "stranded." "Stranded" cost, therefore, results not merely from costs exceeding market, but from customers leaving without paying costs incurred on their behalf. Put another way, the term "stranded" should apply only where there is a violation of a quid pro quo. There is a violation of a quid pro quo where (a) the utility was compelled (by contract or franchise) to make an investment and (b) a customer for whom the investment was intended avoids its cost responsibility for that investment.

This discussion should help clarify the regulatory task. The regulatory task is, among other things, to "prevent stranded cost." But that is not the same thing as "protecting utility shareholders from economic risk." It means preventing customers from leaving without paying for costs incurred on their behalf. As such, "preventing stranded cost" is only one part of the regulatory task, as discussed below.

2. Is It Valid to Identify Particular Components of ECEMP?

Some observers have divided ECEMP into components. For example, an official of Niagara Mohawk identifies the following components: assets (e.g., plant and equipment), liabilities (e.g., purchased power contracts), and regulatory assets and expenses.[10]

One might argue that identifying specific cost components as "stranded costs" is inconsistent with the appropriate definition of ECEMP. Where a utility's embedded cost rates exceed the price of available alternatives, all costs contribute to the difference. There is no particular type of stranded cost. The components of embedded cost therefore must be all the components of embedded cost: for example, fuel cost, ROE, embedded debt, as well as these other listed costs.

When observers sometimes identify particular components as responsible for "stranded cost," they are likely identifying types of costs which the utility is obligated to bear and which its

[10] Theresa Flaim, "Methods of Handling Transition Costs for the Electric Utility Industry," Presentation to the National Association of Regulatory Utility Commissioners, Committee on Electricity, March 1, 1994.

competitor is not. There are a long list of such costs, including DSM programs, nuclear waste disposal fees, and purchases from PURPA facilities. None is any more or less valid than the other; what they have in common, if this category is to be meaningful, is that they were incurred due to a legal mandate.

The utility thus might say: "The reason my costs are higher than my competitor's is because I was required to build a nuclear power plant (or invest in a DSM program) and my competitor was not." This statement, if correct, suggests that the situation is not one of "competition" between the utility and the alternative, but one of the shopping customer seeking to avoid costs incurred on its behalf. The goal, in other words, should not be to target some costs for cutting because they are less "valid" than others, but to ensure that where costs are incurred subject to a legal obligation, they do not affect the competitive result; i.e., they are recovered from shopping and nonshopping customers alike.

The reason to distinguish among types of costs is not to label some as "stranded" and others as "not stranded;" but to determine, for each cost category, who is to bear the risk of competitive versus uncompetitive rates. If the costs were incurred to do a legal mandate on behalf of all customers, they should not be at risk on the grounds that some nonutility competitor did not have the same legal obligation. The regulatory "compact," if there is one, should apply to each customer.[11]

Some do insist, however, that it is good policy to isolate one type of cost, such as purchase power contracts, and create incentives for utilities to reduce them. Thus a commission might tell its utility that it could retain 25% of the cost difference between an existing contract and a renegotiated contract. Any inducement to reduce ECEMP deserves consideration. Such an inducement can be particularly valuable where a commitment has been made but societal costs

[11] We are not suggesting that there can be no de minimis tests. Certainly residential customers, when moving their homes, leave Utility A for Utility B without paying off the costs incurred by Utility A on their behalf. Regulation tolerates this breach of quid pro quo because the dollars are small and because of an assumption, which may or may not be correct, that new customers will balance the departure of existing customers. Where these two assumptions -- small dollars and ingress equalling egress -- no longer apply, a regulatory reexamination of the present treatment would be warranted.

have not been incurred. It may be true, for example, that a utility is bound by a purchased power contract to buy the output of a to-be-built plant for 30 years. It is not clear that a regulator has authority to pressure a utility to breach such a contract. But if the output no longer is needed, society is better off if negotiations can head off construction, thereby reducing utility (and ratepayer costs) while still affording the seller some or all of its original bargain.

If such inducements are used, a regulator must consider whether they are being used discriminatorily. For example, if continued operation of a utility-owned plant will increase future societal costs (such as decommissioning costs), the possibility of removing the plant from operation (and from utility rate base) should be considered on the same objective basis as any other cost reduction measure, such as renegotiation of purchased power contracts.[12]

3. Different Perspectives Produce Different Numbers

The need for a common terminology is underscored by the wide variation in estimates of the "problem." These estimates vary so widely that one must assume that the measurers are measuring different things. For example, Baxter and Hirst[13] estimate "stranded commitments" at $24 billion. They define the term as "the difference between utility industrial price and the regional average." An official of Niagara Mohawk,[14] cites industry estimates of $200 billion to $300 billion.

The two estimates are apparently not measuring the same thing. The larger industry estimate seems to be assuming that any utility generating facility with an embedded cost rate above the market price would have a zero asset value. This implies that the utility would recover

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[12] For a comparison of utility cost-reduction measures, including a discussion of whether utilities will prefer to reduce power purchases rather than remove utility plant from rate base, see National Independent Energy Producers, Is Competition Here? A Preliminary Evaluation of Defects in the Market for Generation for the Harvard Electricity Policy Group 14 (October 1994). One of the authors of the present document, Scott Hempling, worked on the NIEP study. See also Robert E. Burns and Mark Eifert, Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets (Columbus, OH: The National Regulatory Research Institute, 1991), Chapter 5.

[13] Lester Baxter and Eric Hirst, "Approximate Value of Potential Stranded Commitments for U.S. Electric Utilities," Draft, Oak Ridge National Laboratory, Oak Ridge, TN, October 1994.

[14] Theresa Flaim, "Methods of Handling Transition Costs," 2.

no revenues from the facility for its expected remaining life. The smaller figure seems to assume that the facility would have some economic value, but the value would decline because the utility would have to lower its price down to the regional average (which incorrectly may not measure the regional market price). The industry estimate seems to grossly overestimate the reduction in the value of utility assets: it assumes that for any facility with an embedded cost rate greater than the market price, the utility would not attempt to lower its prices to meet the market price. In cases where the facility's marginal cost is less than the market price, it is likely that the utility would receive some revenues (although lower than previously) from selling electricity. It is rational for the utility to accept some profits, rather than no profits. Consequently, it would be wrong to assume that this facility would be stranded, as the utility would be earning some revenues.

The differences in the numbers also may represent differences in perspective. The problem for the utility is different from the problem for the regulator. The problem for the utility is determined by the amount of its perceived economic risk: the total amount by which the utility's embedded cost rate exceeds the marginal costs of its competitors. The problem for the regulator is different: it is determined by that portion of the economic risk from which the government has promised to insulate the utility. Regulators therefore cannot know the scope of the problem unless they determine what obligations regulation has imposed on the utility and what risk the utility undertook voluntarily.

As a technical matter, estimating ECEMP requires estimating future market prices. No one knows what future market prices will be, for several reasons. The most prominent reason is that no one knows the future industry's structure, because it is being debated now. Without knowing the industry's structure one cannot know who will be selling. Without knowing who will be selling one cannot easily know what the quality of the competition will be and therefore what the marginal cost will be and therefore what the market price will be.

There also is a dynamic nature to the problem. Markets evolve in complex and unpredictable ways. Even if one estimated the future marginal costs of some industry players, one could not estimate how competitors including utilities will respond. Moreover, the playing field will depend on the cumulative effect of numerous government decisions about wholesale competition, retail competition, mergers, future rate design, municipalization, and externalities in prices, to name only a few factors.

4. A Note on Units of Measure

One cannot talk of costs and prices without having a common unit. For example, some compare the cost of a utility's installed capacity (per MW) with the cost of a new peaking plant. Other say "My utility is charging me 9 cents when I can get 3 cent power on the spot market," thus defining the issue in cost per kWh. Both can be legitimate comparisons, provided the unit of measure is made clear.

The problem arises when a customer of a utility with ECEMP compares the embedded cost rate of a utility with a market price of an alternative. Uneconomic bypass can occur when the marginal cost of the alternative supplier is higher than the marginal cost of the utility, but because the <u>embedded</u> <u>cost</u> <u>rate</u> is higher than the alternative's marginal cost (<u>i.e.</u>, the market price), bypass would occur. As discussed further in Chapter IV.A, a goal of regulation should ensure that where embedded cost rates exceeds market price, only economic bypass occurs; that is, when the marginal cost of the alternative is lower than the marginal cost of the utility.

B. The Regulatory Questions: Should There Be Recovery of ECEMP; and, If So, How?

The first task is to determine whether ECEMP <u>should</u> be recovered. Carrying out that task requires the judgments referred to above: determining who bore the risks related to a particular cost. That task is discussed is Chapter II. A special application of this issue by the FERC, in the wholesale context, is represented by the pending Notice of Proposed Rulemaking (NOPR). This aspect of the NOPR is the subject of Chapter III.

The second question is more mechanical, but at least as important to the development of competitive markets: for those costs which should be recovered, how should they be recovered? Recovery devices can affect prices and therefore participant behavior and market structure. The proper recovery devices are the ones which have positive effect (or the least negative effect), on economic efficiency. Before choosing a recovery device, therefore, regulators should have considered how to achieve economic efficiency under the new market structure. These questions include:

1. Who should the key players be in the new market?
2. What prospective quid pro quos should exist between the players?
3. What role should regulators play in the new market structure?
4. How will these factors work together to produce economic efficiency?

These questions will be discussed in Chapter IV.

C. The Analytical Framework: Regulatory Consistency, Economic Efficiency and Jurisdictional Rationality

The analytical framework for analyzing this issue has three major parts:

Regulatory Consistency: Regulatory treatment of costs incurred must be consistent with legal promises made concerning those costs. A competitive market cannot work efficiently if competitors perceive inconsistency or unpredictability, in the rules or the rulemakers.[15]

Economic Efficiency: The treatment of these costs must be economically efficient. Since economic efficiency can be defined as the outcomes determined by a competitive market, the treatment must be consistent with the result which would obtain in a competitive market.

Jurisdictional Rationality: The relationships among regulators must be set up so that their actions, taken in combination (which is how the market experiences them), produce economic efficiency and regulatory consistency. Put another way, players should not be able to "forum-shop" to avoid the outcomes imposed by economic efficiency or regulatory consistency.

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[15] By consistency, we mean consistency with respect to how government acts on a particular asset. We are not suggesting that regulators should never reexamine their policies. We are suggesting that regulators should never promise order X and then base compensation on Y.

D. Is ECEMP a New Issue?

Embedded cost can exceed market prices in any industry. In a fully competitive market, the problem of embedded costs exceeding alternatives can be handled according to well-established mechanisms: where the embedded costs are subject to contracts, the contracts allocate the risks between buyer and seller. Where the costs are not subject to contract, the risk by definition lies with the asset owner and he has to absorb the difference (known as "writing down the asset") in order to succeed in the market.

A regulated industry is different because the embedded costs frequently are incurred under a legal regime in which the government mandated the costs be incurred and established (although not always very clearly) who would bear the risks associated with those costs. Where the costs were incurred under a legal obligation, the costs should be recovered according to the terms, if known, of that obligation. In the electric industry, the primary source of legal obligation for retail sales is the State-granted franchise arrangement and for wholesale sales is the FERC-jurisdictional contract. These two items are discussed in Chapters II.C and III, respectively.

For now, it is worth noting that the fact of embedded cost exceeding market prices is not new to the electric industry. For several decades until the 1970s, improvements in generation technology, including increasing economies of scale, meant that new capacity additions cost less per unit than the embedded cost of existing capacity. This fact historically did not raise regulatory eyebrows.

This set of facts is recurring today. New generation alternatives may be lower cost than utilities' embedded cost. There is a significant difference between the ECEMP of yesterday and the ECEMP of today, however. In the ECEMP of yesterday, the new plant was controlled by the utility, customers could not shop, and the addition of the new plant lowered average rates. In the ECEMP of today, the new plant -- with costs below the utility's average costs -- may be owned by a competitor, customers can shop (or at least perceive they have a right to shop). In the ECEMP of yesterday, customers and utilities were collaborators in the financing of new plant to reduce rates. In the ECEMP of today, customers and utilities are diverging, with the former trying to buy from new plants and the utilities trying to retain customers for their old plant.

We make this comparison to suggest that the policy solution lies in returning to regulatory basics. Although the causes of the problem are different and the stakeholders are different, the regulatory problem is the same: how should regulation treat embedded costs exceeding market prices?

E. The Relationship Between an ECEMP Policy and a Regulatory Transition Strategy

With the potential for a competitive market structure, regulators need a transition strategy. This paper does not provide that strategy. The paper focuses, as requested, on the narrower issue of "stranded cost." The paper defines the issue, distinguishes other formulations of the issue, offers ways to determine if there is a problem and then evaluates alternative mechanisms from solving the problem.

Solving the problem of ECEMP, although the subject of this report, is not synonymous with having a transition strategy. Solving the ECEMP problem is only one part of a transition strategy. Throughout this report, we will try to explain how the ECEMP issue relates to the larger transition issue.

PART ONE

UNDER WHAT CIRCUMSTANCES SHOULD EMBEDDED COST EXCEEDING MARKET PRICES BE RECOVERED BY UTILITIES? THE REQUIREMENT OF REGULATORY CONSISTENCY OR QUID PRO QUO

II. REGULATORY CONSISTENCY: LEGAL FOUNDATIONS AND JURISDICTIONAL IMPLICATIONS

A. Introduction

Embedded costs are, by definition, "sunk" costs. Economic theory holds that sunk costs are irrelevant to making efficient decisions about future investment.[16] This statement does not mean that regulators need not be concerned about the treatment. It does mean that in determining whether ECEMP should be recovered by utilities, the answer does not depend on economic efficiency; but on legal understandings. That is the subject of this section.

Chapter II.B discusses the general principle of regulatory consistency: honoring historic quid quo pros between regulators, customers and utility shareholders.

Chapter II.C applies that principle to the retail context, respectively. A detailed discussion of the wholesale context appears in Chapter III, which addresses the pending FERC NOPR.

Chapter II.D addresses the situation where utility shareholders must absorb embedded costs exceeding market prices, and evaluates some options, such as rate base spin-offs, divestiture and financial write-downs.

B. The Requirement of Regulatory Consistency: Honoring Historic Quid Pro Quos

1. The Competitive Market Model

In a competitive, non-regulated industry, the problem of ECEMP is not new. Where there is a buyer-seller contract, the solution is in the contract. If the contract commits the buyer to buy, he continues to buy at the contract (above-market) price. Alternatively, he leaves, breaches his contract and pays the damages required by the contract. The contract

[16] Paul A. Samuelson, Economics, Tenth Edition (New York, N.Y.: McGraw Hill, 1976) 498.

may require the seller to mitigate its damages by selling any excess product on the market at the highest possible price. The objective in this situation of buyer breach, is to place the seller in the same position as he or she would have been had there been no breach.

Where there is no contract, the seller with ECEMP has several options. He can dispose of his "sunk" plant and equipment at market value. In that situation, the difference between market value and book value is absorbed by the firm's shareholders (and taxpayers because of the loss can be used to offset taxable income). Shareholders are willing to endure the resulting lower earnings if they think they earn a better return or sell at a profit later. Otherwise they will sell at a loss now, hoping for a better experience in their next investment. Alternatively, the firm simply goes out of business and its assets are sold off. Creditors, and then stockholders, receive their share of the remaining value until that value is exhausted. Some do not receive the full amount owed or invested. This is the risk they undertook to earn a return on their investment; and, in an efficient capital market, this risk is compensated by the rate of return.

These unrecovered costs (or foregone return) cannot be passed through to customers since, in the competitive market, firms can only charge marginal costs. A firm that charges a price above marginal costs will lose customers and be driven out of business by more efficient firms whose lower costs allow them to charge lower prices.

2. The Regulatory Model

In the non-regulated world, predictability and commercial confidence depend on contracts. In the regulated world, contracts play a limited role. But predictability and commercial confidence are just as important. The substitute for contracts is regulatory clarity and, most importantly, regulatory consistency.

The external factors affecting commercial certainty in the regulated world are no less numerous than in the non-regulated world. Changes in cost and technology, customer departures, new environmental or other regulations: all can change a utility's financial health. To ensure prudent, efficient planning, the utility must know its obligations to its regulated customers just as a non-regulated company must know its obligations to its contract customers. Regulation must establish clear quid pro quos, and regulation must act consistently with those arrangements.

The phrase customarily used to describe the quid pro quo is the regulatory compact or regulatory bargain. In the case of retail customers, the compact is embodied, legally, in a franchise agreement subject to State or local law. For wholesale transactions, the compact is actually a contract subject to FERC jurisdiction. The retail arrangements are discussed in more detail in Chapter II.C. The wholesale arrangements are discussed in Chapter III.

The requirement of regulatory consistency, or quid pro quo, is simply a rule of symmetry. Where a utility's investments contributing to ECEMP were made to carry out obligations imposed by regulation, regulation has to be prepared to pay the utility, consistent with risks undertaken by the utility.[17]

We are not suggesting that absent a formal contract or other written historical document that utility recovery is impossible. But the basis for recovery has to be an expectation based on reasonable reliance on a government-sent or customer-sent signal. Absent evidence of such a signal, the regulator risks upsetting the symmetry between risk and reward. An asymmetrical decision is likely to be an unlawful decision.

If the decision is asymmetrical against the utility's shareholders, it means that the shareholders were compelled by government to take a risk but then not compensated by government for that risk. That type of asymmetry could be confiscatory, in violation of the U.S. Constitution. If the decision is asymmetrical against a utility's customer, it means that the government compelled the customer (due its captive status) to cover a utility's risk (e.g., by paying for a return on equity reflecting the risk of unmarketability) and then also to pay for that risk when it did not work out. That type of asymmetry, while not necessarily unconstitutional (since it is not clear that ratepayers have a property right in fair treatment by regulators), is certainly a cross-subsidy and likely to be unlawful under State law on that basis. If the regulator intends to act within the limits of regulatory law and logic, therefore, he or she has no choice but to determine the historic quid pro quos.

We stress the concept of regulatory consistency and quid pro quo because it differs from other proposed responses to the problem of ECEMP. Some have argued that regulators,

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[17] Regulation has treated ECEMP in different ways. Utility investors absorbed the cost of obsolescence in the case of canals and street cars, while in the case of railroads and certain telephone equipment, customers bore the costs. In Appendix A, we discuss the recent treatment of ECEMP in the gas and telecommunications industries.

in addressing "stranded costs," should "spread the pain," or "make the transition smooth," or "make a deal," or "protect utilities' financial integrity." These terms are subjective. They ask regulators to legislate, instead of applying neutral principles to proven facts. Regulatory consistency is the key principle. Whatever deal was struck, if it can be discerned, is the deal that now applies. It is the pre-existing arrangement, not present arguments, which "spreads the pain."

C. Quid Pro Quos in the Retail Context: The Franchise Relationship

1. The Utility Side of the Obligation

At the retail level, utilities historically have had an obligation to make the investments necessary to provide universal service. The basis for this obligation has been the public utility franchise agreement, or state or local franchise territorial exclusivity laws.[18] Currently each of the 50 States has laws setting up exclusive retail marketing areas for investor-owned utilities. At least 23 States provide specific service area assignments under territorial exclusivity statutes.

These territorial exclusivity statues provide a utility with the exclusive right and obligation to serve in an identifiable service area. In at least 38 states, service area assignment are made through the commission's granting of a certificate of public convenience and necessity. The certification process normally is used to assign retail service areas, with the intention of having a single supplier in a service area.[19]

The granting of a certificate to serve, along with the accompanying obligations and reciprocities and interpretations thereof, as embodied in statutes and case law, constitute the "regulatory compact."[20] The regulatory compact is not necessarily a voluntary agreement

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[18] A fuller discussion is contained in Kenneth Costello, Robert E. Burns, and Youssef Hegazy, Overview of Issues Relating to the Retail Wheeling of Electricity (Columbus, OH: The National Regulatory Research Institute, May 1994), 51-54.

[19] In some states there are both territorial exclusivity statutes and certificates of public convenience and necessity.

[20] Charles Phillips, The Regulation of Public Utilities (Arlington, VA: Public Utilities Report, 1985), 106-07.

which utilities have voluntarily accepted. Rather, it is a balancing of utility rights and responsibilities, enacted by state legislatures and enforced by state public service commissions. It represents the exercise by sovereign states of their police power in a manner consistent both with the Commerce Clause of the U.S. Constitution and the Federal Power Act as contemplated by Congress, as is shown in the legislative history of the Federal Power Act.

Under the current regulatory compact, public utilities have certain responsibilities. First, they have an obligation to serve all who apply for service within their service area. Second, utilities must provide safe and reliable service and not engage in undue price discrimination. The prohibition against undue price discrimination requires that all similarly situated customers receiving identical service must be served on the same terms and conditions and for the same price. Third, the utility can charge only just and reasonable rates and may not earn monopoly profits.

In return for undertaking these obligations, the compact, many believe, grants a right to collect a reasonable price for their services based on their prudently incurred expenses and a reasonable return on prudent investments. The right to recovery of and return on investment must reflect the risks imposed by the compact on the utility. These risks vary. Many utilities have argued that the traditional risks did not include the risk that a customer could shop for alternatives after the utility already had incurred obligatory costs to serve that customer.

2. The Customer Side of the Obligation

What is the customer side of the compact equation? The retail customer class, as a whole, bears responsibility for meeting the obligation of providing for the utility's legitimate costs and return on investment. Traditionally it has been permissible for a customer (or group of customers) to exit, by way of municipalization, self-generation (including cogeneration), or simply shutting down or moving. These events have been limited, and utilities have been permitted to use forms of price discrimination, such as special contract rates and discounted tariffs, to prevent them. Utilities also have been permitted, in many situations, to use non-departing customers as guarantors of cost recovery where departing customers have left costs behind.

There is a strong argument that if the regulatory compact is binding on utilities, it also must be binding on individual customers. Any other rule would produce cross-subsidies among customers. Customer X, a new manufacturing plant, could move into the service territory, and invoke the utility side of the regulatory compact to require the utility to incur major costs to serve the plant. Five years later, Customer X might depart, leaving the utility with unrecovered costs. If these costs are recovered from other customers, a cross-subsidy results because they would have been charged costs incurred to serve another customer. This would be a violation of the quid pro quo on a customer-specific basis. It also would be inefficient; Customer X, knowing it did not have to bear the full cost of service, would induce overinvestment on its behalf. In theory, Customer X could repeat the same behavior once every five years, for 50 years, thereby leaving excess capacity in 10 States.

Some industrial customers say: "If there is power on the market for less than we are paying now, we are entitled to it. Because the utility is standing in our way, there is a problem." These customers argue they should not be responsible for investment "stranded" by their shopping because they "had no obligation." This argument assumes the question away. The question is what obligation does a customer have to balance the obligation the utility has. In most franchise situations, no customer has an explicit contractual obligation to pay for particular costs. That obligation is determined by the regulators in setting retail rates. Under the customer's argument, the obligation to pay is determined by the customer. Under the law, the obligation to pay is determined by the regulator.

The alternative is to have utility investors bear the cost of plant. But requiring utility investors to absorb the prudently incurred costs which they were legally obligated to incur, without compensating them for the risk of such cost absorption, is a regulatory inconsistency that could be termed confiscatory.

This reasoning leads to two considerations as to whether the quid pro quo of regulatory symmetry has been met when a retail customer has abandon costs incurred on its behalf. The first issue is whether the utility was historically compensated through its rate of return for the risk that costs would be unrecovered due to market forces. Certainly, the current rate of return of a utility contemplates a certain degree of market risk. If a utility loses customers because of municipalization, self-generation (including cogeneration), or economic down turns, the utility bears the risk of a revenue shortfall at least until the next rate case. At the same time, regulatory lag provides the utility with an incentive to be more efficient.

It can be argued that because a utility can subsequently come in and request higher rates to spread its required revenue over a smaller base of sales, its rate of return only compensates it for shorter-term market risks. However, some would argue that normal investment risks include the risk that demand would change, and that there is no obligation for a commission to shelter a utility from market forces presented because customers have alternatives. In other words, the utility's rate of return already compensates for the market risk that customers would find alternatives.

The answer depends on one's interpretation of the existing regulatory compact. It all comes down to determining historically who promised what to whom, an objective factual and legal inquiry that is made difficult because of the organic nature of the underlying regulatory compact in retail.

Many regulators are likely to find that the "compact" does not speak clearly on this question. If so, contract law principles are available. These principles suggest that contract gaps should be filled in a manner that serves the broader public interest. In situations where the law is unclear, commissions have sometimes engaged in after-the-fact risk-sharing to serve the broader public interest in recovering transitional costs in a manner that is consistent with the development of more efficient and competitive markets. For example both the FERC and some states have engaged in risk sharing on a 50%-50% basis or other basis between shareholder and ratepayers for the cost of cancelled or abandoned plant, as well as recovering the transitional costs of buying out uneconomical gas supply contracts.[21]

3. Incorrect Analyses

a. <u>Ratepayers are not inherently risk guarantors</u>: Some utilities argue that no costs should go unrecovered because ratepayers are guarantors. This approach does not induce efficiency. It is one thing to say that historically, a utility's legally compelled investments were not subject to systematic competition. It is another thing to say that no matter what the external event, utility shareholders have no risk. That statement sounds wrong when made, and it is. If there were no risk, regulators would set authorized return on equity at the level of a highly-rate bond. Risk bearers become risk managers; and, regulators hope, efficient risk managers. They are more likely

[21] See Burns et al., <u>The Prudent Investment Test in the 1980s</u>; and New England Power Company, Opinion No. 49, 8 FERC para. 61,054 (1979) and FERC Orders 436, 500, and 500H.

to be efficient risk managers if they bear the risk of not being efficient.

b. View all unmarketable investment as inherently "imprudent": It is also a mistake to view all unmarketable investments as being imprudent. Prudence analysis has a temporal component: the regulator analyzes, after the decision was made, the quality of the decision based on the known or knowable circumstances in place at the time the decision was made. A relitigating of the prudence issue violates that prudence standard. If the decision was reasonable at the time it was made, unforeseeable subsequent events are irrelevant.

The frequent statement, "utilities should have seen competition coming," runs into this problem. If a utility was under a legal obligation to incur capacity costs, the utility had to incur those costs even if it did "see competition coming." It is the legal obligation at the time of the investment, not one's guesses about what their legal obligations will be in the future, that count. It may be true that many observers anticipated, as early as 1989, that Congress would change the Public Utility Holding Company Act (to admit more competitors into the generation sector) and the Federal Power Act (to ensure more transmission access on a nondiscriminatory basis). But we are unaware of any situation where those anticipations altered a utility's obligation, under its retail franchise arrangement, to continue incurring costs to serve all its customers. Put another way, when a customer in 1994 says, "Why did you incur these costs on my behalf when I wanted to leave?", a reasonable utility response is "Why didn't you tell me that before I incurred the costs?"[22]

In conclusion, any rates which a customer seeks to escape are based on costs which, by definition, already have been approved by regulators as prudent. Absent discovery of hidden imprudence (actions or decisions that were imprudent at the time they were made, but somehow were "hidden" from the prudence reviewers), there is no legal basis for revisitation of the prudence issue. One example of hidden imprudence would be hidden defects in the construction

[22] For example, while there was a 1991 NRRI report proposing an approach akin to the performance-based incentive ratemaking now under consideration in California and other states, the report itself stated that such an approach would be premature until more open and competitive wholesale markets for electricity became a reality. Burns and Eifert, FACs and PGAs, Chapters 4 and 5. If that conclusion was correct, it would be incorrect in 1994 to penalize the utility for failing to institute such an approach earlier (unless, of course, there were other reasons to do so).

of a plant that are not revealed until after the plant is in rate base.

D. Where Utility Shareholders Must Absorb ECEMP, What Devices are Available?

Where the regulators decide that ECEMP should be borne by shareholders, what are the possible methods? We discuss four possible methods in this subpart. Each of these is examined according to the same economic principles used to explore cost recovery methods examined later. Because these methods do not recover ECEMP, there is no examination of whether these methods serve the quid pro quo criterion.

1. Disallowance from rates: The most obvious approach is to disallow the costs from rates; this is the type of situation to which the "used and useful" label gets applied.

A cost disallowance has different financial effects than other approaches. For example, a utility might discontinue accounting as a regulated enterprise, because of emerging competition. That competition would limit the utility's ability to sell its services at rates that recover costs. Under FAS 101, if deregulation or competition causes the recovery of costs to no longer be probable, then regulatory accounting is no longer applicable and a more general financial write-down is required. Under a "disallowance" the financial write-down would be limited to those costs that the regulator has disallowed, because only the recovery of those costs would be considered to be no longer probable.

The effects of a disallowance would be that overpriced assets or costs above market price would no longer be recoverable. The utility would be more statically efficient as costs would come down to market price, because as costs come down to marginal cost, uneconomic bypass is less likely to occur. Less certain are the dynamic efficiency effects or the effects in the development of competitive markets.

2. "Rate base spin-off" as part of a new "regulatory compact": Once a regulator develops a vision of a future market structure, he or she must design strategy for getting there. It may require establishment of a new quid pro quo, a new regulatory compact. Consider the concept of moving generation, presently in the utility's rate base, in a separate company. The separate company might be affiliated or nonaffiliated, but it would be subject to competition, and the sale

of the asset would be at a market price.[23]

A utility might be willing to sell off its presently rate-based generation plant to an affiliate, if the profits available in a market-based wholesale environment were higher than what the utility expected in the retail environment. For example, if a utility has ECEMP, one way of minimizing its losses, rather than having a plant become "unused" or "excess" with possibly no cost recovery at all, is to find some other customer group willing to pay the current market price.

In this area, there is a series of regulatory questions. First, the regulator must decide whether the utility should be permitted to keep the proceeds from these sales, as opposed to sharing the proceeds with the retail ratepayers (who may have borne the risk of the asset). Second, would the remaining plant that is still subject to traditional cost-of-service require lower rates, allowing the utility to be more attractive to its customers than other alternatives available to the customers.

3. Divestiture: Related to selling off a plant is selling off an entire function: divestiture, to independent owners, of generation from the distribution and transmission company. This approach is particularly feasible, if the market value of transmission is above its embedded costs. If divestiture were required, the utility might be allowed to sell off its transmission facilities for more than depreciable embedded costs and be allowed to use the gain from the sale of transmission facilities to offset whatever state commissions determine are recoverable "stranded costs." Again, the question of who gets to gain is critical to whether this works for the utility.

Such divestiture might be part of an effort to restructure the electric market so that there are transmission entities (so-called "poolcos") that are not owned by the utilities that will buy and

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[23] Transfers to an affiliated or nonaffiliated "exempt wholesale generator" is permitted, subject to State commission approval, but new Section 32(c) of PUHCA, added by EPAct Section 711. For jurisdictional state commissions to allow such "rate base spin-offs," they would need to make a specific determination that allowing such a plant to become an EWG in the wholesale market will benefit consumers, is in the public interest and does not violate state law. For an affiliate of a regulated holding company, such a determination would need to be made with respect to the facility by every state commission having jurisdiction over the retail rates of the affiliate. For more information on this subject, see Kenneth W. Costello et al., A Synopsis of the Energy Policy Act of 1992: New Tasks for State Public Utility Commissions (Columbus, OH: The National Regulatory Research Institute, 1993), Chapter 4.

sell power on behalf of all entities. Alternatively, others have suggested that utilities be required to divest themselves of all generation facilities, keeping only the monopoly transmission and distribution facilities. Such a sale of generation facilities may not fully recover ECEMP in many regions where there is currently an excess of generation capacity. Depending on the approach taken, divestiture can be part of a more general transition that includes restructuring.

Divestiture lessens the market power of the utility and lessens the possibility of leveraging of market power from a monopoly (transmission) market to a more competitive generation market. Also, divestiture can play a very positive role in the development of competitive power markets.

4. Financial write-downs: A fourth method of dealing with ECEMP would be to take a financial write-down of assets because then capital cost recovery is no longer probable as required by FAS 71. Such a financial write-down, if taken, would allow the utility to take a loss against income, which would be shared with the general taxpayers at the utility's marginal tax bracket. This approach would have the desirable effect of spreading part of the burden of stranded costs over as broad a base as is feasible. If accompanied by a regulatory write-down from rates, financial write-downs might ease the burden on the ratepayers in any one area, while spreading the burden more broadly.

Some argue that this approach would be particularly appropriate where investment in the underlying asset was encouraged or promoted by Congress and an agency of the federal government as might be argued in the case of nuclear power.

III. REGULATORY CONSISTENCY IN THE WHOLESALE CONTEXT: A REVIEW OF THE FERC NOPR

In the electric industry, wholesale relationships are determined largely by contracts or tariffs. Exclusive jurisdiction over these contracts, if they address the sale of electric power in interstate commerce, is with FERC. See Section 201 of the Federal Power Act.

The pending FERC NOPR addresses, among other things, the question of recovery of ECEMP through wholesale contracts. This Chapter III analyzes that component of the FERC NOPR relating to whether ECEMP should be recovered through FERC-jurisdictional contracts.[24]

Chapter III.A explains why the wholesale context matters to State commissions.

Chapter III.B explains how the wholesale quid pro quos are found in FERC-jurisdictional contracts.

Chapter III.C describes the FERC NOPR, which proposes FERC modification of contracts.

Chapter III.D asks whether the FERC NOPR's approach is consistent with the contractual quid pro quos.

Chapter III.E discusses possible rationales for wholesale contract modification.

Chapter III.F concludes by asking whether the FERC NOPR's treatment of wholesale contracts is based on logical policy analysis.

A. Does the Wholesale Context Matter to State Commissions?

Although State commissions regulate retail transactions, the resolution of ECEMP issues at the wholesale level is important to States, for several reasons.

1. For some utilities, wholesale contracts account for a large percent of their total costs, which then are recovered through retail rates. For these utilities, the treatment of wholesale costs can affect significantly the ultimate retail rates.

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[24] Another method suggested by the FERC NOPR -- recovery through the price for transmission service to transmission-dependent customers -- is discussed in Chapter IV.

2. There is uncertainty about the allocation of cost between wholesale and retail customers. If FERC were to deny a utility the recovery of certain ECEMP from wholesale customers, that utility might seek recovery of the same costs at retail. This issue is discussed further at Chapter V.C.5 below.

3. Where a utility provides retail transmission service (either voluntarily or upon State mandate), costs left unrecovered may be subject to FERC recovery rules, even if the costs historically were incurred to support retail customers. This possible legal treatment is posited by the FERC NOPR.

4. A consistent method for analyzing wholesale contracts can assist States in creating consistent policies respecting the retail franchise. There are differences between contract relationships and franchise relationships. They are similar in that both are forms of legal commitment. Models for identifying and living with quid pro quos in one context may be useful in the other.

5. An orderly transition to competition can benefit retail customers. An orderly transition to competition necessarily means encouraging new relationships. New relationships will be discouraged if each party believes that the other party will seek a regulatory exemption from the relationship when it takes a negative turn for that party. Inconsistencies in the FERC treatment of contracts can deter this transition.

B. The Terms of the Wholesale Quid Pro Quos: FERC-Jurisdictional Contracts

1. The Centrality of Contract in the Wholesale Context: FERC Modification is Permitted Only In the Rare Circumstance of "Unequivocal Public Necessity"

For over 30 years, the courts consistently have held that a contract, once approved by FERC, cannot be changed except according to its terms. In short, the government cannot release companies from their bargains. This principle is known as the Mobile-Sierra doctrine, named after a pair of U.S. Supreme Court cases in which the seller in a fixed-price contract sought approval to increase the price. Because the contracts' terms did not permit the seller to request a price increase, the Federal Power Commission was prohibited from making the change, no matter how inconvenient to the seller. Thus in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332, 343-44 (1956), the Court stated:

> There is nothing in the structure or purpose of the [Natural Gas] Act from which we can infer the right, not otherwise possessed and nowhere expressly given by the Act, of natural gas companies unilaterally to change their contracts.

The Court applied this same reasoning to electric utilities in Federal Power Commission v. Sierra Pacific Power Company, 350 U.S. 348, 352-55 (1956), adding that a utility was not "entitled to be relieved of its improvident bargain."

The basis of the Mobile-Sierra doctrine is the centrality of contract in an efficient economy:

> Our conclusion that the Natural Gas Act does not empower natural gas companies unilaterally to change their contracts fully promotes the purposes of the Act. By preserving the integrity of contracts, it permits the stability of supply arrangements which all agree is essential to the health of the natural gas industry.

Mobile, supra, 350 U.S. at 344.

The Mobile-Sierra doctrine does permit FERC abrogation of contracts, but only in very rare circumstances: specifically, when the public, or some nonparty to the transaction, would be harmed if the change is not made. As the Supreme Court has stated:

> The regulatory system created by the Act is premised on contractual agreements voluntarily devised by the regulated companies; it contemplates abrogation of these agreements only in circumstances of unequivocal public necessity. See United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956). There was here no evidence of financial or other difficulties that required the Commission to relieve the producers, even obliquely, from the burdens of their contractual obligations.[25]

In determining whether to modify a contract and thus relieve a utility of its "improvident bargain," the emphasis is on the public interest, not the private interest:

[25] Permian Basin Area Rate Cases, 390 U.S. 747, 822 (1968).

> [T]he sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory. That the purpose of the power give the Commission in [FPA] Section 206(a) is the protection of the public interest, as distinguished by the private interests of the utilities, is evidenced by the receital in Section 201 of the [Federal Power] Act that the scheme of regulation imposed "is necessary in the public interest." When Section 206(a) is read in the light of this purpose, it is clear that a contract may not be said to be either "unjust" or "unreasonable" simply because it is unprofitable to the public utility.

Sierra Pacific Power, supra, 350 U.S. at 355. FERC recently reaffirmed its adherence to this concept:

> In the 'classic' Mobile-Sierra situation, for example when a seller utility unilaterally seeks an increase from a fixed-rate contract already on file with the Commission, the public interest (as opposed to the private interest of the party seeking the rate increase) only rarely is served by making the requested change (that is, granting the requested increase), and a strict standard is appropriate.

Northeast Utilities Service Company (Re: Public Service of New Hampshire), 66 F.E.R.C. para. 61,332 (1994).

2. Is "Stranded Investment" Possible in a Contractual Context?

In the Introduction, subpart A.1, we defined "stranded costs" to refer to costs unrecovered due to a

> violation of a "quid pro quo"; specifically, where (a) the utility was compelled (by contract or franchise) to made an investment and (b) a customer for whom the investment was intended escapes its cost responsibility for that investment.

Under Mobile-Sierra, "stranded investment" thus defined is a logical impossibility. The Federal Power Act requires the buyer to pay the contract amount: no less and no more. In the contract regime, unrecovered cost is part and parcel of contractual risk. If cost is unrecovered, it is unrecovered because the parties intended not to provide for its recovery.

This approach is

> refreshingly simple: The contract between the parties governs the legality of the filing. Rate filings consistent with contractual obligations are valid; rate filings inconsistent with contractual obligations are invalid.[26]

FERC's "Stranded Cost" NOPR is a "Stranded Customer" NOPR: Under the Federal Power Act, therefore, no cost can be "stranded": unless the FERC changes the quid pro quo by changing the contract. The FERC NOPR does seek to change the contracts. The changes would ensure recovery of costs which the contracts leave unrecovered, not the other way around. Under the FERC NOPR, any "stranding" is a stranding of customers.

C. The FERC NOPR: FERC Modification of Contracts

The NOPR distinguishes between costs associated with "existing" contracts and "new" contracts

New Contracts

New contracts are wholesale requirements contracts executed before that date.

1. Costs may be recovered only according to provisions in the contracts.

2. Stranded costs associated with new contracts may not be recovered through transmission rates.

Existing Contracts

Existing contracts are wholesale requirements contracts executed before the date of Federal Register publication of the NOPR.

1. There is a three-year "transition period" which provides utilities an opportunity to seek modification of existing approved contracts to ensure recovery of "stranded" costs.

2. If the existing contract "explicitly addresses stranded costs through an exit fee or other stranded cost provision," the contract rules; no recovery is permitted except as specified in the contract.

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[26] Richmond Power & Light v. FPC, 481 F.2d 490, 493 (D.C. Cir. 1973) (citing Federal Power Commission v. Sierra Pacific Power Company, supra, 350 U.S. at 355; United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956); United Gas Pipe Line Company v. Memphis Light, Gas and Water Division, 358 U.S. 103 (1959)).

3. If the existing contract does not "explicitly address stranded costs," the parties have three years to make a "good faith attempt" to modify the contract so that it includes a stranded cost provision. The utility would file any agreed-upon amendment with FERC for approval under Section 205 or 206 of the Federal Power Act.

4. If the negotiations do not produce an agreement, the utility, if a "public utility" under the Federal Power Act, may file, unilaterally, an amendment for Commission approval before the end of the three-year period. (The NOPR does not indicate how FERC will evaluate whether the amendment is "just and reasonable, and not unduly discriminatory or preferential.")

5. If the utility does not file the amendment before the end of the three-year period, and a customer leaves before that time, the utility may not recover any "stranded" costs.

6. The utility may recover "stranded" costs <u>through its transmission tariff</u> only if the following facts exist:

    a. The existing wholesale requirements contract does not "explicitly address stranded costs," and

    b. The customer gives notice, before the end of the three-year period, that it no longer will purchase all or part of its requirements from the selling utility but instead will purchase from that utility transmission service that will begin before the end of the three-year period.

7. If the existing wholesale requirements contract contains a "notice provision," and the utility seeks recovery of stranded costs, there is a rebuttable presumption that the utility had "no legitimate expectation of continuing to serve the customer beyond the period provided for in the notice provision."

D. Is The FERC NOPR's Approach Consistent With the Contractual <u>Quid</u> <u>Pro</u> <u>Quos</u>?

The NOPR recognizes (at 6), as it must, that its authorization of "stranded" cost recovery is "extra-contractual." The NOPR thus proposes to create a generic exception to the <u>Mobile-Sierra</u> doctrine. This Chapter III.D evaluates this exception. We ask 5 questions:

1. Is There <u>Factual</u> Support for the NOPR's View That Utilities Did Not Have A "Reasonable Expectation" of Unrecovered Costs?

2. Is There <u>Legal</u> Support for the NOPR's View That Disappointed "Expectations" Justify Cost Recovery?

3. Does the Problem Satisfy the Legal Requirement of "Unequivocal Public Necessity"?

4. The NOPR's 3-Year Good Faith Negotiation Period: What is "Good Faith"?

5. If A Customer Leaves and the Shareholders are not Responsible, Who Pays?

We conclude that the FERC NOPR's treatment of wholesale contract costs may not produce results consistent with historical <u>quid</u> <u>pro</u> <u>quos</u>.

1. Is There <u>Factual</u> Support for the NOPR's View That Utilities Did Not Have A "Reasonable Expectation" of Unrecovered Costs?

As a basis for its proposal to amend wholesale contracts, the NOPR states (at 16):

> Contracts negotiated prior to the recent movement toward increased transmission access and competitive bulk power markets may not contain provisions requiring notice of termination and/or allocating responsibility for stranded investment costs.

This statement does not answer the statutory question, which is: "Should government intervene to amend the contract?" The relevant fact is not whether a contract contains a utility-protective clause, but whether the contracting parties had an opportunity to put one in. If they had the opportunity and did not, the <u>Mobile</u>-<u>Sierra</u> doctrine requires FERC to respect the contract.

There is no evidence that utilities lacked the opportunity to protect themselves from unrecovered costs. Utilities knew of the risks, and their utility wholesale contracts reveal active attention to those risks.

a. Wholesale Customers Have Been Trying to Shop for Over 20 Years

Proponents of "stranded investment" adders in transmission tariffs sometimes argue that "utilities did not see this coming." The implicit assumption is that although utilities legally could protect themselves, they saw no need to and did not. For example, the NOPR states (at 31):

> [Twenty] years ago,...the parties likely did not foresee the advent of competition in the wholesale generation markets and the ability of

transmission-dependent utilities to gain access to their supplier's transmission system to reach other sellers.

The NOPR also states (at 10) that "[i]ncreased competition in wholesale power generation began with the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA)."

Both statements are wrong, as the Commission must know. The Commission itself has acknowledged competition, or at least efforts by customers to make competition possible, in many contexts preceding, or unrelated to, PURPA. Prominent examples include:

a. Multi-year litigation involving Louisiana wholesale customers' attempts to obtain their own generation source, thus reducing their dependence on the surrounding transmission-owning utilities. The litigation produced the oft-cited U.S. Supreme Court decision of Gulf States Utilities Company v. FPC, 411 U.S. 747 (1973), requiring the Federal Power Commission (now FERC) to consider antitrust policy its decisions.

b. The efforts by Kentucky municipal wholesale customers, depending on Kentucky Utilities (KU) for generation and transmission, to replace some KU power with purchases from the Southeastern Power Administration. KU had declined to transmit the SEPA power, and the FERC, interpreting Section 211 of the Federal Power Act (as added by the Public Utility Regulatory Policies Act of 1978 but before being amended by the Energy Policy Act of 1992), upheld KU's refusal. Southeastern Power Administration v. Kentucky Utilities Co., 25 FERC para. 61,204 (1983), reh. denied, 26 FERC para. 61,127 (1984).

c. Efforts by Florida municipals to obtain alternative power supplies. Florida Power & Light Company, 8 FERC para. 61,121 (1979), reh. denied, Oct. 4, 1979.[27]

d. Efforts by Minnesota towns to create their own municipal systems by buying generation from other utilities and transmitting it over lines owned by Otter Tail Power Company. These efforts culminated in the seminal United States Supreme Court decision in Otter Tail Power Company, 410 U.S. 366 (1973).

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[27] The Commission concluded that

> FP&L's proposed tariff restriction would eliminate the only practical source of base-load power or energy to competing utilities within the markets dominated by the Company. Furthermore, the proposed restrictions would appear to create the potential for additional anticompetitive effects by inhibiting the formation of new distribution utilities within these markets.

Efforts by wholesale customers to seek competitive options have been well-known, and vigorously litigated, steadily for over two decades.[28]

b. Utility Contracts Reveal Active Attention to the Risks of Future Economic Changes

The notion that utilities could not have protected themselves from the risk of unrecovered cost is inconsistent with actions utilities took in their contracts. The Commission historically has permitted utilities to protect themselves from unrecovered investment. As the NOPR states (at 16, footnote omitted):

> The Commission always has permitted public utilities to include reasonable cancellation provisions in power sales contracts in order to protect themselves from stranded costs and to plan for the future needs of their systems.

Given this authorization, the presence or absence of contractual protection must have been a

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[28] See, e.g., Conway Corp. v. FPC, 510 F.2d 1264, 1268 (D.C. Cir. 1975) (wholesale competitors "seek to maintain customer satisfaction with the quality and price of their service in order to attract new industries and to retain existing customers"); Town of Massena v. Niagara Mohawk Power Corp., 1980-2 Trade Cases para. 63,526 at p. 76,799 (1980) (retail franchise competition provides consumers "with their most meaningful opportunity to compare alternate price, quality and service. Indeed, at the retail service level, it is this very potential that provides an incentive for [wholesale competitors] to control costs and improve their performance in the areas that they serve.").

See also Alabama Power Co., 13 N.R.C. 1027, 1061-62 (1981) ("the existence of a potential [wholesale] competitor may have an effect on the actions of another distributor"); City of Groton v. Connecticut Light & Power, 662 F.2d 921, 930, 934 (2d Cir. 1981).

Also, the Wisconsin Public Service Commission has found:

> Having equitable [wholesale transmission] use agreements available between and among the state's utilities has the potential for stimulating efficiency benefits for all [retail] ratepayers as a result of the increased competitive supply options available for all wholesale power purchasers. . ..

"Findings of Fact, Conclusions of Law and Order" at p. 58, Docket No. 05EP5 (Wisc. Pub. Serv. Comm. Apr. 6, 1989) (emphasis added).

See generally Meeks, "Concentration in the Electric Power Industry: The Impact of Antitrust Policy," 72 COLUM. L. REV. 64 (1972).

product of negotiations; a part of the quid pro quos.

The NOPR (at 25-26) lists the type of "stranded cost" provisions which parties should include in future contracts.

1. "Adequate notice...to reflect the realities of supply planning"

2. "Exit fees that buys would be required to pay if the buyer prematurely exists the system"

3. Provisions which "preserve the rights to exit contracts when market conditions warrant it."

The list contains no provision which has not been included in past contracts.

Contract length: Contract length is a good example of the issue. Most contracts contain a term of years: a minimum period of time during which the customer must pay. The NOPR does not reconcile statements about "inadequate" protection with the reality that contracts often have minimum terms. A term of years provision serves precisely the same function as a notice provision or an exit fee provision: it protects the utility from making investments to serve beyond the years when a customer is bound to buy.

The Commission (at 30) does apparently see a distinction, between

a. an existing contract which contains a "notice provision," and

b. an existing contract which simply states a term of years.

But the NOPR does not explain this distinction. A term of years would indicate that at the end of the term no one is obligated to anyone else. A notice provision would state a period of time before which one party or the other no longer is obligated to the other. The notice provision and the term therefore achieve precisely the same goals. To distinguish contracts which have notice provisions from contracts which have terms is not a principled distinction.

The Commission does state (at 33), correctly, that in considering a stranded cost amendment, it will "take into account the other contractual provisions and hear arguments as to why other contractual provisions may also need to be amended." In other words, the Commission needs to analyze the quid pro quos in a contract and to ensure they remain consistent after any modification.

Similarly, the NOPR (at 30) appears to see a distinction between:

a. an existing contract which does not permit recovery of stranded costs; and

b. an existing contract which prohibits stranded cost recovery.

Assuming competent parties, there is no principled distinction between contracts which address the issue explicitly or implicitly, and those that implicitly address the issue. A contract which has a prescribed term, after which the seller has no obligation to provide capacity and a buyer has no obligation to pay for capacity, allocates the rights clearly.

By definition, a term is the period of years after which the buyer is no longer obligated to pay for capacity, and the seller is no longer required to buy capacity. Where the parties negotiated a clear term period, there would be no clear need for a provision addressing "stranded investment" because the contract would not permit any action stranding investment. A customer which stopped buying capacity before the term ended would remain contractually liable for the payments. Under such a contract period a provision on "stranded investment" would be a redundancy or meaningless.

Other methods of protection: The utility also could obtain compensation for the risk of the customer's departure through some other term in the contract, like return on equity. Or there might be some other provision, unrelated to stranded cost recovery, which the utility demanded in return for not protecting itself in the unrecovered cost area. FERC's approach, by permitting recovery for which the contract did not provide, without adjusting the contract's other terms, would alter the arrangement between the parties. We are unaware of any contract which commits the utility to incur costs to serve a wholesale customer beyond the term of the wholesale customer's contract, where the contract does not somehow already compensate the utility for those costs.

Since a rational utility already would have demanded adequate compensation, through the return on equity or other terms, for any commitment to invest now for service going beyond the contract term, recovery of the extra costs would insulate the utility from a risk for which the utility already had been compensated, and therefore be excessive recovery.

The NOPR does not explain why some utilities protected themselves and others did not. Nor does the NOPR explain why Commission policy should treat utilities in these two different categories differently (by, for example, not permitting some type of bonus adder for utilities in the first group, but permitting a bonus, i.e., "extra-contract" adder for the second category).

Finally, the Commission has proposed a rebuttable presumption to the effect that existing contracts with notice provisions reflect no reasonable utility expectation of continuing to serve the customer beyond the term provided for in the notice provision. NOPR at 30. The Commission seeks comment on whether this presumption should be applied to any contract entered into after EPAct. No presumption is necessary, for the reasons the Commission implied. At the very least, all utilities are on notice that their transmission system would be made available, at a fair price, for usage by formerly captive whole customers seeking alternatives. As we discussed in Chapter III.D.1 above, this expectation should have predated EPAct by many years.

c. Utilities Had No "Reasonable Expectation" of Asymmetrical Obligations

Assuming "expectations" (as opposed to contract language) are relevant, one must determine what the expectations were. There is no legitimate expectation of asymmetrical obligations. The NOPR appears to make this error.

The NOPR states (at 26):

> Asymmetrical rights and obligations that allow exiting customers to leave their current suppliers consistent with their existing contractual obligations, but that require sellers to continue to serve those customers beyond the terms of their existing contracts, would not be efficient or fair.

The statement is correct. But it is not clear what source of law, other than the contract, would "require sellers to continue to serve those customers beyond the terms of their existing contracts." If the source of law is the contract, and the contract was approved originally by FERC as just and reasonable, then it is unlikely that the contract imposed "asymmetrical rights and obligations." Modifying the contract, as the NOPR proposes, would upset the existing symmetry.

The NOPR further states (at 26):

> [T]he Commission does not believe that it is appropriate to impose on wholesale requirements suppliers a regulatory obligation to continue to serve their existing requirements customers beyond the end of the contract term. That means that a requirements customer is responsible for planning to meet its power needs beyond the end of contract term.

The NOPR appears to be referencing a prospective policy. But one could argue that the Federal Power Act has worked that historically, never imposing on utilities an extra-contract obligation.[29]

If there was no historic obligation to serve beyond the contract term, then to impose an obligation to pay beyond the contract term is asymmetrical. That is what the NOPR does, without taking a clear position on the historical obligation-no obligation debate.

Asymmetry appears in an additional way. If an existing wholesale contract had an exit fee, the Mobile-Sierra doctrine would prevent the customer from moving to eliminate it. If the contract does not have an exit fee, however, the NOPR would permit the utility, unilaterally, to file for one.

If the foregoing assumptions are correct (and we welcome a critique of them), then a utility "expectation" of recovery beyond the contract would be an unreasonable expectation because it would presume asymmetrical obligations.

d. If Expectations Do Matter, When Did Reasonable Expectations Become Unreasonable?

If the Commission were to permit modification of contracts, the question is which contracts could be modified. Assuming one accepts the NOPR's error of basing recovery on the utility's "expectations," the proper approach would be a case-by-case determination of when a particular utility's "expectations" should have changed. When should the utility have been on notice that customer should not be assumed to be captive?

One legitimately could argue even argue that "notice" occurred in the early part of this century, when the nation's antitrust law policies began to take shape. The "essential facilities"

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[29] Practitioners have differed over what if any obligation there is between a utility and its wholesale customer. For summary of the debate on this topic, see D. Yaffe, "The Requirement to Provide Wholesale Service Under the Federal Power Act: A Remedy of Continuing Vitality to Promote Efficiency and Prevent Discrimination," 9 Energy Law Journal 459 (1988); L. Bouknight and D. Raskin, "Planning for Wholesale Customer Loads in a Competitive Environment: The Obligation to Provide Wholesale Service Under the Federal Power Act," Energy Law Journal Vol. 8 No. 2 (1987); Pace, "Wheeling and the Obligation to Serve," 8 Energy Law Journal 265 (1987); Norton and Spivak, "The Wholesale Service Obligation of Electric Utilities," 6 Energy Law Journal 179 (1985).

doctrine, holding that a firm controlling a "bottleneck" facility essential for competition must share it with its competitors, dates to the U.S. Supreme Court's decision in United States v. Terminal Railroad Association of St. Louis, 224 U.S. 383 (1912). Other options include:

a. In 1973, when the U.S. Supreme Court issued the Otter Tail decision, making it explicit that transmission was a bottleneck monopoly which utilities had to share with their competitors.

b. At least two decades ago, when municipal customers frequently challenged, and challenged successfully, utility control of their power supply options.

c. Oct. 24, 1992, when Congress authorized FERC to order transmission access.

The NOPR's proposed date, the date of Federal Register publication of the NOPR, bears no relationship to the industry's actual knowledge that customer shopping was a possibility.

2. Is There Legal Support for the NOPR's View That Disappointed "Expectations" Justify Cost Recovery?

A factual premise in the NOPR, as discussed above, is that customer shopping at the end of a contract term is inconsistent with utilities' expectations. In the previous subsection we argued that there was no factual basis for this premise. We turn now to the legal premise: that disappointed expectations are a legitimate basis for government modification of contracts. We think they are not.

a. **The Mobile-Sierra Doctrine Protects Contracts, Not Expectations**: The NOPR (at 21) states:

> Costs may have been incurred by wholesale suppliers under an implicit regulatory "bargain," i.e., based on a reasonable expectation that captive customers would continue taking service beyond the term of their contracts and that the utility would continue to plan for their needs.

An "expectation" is different from a contract. Parties to a contract always have expectations about how they will fare under the bargain they have struck. Results may vary from those expectations, but that fact does not justify changing the bargain retroactively. The entire purpose of a contract is to allow parties to chance to allocate the risks of disappointment. Where a party has failed to protect itself through the contract, the market will exact a penalty. That fact is not remarkable in the nonregulated world. The Mobile-Sierra applies the same fact to the regulated wholesale world.

b. **FERC's Jurisdiction Over Termination of Service Does Not Give it Jurisdiction to Change a Contract**: The NOPR notes (at 21 n.32) that FERC has jurisdiction over termination of service. The implication is that because a utility cannot terminate service without FERC approval, there is a "regulatory bargain" outside the contract. The further implication is that this bargain includes a customer obligation to pay for the prudent cost incurred by the utility in reasonable expectation that the customer would remain beyond the term of the contract.

The NOPR does not furnish legal support for these implications. In response, one might argue that the purpose of the required pre-termination filing is not to establish an extra-contract "bargain" between the contracting parties but to protect the "public interest." See Mobile-Sierra. The Commission might determine, for example, that termination could cause public harm by endangering reliability. In this situation the Commission would use its termination jurisdiction to prevent or mitigate such harm. This interpretation of the pre-termination provision is more consistent with the Mobile-Sierra doctrine than the one implied by the NOPR, i.e., that the pre-termination provisions establish an extra-contract "bargain," coincidentally measured by the amount of the utility's unrecovered costs.

In fact, the NOPR suggests (at 26) that a requirements customer should be "responsible for planning to meet its power needs beyond the end of the contract term." A requirements customer always has had that responsibility. The legal fact that a utility may not terminate service without authorization does not mean that a utility has an obligation to plan for a customer's needs.

c. **Conclusion: The NOPR's Concern with the "Adequacy" of Utility Bargains Expresses a Bias Not Permitted by the Federal Power Act**: The Commission states (at 25, emphasis added):

> [W]e are aware that many existing contracts, entered into prior to the time that unbundled transmission access became more widely available, may not have adequately addressed the potential for stranded costs.

The implication is that if a contract, freely entered into by the utility, is not "adequate" if it results in financial disappointment to the utility. This bias has no basis in the Federal Power Act. In a contracting environment, it is the job of the utility, not the FERC, to ensure that a bargain is "adequate." Any other assumption creates uncertainty in all contracts.

3. Does the "Contracts" Problem Satisfy the Legal Requirement of "Unequivocal Public Necessity"?

Acknowledging Mobile-Sierra's restriction on contract modification, the NOPR states (at pp. 31-32), that failure to permit stranded cost recovery could "harm the public interest." The NOPR offers two main reasons: utility financial difficulties and the goal of "facilitating competition." Neither goal rises to the level of "unequivocal public necessity" of Permian Basin Area Rate Cases. The NOPR omits mention of the Permian Basin standard completely.

a. Utility Financial Difficulties

Utility financial condition requires a case-by-case analysis. The Commission is concerned that the magnitude of unrecovered costs is so large that it could "seriously erode a utility's access to capital markets, or could drive the utility's cost of capital to unprecedented levels." NOPR at 32. There is no analysis or facts in the NOPR to support such a finding. Even large utility financial difficulties do not justify government intervention if the difficulties were of the utility's own making. See the discussion of Market Street Railway in Chapter I.A.1 above.

The possibility that market alternatives will develop lies at the heart of any contract. It is not a possibility but an inevitability, and does not justify government intervention. The entire purpose of a contract price, and a contract term of years, is to allocate the risk that the price will vary from market in the future. The existence of such terms in the contract is evidence that the parties thought about, and allocated, the risk. To deny this fact is to deny the contract. That is the opposite of the law, as stated by the Mobile-Sierra doctrine.

b. "Facilitating Competition"

The NOPR asserts, but does not explain, a connection between extra-contract cost recovery and the enhancement of competition. The connection is not obvious. Existing contracts deal with past costs. Competition should concern future costs and future relationships.

FERC's jurisdiction to "facilitate competition" competition is housed, primarily, in its transmission authority under Section 211 of the Federal Power Act. Nothing in past contracts prevents it from exercising this authority, by ordering transmission where necessary to create efficiency.

The NOPR could have opposite effect on competition. Essential to competition is commercial confidence. There cannot be commercial confidence when parties can ask government for relief from contracts. Competition also must mean that at the end of a contract, each trader is free to seek new partners, or a new deal with their existing partners. To block or burden a new relationship, because on party to the old relationship will be disappointed, is inconsistent with competition.

4. The 3-Year Good Faith Negotiation Period: Is "Bad Faith" to Insist on Contract Compliance?

The NOPR states (at 28) that customers must make a "good faith" effort to negotiate resolution of stranded cost recovery. The NOPR does not define "good faith" or distinguish it from "bad faith."

This gap creates a potential reversal of roles. In the three-year negotiations, the utility who insists are changing the terms of the contract it negotiated is perceived as carrying out the FERC's priority; while the customer who insists that the utility abide by the terms of the contract risks being accused of "bad faith."

Moreover, the NOPR does not state what it would do if it found the customer "in bad faith." The Federal Power Act does not give the Commission jurisdiction over the buyer. It is not clear, therefore, what action the Commission could take, based on the buyer's behavior, when FERC interprets or modifies an existing contract. It would seem that if there is any recovery of ECEMP, the amount should depend on the level of actual costs, the relation of these costs to market prices, and the extent of the utility's "legitimate expectations," rather than the willingness or unwillingness of the customer to insist on its contract rights during the 3-year negotiation period.

5. If A Customer Leaves and the Shareholders are not Responsible, Who Pays?

The NOPR describes (at 37-38) an allocation problem arising where:

a. the Commission does not permit modification of an existing wholesale contract to recover the costs because the utility had no "reasonable expectation of continuing to serve that customer," and

b. the customer, upon departure, obtains unbundled transmission service not from its former supplier but from another utility.

The Commission states "we anticipate that in such a case any prudent costs that are stranded as a result of the customer's departure would be reallocated to remaining customers in the utility's next requirements rate case."

This position contains a fundamental conflict. A utility which incurred costs to serve a customer, while having "no reasonable expectation of continuing to serve that customer," is not a "prudent" utility for purposes of ratemaking. Such a utility, by definition, was not acting on behalf of its customers when it incurred costs based on "no reasonable expectation of continuing to serve that customer." The utility was a knowing risk-taker, but the risk was not incurred for the customers who now would cover it. Reallocating these costs to other customers amounts to captive customer subsidy of utility business risk.

The NOPR is concerned with "expectations." The remaining customers had no expectation of covering costs incurred by a utility for another customer, whether or not the utility had a "reasonable expectation" of continuing to serve that customer. It would not be consistent for the FERC to credit utility "expectations" but disregard customer "expectations."

A similar argument should be available to reject any argument that the costs must be allocated by State commissions to retail customers. This matter is discussed at Chapter V.C.5 below.

E. Possible Rationales for Wholesale Contract Modification

This section discussion two possible rationales, not explicitly discussed in the NOPR, for modifying a wholesale contract to permit recovery of costs otherwise left unrecovered by a customer's departure: (a) where the utility was legally compelled to build the generating facilities, and (b) where FERC had rejected the utility's notice provision as too long.

1. Legal Compulsion to Build the Generating Facilities

There is a possible argument that a utility might have been compelled by antitrust law, and particularly the essential facilities doctrine, to provide generation service. In that situation, a utility could argue it was compelled to incur the cost and therefore the full cost should be recovered from the customer before the customer shops elsewhere.

The FERC NOPR does not make this distinction, between (a) generation dependency resulting from the justifiable absence of transmission access (such as natural or government-imposed shortage) and (b) generation dependency resulting from utility refusal to deal.

Consider transmission facilities, which are often viewed as essential facilities. A utility which was compelled by antitrust law (with or without an actual court decision) to provide transmission to a municipal would be justified in charging for the cost of that transmission. If the utility otherwise did not need the facility, the customer fairly could be charged the full cost of the facility. If a customer faced with the full reasonable cost of the line did not want to pay it, then by definition the transaction would be uneconomic. The utility would not be required to make the transaction happen. Antitrust law provides no right to engage in an uneconomic transaction and someone else's expense.

The same situation could arise with generating facilities. A municipal system might be "landlocked" within a utility's territory and, because of its small size, be unable to construct its own generation economically. Assuming, for purposes of constructing the hypothetical, that no transmission were available (perhaps because of a shortage of sites, or environmental restrictions), then the customer would be completely dependent on the utility for generation. In this hypothetical, the dependency results not from the utility's behavior but from natural circumstances. The generation dependency is a result of the absence of transmission facilities (as distinct from the utility's refusal to grant nondiscriminatory transmission access). In this situation, the utility is obligated to build generating capacity for the captive customer.

If circumstances then change, so that transmission can be built and generation alternatives become available, who then must bear the cost of generation facilities built? One could argue that the customer should pay before leaving.

Where the legal compulsion resulted from a customer lawsuit, the quid pro quo principle would favor the utility. A customer should not sue for a right without expecting to pay for it. Where the legal compulsion did not result from the customer lawsuit, the proper resolution is not as clear. Where the utility is compelled by government to incur costs, it is difficult to think of a legal theory by which the utility must absorb those costs.

2. FERC Rejection of Notice Provision as Too Long

Assume a utility sought a notice provision in a contract which the utility thought was necessitated by its power planning responsibilities for a customer, but which FERC decided was too long to be just and reasonable. For example, a utility, because of a imminent capacity deficit, might have decided that the most economical action was to make a 20-year commitment to purchase power (or build capacity with a 20-year life). The utility also might have determined that it was most economical to size the commitment large enough to accommodate both its retail load and its wholesale requirement load. In order to ensure recovery of the cost of this commitment, the utility might seek a 20-year notice provision in its requirements contract with its wholesale customer. FERC might have decided that 20 years was too long a notice provision, thereby denying the utility an opportunity to protect itself from future "stranded" costs. In this situation, one might argue that the utility faces unrecovered costs, not because of imprudence or voluntary risk-taking.

In this context, FERC must take care not to contradict itself. If, when the utility initially sought the 20-year notice provision, the Commission rejected it because it was unjust and unreasonable (because, e.g., it was anticompetitive), the Commission can not now authorize the same provision on the grounds that it is just and reasonable.

F. Conclusion: Is the FERC NOPR Based on Logical Policy Analysis?

This paper focuses on two inquiries: whether ECEMP should be recovered; and, if so, how ECEMP should be recovered. We have tried to show that the answers to these questions require substantial factual, legal, jurisdictional and policy analysis.

We believe the NOPR lacks this type of analysis:

> As to whether ECEMP should be recovered, the NOPR seems to answer "Yes, unless the utility expressly contracted to risk these costs."
>
> As to how ECEMP should be recovered, the NOPR seems to answer: "By those devices which are within our jurisdiction. We do wholesale contracts and transmission service. Therefore the costs should be recovered through wholesale contracts and transmission service."

As discussed further below, we believe both inquiries require more care.

PART TWO
ASSUMING ECEMP MUST BE RECOVERED, HOW SHOULD IT BE RECOVERED?

IV. RECOVERY DEVICES: ECONOMIC EFFICIENCY AND JURISDICTIONAL CONSIDERATIONS

A. Introduction

Assuming that the utility is to recover some or all of the ECEMP, what recovery device is appropriate? This Chapter IV analyzes 10 such devices. In Chapter V, we return to the FERC NOPR, to discuss in detail its proposed adder to the transmission services rate.

We have divided the recovery techniques into two broad categories: transaction-related and non-transaction related. "Transaction-related," is defined as options that are directly related to a specific event, e.g., a customer reducing their purchases from the utility or customers. These options are designed to recover some or all the ECEMP costs from the departing customer(s). "Non-transaction-related" refers to ECEMP cost recovery mechanisms that are not tied directly to a specific event. These options allow the utility to recover some or all the ECEMP costs from either the remaining ratepayers or from a broader group of ratepayers, sellers, or taxpayers. Non-transaction related recovery devices, therefore, focus on sources of funds rather than particular transactions. Although the parties to a transaction might be included in the universe of payors, the transaction itself would not be the basis for the payment. The groups of payors include ratepayers of the utility and broader bases. We discuss each in turn. See Table IV-1 for a list of all the recovery devices discussed below.

Each device is described as to how it might be structured and who would pay it. They are then evaluated based on the following criteria:

- Economic efficiency, including
  - Static efficiency,
  - Dynamic efficiency, and the options'
  - Consistency with Evolution to a Competitive Market
- Consistency with Regulatory Quid Pro Quo, and
- Implementation Difficulty.

TABLE IV-1

OPTIONS FOR RECOVERY OF ECEMP COSTS

Transaction-Related Recovery Devices:

- Access Charge Tied Directly to Continued Transmission or Distribution Service
- Exit Fees Charged to Departing Customers, Unrelated to Costs Incurred on Behalf of that Customer
- Exit Fees Charged to Departing Customers, Calculated to Recover Costs Incurred on Behalf of that Customer
- A Share of the Net Generation Savings Realized by Departing Customer Over Time

Non-Transaction Related Recovery Devices:

<u>Ratepayers of the Utility</u>:

- Shifting Costs to Captive Customers
- Charging Ratepayers Above-Cost Prices Where Market Exceeds Cost
- Accelerated and Decelerated Depreciation
- Price Cap or Performance Based Rates

<u>Broader Bases</u>:

- Entrance Fees Charged to New Generation
- All Sellers (by kWh)
- Taxes:
    - ♦ Tax Credits for Financial Write-Downs
    - ♦ Trust Fund to Subsidize NUG Contract Buy-Out

Three aspects of economic efficiency are discussed for the ECEMP cost recovery options. The discussion of economic efficiency is intended to provide an analysis on the relative efficiency between the various options discussed. As discussed at the beginning of Chapter II, recovery of ECEMP is not necessary for economic efficiency because ECEMP is, by definition, a sunk cost. However, regulators may have decided that some recovery is required due to past regulatory quid pro quos. These options and the discussion of economic efficiency are intended to provide regulators a means to compare and possibly select an option or combination of options. Most of these options are not mutually exclusive. In Chapter VI, the relationship between with the policy goals of regulatory consistency and economic efficiency is discussed.

The discussion of static efficiency asks the question: Does the recovery option encourage only economic bypass of the utility's system and discourage uneconomic bypass? Economic bypass is defined as occurring when the alternative supplier's marginal cost is lower than the utility's. This is called "static" efficiency because is assumes no change in the utility's marginal cost or the alternative supplier's. The relationship between ECEMP costs and bypass is that the bypass, if it occurred, would cause the embedded costs associated with that customer to be unrecovered (because it exceeds market price).

Dynamic efficiency assumes that the utility's marginal cost is not fixed or static over time. Dynamically efficient options provide an incentive for the utility to reduce its marginal costs by, for example, renegotiating fuel contracts and reducing operation and maintenance costs. A key difference between static and dynamic efficiency is the element of time. As with static efficient options, only economic bypass occurs. However, options that are dynamically efficient have the added advantage of reducing the utility's costs and, therefore, reducing the amount of ECEMP costs. By definition, if an option is perfectly dynamically efficient,[30] it is also statically efficient since it would lead to the utility's marginal costs being reduced to the market price or the marginal costs of the alternative suppliers. Dynamic

[30] No option fits the description of perfectly dynamic since this could only occur in a perfectly competitive market. Therefore, as will be discussed, some options can increase dynamic efficiency but not static efficiency.

efficiency would require that the market price of electricity be the marginal cost of all suppliers.

ECEMP costs may be based on historic commitments, however, they are not all determined at this time. Competition will determine ECEMP costs over time. Utilities can make adjustments now to reduce their costs and hence rates, making themselves more competitive and with less exposure to ECEMP costs. As explained below, the Maine legislature passed a bill that allows, with the Maine Public Utilities Commission approval, utilities to receive a low-cost loan to buy out nonutility contracts. Even without subsidization from the state, this is one example as to how utilities can reduce their costs (in this example, when the contracts require a utility to purchase power at a higher cost than either it could produce or what is available from alternative suppliers). Costs, including ECEMP costs, should not be considered fixed and constant through time. This is another reason why it is difficult to determine ECEMP costs in advance, either for the country or an individual utility.

Although <u>static efficiency</u> is important, it would be a mistake to focus exclusive on it. The debate concerning ECEMP costs often focuses on just static efficiency, which works to the advantage of utilities, but not their ratepayers. This is because utilities would always be compensated for any lost revenue from a departing customer at their existing costs. Regulators should consider <u>dynamic efficiency</u> as a primary goal of an ECEMP policy (along with regulatory consistency). Indeed, a major reason for moving to a more competitive market is to increase dynamic efficiency. Regulators should, therefore, give preference to options that are consistent with the goal of dynamic efficiency and avoid ones that are at odds with it.

Consistency with the <u>evolution of a competitive market</u> is related to efficiency in that the more a competitive market develops, and the extent that recovery options contribute to or not inhibit its development, it is more efficient. This is not circular since it is independent of <u>static efficiency</u> in that it is possible to have static efficiency (no uneconomic bypass) but not contribute to the developing competitive electric market. In general, options that are dynamically efficient, however, are consistent with the evolution of markets.

These concepts are related to the polices of bypass and allowing competition. As noted earlier in this document, however, the possibility of some bypass and the advantages of a competitive market are not debated here, but are assumed to exist.

Each option is also examined for its consistency with the regulatory quid pro quo. It is considered consistent if it would collect ECEMP that is stranded by departing customers who are not fulfilling their regulatory or contractual obligation in a manner that does not violate the existing regulatory compact or contractual obligation. Also discussed for each option are some of the problems that may arise if the option for ECEMP cost recovery is implemented.

As can be seen from the discussion, no option is ideal. Options that are statically efficient may not be dynamically efficient and vice versa. This suggests that a combination of options may be the best regulatory strategy. Each option is discussed below in terms of the three main criteria (economic efficiency, consistency with the quid pro quo, and implementation difficulty) relative to other options but in isolation. It should be noted, however, that these criteria are highly dependant on other regulatory policies and well as other options used for ECEMP costs.

B. Transaction-Related Recovery Devices

1. Introduction

There is logic to recovering ECEMP costs from parties to the transaction, if the customer has left behind its contractual obligations, whether from a wholesale contract or from a retail franchise arrangement that is subject to a regulatory compact. Another basis is the party's benefits from the transaction: those who benefit from a transaction should also bear at least a portion of its costs.[31] Assuming the underlying transaction is efficient, so long as the parties of the transaction are not required to pay costs greater than the benefits that they receive, efficient transaction will go forward, unrecovered costs will be mitigated (at least partially recovered), and remaining customers will be buffered (to the extent feasible) from cost shifting as a result of ECEMP costs.

[31] There is a reasonable argument, however, that the costs are not caused by the new transaction itself (i.e., the customer buying from the new seller) but by the relationship between the pre-existing embedded costs and market price. Under the argument, a party searching for a more efficient transaction does not "cause costs." It is the customer's departure before paying his share of the existing costs which is the problem.

Four options are discussed in this section of transaction-related recovery devices:

1. access charge tied directly to continued transmission or distribution service,
2. exit fees charged to departing customers, unrelated to costs incurred on behalf of that customer,
3. exit fees charged to departing customers, calculated to recover costs incurred on behalf of that customer, and
4. a share of the net generation savings realized by departing customer over time.

As noted, the term "transaction-related" is used here because it refers to a specific transaction related to the action of a customers of the utility.

2. Access Charge Tied Directly to Continued Transmission or Distribution Service

This approach ties the collection of an access charge directly to continued transmission or distribution service. The effect of this approach is to place the burden of ECEMP costs on the departing customer, if that customer depends on transmission access. Whether the access charge is tied to continued transmission service or continued distribution service will place the recovery device either in FERC or state commission jurisdiction, respectively.[32] If the access charge is collected at the retail distribution level, it could be within the jurisdiction of the state commissions to implement. An access charge tied directly to continued distribution service for existing customers (buyers) can be collected over a period of time.

By spreading out payments over an extended time period, state commissions might set an access charge at a level that collected ECEMP costs while not unduly foreclosing entry into the market. However, the calculation of such an access fee must be based on the cost savings realized from the transaction to avoid this approach becoming a barrier to entry. While there is certainty to this approach, it might foreclose otherwise efficient transactions if

[32] Section 201 of the Federal Power Act vests FERC with exclusive jurisdiction over transmission service in interstate commerce, but not over "local distribution facilities." The relationship between "transmission service" and "local distribution facilities" has been subject to discussion, particularly in the context of whether FERC has jurisdiction to establish rates for retail transmission service.

the access charge were a fixed fee, whether in a lump sum or spread out in payments over a set period of time.

Otherwise, however, this approach is not consistent with the evolution of a competitive market. It raises the cost of engaging in these transactions by charging an access charge fee. Even if one could argue that this approach were reflective of quid pro quo relationships, it would still not be procompetitive, looking prospectively.[33]

Further, because this arrangement might result in the leveraging of market power from a monopoly market to a more competitive generation market, this approach might be inconsistent with antitrust laws and principles.[34]

If the access charge were tied to continued transmission service for existing customers (buyers), then arguably the access charge could be considered a term or condition of transmission access and would be jurisdictional to the FERC.

One method of setting an access charge would be to set the access fee based upon a "top-down" method. The access fee would guarantee that the host utility's embedded fixed cost of distribution and transmission as well as its embedded cost of generation (or that portion which the regulator has determined should be recovered) were recovered. This method would hold the host utility harmless from ECEMP the regulator-identified cost of generation.

Whether the method would be considered anticompetitive, in an antitrust sense would depend on whether costs recovered are those which were subject to a past quid pro quo.

If the access charge was calculated as the difference between the utility's embedded cost price (calculated in the top-down manner described above) minus the utility's marginal or avoided

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[33] Labeling a recovery device as "not procompetitive" does not mean it should be rejected. To the extent a device does not more than require a customer to pay for costs incurred historically on that customer's behalf, the device is no different from a payment obligation in a contract. All contracts are "anticompetitive" in the simplistic sense that they bind the parties to an existing agreement and therefore prohibit them from entering into new contracts. Just as one would not ban all contracts on this basis, similarly one would not necessarily reject all transaction-related adders on this basis.

[34] The relationship between transaction adders and antitrust law is addressed in the Cajun opinion, discussed in Part V.B.2 below.

costs, then static efficiency would be achieved. Customers of the host utility would only bypass the utility when economic; that is, when the alternative supplier's marginal cost is below the utility's. There is a downside, however, since the utility is compensated fully for the difference between its price and marginal cost, it has little incentive to attempt to retain the customer by cutting costs (assuming rate flexibility). Also, the utility would no longer have to pay the marginal cost avoided by not supplying the power to the departing customer. As a result, this method alone would not achieve dynamic efficiency.

If it were based on a fixed charge, and differed from the utility price minus utility marginal cost, then static efficiency would likely not be reached either. If it were set too low, then some uneconomic bypass may occur. If it were set too high then opportunities for economic bypass may be missed and the utility would be subsidized by the departing customer (because they would be paying some of the avoided marginal cost as well as the price minus cost). If the access charge were set too low, and the utility had rate flexibility, then it could contribute toward dynamic efficiency since it may force the utility to reduce its costs to the market price (if its costs, however, were above the market price). This outcome would be incidental, however, and more importantly, overall dynamic efficiency would be prevented since the departing customer would not pay the marginal cost at any positive level of access charge.

This approach would appear to be consistent with the honoring the quid pro quo of the existing regulatory compact, because it places the burden of cost recovery on the customer that is leaving the host utility and does not necessarily (by itself) lead to cost shifting to other remaining customers. As noted, above the principal implementation difficulties with this approach are that if the access charge is tied directly to continued transmission service, the recovery mechanism would be jurisdictional to the FERC, not to states.

This approach is the basis for one component of the FERC NOPR. This aspect of the FERC NOPR is discussed in detail below in Part V.

3. Exit Fees Charged to Customers, Unrelated to Costs Incurred on Behalf of the Customer

Here the exit fees would be charged to customers and the fee would be set unrelated to the costs incurred on behalf of that customer. Such exit fees can be charged to customers through lump sum, a stream of revenues, or amortizing ECEMP costs. This option is not directly related to the costs (past or future) of serving that particular customer. The distinguishing characteristic from the transmission or distribution access charge discussed above is that the exit fee here is not tied to the provision of any service by the utility seeking to recover the costs.

The efficiency affects of this option are similar to the previous option. It has been suggested that the way an exit fee of this type should be calculated it as the difference between the utilities embedded cost price and its marginal cost. If done in this manner then, by definition, static efficiency is achieved. Again, as with the previous option, this method does not encourage dynamic efficiency since prices are held above marginal cost and the utility is not encouraged to lower its costs.

This approach could be attractive to state commissions because requiring exit fee is within the jurisdiction of the commission. However, exit fees are problematic. If set too high, the exit fee can create a barrier to entry in the generation market for competitors of the utility. There is an implementation problem as well. While the price is easily determined, it is exceeding difficult to calculated marginal costs, and therefore relatively easy to set price too high or low, resulting even static efficiency not be reached.

Exit fees that are set unrelated to the cost incurred on behalf of the customer may violate the quid pro quo of the historic regulatory bargain, which would have each customer pay an exit fee that is related only to the costs historically incurred on behalf of the customer. Risk sharing, however, may provide an approach that has some precedent from plant cancellations.

4. Exit Fees Charged to Customers, Calculated to Recover Costs Incurred on Behalf of the Customer

Another method of recovering ECEMP costs, closely related to the one just described, is to set an exit fee, but charged to the customer based on the cost of serving that particular customer. For example, one could set an exit fee for a particular customer based on the stranded cost of serving that customer (fixed generation costs plus applicable distribution and transmission costs).

Such a stream of revenues approach is essentially a "top down" pricing approach, which is the approach many commissions used for state gas transportation programs. Although a familiar approach, it too may provide significant barriers of entry, by effectively tying the cost of historical generation to customers who shop for alternatives. While other similar approaches might be taken to adjust the amount of capital recovery the utility can recover; they require an administratively determined figure on how great are the ECEMP costs.

For these cost fees, static efficiency would be reduced if the capital component is large enough to prevent bypass that, on a marginal cost basis, would be efficient. In addition, dynamic efficiency would be reduced since the utility would have little incentive to reduce its costs when it is in effect being compensated for existing generating plant.

Unlike the previous device, having exit fees charged to exiting customers set at the cost of serving that customer would be consistent with the regulatory quid pro quo. Also, implementation may be simpler than the previous device since it would involve techniques similar to those commissions now use.

5. Exit Fees Set at a Share of the Net Generation Savings Realized by the Exiting Customer Over Time

There is a subtle difference in approach between this exit fee and the previous two just discussed. With the previously discussed exit fees, the incentives that buyers may have to enter the market and engage in efficient transactions may be lessened or removed. With the net generation savings approach, only a percentage of the generation savings would be collected for ECEMP costs so that efficient transactions would be encouraged. Thus, the difference in this approach is that it actually collects ECEMP from the benefits generated from the competitive market. (The costs are only nominally on the exiting buyer who shares the benefit of the net generation savings that it realizes with the host utility.)

It might also be argued that, like other exit fee approaches, this approach reduces dynamic efficiency because it provides the utility with less incentive to cut its own costs to be competitive. However, because the utility gets a percentage of the net generation savings, the utility still has an incentive to produce net generation savings by becoming more efficient by cutting costs. If designed properly this approach, when combined with other devices (price caps and/or performance-based incentives) can be part of a more dynamic efficient solution to collecting ECEMP costs. A similar approach is discussed below under the price cap option. This approach would provide a percentage of the net generation savings realized by the exiting customer and would go toward offsetting ECEMP costs. This would match the burden of ECEMP costs with those who benefit from exiting. It also does not discourage any otherwise efficient transactions as an exit fee that is set too high. The generation savings are net of transmission costs so that no otherwise efficient transaction is foreclosed by collecting a percentage of the net savings, making it possible to achieve static efficiency as well.

This approach could be considered consistent with recovering historic ECEMP incurred under the existing quid pro quo if the recovery mechanism were used to collect a calculated historic ECEMP over an undetermined period of time. While it does not directly burden the customer that is leaving the host utility and stranding historic costs, it does take a share of the benefits that a customer receives from the competitive market to pay off those costs so that they will not be shifted to the remaining customers.

The approach is hard to implement because it may require FERC-state and state-state coordination to provide that the most efficient transactions take place and that ECEMP costs are recovered without foreclosing efficient transactions. Such cooperation would require the use of new federal-state and state-state regulatory institutions.[35] This approach fits well with market structure models that call for a power exchange market to coordinate bilateral, spot, and long-term power arrangements and provide for the development of a competitive market across state lines. Further, to implement this approach, it might be necessary for a state commission to have the exiting customer file a copy of its new power purchase agreement with that commission so that the commission would have the confidential information necessary to calculate and collect a share of the net generation savings.

[35] See the discussion of regulatory alliances in Robert E. Burns and Mark Eifert, A Cooperative Approach Toward Resolving Transmission Jurisdictional Disputes (Columbus, OH: The National Regulatory Research Institute, 1994).

6. Exit Fee Example: California PUC's Proposed Competition Transition Charge

The California Public Utilities Commission's orders instituting rulemaking and investigation[36] proposed a "competition transition charge" (CTC). The CTC is intended to prevent uneconomic bypass, while ensuring recovery of ECEMP left unrecovered by economic bypass. This charge would be assessed as part of the demand charge for direct access consumers. Under the proposal, a utility is at risk only for those revenues tied to the "economic" portion of the utility's generating assets and any overhead tied to the delivery of generation services. The "uneconomic" portion of the utility's generating assets are not at risk.

To determine economic and uneconomic costs, the CPUC proposes using the utility's system marginal cost of generation to determine the market value of each utility plant (using the utility's system marginal cost of generation as a proxy for the market price of electricity). Plants whose marginal cost fall below the system marginal cost will have a positive market value; those whose marginal cost exceeds the system's will have negative market value. If the net difference between the utility's stock of economic and uneconomic assets is positive, then there would be a gain distributed between consumers and shareholders. If the net difference is negative, the losses would be reflected in the CTC assessed to each customer's demand charge. This assessment may include the cost of funding utility programs (for example, low-income consumer programs) that competing nonutility providers are not subject to.

To the extent that the CTC reflects the difference between the utility's price and its marginal cost, then only economic bypass will occur (statically efficient). As with an exit fee, dynamic efficiency is not achieved since the utility is fully compensated through the CTC for uneconomic assets. Although the CPUC proposal does not say so, benchmarks other than

[36] California Public Utilities Commission, Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, R.94-04-031 and Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, I.94-04-032, April 20, 1994.

system marginal cost are possible. These might include regional marginal costs. If the benchmark is lower than the utility's system marginal cost, less of the utility's assets would be considered economic and more dynamic efficiency would be obtained. This is because the benchmark is no longer tied to the utility's cost, but an external measure of efficiency. If the benchmark, is higher than the utility's system marginal cost, more of the utility's assets would be considered economic and the utility would be rewarded for its relative efficiency.

C. Non-Transaction Related Recovery Devices

Non-transaction related recovery devices focus on sources of funds rather than particular transactions. Although the parties to a transaction might be included in the universe of payors, the transaction itself would not be the basis for the payment. The groups of payors include ratepayers of the utility and broader bases. We discuss each in turn.

1. Ratepayers of the Utility

a. Introduction: Recovering Costs from Customers of a Monopoly Service

Typically, if a state public service commission does not have an existing policy on ECEMP recovery, those costs that are left unrecovered when customers leave the system will create an issue in the utility's next rate case: should the costs be absorbed by other ratepayers or by shareholders? Under the Financial Accounting Standards, the utility would have to take a financial write-off of the ECEMP if rate recovery of an ECEMP component was not probable.[37]

This section discusses the effects of recovering the amount from the remaining ratepayers. In terms of static efficiency, the effect could be to increase the potential for uneconomic bypass, by widening the spread between the utility's price and its marginal cost or market price. As noted in our discussion of when the utility is fully compensated for the ECEMP costs, there is little incentive to reduce costs, thereby decreasing dynamic efficiency. This effect diminishes as ECEMP costs are phased out over time.

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[37] Recall that financial write-downs have been discussed earlier in Part II.D. on devices available where utility shareholders must absorb ECEMP. The Financial Accounting Standards Board sets out Financial Accounting Standards that play a key role in establishing the Generally Accepted Accounting Principles (GAAP) that all financial accounting must meet. The objective of FAS is to establish the standards fairly and accurately to report the financial condition of firms.

Allowing remaining customers to pay for the ECEMP costs left unrecovered from an exiting customer is not consistent with the regulatory quid pro quo. If regulators allow ECEMP costs to be recovered from remaining customers, the remaining customers will bear more costs not incurred on their behalf. As shown in the figure below, this approach could cause a shift to a capital cost recovery pattern that favors those customers with the most alternatives (typically large industrial customers). If the utility provides discounts to keep those with alternatives on the system, capital costs recovery would tend to mimic that found under Ramsey pricing, with each customer class paying capital cost in inverse portion to their elasticity of demand.[38] The result is a new set of cross subsidies that are inconsistent with cost causation principles under the regulatory compact.

Although on its face, recovering costs from the remaining customers of the monopoly service is easy to implement, (in the sense that it is relatively easy to write the commission order) even those captive customers who appear to lack alternatives respond to price by conservation and switching from electric to gas or propane or heating oil for heating, or banding together and shopping elsewhere (municipalization). Thus, shifting the recovery of ECEMP costs to remaining customers may be a strategy that is in the long run self-defeating as it encourages more and more customers to find alternatives to expensive power. It is a solution which may perpetuate the problem.

b. Charging Ratepayers Above-Cost Prices Where Market Prices Exceed Embedded-Cost Rates

Traditional rates are based on embedded cost of the underlying asset, as stated on the utility's books. This value usually diverges from market value. A possible change would be to permit higher earnings on assets whose market value exceeds the book value. Transmission assets are an example, but would require FERC action. A related possibility is Alfred Kahn's

[38] See Frank P. Ramsey, "A Contribution to the Theory of Taxation," Economic Journal (March 1927): 47-61. For an explanation of how Ramsey pricing relates to public utility regulation, see James C. Bonbright et al., Principles of Public Utility Regulation 2nd ed. (Arlington, VA: Public Utilities Reports, 1988); and J. Stephen Henderson and Robert E. Burns, An Economic and Legal Analysis of Undue Price Discrimination (Columbus, OH: The National Regulatory Research Institute, 1989).

figure here

suggestion of price caps beginning with a rate freeze at current rates.[39] The utilities then would use any profit to write-down assets that have a book value above market.

It would be consistent with regulatory economic theory to allow utilities to charge marginal cost for the use of assets that have a book value and embedded cost rates *below* market prices. This would then be both statically and dynamically efficient to allow marginal cost pricing for these assets. Moreover, for ECEMP costs, the utility would be able to make up some of the difference between embedded cost rates above market prices. This also would be statically and dynamically efficient. However, it would be unlikely that the assets above market prices and those below would be equal. Therefore, other methods would have to supplement this policy if the ECEMP cost recovery was deemed insufficient.

If there is a surplus, part of the gain could go to ratepayers. The commission should consider allowing the utility to retain some of the gain to allow some dynamic efficiency. This would also be consistent with the development of a competitive market since prices would more closely approximate marginal cost. The utility would have an incentive to reduce its costs.

Some might argue that this recovery method would tend not to be consistent with the current historic quid pro quo because it would recover uneconomic costs from remaining customers at a level other than those available under traditional cost-based rates, however, if the market value is greater than book value then recovering costs based on current market value may more truly reflect cost based rates than rates based on historical costs.

Because, as noted, this approach would require FERC action and involves a novel way of pricing transmission assets, it would require state-federal cooperation and be difficult to implement.[40]

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[39] Alfred E. Kahn, "Can Regulation and Competition Coexist? Solutions to the ECEMP cost Problem and Other Conundra," The Electricity Journal Vol. 7 No. 8 (October 1994): 23-35.

[40] This approach has some resemblance to the concept of selling transmission assets at a "market price" and using the proceeds to defray ECEMP. This concept is discussed in part C below.

c. Accelerated and Decelerated Depreciation

One alternative method of ECEMP cost recovery that has been suggested and used in at least one state is to simultaneously accelerate the depreciation rate of generation plant with ECEMP while decelerating the depreciation rate of transmission and distribution plant that may have embedded costs below marginal costs. This approach would have the effect of allowing a utility to recover ECEMP costs for otherwise uneconomic plant by accelerating depreciation recovery for the plant, without raising rates, because the depreciation rate on other plant is being extended. This has the same effect as if the utility were to refinance its otherwise uneconomic generation plant using its other assets. When the other assets are transmission assets, this indirectly amounts to added costs on future transmission service to recover at least a portion of uneconomic generation cost.

The California PUC recently addressed the question of allocation of cost due to uneconomic investments. In D.9405068 the CPUC granted a request from Southern California Edison (SCE) to accelerate the recovery of SCE's investment in the San Onofre Nuclear Plant. Although the acceleration was relatively minor (recovery would be moved forward by two years), the basis of SCE's argument was that the imminent move to a more competitive market for electricity meant that generation sources such as nuclear plants would likely be less competitive in the future. Although the utility stopped short of claiming that costs due to uneconomic assets should be recovered from ratepayers, it did contend that the acceleration of costs now would give the Commission additional flexibility in ratemaking when it tackled the question of the emerging competitive market. In response to complaints that such flexibility would come at the cost of increased rates for current ratepayers, SCE modified the proposal to include deferred depreciation for transmission and distribution assets. In other words, the utility proposed (and the Commission approved) a two-fold approach: accelerated depreciation to provide recovery today for generation assets that pose a risk of becoming "stranded," (embedded cost exceeding market prices) while stretching recovery of costs for the transmission and distribution assets which are assumed to remain monopoly services in a future market.

Some might actually seek or suggest to accelerate depreciation without offsetting deceleration in transmission and distribution or some other asset. Such an approach would increase rates by increasing the general depreciation expense. If the utility already had rates based on ECEMP costs, then increasing those rates will merely exacerbate the problem of uneconomic rates, invite in competitors or cause buyers with alternatives to accelerate efforts to seek out those alternatives. Accelerated depreciation, therefore, without offsetting mechanisms to keep rates from increases may actually make the situation worse for a utility with ECEMP. For such utilities, rates based solely on accelerated depreciation lead to a race against time to recover capital costs before competition becomes a reality.

This method would not contribute to either static or <u>dynamic efficiency</u>. <u>Static efficiency</u> would not be met since uneconomic bypass still may occur and may, if rates increase, lead to more bypass in the future. Dynamic efficiency would not be increased since the utility would recover its ECEMP costs, and utilities would have little incentive to reduce their costs to market prices. Also, this method would not be consistent with the development of a competitive market, for the same reason noted above where remaining ratepayers are required to incur ECEMP costs. If the decision is rate-neutral with offsetting accelerated and decelerated depreciation, then the same effect would occur; the utility would become less competitive over time, but in a less significant manner.

It can be argued that so long as this recovery method does not increase rates for customers that it is consistent with the <u>quid</u> <u>pro</u> <u>quo</u> of the regulatory bargain. However, as noted below, some versions of this proposal would increase rates. In those cases, burdening customers with accelerated depreciation could be argued to violate the regulatory bargain because it requires customers to pay more than their just and reasonable rates.

One implementation problem with this approach is that the accounting may result in depreciation problems no longer matching the estimated useful life of the plant, potentially in violation of GAAP. Cost recovery of capital in competitive markets does not necessarily follow the depreciation patterns set by accounting rules. (If there is capital recovery over the depreciation sale, there is a profit; if the capital cost recovery is less than depreciation, there is a loss.) But, for regulated rates, it is expected that there is cost recovery of depreciation in sales. For a utility to actually recover its ECEMP from accelerated depreciation (even if offset by decelerated depreciation), a utility must have assurances that it does not have competition for the period of the capital cost recovery. Thus, although this method would appear to be well within the jurisdiction of state regulation to implement, it may require that the utility be able to maintain its exclusive retail function to recover its costs. There are two methods by which the utility can do so: first, by becoming more efficient and cutting costs so that competition cannot compete; or second, by finding ways of forestalling competition. Without other mechanisms in place, the former may be unlikely. Forestalling competition would be unfortunate.

d. Price Cap or Performance Based Rates

Using price caps and/or PBR mechanisms to recover ECEMP means that the utility's ability to recover ECEMP depends on its own increased efficiency. In the case of price caps, prices are first set in a traditional cost-of-service way. The utility is allowed to keep all or a share of the revenues that it gets from cost-cutting efficiencies that bring its cost of service below the price cap. There is a periodic readjustment of the price cap for inflation, or other factors such as industry-wide increased productivity. This "x" factor is subtracted from the inflation factor (CPI - x, for example) to determine the price change for the given period. Some states also include a "z" factor to allow the utility to shift to ratepayers the risk of unexpected cost increases beyond the control of the utility.

Performance-based incentive rate mechanisms are associated with the utility's performance either with a particular operation, such as a power plant's heat rate or capacity factor, or with its overall performance against indices or similarly-situated utilities. The utility is rewarded or penalized to the extent that the utility can out preform a predetermined benchmark(s).

These mechanisms do not shift costs. They are particularly attractive because they prevent cost shifting to captive customers. Indeed, an efficiency premium or revenue cost sharing mechanism might allow for lower rates for even captive customer classes.

The incentives provided the utility to reduce costs (and use their resources efficiently) are better with these methods than an exit fee. Under these methods there is a new, future quid pro quo to the utility which is consistent with ratepayer interest and similar to what competitive nonregulated firms face (which are not there with an exit fee). That is, the utility assumes the risk of a downside loss, but can capture a larger portion of the gain if it is able to reduce its cost and retain or increase its number of customers. As a result, the efficiency and competitive effects would be similar to the rate freeze discussed above. This new mechanism would allow the utility to recover costs that are "stranded" from customers not fulfilling their obligation under traditional regulation, form efficiency gains that result form the quid pro quo.

This implementation of price caps and/or PBRs are already within the jurisdiction of some state commissions. Although these pricing mechanisms differ from traditional cost-based regulatory methods with periodic rate cases, price caps, or PBRs might provide a useful regulatory approach that provides state commissions with the means to provide its jurisdictional utilities with an incentive to cut costs; and by cutting costs, the utility will be able to recover a portion of its ECEMP from its own increased efficiency. This makes the use of a price cap or a well-designed PBR a very procompetitive, efficient approach that can allow a utility to recover its ECEMP while becoming more competitive.

e. Price Cap Example: New York DPS Staff Proposal

An example of this approach is the one proposed by the staff of the New York Public Service Commission. In the proposal, an transition/indexing approach would allow the recovery of a declining portion of "transition" costs for Niagara Mohawk Power Corporation (NMPC).[41] This mechanism would work within a price cap or indexed proposal.

The staff proposed unbundling NMPC's prices into two main components: transmission, distribution and customer cost (TDC) and generation (GEN). GEN would be further divided into a market price component (MAR) and a transition cost component (TRANS). MAR would be determined each year based on market price (or marginal cost) for generation. TRANS would be GEN minus MAR. To determine NMPC price cap, two calculations would be made each year to create two streams of prices. First, one stream of prices would reflect an indexed price based on the 1995 price calculated in a traditional cost-of-service manner. The second stream, competitive prices, would be the sum of TDC and MAR (the uncompetitive portion, transmission, distribution, and customer costs, plus market prices for generation). The difference between the two streams would be TRANS. A portion

[41] New York Public Service Commission, In the Matter of Cases 94-E-0098, 94-E-0099, and 94-G-0100 (Niagara Mohawk Power Corporation), Prepared Staff Testimony, August 1994.

of TRANS would be added back to the TDC and MAR stream to create a third stream of transition price up to which NMPC is allowed to set prices. A decreasing percentage of TRANS would be included in the NMPC's rates and phased out over ten years. NMPC's average overall price cap for each year would be TDC plus MAR plus 90% of TRANS in 1996, 80% of TRANS in 1997, 70% in 1998, and 60% in 1999 and so on.

This proposal takes into account the obligation to past cost recovery but also recognizes that it may not necessarily be into perpetuity. The fact that the utility is not fully compensated for all ECEMP costs enhances the dynamic efficiency affect of the price cap. Static efficiency is eventually increased since the utility's rate will depend, in part, on the market price. Since there is still an embedded cost component that can cause a difference between the utility's rate and the market price, it will not be perfect.

2. Broader Bases

The rationale for recovery from a broader base than the parties to the transaction is that everyone benefits from a smooth transition to a competitive marketplace and that therefore everyone should pay. Also, there is a simple political point: the broader the base, the less the effect on a particular interest group; also, the less the distortion to prospective prices. Further, we are talking about enforcing the rule of symmetry to past costs which everyone benefitted from. It would be inconsistent with cost-based ratemaking for someone (leaving the system) to pay past costs less than once while making someone else without choices to pay past costs more than once.

In general, efficiency affects are not as pronounced as the other methods discussed above. The effect is spread out, by definition, among a broader group so the distorting effect on prices is smaller the larger the group sharing the burden. If the utility is able to recover ECEMP costs through a tax, for example, then it may assist the utility in becoming more competitive by lowering its costs relative to its competition.

It is difficult to assess the dynamic efficiency affects in isolation. Dynamic efficiency, as with other options, would depend on other regulatory actions of the commission. For example, if the commission instituted a price cap while the utility was allowed to recover ECEMP costs, then dynamic efficiency would improve. But this not from the recovery method itself. As with other options to recover ECEMP costs, if the utility is fully compensated, the incentive to reduce costs to market prices is diminished.

Static efficiency may increase if the embedded cost of the utility is reduced. The difference between the utility's embedded cost and the utility's marginal cost would decrease. This effect does not preclude some uneconomic bypass, however, if there remains a significant difference between the utility's rates and market prices.

a. Entrance Fees Charged to New Generation

One mechanism to collect ECEMP costs from a broader base is to have an entrance fee charged to new generators. The idea here is that the new generators benefit from the more open and competitive markets and should contribute to paying the transition costs of existing generators. All sellers of new generation, whether utility, nonutility or self-generation could be covered. But a major question would be who would collect the entrance fee and how would it be collected. If the transmission-owning utility were to collect it, that would amount to leveraging market power. The same problem exists for distribution-owning utilities. Further, those collecting fees would not necessarily be those with ECEMP. Without new enabling legislation, collection of such fees would appear to be beyond the jurisdiction of the FERC or state commission.

Use of fees to raise the costs of competitors in the market (although distinguishable from Cajun, where Entergy sought to collect such fees from the buyer) suffers from the same malady that it attempts to recover the utility's ECEMP costs by tying the recovery of these costs to a monopoly service, transmission and/or distribution.

It would be difficult to argue in favor of customer fees charged to service contracts. First, new sellers in the market are not a part of the existing regulatory compact and therefore they are not subject to the "quid pro quo" responsibilities that might flow from the regulatory compact. Therefore, there is no existing legal theory that can be used to have these utilities bear the costs of transmission from traditional cost of service regulation to a competitive market. Further, this approach is clearly anticompetitive and inconsistent with the development of more open, competitive, and efficient power markets. This approach would raise direct barriers to entry to the new power generators that would be the utility's competitors.

b. All Sellers (by kWh)

Another cost recovery mechanism is to provide that all sellers pay a per kilowatthour tax on generation. This would mean that everyone who sells power would pay the tax that would compensate existing utilities for ECEMP.

This option would spread the ECEMP costs out among all sellers. As a result, static efficiency would increase since the alternative suppliers would also have their prices raised. Again, dynamic efficiency is not addressed directly by this method and would depend on other regulatory actions.

This mechanism would be consistent with the current regulatory quid pro quo in that it would provide for cost recovery of obligations undertaken under the current regulatory compact, without cost shifting to current customers.

The implementation problem here would be that it would require legislation to implement such a tax.

c. Taxes

Some have argued that ECEMP costs should be collected from taxpayers. Taxpayers are the broadest possible base for the collection of ECEMP costs. Also, arguments are made that the major source of ECEMP costs are unmarketable nuclear power plants, which the Atomic Energy and Nuclear Regulatory Commissions actively encouraged as a part of federal policy intended to benefit the nation. It is argued then that because many ECEMP costs (particularly those incurred as a result of nuclear plants) are the result of an active federal policy encouraging nuclear power, that the costs should be collected from the federal budget, and collected by means of a tax. If the tax were an excise tax or usage tax on electricity usage on a per kilowatthour basis, such a tax should not distort the development of competitive wholesale electric markets. However, that might discourage the consumption of otherwise economical sources of power.

The use of taxes to recover ECEMP can be argued to be consistent with the underlying quid pro quo of the regulatory bargain because it does not disturb the underlying bargain and does not shift costs to the remaining customers.

Implementation of such an approach might be difficult because it would require an unlikely cooperation among disparate interests to enact legislation.

i. Tax Credits for Financial Write-Downs

One item related to, but different from, direct taxes is a draft proposal prepared by the Ohio Consumers Counsel and United States Representative Marcy Kaptur. The proposal would provide a tax credit for a portion of uneconomic investments in utility plant and equipment written off after the enactment of EPAct, with the goal of encouraging utilities to take such financial write-offs of uneconomical plant so as to make the firms financially sound and competitive in the long run, while broadly sharing the burden of the transaction costs necessary to make a transition to competition.

According to the draft proposal, the tax credit would be available only upon several conditions.

1. the utilities receiving the tax credit would have to write-off the proportion of all plant whose total costs per kilowatthour averaged over the reasonable life of the investment exceeds a competitively derived price.
2. the utility would have to lower its rates for all classes of service to competitively desired prices.
3. the implementation necessary for the tax credit must be customer class neutral.
4. utility holding companies and their affiliates would not be permitted to invest in foreign utilities, other diversified businesses, or EWGs to avoid creating new financial risk.
5. the company must implement a revised (integrated) resource plan based on the newly changed circumstances.
6. the utility would have to implement all cost effective DSM based on the new competitive price.

The proponents of this draft proposal hope that it could provide utilities with the means of lowering their rates, while simultaneously providing economic development and spreading from the lower utility rate to help offset any Treasury revenue loss (with arguably, less of a negative Treasury revenue effect than allowing financial write-offs to merely happen). The proponents also hope to provide DSM, IRP, and protect retail customers from cost shifting, all laudable social goals.

Here too, offsetting ECEMP from a broader base such as tax credits and write-downs is consistent with the quid pro quo of the regulatory bargain.

Because this recovery method is couched in terms of a tax credit that is meant to avoid the full consequences of tax write-offs, even though it requires legislation, it might be a more viable legislative option.

ii. Maine legislation: trust fund to finance NUG contract buy-out

The Maine legislature established a $100 million trust fund to finance buy-outs and price reductions in utility contracts with nonutility generators.[42] The trust fund allows utilities to renegotiate contract terms with nonutility generators who, at the time the bill passed, were purchasing power at 7 to 12 cents/kWh. In June of 1994, Central Maine Power reached an agreement to pay $78 million to buy out a contract of a 33 MW wood-fired plant and intended to finance the buy-out by applying for a low-cost loan from the trust fund.[43] The Maine Public Utilities Commission approved both the request for the buy-out of the contract and the loan.[44]

3. Sell Transmission Assets at Market Price and Devote Proceeds to Retirement of ECEMP

Some have proposed addressing ECEMP by authorizing the utility to sell its transmission assets on the market and using the proceeds to defray the cost of shareholder absorption of ECEMP. This proposal makes at least three fundamental errors:

1. Because transmission is a monopoly, it should not have a "market value" exceeding its cost: The assumption that there will be gain from this is fundamentally at odds with the manner in which regulators should set rates for a monopoly asset. The buyer of the transmission asset will be selling transmission at FERC-set rates. FERC has made clear that where transmission is a monopoly asset, it will set prices based on cost. Any other approach authorizes monopoly rent

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[42] "Maine Enacts Financing Bill Aimed at Helping Buy Out NUG Contracts," Industrial Energy Bulletin, Mc Graw-Hill, Inc., May 6, 1994, 13.

[43] "CMP to Buy Out Hydra-Co/U.S. Energy Pact and Take Title to 33-MW Plant," Independent Power Report, McGraw-Hill, Inc., June 17, 1994, 1.

[44] Sharon Reishus, Maine Public Utilities Commission, personal communication, November 1, 1994.

for the transmission owner, a result which leads to inefficiency and is inconsistent with the very reason for regulation.[45]

If the FERC-set transmission rates are based on cost (which is the correct approach for a monopoly asset), then the market value of the transmission asset is no more than the net present value of the future stream of revenues, where those revenues are based on cost. Under these assumptions, it is unlikely that there will be much gain from this sale. Put another way, it is unlikely that FERC will accept, as the cost basis for the transmission price, a figure representing the "bid-up" price for an asset valued by the market under assumptions which are inconsistent with what FERC otherwise would do.[46] There is a strong argument that the sale of the transmission asset at "market" is inconsistent with the transmission pricing provisions of new Section 211 of the Federal Power Act, which requires transmission prices to be based on cost.

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[45] There is a debate, and decisions, on whether the embedded cost should be average embedded cost or marginal cost. But the basis for the FERC-set transmission rates is cost, and the argument in the text does not depend on whether the cost-based transmission price is an average embedded cost price or a marginal cost price.

[46] In Minnesota Power & Light Co. and Northern States Power Co., 43 FERC para. 61,103 (1988), the FERC discussed the treatment of the acquisition premium by the FERC Uniform System of Accounts. Where the acquisition cost exceeds the original cost, the utility is to debit the difference to an acquisition adjustment account. The Commission adopted this accounting policy in response to "widespread abuses in the electric utility industry." Id. at p.61,342. Before adoption of the rule, a utility would inflate the price of its properties and sell them to another utility at a large profit. The buying utility then would include the inflated price in its rate base. As a result, "ratepayers paid higher rates for electric service but received no increase in benefits." Id.

The FERC has permitted inclusion of an acquisition premium in rates, however, under certain circumstances. See, e.g., Gulf Energy & Development Corp., 4 FERC para. 61,080 at p. 61,173 (1978) (requiring proof that the "excess of acquisition cost over the depreciated original cost produced consumer benefits in the form of reduced rates or improved service"), citing United Gas Pipe Line Company, 25 FPC 26 (1961); Minnesota Power & Light, supra, 43 FERC at p. 61,343 (recovery of premium permissible if utility establishes that the acquisition was "prudent" and provides "demonstrable benefits" to the consumer).

Based on the foregoing, it is unlikely that FERC would approve the sale of the transmission asset on this basis. A utility's sale of transmission assets would require FERC approval under Section 203 of the Federal Power Act. Among other things, FERC must determine whether the sales price is fair. If FERC believes that the sale price assumed that FERC later would set transmission rates on a basis inconsistent with the Federal Power Act and FERC's policies, FERC will not approve the sale.

Who would receive the gain from the sale? Even if it was sensible to sell the transmission asset at "market price," this sale does not indicate who should get the profit. Many utilities, in arguing for particular transmission prices, state the goal of benefiting "native load." This argument, when made consistently with fair competition, is a statement that native load ratepayers have borne the risk of a transmission asset and therefore should be permitted to realize its benefits. They have paid cost when cost exceeded market; therefore, they should receive market when market exceeds cost. Under this argument, they, not the utility's shareholders, are entitled to receive the gain from the sale of the asset. This result provides no assistance to the utility which has ECEMP. In fact, this reasoning exposes the economic reality underlying this proposal: it would force captive ratepayers to pay off the utility's ECEMP. Again, this explanation assumes that it is proper to sell the transmission at a market price, which it is not.

The proposal would be consistent with regulatory theory only if there was a competitive market for transmission service. There is not. If there were a competitive transmission market, the market price would not have monopoly rent useful to pay down ECEMP; the market price would approach marginal cost, leaving smaller amounts of gain for the utility. In any event, the figure would bear no relation to the amount by which the embedded cost of non-transmission assets, owned by the utility that happened to own the transmission assets, exceed market price.

At its bottom, the proposal assumes that the price of a monopoly product should be set at the level that "the market will bear." Interpreting the Federal Power Act, the United States Supreme Court expressly rejected that premise over two decades ago:

> It is certainly true that the same service or commodity may be more valuable to some customers than to others, in terms of the price they are willing to pay for it. An airplane seat may bring greater profit to a passenger flying to California to close a million-dollar business deal than to one flying west for a vacation; as a

> consequence, the former might be willing to pay more for his seat than the latter. But focus on the willingness or ability of the purchaser to pay for a service is the concern of the monopolist, not of a governmental agency charged both with assuring the industry a fair return and with assuring the public reliable and efficient service, at a reasonable price.[47]

2. The proposal assumes that all of ECEMP should be the responsibility of transmission users, whose demand for power may have had nothing to do with the creation of the ECEMP: ECEMP is the embedded cost exceeding market prices. Given the relatively small share of total utility assets represented by transmission, most of ECEMP will be represented by assets created for customers other than the transmission users. At the core of this proposal is a cross-subsidy.

3. The proposal would lead to numerous inconsistent transmission prices: Rather than uniform transmission prices which makes a market work consistently, there would be a patchwork of transmission prices based not on transmission cost of service but on whether the underlying transmission asset had been owned by a utility with a large amount of non-transmission assets with embedded cost exceeding market price.

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[47] Gainesville Utilities Department v. Florida Power Corp., 402 U.S. 515, 528 (1971) (emphasis added).

V. A RETURN TO THE FERC NOPR: THE COMPETITIVE AND JURISDICTIONAL IMPLICATIONS OF RECOVERING ECEMP THROUGH AN ADDER ON THE TRANSMISSION PRICE

A. Introduction

Transmission or distribution service has become a much-discussed possibility for stranded cost recovery. Several reasons have been given. For example:

1. The transmission transaction is the cause of the "stranding." Were it not for transmission the customer could not take advantage of competitive options. By taking advantage of competitive options, the shopping customer leaves the utility's costs unrecovered.

2. Transmission is a monopoly which all customers need. Making transmission a "wires" charge on a product for which there is inelastic demand ensures that no customer escapes his cost responsibility.

3. Stranded investment is a national problem of a national market. Therefore the solution should be imposed nationally. FERC is the national agency and its jurisdiction is over transmission access. Therefore transmission service is the best place to recover all costs. The most prominent example of such a proposal is the FERC NOPR. The NOPR suggests that FERC has exclusive jurisdiction to set rates, terms, and conditions for the transmission of retail electricity in interstate commerce. The NOPR further suggests that if FERC has exclusive jurisdiction over the price of retail electricity, it can use that jurisdiction to order the recovery of "stranded" costs.[48]

This section addresses these aspects of the NOPR from two perspectives: competition and jurisdiction.

B. Competition Considerations

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[48] The NOPR distinguishes "wholesale transmission services" from"retail transmission services." There is a distinction between "transmission of wholesale power" and "transmission of retail power." These terms are more accurate than "wholesale transmission services" and "retail transmission services." Technically, both types of transmission service are <u>retail</u> transmission service in that the buyer of transmission service is the direct consumer of it. "Wholesale transmission service," properly defined, would be transmission service which is purchased by X and then resold by X to Y. That is not what the Commission meant when they use the phrase "wholesale transmission service.

1. The NOPR Question: Is Past Market Power a Justification for ECEMP Recovery?

In describing the causes of "stranded investment," the NOPR states (at 11): "As competition in wholesale power generation has increased, so has the ability of customers to gain access to the transmission services necessary to reach competing suppliers." The statement appears to imply that "stranded investment" will be a result of Congress' 1992 decision to grant transmission access.

This premise is incorrect. A utility's risk that its rates exceed the rates of alternative sellers is independent of the availability of transmission access. That risk requires consistent regulatory treatment. Utility control of transmission simply places the decision of whether, when and how the utility will bear that risk in the hands of the transmission owner rather than the regulator.[49]

There was no bar to transmission access before 1992. To the extent transmission access was not available before 1992, it was not available because of each utility's independent decision to deny it, not because of the absence of Commission decisions to order it.

EPAct changed the extent to which a utility could expect to continue controlling access to bottleneck transmission highways. This expectation was likely to be inconsistent with antitrust principles. To base "stranded investment" recovery on this change in expectation is to credit an expectation premised on behavior that was inefficient and possibly unlawful. It would view, as compensable "costs," generation cost recovery and profit which could be realized only because of control over transmission. That compensation would credit the "tying" which antitrust law forbids. See Gulf States Utilities Co. v. FPC, 411 U.S. (Commission must take antitrust law and policies into account in making its decisions).

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[49] Those denials frequently were based on a utility's decision to place the welfare of its ratepayers and shareholders ahead of the welfare of its competitors. That type of behavior, in a competitive market, can be consistent with economic efficiency. In a monopoly market, the behavior can be inefficient and produce monopoly rents.

The NOPR seems to move in the opposite direction. It will base compensation on whether a utility had a "reasonable expectation of continuing to serve a customer." In determining whether a utility had such a "reasonable expectation," the Commission will take into account (Id. 41) "whether the customer [at the time the cost was incurred] had access to alternative suppliers."

The NOPR does not indicate whether this analysis would distinguish among the reasons why the customer might not have had access to alternative suppliers. If the customer lacked such access because of the utility's anticompetitive refusal to offer transmission service, the utility should not be permitted "stranded cost" recovery for the reasons explained above. The cost incurred by the utility would have been incurred based on the utility's illegitimate expectation that it would continue to be able to exercise monopoly control over the customer.

The NOPR recognizes the anticompetitive problems with using transmission service as a cost recovery device. A provision quoted above bears revisitation. The NOPR states (at 14 n.18):

> "Retail stranded costs may also result from customer "self-help" actions such as customer selfgeneration, or a customer building its own transmission line, or a customer relocating to another utility's service territory. These types of retail stranded costs have long been a fact of life for utilities. This proceeding is not intended to address stranded costs resulting from customer "self-help" actions."

The NOPR thus acknowledges that there have been situations to which the utility's market power could not extend. In those situations, the NOPR implies, the utility will have to bear the cost of stranded investment. Where the utility has a chance at cost recovery is where the utility does have market power: over a customer historically dependent on the utility.

EPAct did create the EWG category, thereby creating the potential for a larger number of competitors to utilities. One could argue that although utilities could control transmission access (and therefore cannot argue "changed expectations), the EWG situation is different. The argument might look like this:

Since 1935, the Public Utility Holding Company Act confined the generation competitors to utilities only. PURPA in 1978 did add QFs, but the number was limited. No one could have anticipated that in 1992, Congress would amend PUHCA to eliminate all restrictions on entry by wholesale generators.

While these sentences seem reasonable, their implication is not. The problem, remember, is ECEMP: embedded costs exceeding market prices. The implication is that because there was no expectation of many new competitors, there was an expectation that embedded costs could remain high. That expectation is not reasonable. Utilities have an obligation to minimize costs whether there is competition or not.

Finally, in determining whether a utility's expectation of continuing to serve a customer was "reasonable," the Commission will take into account "evidence that [the utility's] expectation was based on the actual conduct or course of dealing of the two parties (the utility and its customer)." NOPR at 41-42. This statement seems to invite amendments to the contract where there may be no legal basis for amending the contract. If a contract has a term of 20 years, there is no basis for assuming the parties will continue in Year 21. If by "actual conduct or course of dealing" the Commission means that the customer has given no signs that it will sue the utility under the antitrust laws for failing to provide transmission access, this evidence would not support an award of stranded investment cost recovery for the reasons explained above: it would reward the utility for violating antitrust laws.

Even if there were "conduct or course of dealing" which indicated customer satisfaction and a desire to extent the contract, this evidence should not be used absent an ambiguity in the contract. As the Mobile-Sierra doctrine says, the contract rules.

2. The U.S. Court of Appeals' Cajun Decision

The antitrust issue discussed above arose, somewhat indirectly, in the "Cajun" case. The case was an appeal of a FERC decision approving Entergy's proposal to include, in the price of transmission service, an adder reflecting costs which Entergy had incurred to supply generation for the customer, where the customer was using the Entergy transmission service to buy generation from an alternative seller. The costs which could be included in the adder were not restricted to those identified in the FERC-jurisdictional wholesale contract, but included any which Entergy prudently incurred on the reasonable expectation that the customer would continue to be an Entergy customer.

On July 12, 1994, the United States Court of Appeals for the District of Columbia issued its opinion in Cajun Electric Power Cooperative v. FERC (Case No. 92-1461). The opinion remand the case back to the FERC to conduct further proceedings, due to procedural and substantive errors.

FERC procedural errors: FERC did not conduct an evidentiary hearing on tariffs for market-based wholesale power and an open access transmission service tariff filed by Entergy Services. The FERC had denied the need for any hearing (including a paper hearing) on the grounds that the intervenors objecting to the transmission service tariff had failed to raise any factual issues, but merely policy issues that could be decided without hearing, The FERC held that trial-type hearings need only be conducted if material facts are in dispute that cannot be resolved on the basis of a written record and that the written submission were adequate and there were no issues of fact in dispute. On a motion for rehearing, the intervenors pointed out that FERC regulations do not require evidence to be submitted in interventions and that disputed issues of material fact need only be and had been pleaded. The FERC denied the motion for rehearing finding that the intervenors could have and should have requested more time to submit supplemental comments with evidence, and the FERC concluded that the issues raised by the intervenors were either premature, immaterial, or policy or legal (not factual) issues. Among other issues raised, the intervenors had pleaded disputed issues of material fact in relationship to whether the provisions of the transmission service tariff adequate mitigated Entergy's market power. (Indeed, the Court later found these provisions could increase Entergy's market power.) The Court held that the intervenors had identified several material facts that were in dispute. Specifically, the Court found that the failure to conduct evidentiary hearings was arbitrary and capricious.

To the extent that the Cajun decision is read narrowly as turning on this procedural point, there would be little to learn from the case, other than the FERC must hold evidentiary hearings when there are disputed issues of material fact concerning the impact of an open access transmission tariff on the filing utility's market power. A finding of a lack of market power makes it possible for the FERC to then approve market-based wholesale rates.

Substantive errors: The Court held that transmission service tariff contained an illegal tying arrangement by requiring the transmission customer to reimburse Entergy for the cost of any investment of any investment made in production, transmission, or distribution facilities that are unrecovered as a result of providing transmission service. The recovery of such stranded costs were to be subject to FERC review. The FERC, in its decision below, stated that stranded cost provisions are not unique and that utilities can protect themselves from exposure to such cost by including reasonable cancellation provisions in their wholesale supply contracts. However, Entergy had apparently not included such provisions in its wholesale power supply contracts. Because the newly filed transmission service tariff could exacerbate Entergy's exposure to stranded costs beyond what had been contemplated in its current power supply contracts, the FERC held that it would allow Entergy to recover legitimate and verifiable stranded costs on a case-by-case basis so that Entergy would not be reluctant in offering open access transmission tariffs.

The Court took the FERC to task holding that the transmission service tariff provisions regarding stranded investment constituted an illegal tying arrangement which is the antithesis of competition. The Court then engage in an analysis of the stranded cost provision that showed that the underlying concern of the Court was that such a tying arrangement could be used by Entergy to leverage its monopoly power in one market into another. Specifically, the Court was concerned that Entergy could use its bottleneck monopoly in transmission service to eliminate competition in the market for generation service. Although the FERC had argued that it was permissible to wait for case-by-case requests for stranded cost recovery, the Court disagreed, noting that the issue that must be decided now is whether the stranded investment provision in the transmission service tariff precludes any mitigation of Entergy's market power. Mitigation of market power could be precluded because even if stranded costs are legitimate, verifiable, and accurately determined, the provision could have a chilling, deal-killing effect because of the transactional costs and uncertainties associated with a subsequent determination of stranded costs by the FERC.

Thus, even if recovery of stranded costs were equitable, providing for them in the setting of a transmission service tariff, presents problems. The issue in the case is whether the transmission service tariff with the stranded cost provision mitigates Entergy's market power sufficiently that FERC can find that Entergy's requested market-based rates are reasonable under the Federal Power Act. The Court found FERC's substantive decision in error, because such a determination of mitigation of market power in a necessarily factually laden decision that cannot be made without a hearing.

Some have incorrectly interpreted Cajun to stand for the proposition that recovery of generation costs through the transmission rate violates antitrust principles. Cajun does not say this and neither does antitrust law. If the adder consists of costs which the customer was previously obligated to pay, the transmission adder is being used to hold the customer to its existing bargain. That concept, by itself, is not tying or leveraging.

The problem in Entergy is that the transmission service adder was being used not to recover costs for which the transmission customer was already obligated, but to require the customer to pay costs for which he was not obligated. The customer's contract expired and the customer hoped to find a new seller. In that context, the transmission adder had the effect not of holding the buyer to its existing obligation but to penalize the buyer for entering into a new obligation. The FERC NOPR makes the same error, to the extent the costs in the adder were not part of the contractual quid pro quo.

C. Jurisdictional Considerations

1. Overview of NOPR's Treatment of Retail "Stranded" Costs

The NOPR views the treatment of costs incurred for retail customers to be "primarily" a State matter. NOPR at 52. It then offers two alternatives for how FERC might deal with such costs where a retail customer or group of retail customers leaves their present utility supplier.

Under Alternative 1, if the utility is providing unbundled retail or wholesale transmission service to the departed retail customer, the utility may file at FERC to recover the costs through that transmission rate. This option would be available only if one of three conditions is met:

1. the State is silent on "stranded cost" recovery;
2. there is a "conflict among authorities in a State"; or
3. there is "conflict" among States.

Under Alternative 2, recovery would be unavailable at FERC. The NOPR indicates there could be "exceptions" to this rule, but does not describe them.

2. Who Has Jurisdiction Over Unrecovered Retail Costs?

a. Can FERC Have Any Jurisdiction Over Retail Non-Transmission Costs?

Assuming FERC has authority to set the rate for the "transmission" of retail power, does FERC have authority to include in the retail "transmission" rate costs associated with capacity formerly used to provide electricity at retail? The NOPR answers (at 51):

> "Because the Commission has jurisdiction over the rates, terms and conditions of both wholesale and retail transmission service in interstate commerce by public utilities, arguably it may allow retail stranded cost recovery in rates for either wholesale or retail transmission services."

When would the issue arise? The Commission describes a "Scenario 3," in which a retail franchise customer obtains unbundled retail transmission service from its existing power supplier in order to reach a new power supplier. This scenario can occur, according to the NOPR, either through "voluntary unbundled retail transmission services or as a result of a State or local action requiring the existing supplier to provide such retail transmission services." NOPR at 15.

This scenario is completely within the control of the State commission. The costs were incurred because of the utility's state law obligation to provide universal service. The decision to authorize retail access stems either from a state or local action, or the utility's own decision. No event jurisdictional under the Federal Power Act has occurred.

The NOPR does not offer support for its view that the Commission "may allow retail stranded cost recovery in rates for either wholesale or retail transmission services." In opposition to this statement, one might offer two rationales: statutory and policy.

Statutory Rationale: The Problem of Uneconomic Capacity Is Independent of the Existence of a Retail Wheeling Transaction: The triggering event is not the retail wheeling decision, but the underlying economics: embedded costs exceeding market price.

Nothing prevents a State commission from reducing rate base due to excess physical capacity or excess economic capacity, even if the excess is prudent. See Duquesne Power & Light v. Barasch. No one would suggest that FERC has jurisdiction to determine the treatment of the uneconomic capacity in the absence of a retail wheeling proposal. A retail wheeling transaction adds no facts to this equation.

Policy Rationales: Assume the State policy was to disallow excess economic costs, while the FERC policy was to permit recovery of such costs. If jurisdiction over uneconomic capacity as between States and FERC depends on the existence of a retail wheeling transaction, then utilities could "shop" for the FERC forum by inviting the customer to instigate a retail wheeling transaction, since that would shift the cost recovery issue from State to FERC, in order benefit from FERC-ordered recovery, possibly from non-parties to the transaction.

There may be justification for a federal forum when States are in conflict and neutral party is necessary. There two general types of conflicts: (1) Where States use different mathematical formulas to allocate common costs among the jurisdictions; (2) Where a particular State prefers a resource option available to that State only; the use of which results in lower costs (or other benefits) for that State but higher costs for the system as whole, relative to some other alternative.

Of course, there are numerous situations today where both types of conflict arise yet there is no federal resolution. These situations usually involve multistate utilities which do not operating through the holding company form. Examples are UtiliCorp, PEPCO and PacifiCorp. The situation also can arise for any utility, including a single utility, which has both retail customers and wholesale customers. In these situations, facilities used for both sets of customers are subject to the State and FERC jurisdictions. As with separate States, the two jurisdictions can make different allocation judgments; there is no preemption by FERC of the State in that situation.

Conclusion: The Commission (at 52) correctly expresses its preference that states address the issue of retail stranded cost recovery, because the stranding "will occur primarily as a result of state and local decision making regarding retail franchise areas and the creation of new wholesale entities." But the statute does not have room for preferences. A matter is either State-jurisdictional or it is not, regardless of anyone's preference.

b. If There is FERC Jurisdiction, Could it Be Non-Exclusive?

Assuming FERC could have jurisdiction over retail non-transmission cost, could that jurisdiction be nonexclusive? The NOPR suggests the answer is "yes." The NOPR states (at 51):

> While we believe the Commission has the authority to address retail stranded costs through its jurisdiction over the rates, terms and conditions of interstate transmission services used by retail or newly-created wholesale customers, we also believe that the recovery of the costs of transition to competition at the retail level is a matter that should be addressed by state authorities.

We disagree with the implication that jurisdiction could be nonexclusive. The Federal Power Act has a "bright line." Jurisdiction is not voluntary, and it is not overlapping with respect to the same customer costs. If FERC has jurisdiction over these costs that jurisdiction must be exclusive.

The NOPR posits FERC authority to address retail stranded costs, but doesn't state the source of that authority. The NOPR implies that this jurisdiction flows necessarily from FERC's authority to set retail transmission rates.

There is nothing new about the Commission and the state commission simultaneously looking at the same costs, for example, where a wholesale and retail customer both are using the same asset and the costs are allocated between the two jurisdictions, with each jurisdiction arriving at its own decision as to the reasonableness of these costs. But where FERC is determining whether to include retail generation costs in the retail transmission rate, the situation is different. In that situation, there is not a cost being allocated between two jurisdictions. There is instead a past cost, incurred on behalf of the retail customer while it was a retail customer. FERC and the State would be acting on exactly the same cost assigned to the same customer, rather than a particular cost allocated between two customers.

c. Does the Answer Depend on Whether States Have the Authority to Order Retail Transmission Service?

The Commission declined (at p.47 n.53) "to address here whether states have authority to order retail wheeling in interstate commerce." This failure creates a gap in the analysis, because under the preemption doctrine, the jurisdictional outcome may depend on whether States do or do not have that authority.

Assume a utility provides transmission service. Assume FERC then issues a transmission rate decision which does not include a stranded investment adder. The State commission may find this FERC decision unsatisfactory, because it leaves certain costs, incurred by the utility on behalf of the shopping customer, unrecovered. The State might wish to protect the remaining customer from this unrecovered cost, either by assigning it to the shopping customer or to the utility's shareholders.

It appears that the State commission's authority to issue such a decision may depend on whether the utility's decision to offer retail transmission service was voluntary. If the State does not have authority to order retail transmission, then given the EPAct ban on FERC retail wheeling orders, any retail transmission service would result from a utility's voluntary decision.

If the utility action was voluntary, then the State commission could argue that the utility took the risk that its costs might go unrecovered. Under this argument, the State commission could assign those costs to the utility's shareholders. Similarly, since the decision to take the service was the customer's, the State might not be barred from assigning to this voluntary shoppers the unrecovered cost.

In contrast, where the State ordered the utility to offer transmission service, and then FERC issued a stranded investment adder decision unsatisfactory to the state, the result may be different. By ordering the utility to offer a FERC-jurisdictional service, the State may be precluded from saying afterward that it does not like the FERC price.

In both the voluntary and mandatory situations, both the utility and the customer might argue that such State action would interfere with the filed rate, which limits what the utility can recover and what the transmission customer must pay. The State, under this argument, would be adjusting the FERC-set rate by adding to it (in the case of a State-imposed customer shopping charge) or subtracting from it (in the case of assigning the unrecovered costs to the utility shareholders) the unrecovered cost.

The preemption answer may depend on whether the State action is characterized as "setting a transmission rate" or determining the recovery of the cost of retail service." Since by definition the costs are not cost of transmission service but non-transmission cost left unrecovered by a customer decision to shop, the State would seem to have a strong argument that it is not interfering with the FERC-set rate. If there is interference, the State might argue, the interference would occur when FERC considered the issue of whether to include or exclude State-jurisdiction, retail costs in the FERC-jurisdictional retail rates.

d. Can FERC Review the "Adequacy" of State Actions?

i. In General

FERC has a "strong preference" that States act on the quantification and recovery of stranded investment costs incurred for retail customers. NOPR at 54. But, if State action is not "adequate," the FERC may assert jurisdiction and act. Inadequacy could result from (a) State inaction, (b) conflict within a State and (c) State-State conflict.

The NOPR then requests (at 53-54) comments on whether various state-level mechanisms for dealing with the recovery of retail stranded costs are "adequate." This statement implies that the Commission would judge the adequacy of state commission actions.

Never in the history of the Federal Power Act has a FERC made such a suggestion. The FERC is not an appellate court judging State decisions. It is a joint regulator of the industry. The Federal Power Act draws a "bright line" between certain transactions which are state jurisdictional and certain transactions which are FERC jurisdictional. Together they regulate the industry. Where States act to interfere with a FERC-filed rate, the Courts, not FERC, make that determination. Similarly, when FERC enters an area delegated by statute or Constitution to the States, the Courts will invalidate the action. The two levels of government do not judge each other's adequacy.

Similarly, the Commission statement in United Illuminating, 63 FERC para. 61,212 (1994), that FERC might be available to parties who have "exhausted their remedies" at the State level, misconstrues the clear jurisdictional line drawn between state commissions and FERC by the Federal Power Act. The phrase "exhaustion of legal remedies" exposes the problem. "Exhaustion of legal remedies" is an appellate concept; but FERC is not an appellate agency, relative to the State commissions.

Separately there is the question of "Adequate from whose perspective?" As with the case of wholesale unrecovered costs, where the NOPR suggests that some contracts might not be "adequate," the Commission must be clear about which interest it intends to protect, and which interest it is statutorily bound to protect. It does not appear, however, that FERC ever has reviewed the "adequacy" of state commission decisions where the result of inadequacy might be customer harm.

ii. The "Adequacy" Analysis

No clear State expression: The NOPR proposes (at 54-55) that the Commission would entertain requests to recover retail stranded costs where there is no "clear expression by an appropriate state authority that has dealt with the issue." Again, there is no basis for such appellate authority in the Federal Power Act.

Conflict between States: The FERC NOPR describes as a "conflict between states" a situation where State A permits a municipalization, the new municipal obtains transmission service, and leaves stranded costs behind, and State A allocates less than all of the stranded costs to itself; then, State B, the other state in which the utility operates, does not allocate any stranded costs to its retail customers. This situation seems no different from any other cost allocation situation, where two states use different allocation formulas, creating either underrecovery or overrecovery. The only difference here is that FERC might have jurisdiction over retail transmission service. But this is an example of how FERC's assertion over (1) retail transmission service and (2) the inclusion of generation costs as an adder to that retail transmission service can extend FERC authority well beyond its historic and legal boundaries.

The NOPR does not address the mirror image, where the two States in this example allocated costs in the manner that produced overrecovery of the stranded investment costs. Could a retail customer in state A or state B file a complaint at FERC seeking a reduction in retail rates due to this "conflict" between the states? In this situation, FERC would be entertaining requests concerning retail rate recovery. This scenario demonstrates the impossibility of the legal analysis FERC uses to assert its jurisdiction over the retail costs. It also exposes the asymmetry in the Commission's plan, i.e., to use its new "jurisdiction" to approve recovery of stranded costs, but not to deny it. Assuming, as is correct, that the retail customer complaining about inconsistent and overlapping allocation of costs cannot come to FERC, can it go to its state, or will the state be preempted by the FERC decision? What happens if the utility thinks there is conflict-induced underrecovery, and retail customers thing there is conflict-induced overrecovery? Do these various complainants go to different jurisdictions? Again the NOPR does not say.

State silence: The Commission asks whether state silence would justify a FERC role, where, for example, the silence had adverse effects on financial health or reliability. Even limiting FERC intervention to these two areas would have no historical or legal precedent. States frequently take actions which affect financial health. It is commonly argued that the bankruptcy of Public Service of New Hampshire resulted from the New Hampshire Commission's decision to disallow Seabrook costs from rates. There was no FERC intervention, nor is there a statutory basis for it. If the effects of State action or inaction on utility financial health were a basis for FERC jurisdiction, then every State decision disappointing to a utility's investors could be "appealed" to FERC on grounds of "adequacy." The "bright line" would be no line.

State as exclusive decisionmaker: The NOPR does offer a second jurisdictional alternative, where the State would be the exclusive decision maker on the recovery of retail stranded costs. The Commission does request comment on whether "there should be limited exceptions" to this rule. One exception might be where one state has taken an action regarding retail stranded costs which has "adverse consequences for another state." Id. at 55. Another example, according to FERC, would be circumstances "under which a state may not have an adequate mechanism for addressing retail stranded costs, and may want the Commission to provide a forum." As discussed above, there simply is no statutory basis for FERC having jurisdiction where a state which otherwise has jurisdiction does not want to exercise it.

In summary, the concept of "inadequate" State forum does not survive careful analysis. Even if the State commission failed to act, a disappointed party can appeal the failure in State court.[50] If no appeal is available, it is because the State legislature has failed to recognize the problem as deserving legal solution. If that failure is "inadequate," it is an inadequacy of democracy. The FERC, at least not without Congressional authorization, cannot change that result.

e. Can FERC Interpret the Terms of the Utility's Retail Franchise?

The NOPR proposes to have the Commission determine the allocation of retail unrecovered costs according to the terms of the utility franchises. See pp. 56-57.

The NOPR suggests that the Commission would not apply the "reasonable expectation" test to retail stranded costs that it proposes to apply to wholesale stranded costs, since that would involve FERC in reviewing the terms and conditions of utility franchises. Yet the NOPR then offers an interpretation of the franchise obligation, suggesting it was a symmetrical obligation between retail customers and the utility.

Asserting that the franchise obligation was a symmetrical one implies that the utility had a reasonable expectation that no customer would leave. Based on this assumption, the regulations appear to propose assigning all retail stranded costs to the former franchise customer. This

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[50] The disappointed party might be the utility (if it had lost a customer) or a customer (if it wanted an opportunity to escape).

assignment raises several questions. For example:

a. Would FERC's cost assignment be binding on the states, or could the states, if they want, shift these costs to somebody else, or to the utility's shareholders?

b. If the FERC assignment is preemptive of the States, what is the statutory basis for the preemption? Is there a FERC-jurisdictional "filed rate" with which the State has interfered?

3. Who Has Jurisdiction Over Discrimination in the Provision of Retail Transmission Service?

Some utilities have proposed offering retail wheeling to industrial customers but not to residential customers. If FERC has jurisdiction over the rates, terms and conditions of retail transmission service, then the issue of whether such a restriction is unduly discriminatory would be a FERC issue under Section 205 or 206 of the Federal Power Act. But this issue -- who should be a captive customer and who should be permitted to shop -- seems inherently a state commission issue because it affects the exclusivity of the retail franchise. Yet if FERC has exclusive jurisdiction over the rates, terms and conditions of retail service, it would seem difficult to separate this discrimination issue from other issues.

4. Should the Jurisdiction Over ECEMP Vary with the Type of Transactional Event?

A regulatory solution to ECEMP will not be rational if the treatment varies with the transactional event. As discussed in Chapter I.A, the regulatory problem arises from an economic fact: rates exceed the price of alternatives. If rates are higher than alternatives, the regulatory decision whether to address this problem should not depend on

a. whether a customer takes action; or

b. the form of the customer action (such as plant closing, conservation, municipalization, retail shopping or self-generation).

The cost treatment should be based on the dual principles of economic efficiency and regulatory symmetry, as explained in Chapter II.B. There is no justification for answering the efficiency or symmetry questions differently depending on the transactional event.

The FERC NOPR seems to violate this principle, when it states (at 14 n.18):

> "Retail stranded costs may also result from customer "self-help" actions such as customer selfgeneration, or a customer building its own transmission line, or a customer relocating to another utility's service territory. These types of retail stranded costs have long been a fact of life for utilities. This proceeding is not intended to address stranded costs resulting from customer "self-help" actions."

That something has been a "fact of life" does not justify regulatory inconsistency. If the costs should be recovered, they should be recovered. The utility should forego recovery merely because it lacks market power over the buyer.

5. In a Retail Transmission Environment, How Might Costs Be Allocated Between FERC and States?

If costs incurred by a utility for its wholesale customers are rendered unrecoverable from those wholesale customers, they do not necessarily become the responsibility of retail customers. Applying cost causation principles, if the costs were caused by the wholesale customer they are the wholesale customer's responsibility. Put another way, the state's retail ratepayers are not the guarantors of cost recovery for wholesale customers. This reasoning would be particularly appropriate where the utility planned the size of its plant to meet the needs of its wholesale as well as the retail customers. If FERC chooses not to make the wholesale customer pay, that decision does not change the fact of cost causation. There should be no imperative that the State allocate this cost to its retail ratepayers. If the shareholders suffer underrecovery, their remedy is to appeal the FERC decision to the courts. In addition to cost causation, another legal theory for denying state recovery would be prudence: specifically, that the utility was imprudent for negotiating a contract with its wholesale customer that left the wholesale customer free to depart before costs incurred to serve that customer had been fully recovered. To avoid "trapping" the utility's costs, the State commission first would have to find that FERC policies did not preclude the utility from protecting itself from this stranded cost problem. If, for example, FERC would have outlawed a contractual provision necessary to protect itself from early departure of the wholesale customer, the state which disallowed costs on the grounds that the utility should have had such a provision might be guilty of cost-trapping.

Another approach to jurisdictional rationality is not to ask the question of who should regulate what, particularly where the jurisdiction and regulatory approach used might depend on any one, some combination of, or all of the following: the form of the triggering event, on the identity of the customer taking the action, on the regulatory approach or action contemplated, on whether transmission access is necessary for the transaction, and on the timing of the event. The implications of such an approach of determining jurisdiction by one or more of the just mentioned factors, is mechanical, subject to gaming, and allows a choice of forums in situations where the party choosing the forum is doing so for reasons that are not procompetitive in nature. Principles of jurisdictional rationality should apply to all facets of the questions surrounding stranded costs: not only to whether there should be a recovery, but what recovery device as well.

Two recent NRRI reports, Regional Regulation of Public Utilities: Opportunities and Obstacles (1992) and A Cooperative Approach Toward Resolving Transmission Jurisdictional Disputes (1994), proposed a solution to problems of jurisdictional rationality problems when dealing with shared facilities. Namely, the formation of regulatory alliances involves the bringing together of sovereign regulatory entities, each exercising its own jurisdiction, to cooperate and coordinate federal and state regulation over issues such as stranded cost, transmission pricing and access, and overseeing the development of competitive wholesale and retail electricity markets in such a way that the outcomes from such a market are dynamic and efficient. Dynamic and efficient power markets could provide net benefits, a portion of which could be mutually shared in such a manner that the net generation savings that occurs because of increased competition finances the transitional cost of going from regulated to competitive markets. Such an approach could allow the FERC and state commissions to explore cost recovery options for stranded costs that would allow the recovery of such cost in a manner that actually creates an incentive for utilities to be efficient players in the development of such a market. However, for such cooperation to be possible and productive, steps must be taken (immediately) to begin the process of forming regulatory alliances to provide coordination an cooperation between regulatory entities with shared jurisdiction over shared facilities. Otherwise, inconsistent regulatory policies will be developed and opportunities for cooperation and coordination will be lost.

6. Conclusion: The Appropriate Allocation of Responsibility of ECEMP

Jurisdiction Between FERC and States

To allocate regulatory responsibility rationally, one first should define the responsibilities to be allocated. This paper has distinguished two regulatory responsibilities:

1. The determination of whether ECEMP should be recovered by utilities: Responsibility should lie with the jurisdiction which created the legal obligation to incur the costs. Thus:

    a. If the costs were incurred for a retail customer, the State should determine whether the costs should be recovered.

    b. If the costs were incurred for a wholesale customer, FERC should determine whether the costs should be recovered.[51]

2. The determination of what recovery device should be used: If the device affects the efficient operation of markets outside a particular State, jurisdiction should lie with FERC. Otherwise jurisdiction should lie with the State commissions.

The error of the FERC NOPR is to combine these functions. Distilled, the FERC NOPR says:

1. We have jurisdiction over a device: transmission of wholesale and retail power.

2. Because we have jurisdiction over this device, we have jurisdiction over whether costs should be recovered; but, in the case of retail costs, only when the proponent of recovery proposes to use this recovery device. Otherwise we do not have jurisdiction over whether the costs should be recovered.

3. Where costs were incurred for retail customers, we prefer that States handle the problem. But if a State does not handle the problem "adequately," we will have jurisdiction to handle the problem. Thus we have jurisdiction not only over retail costs, but over whether retail costs are handled adequately by the State jurisdictions.

4. A challenge to the "adequacy" of a State action may be brought by a utility complaining of unrecovered costs, but not by a customer complaining of having to

[51] There is a third possible situation: where a cost was incurred by the utility for a retail customer; which then became a wholesale requirements customer of the utility, i.e., continuing to be obligated to the utility for the historic costs incurred on its behalf; and then leaving that utility for another wholesale supplier. In that satiation, the costs left behind were originally retail costs, but the "stranding," if any, occurred when the customer was a wholesale customer. In This scenario, there are two jurisdictions involved: (a) the jurisdiction under which the cost obligation was incurred by the utility, and (b) the jurisdiction with authority over the costs at the time of the "stranding."

pay costs.

The FERC NOPR thus makes the following legal and policy errors:

1. It views FERC and States as having concurrent jurisdiction over the same costs, where the Federal Power Act creates a "bright line."

2. It would displace (or overlap) State courts by making FERC an appellate authority over State decisions.

3. It creates a right of appeal for utilities but not for consumers.

4. It makes recovery of retail costs, at FERC, dependent on the particular recovery device chosen.

FERC has stated that it prefers States to handle the problem. The first alternative of its proposal does not have that effect. If FERC wanted to ensure that States should handle the problem, FERC would state that under no circumstances would costs incurred for retail customers be recoverable at FERC. No utility could recover retail non-transmission costs through a FERC transmission rate. If FERC made this point clear, then all parties would solve the problem at the State level, which is FERC's stated preference.

The easiest approach for FERC is to abide by the Federal Power Act. The FPA authorizes FERC to set the price for wholesale sale of electricity and for the transmission of electricity in interstate commerce. The recovery of costs incurred for retail electric service is not the wholesale sale of electricity or the transmission of electricity in interstate commerce. There is no authority in FERC to address the issue the way it has.

VI. CONCLUSION

HARMONIZING REGULATORY CONSISTENCY, ECONOMIC EFFICIENCY AND JURISDICTIONAL RATIONALITY

This document has explained that the treatment of ECEMP requires two distinct decisions. The first step requires a decision on whether ECEMP should be recovered by the utility. Chapter II explained that the whether question should be answered by reference to the historic quid pro quos, and Chapter III analyzed the FERC's NOPR from that perspective.

The second decision concerns how ECEMP should be recovered, if the regulator answers "yes" to the first question. Chapter IV evaluated 10 recovery devices, using the criteria of economic efficiency, consistency with the quid pro quos and implementation difficulty. Chapter V analyzed the FERC NOPR from that perspective.

The regulatory decision must harmonize the three major themes in this document: regulatory consistency, economic efficiency and jurisdictional rationality. It is the implementation of the recovery where these three themes meet.

Table VI-I displays each of the recovery devices, on a matrix with two variables. The vertical axis displays the concept of regulatory consistency or quid pro quo. The farther down the vertical axis, the closer the device is to satisfying the historical quid pro quo. The horizontal axis displays dynamic efficiency. The further to the right, the higher the dynamic efficiency.[52] Options are placed in an approximate region on the figure, since an exact location is not known with precision. Options that allow utilities full recovery of costs are displayed along the vertical axis. As regulatory consistency improves, dynamic efficiency decreases. As a result, no options are in the lower right-hand corner (high dynamic efficiency and high regulatory consistency).

[52] For purposes of making a regulatory decision, dynamic efficiency is what matters. Chapter IV did discuss static efficiency, for two reasons. First, it is easier to discuss dynamic efficiency by understanding static efficiency, which is more commonly discussed. Second, it is dynamic efficiency that is better for ratepayers. Since this table is restricted to two-dimensions, we have limited the display to dynamic efficiency.

TABLE VI-I

Table VI-I here

In the upper right-hand corner is price cap/performance-based regulation. In is placed here since it provides the maximum incentives to reduce costs, but is not consistent with regulatory quid pro quos. The opposite in the lower left-hand corner are exit fees related to customer costs that have very high regulatory consistency but little dynamic efficiency (note, from the analysis of Chapter IV, this option has high static efficiency). Shifting costs to captive customers, in the upper left-hand corner, is low in both dynamic efficiency and regulatory consistency.

Table VI-I does not display the theme of jurisdictional rationality. Rather, the table helps the regulator select the proper recovery device. Which regulator should do the selecting? As we discussed in Chapter II, the regulator which determines whether ECEMP should be recovered is the regulator which imposed the legal obligation under which the relevant costs were incurred. If the cost was incurred to carry out the utility's retail obligation, the State commission with jurisdiction over that utility's retail rates should decide.

The selection of the recovery device requires a different analysis. The process can begin with the same regulator. If that regulator wishes to use a recovery device which affects only residents of that state, that same regulator should be able to make the selection and execute the device. If the selector is a State commission but the device requires FERC action, FERC should work with the State in the execution. Thus the State commission might choose to have retail wheeling, and want the shopping customer to pay for ECEMP through a retail transmission service adder. This much of the decision should be made by the State, and FERC in establishing the retail transmission rate should defer to the State's preference.

The State might prefer a recovery device such as tax on all the sellers. This result affects players outside the State, assuming the relevant market for sellers extends beyond the State's boundaries. The State could pass a State tax which, if applied fairly to all sellers selling power to the State, regardless of whether the seller is a resident or a non-resident of the State, may pass Commerce Clause muster. But a better approach would be to use a joint state-FERC conference to assess the effects of such a tax on the entire marketplace, and then achieve the same result through FERC-set and State-set rates rather than a tax which might require Congressional or State legislative action.[53]

There likely are numerous other interactions between recovery device and forum that require explanation. For example, if an access charge were tied directly to continued transmission service (as would be necessary to collect an access charge from a large industrial customer), then the collection of that charge would arguably be FERC jurisdictional because it would be related to the collection of a charge related to the prices, terms, and condition of transmission service. Yet, it jurisdictionally rational for state commissions to determine whether and, if so how much, transition costs are collectable because they are "stranded" by a customer leaving the retail market. If a state commission were to decide that the "best" way to collect these costs form a customer were through a transmission access charge, then cooperation and coordination between state and federal policies would be necessary. Such cooperation and coordination might take place on a limited basis or as a part of a broader context, dealing with regulatory oversight of poolcos and regional transmission groups.

Three recovery devices that to some degree promote dynamic efficiency are discussed. Indeed, one such cost recovery device, the collection of stranded costs as a percentage of net generation savings realized through the competitive marketplace could best be implemented if state and federal agencies cooperated in a manner in which their policies on competition were coordinated. To be able to properly cooperate and coordinate policies in a manner that produces regional electricity markets that are dynamically efficient requires state-state and state-federal cooperation and coordination of transmission pricing, access (including retail or direct access), transmission siting, and ECEMP policies, as well as consistent state-federal regulation that assures that electricity markets are operated by independent comptrollers who clear short-term, and long-term transactions by maximizing the value of those transactions on the transmission grid. Without state-federal coordination, an attractive cost recovery option that uses a share of the new money produced by competitive markets to pay of the obligations and transitional costs from the old regulatory compact could not be implemented.

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[53] Burns and Eifert, A Cooperative Approach Toward Resolving Transmission Jurisdictional Disputes, Chapters 2 and 3.

A second cost recovery device that promotes dynamic efficiency, charging above-cost prices where market rates exceed embedded-cost based rates would also require some degree of federal-state cooperation because some, perhaps most, of these assets would likely fall under FERC jurisdiction.

The implementation of a third cost recovery device that promotes dynamic efficiency, that of price cap and performance-based incentive regulation, would also work best if federal-state agency regional regulatory alliances were formed to encourage more open and competitive markets that could produce efficiencies that promote a win-win approach.

The goal must be to have the level of jurisdictional cooperation necessary to achieve this harmonization between regulatory consistency, economic efficiency and jurisdictional rationality. We are unaware of such cooperation today, and none is proposed in the FERC NOPR on Stranded Costs. However, in the FERC Notice of Inquiry on Alternative Power Pooling Institutions Under the Federal Power Act, there is some recognition that institutions can be set up that have the potential to resolve or mitigate the stranded costs from net generation savings and that greater federal-state cooperation and coordination might be necessary for the proper regulatory oversight of new alternative institutions that can make dynamically efficient competitive markets a reality. Such cooperation and coordination must be pursued as a primary vehicle that allows state commissions and the FERC to harmonize regulatory efficiency, economic efficiency, and jurisdictional rationality to solve the "stranded cost" problem in a manner that is consistent with the development of more open and competitive markets.

APPENDIX A

EXPERIENCE FROM THE GAS AND TELECOMMUNICATIONS INDUSTRIES

The Natural Gas Experience[54]

Since the early 1980s, the natural gas industry has addressed the transition costs problem on two different occasions because of industry-restructuring Orders by FERC. The first problem originated from the long-term contracts between pipelines and natural gas producers. These contracts typically contained take-or-pay provisions that specified a minimum payment that must be made to producers, regardless of whether delivery is actually taken.[55] For example, pipelines were not able to take delivery of a substantial amount of gas as a result of an unexpected slow growth and, in some cases, a decline in gas demand. Pipeline take-or-pay liabilities rose dramatically over the early and mid-1980s. FERC estimated potential liabilities at close to $8 billion by the end of 1986. The former chairman of FERC remarked at a 1989 industry conference that pipelines have paid out about $9 billion to renegotiate take-or-pay liability under producer contracts.[56]

FERC Order 380, promulgated in June 1984, accentuated the take-or-pay problem by stimulating the gas spot market. The Order significantly reduced the cost for LDCs of switching commodity gas supplies.[57] By prohibiting recovery of take-or-pay liabilities

[54] This discussion was contributed by Kenneth Costello of NRRI.

[55] It was common for pipelines to contract for new gas reserves that called for "take-or- pay" of 75 percent to 95 percent of deliverable volumes.

[56] Remarks of Chairman Martha Hesse, Institute of Gas Technology Conference, Arlington, Virginia, April 10, 1989.

[57] The Order eliminated the variable cost component of pipeline minimum bills.

through minimum bills, pipelines were denied an important mechanism for mitigating their take-or-pay exposure.[58]

In 1985, FERC responded to the take-or-pay problem, exacerbated by Order 380, by issuing a Statement of Policy that required pipelines to file individual rate cases in order to determine how they can recover their renegotiation costs and how these costs should be allocated among customers. The Statement prohibited these costs from being recovered through the purchased gas adjustment clause. Over the next few years, FERC allowed a portion of these costs to be directly billed through the pipeline's commodity sales rate. Such action was partly nullified by competitive forces that made it extremely difficult for most pipelines to include take-or-pay costs in their commodity rates without losing market share. Consequently, pipelines ultimately agreed to absorb a portion of the take-or-pay costs under the condition that they would be permitted to recover these costs through their demand rates.

In 1987, FERC Order 500 was pivotal in specifying how pipelines could pass on the costs of "buying out" or "buying down" contracts with gas producers. The Order and its companion, Order 500-H, established a transition-cost-recovery (TCR) methodology allowing pipelines to recover between 50 percent and 75 percent of their prudently incurred take-or-pay costs. Most pipelines reached a settlement with their customers that called for a 50/50 split of these costs. LDCs, after litigation by some state commissions and consumers groups, were able to recover almost their entire share of the take-or-pay costs.

The FERC's position in issuing Order 500 was that the burden of take-or-pay costs should be shared among all stakeholders in the industry. The Order, for example, required gas producers to credit against a pipeline's take-or-pay liability for any gas transported for them. The actual amount of credits were small, however, as producers found ways to avoid the granting of such credits.[59]

A third provision of Order 500 allowed pipelines to establish gas inventory charges (GICs)

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[58] FERC felt that minimum bills were anticompetitive because they unduly raised the cost of switching gas suppliers.

[59] Crediting was also restricted to a portion of the contracts signed during 1986 and 1987.

that compensated them for providing customers with gas service on demand. GICs served the dual purpose of avoiding future take-or-pay problems and allowing pipelines to directly bill customers for the costs of providing firm gas-supply service. They function, in effect, as a demand charge for pipelines.

The cumulative take-or-pay costs incurred as of June 3, 1992 was estimated by FERC at around $10 billion.[60] These costs have been absorbed by producers, pipelines, LDCs and their customers, and other pipeline customers. Many producers were willing to absorb large losses in order to market their gas. They felt that litigation would have taken too long to resolve to offset the cost of having their gas shut-in for an extended period. Pipelines have absorbed around $3.6 billion as of June 30, 1992.[61] LDCs have also absorbed large costs but, as noted earlier, have been successful in recovering almost all of these costs from their customers.

The second round of transition costs arose from the issuance of FERC Order 636 in April 1992. These costs are grouped into four categories, gas supply realignment (GSR), unrecovered gas (Account 191), ECEMP costs, and new-facilities costs. FERC has estimated these costs to be as high as $4.5 billion.[62] Pipelines have filed at FERC $1.6 billion in total transition costs as of June 1994.

Under Order 636 pipelines can recover all transition costs that are "prudently incurred" as a result of restructuring. FERC specified that 10 percent of their costs must be recovered for interruptible service.

It should be noted that, unlike the take-or-pay costs policy, FERC allows pipelines to recover all "prudently incurred" costs relating to restructuring. Currently, there still exists some uncertainty over what transition costs filed by pipelines will be considered prudent by FERC.

Lessons for Electric from the Natural Gas Industry

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[60] U.S. Department of Energy, Energy Information Administration, Natural Gas 1994: Issues and Trends (Washington, D.C.: Energy Information Administration, July 1994), 114.

[61] Ibid.

[62] The rise in oil prices has reduced the magnitude of transition costs, as the market price of gas increases as a consequence.

The treatment of transition costs in the natural gas industry provides some useful lessons for the electric power industry. First, large transition costs should not be a defense for slowing down the movement of competition in an industry. The natural gas industry has had to struggle with transition costs for over a decade, and will continue to do so over the next several years, without causing undue delay in the advancement of procompetition regulatory policies.

Second, competition can increase efficiency to offset a portion, and perhaps a large portion, of the cost of write-downs and contract renegotiation. In the natural gas industry, a large portion of take-or-pay liabilities were simply absorbed by the large efficiency gains that resulted from wellhead gas deregulation and open access of the pipeline network. These gains have benefitted all stakeholders including gas producers, pipelines, and retail consumers.[63] There is no reason to believe that the same could not hold for the electric power industry.

Third, a political if not economic solution to the transition-costs problem may require a sharing of these costs among all stakeholders, including electric utilities, core customers, and noncore customers. This was the position taken by FERC in its Order 500 decision. It can be argued that sharing creates a perception of equity that may be absent from other cost allocations. Regulators should acknowledge, however, that certain stakeholders, namely noncore customers, will tolerate only so much responsibility for such costs before they find ways to avoid them through bypass or some other means. Even customers that are currently regarded as core customers may look for other alternatives if transition-costs surcharges become "excessive."

[63] Stakeholders and analysts have questioned whether these benefits could have been more "optimally" distributed.

The Telecommunications Experience[64]

Episodes where the embedded cost of investment could exceed the marginal price that could be extracted for its use have occurred at least three times in the telecommunications industry. The first episode occurred after the Federal Communications Commission deregulated customer premise equipment. The embedded cost of *leased rotary telephone set* and some specialized switching equipment was at risk of being unrecoverable.[65] The second episode occurred when division of assets accompanying the divestiture of American Telephone and Telegraph (AT&T) uncovered essentially obsolete investment whose embedded cost exceeded its marginal price. The third episode occurred when increasing competitive pressures in all sectors of the telecommunications industry tended to accelerate the obsolescence of existing investments.[66] The third episode is still in progress.

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[64] This was contributed by Robert Graniere of NRRI.

[65] The specialized equipment at risk was used to provide CENTREX service. In its most primitive form, CENTREX service is a five-digit dialing plan that connects telephones within a single building, within a university, within a hospital complex, or any other application where five-digit dialing is permissible.

[66] AT&T and other providers of interstate services have made inroads in the area of intraLATA service, which are essentially intrastate long-distance services. For some time after the divestiture of AT&T, intraLATA calls were processed exclusively by local exchange companies. The local exchange companies have been in competition with unregulated enhanced and information service providers for some time. In some respects, the unregulated companies are the more advanced in this area of service. The local exchange company has had to deal with "shared tenant service" providers who provide arbitrage services for business complexes in the downtown or business sections of the community. In fact, shared tenant service providers resell the high volume local exchange services that they purchase form the local exchange company. For approximately ten years, the local exchange companies have had to deal with the competitive pressure that has been created by fiber-optic-loop companies. These unregulated firms lay fiber-optic cable around the community's business area and enter into contracts with business to provide transport services for any type of telecommunications service. These firms would like to extend their services to residential end users. Finally, the local cable companies are poised to compete the local exchange company in the area of residential telecommunications services.

During the first episode, the predominant regulatory responses to the embedded cost problem were: (1) to accelerate the recovery of the undepreciated portions of CPE and CENTREX investment, (2) to use the revenues from the sale of rotary telephone sets to partially offset the cost of undepreciated investment, and 3) to discount the rates for CENTREX services. The regulatory responses were more general during the second episode. Generic dockets on depreciation were opened, and general rate cases were convened. The usual result was an increase in depreciation rates.

The regulatory response to the third episode has been the most general. The terms and conditions of economic regulation have been altered. In particular, the emphasis on cost of service and profits has given way to an emphasis on prices for telecommunications service, thereby leaving costs and profits to take care of themselves. If it is assumed that competitive pressures are strong enough to keep the prices of telecommunications services at reasonable levels, which is the fundamental assumption of price-cap regulation, then the resolution of the embedded cost issue is simple. All of the burden for the recovery of the undepreciated portion of obsolete investment is on the utility's management and stockholders.

Lessons for Electric from the Telecommunications Industry

There are several transferrable lessons that can be learned from the telecommunications experience. First, regulatory responses depend on why the embedded cost is viewed as "too high" in some sense. Second, the introduction of competition into a formerly monopolistic industry creates the embedded cost problem. Third, the exposure to these costs were usually shared by stockholders and ratepayers. Fourth, the severity of the embedded cost problem increases as competition is sustained and becomes more robust. Fifth, regulatory responses are not set in concrete.

There are four phenomena that are associated with these lessons. First, the depth and breadth of the competition has influenced the regulatory responses to the embedded cost problem. When competition is either incipient or maturing, the regulatory responses tended to minimize the adverse effects on stockholders. As competition established itself, ratepayers tended to be favored over stockholders. Second, the character of the embedded cost problem has changed over time. In the beginning, the problem was restricted to specific elements of the firm's business.

Now, the problem affects all aspects of the firm's business. Third, regulatory authorities have significant latitude and flexibility as they attempt to respond to the embedded cost problem. There has been realignment of depreciation rates on both an *ad hoc* and generic basis, approvals of rate flexibility and discounts, convened rate cases, and adopted changes in regulatory formats. Fourth, the dominant share of the responsibility for the recovery of this particular type of cost shortfall has shifted over time from the ratepayers to the stockholders. The reason is readily apparent. Significant and increasing competition in any industry causes existing plant and equipment to become obsolete more rapidly as new technologies replace older technologies in an effort to reduce costs and efficiently introduce new products and services

APPENDIX B

STATE ACTIVITIES ON RETAIL WHEELING AND ECEMP COST RECOVERY

This appendix includes a survey of state activities on retail wheeling and "ECEMP costs." Major sources include the September Edison Electric Institute Update of Retail Wheeling, material from the Electricity Consumers Counsel, and information collected by the authors. This is not an exhaustive list of all state actions, but a sample of some action taken to date.

<u>Arizona</u>

The Arizona Corporation Commission opened a generic case docket on May 20, 1994 (Docket No. U-000-94-165) concerning competition in electricity. A one-day workshop to discuss this docket was scheduled to take place on September 7th. While the workshop agenda does not contain the term "retail wheeling," specific issues to be addressed in the workshop include cost of transmission access, access to low cost suppliers, reliability, short term benefits versus long term costs, dispatch, scheduling and control area issues, jurisdictional considerations, limited beneficiaries, "ECEMP costs", adverse impacts on integrated resource planning and demand side management, renewable and environmental initiatives, and effects on the obligation to serve. The workshop also considered alternative ways of achieving lower cost power such as price flexibility, improved rate design, and performance-based ratemaking. The opening of the generic docket on competition followed the Commission's approval of a rate reduction settlement for Arizona Public Service Company in Docket No. U-1345-94-120 in which the staff and company agreed to study innovative pricing to better respond to competition. The study is to be completed and the results reported to the commission within one year.

California

On April 20, 1994, the California Public Utilities Commission proposed a plan for reorganizing the electricity market in a manner that phases in retail wheeling for all customers over an eight year period. The Commission also proposed to replace traditional cost of service regulation for remaining customers buying traditional bundled utility services with performance-based ratemaking.[67] Four rounds of full-panel (before all five commissioners) hearings have been completed. The first three rounds of hearings and initial and reply comments address direct access to electricity, restructuring, and the performance-based regulation proposal. The First Round of full panel hearings was held on June 14 and 15 on the topics of competitive premise, regulator's role, and marketplace implications. The Second Round hearings were held on July 1st on balancing public policy objectives in the competitive environment, a topic which covered low-income ratepayer assistance, economic development, low-emission vehicles, fuel diversity, demand-side management and conservation, and renewable resources. The Third Round of full panel hearings were held on August 4th on the role, structure, and efficacy of wholesale electric markets and market institutions in the restructured electric industry. During the Third Round hearing there seemed to be a shift of topics from whether to implement retail wheeling and limit reforms to wholesale markets to how to best implement direct access (retail wheeling), whether through a pool or through bilateral contracts. These proposals contained proposals for measuring and assigning unmarketable costs. Southern California Edison Company has proposed a wholesale pooling proposal called a "poolco" as opposed to direct access (retail wheeling) regime that allows bilateral contracts. Also, during Round Three, San Diego Gas & Electric Company has offered to divest itself of its transmission facilities. A Fourth Round of hearings on customer choice through direct access was held on September 16th. A continuation of the Fourth Round hearing was held on October 24th. Direct access approaches continued to be examined. At that hearing SCE posited that its poolco proposal allowed "efficient direct access" as described by

[67] California Public Utilities Commission, Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, R.94-04-031 and Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, I.94-04-032, April 20, 1994.

Professor Hogan. A Fifth Round of full panel hearings on transition costs is expected to be announced for October.

In the meantime on May 23rd, two committees of the California Assembly have held joint hearings on the Commission proposal. On June 13th, the legislature established a Joint Oversight Committee on Lowering the Cost of Electric Services and approved a nonbinding resolution requesting the Commission to respond to how the restructuring proposal will meet existing state energy policies. The first hearing of the Joint Committee is scheduled for October 28th.

Connecticut

In Connecticut, the Connecticut Department of Public Utility Control issued a draft decision on August 5th for comment by the parties in its generic retail wheeling investigation. They concluded that retail wheeling is technically feasible and can legally be authorized by the State. However, they also decided that retail wheeling was currently not in the best interests of stakeholders, the state energy policy, or the Connecticut economy. According to the draft decision, retail wheeling should only be introduced at a time where capacity is needed and then only after careful structuring to minimize the adverse effects on inelastic ratepayers and maintain the viability of the host utilities. New capacity is not projected to be needed by Northeast Utilities Company until 2007. In its draft order the Commission expressed concern about social and "stranded" costs, including the fossil-resources conservation program, the effect on low-income customers and economic development programs, and ECEMP costs from a variety of sources. These included ECEMP costs from the amortization of Millstone 3 and Seabrook, QF contract charges in excess of the market, FAS 106 pension charges, trash to energy subsidies, nuclear decommissioning costs, high and low-level nuclear waste assessments, real property taxes, an generation cost in excess of the market. The final order was voted on and approved in early September.

Delaware

On May 31, the gubernatorial Delaware Public Utility Regulatory Task Force issued its report recommending specific legislative changes be made to give the Delaware Public Service Commission authority to deregulate or change the way it regulates. The Task Force recommended legislative changes to allow the Commission (1) to deregulate services where the Commission finds a competitive market exists and where deregulation would be in the public interest and (2) to use alternative forms of regulation where the Commission finds it would be in the public interest and where just and reasonable rates would result. A working group of the Task Force discussed detailed recommendations to the full Task Force on open access and retail wheeling. However, these recommendations were not adopted by the full Task Force. The Working Group found that open access and retail wheeling are complex issues that may affect existing state laws, the obligation to service, and related franchise and public utility status issues. The Working Group, nevertheless, found that the public interest may be better served by open access and resale option. The Working Group suggested that the full Task Force recommend that the Commission initiate a full and complete study of open access for each utility industry.

Florida

In Florida, House Bill 405, which would have certified existing utility service territories and required the Commission to provide utilities serving those territories an exclusive franchise and obligation to provide retail service, was defeated. The bill would have required Commission approval for suppliers other than the host utility to serve retail customers.

Illinois

In Illinois, the Illinois Commerce Commission conducted a retail wheeling workshop in April 1993. Since then, the Illinois State University Center for Regulatory Studies has been facilitating a Illinois Regulatory Initiatives Task Force to report to the Commission. The Commission itself would recommend any legislative changes to the legislature. The mission of the Task Force is to examine numerous issues including unbundling, retail wheeling, flexible pricing, the obligation to serve, expedited certification, incentive regulation, ECEMP costs, cross-subsidization, allocation of transition costs, cost shifting, leveling the competitive playing field and removing subsidies for municipal and rural coops, the regional transmission groups. The Task Force has two working groups: one on competition and one on regulatory and legislative policy. The competition working group meet August 9th and is expected to meet again in September to document the evolution of competition in the state, to define competition in retail and wholesale markets, and to determine whether restructuring would enhance the ability of the electric utility industry to meet the goals of the Illinois Public Utility Act, given emerging more open and competitive markets. The regulatory and legislative policy working group met on August 25th to discuss how to reconcile meeting the goals of the Illinois Public Utility Act with the operation of more competitive markets, and is examining performance-based and incentive regulation.

Indiana

In Indiana, the Chairman of PSI Energy, Jim Rogers, announced in Congressional Testimony on July 13th, that his company is considering offering retail wheeling service to its largest forty customers after the customer provides advance notice. PSI Energy would also offer, for a fee, to assist these customers find cheaper sources of power from other supplier and would also be willing to supply these customers with PSI power. PSI expects to make a filing with the Indiana Utility Regulatory Commission. At the time of this writing it is not clear whether or how the filing will deal with unmarketable costs.

Iowa

On June 8th, the Iowa Utilities Board held a one day roundtable conference on Perspectives on Retail Wheeling in Iowa. The conference addressed the following issues: whether retail wheeling is in the public interest, federal-state jurisdictional issues over transmission pricing, federal impediments to state-ordered retail wheeling, Iowa statutory barriers to retail wheeling, economic development and retail wheeling, and technical barriers to retail wheeling. No additional formal proceeding have been scheduled at this time.

Kentucky

In Kentucky, a retail wheeling conference, sponsored by the Kentucky Public Service Commission and the University of Kentucky, is being held on October 18th and 19th to familiarize participants with retail wheeling issues and retail wheeling developments around the country.

Maine

In Maine, although there are no retail wheeling proposals currently pending in the state, there are a number of municipalization efforts underway. In May, the Commission issued an order opening a generic investigation (in Docket No. 94-176) of backup rates and the treatment of ECEMP costs. The Commission intends to consider policies on the regulatory treatment of ECEMP costs in this docket in the event that retail wheeling is permitted in the future. The Commission does not intend to debate the merits of retail wheeling. In the meantime, two bills relating to retail wheeling were defeated in committee during the session of legislature that ended in April.

Maryland

In Maryland, the Commission has imitated a proceeding to examine developments in the electric utility industry brought about by increasing competition in generation and procompetitive federal regulatory policies. The staff is expected to prepare a discussion paper by November, with a subsequent comment period from December through February 1995. The Commission anticipates a final order in May 1995.

Massachusetts

In December 1993, the Massachusetts Governor set up an Electric Utility Market Reform Task Force co-chaired by the head of the Division of Energy Resources and the Chairman of the Massachusetts Department of Public Utilities, with Professor William Hogan moderating. The Task Force focused on a variety of issues related to retail wheeling including, protecting the interests of captive utility customers and shareholders; mechanism to ensure low-income consumers retain access to utility service; the obligation to serve if there is retail wheeling;

environmental protection and energy efficiency in the face of short-term price pressures of a competitive retail market; and the effect of retail competition on fuel diversity, the medium- and long-term price of electricity, the role of NEPOOL, and an RTG. The Task Force also discussed rules that would be used in designing a competitive retail market including a mechanism for the recovery of sunk costs consistent with transmission access and pricing principles. The Task Force recommended that cost-based regulation be replaced with performance-based regulation and while the Task Force agreed that the state should further study the implication of retail competition on stakeholders, it could not reach on consensus on how or whether to introduce retail electric competition or retail wheeling at this time. In the meantime, the Massachusetts Senate Committee on Post Audit and Oversight issued a report on June 1st recommending greater reliance on market forces to price electric generation, although its framework for increased competition appears more focused on the wholesale rather than retail market. Two Massachusetts House Bills (nos. 79 and 80) which would have allowed some limited retail wheeling were defeated during the 1993 legislative session. Finally, the Massachusetts Bay Transportation Authority (MBTA) recently achieved the status of a public utility under state law with the right to competitively procure power from any supplier. MBTA is about to initiate power procurement from Boston Edison instead of its former host utility, Massachusetts Electric Company. Massachusetts Electric has filed a transmission rate with the FERC requesting a rate that allows for the recovery of "stranded" costs for the recovery of a portion of a long-term purchase power contract used to meet MBTA demand. The Massachusetts Commission has opened a prudence investigation (Docket DPU 94-102) into the ECEMP costs due to Massachusetts Electric's loss of part of the MBTA load.

Michigan

On April 11th the Michigan Public Service Commission ordered a five-year experimental retail wheeling program for one percent of the loads of Detroit Edison and Consumers Power. In order to ensure that customers cannot escape present unmarketable costs, as well as uneconomic bypass, no one can engage in retail wheeling until there is more demand; thus, the start of the experiment would coincide with each utility's next capacity solicitation. The net capacity solicitation for Detroit Edison is estimated to be due in the year 2000. In that interim order the Michigan Commission asserted jurisdiction to both order retail wheeling and to approve prices, terms and conditions of the experimental retial wheeling program. In reaction, Detroit Edison is appealing to the United States District Court for the Western District of Michigan on the grounds that the Michigan Commission cannot set rates,terms, and conditions of transmission service, as well as on the grounds that the Michigan Commission does not have authority to order retail wheeling. That case is pending. On August 26th, both Detroit Edison and Consumers Power filed retail wheeling tariffs with the Michigan Commission.

Minnesota

A bill that would have required utilities to wheel QF power to retail customers was never introduced in the Minnesota legislature. And, the Montana PSC decided in an April informal work session that it did not need to pursue a generic investigation of retail wheeling at this time.

Nevada

The Nevada legislature enacted the first retail wheeling statue when it passed Senate Bill 231 which was signed by the Governor into law in June 1993. It allows the PSC to authorize utilities to purchase or transmit a portion of the electricity provided to qualified businesses (for economic development purposes) to reduce the overall cost of electricity to the business.

New Hampshire

Current New Hampshire law allows limited retial wheeling by QFs, authorizing small QFs of less than 5 MW to sell power to up to three retail customers unless the franchised utility would incur a substantial loss. On August 1st, a new entity called Freedom Electric Power Company has filed with the New Hampshire Public Utilities Commission for approval to do business on a limited basis as a public utility, using the transmission system of Public Service Company of New Hampshire to receive power and deliver it to large, transmission-level retail customers. As of this writing the Commission has not yet acted on this petition.

New Mexico

During 1993, several bills were introduced in the New Mexico Senate to mandate retail and self-service wheeling. These bills were rejected in favor of a two-year study of retail wheeling by a joint house and senate interim committee. The New Mexico Public Service Commission contracted with the National Regulatory Research Institute to conduct a study.[68] The Integrated Resource Planning Committee, a joint legislative committee that has been studying retail wheeling issues has in August, September, and October and heard testimony on retail wheeling. The committee is distilling information and is developing its report and recommendations to submit to the legislature by the time it reconvenes in January 1995.

New York

The New York Public Service Commission has a two phase investigation into the transition to a competitive market. The first phase focused on wholesale competition. On August 9, in Case 93-M-0229, the Commission opened Phase 2 which is focussed on developing a fully efficient wholesale market for electricity and any pricing reforms necessary to reflect those market efficiencies in retail customer rates. The Commission asked the parties to address whether divestiture of generation assets would enhance the transition to a competitive wholesale market. The Staff has recommended dramatic changes to Niagara Mohawks's [pricing structure that requires rates to decline to market levels within ten years. On September 12th, the Commission held a conference for the parties to discuss achieving the goals of maintaining safety, environmental, affordability and service quality, while making the transition to more competitive wholesale and retail markets, as well as dealing with the definition and treatment of stranded investment. On June 14th and 15th, the New York State Energy Research and Development Authority cosponsored a conference with Niagara Mohawk on the implications of transitioning into increasingly competitive electric markets.

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[68] Costello et al., An Overview of Issues Relating to the Retail Wheeling of Electricity.

Ohio

In Ohio, a retail wheeling bill was introduced in February, but died in committee. The Ohio Energy Strategy Report calls for informal roundtable discussion on electric energy issues including competition, unbundling, and retail wheeling. The first roundtable discussion was held on October 17, 1994 and a second is scheduled for December 8th.

Pennsylvania

The Pennsylvania Public Utility Commission held a workshop on retail wheeling in 1993. The Commission instituted a generic investigation into competition, restructuring, and retail wheeling in May 1994 in reaction to a petition for retail wheeling from Findlay Township filed in December 1993. Questions on retail wheeling included: whether systems should be opened up to retail wheeling, whether FERC preempts oversight of retail wheeling, whether the PUC should hold retail wheeling in abeyance to allow wholesale markets to develop, whether retail wheeling should be considered a supply or DSM option in IRP proceedings, how much ECEMP cost would retail wheeling cause, what are the costs and benefits of retail wheeling, and how is the obligation to serve affected. Questions on increased competition addressed whether universal access to electricity can be guaranteed in a competitive environment, how systems operations and coordination be handled, how the Commission can assess the structure and performance of competitive markets, challenges to state and federal jurisdictions, how to price wheeling services, how are remaining utility customers impacted, can an obligation to serve be assigned by customer class or geography, and the impacts on the PJM power pool. Also to be addressed are whether the unbundling of generation and transmission services allow for the disaggregation of their cost, whether it is more efficient for competitive markets to have separate companies provide generation, transmission and distribution services, and whether the FERC pricing model should be used for retail wheeling. Initial comments were due October 11th. Also, the House Consumer Affairs Committee of the Pennsylvania General Assembly held hearing on July 11th and 12th on competition in the electric utility industry and retail wheeling. The Commission will hold a workshop on competition and retail wheeling on December 5th.

South Carolina

In South Carolina, the Commission required Carolina Power and Light to consider retail wheeling as part of its integrated resource plan. On June 6th, the Rhode Island Public Utilities Commission received a petition from an association of over 100 large industrial, institutional, and commercial customers requesting an investigation of unbundled electric rates and retail electric transmission and distribution services.

Texas

The Texas Public Utility Commission initially required Houston Light and Power Company to consider self-service wheeling as an alternative to building new generation. (A later proceeding found the plant in question would not be needed until 1999.) A proposed integrated resource planning rule which might have required utility solicitations for purchase power to include self-service wheeling option was tabled on May 25th. The issue of self-generation and affiliate wheeling is being considered in a current Houston Light and Power case in Docket No. 12957. In addition, retail wheeling may be considered as a part of the Texas legislature's sunset review of the Texas Public Utility Regulatory Act and the Commission.

Utah

The Utah State University is soliciting electricity power suppliers to replace its municipal supplier when its contract expires in July 1995. The West Virginia Public Service Commission has threatened retail wheeling as alternative to Wheeling Power's refusal to offer industrial customers a reasonable interruptible rate. In Wyoming, a collaborative workshop on retail wheeling was held on October 11th.

Washington

The Washington Utilities and Transportation Commission has held a series of informal discussions addressing power competitiveness issues, including wholesale competition and transmission, the future of integrated resource planning and demand-side management, competitive bidding, and changes in regulation more appropriate to the newer competitive environment, transmission access, regional transmission groups, and other topics including the feasibility of retail wheeling. The Commission was to issue a formal notice of inquiry in October.

Wisconsin

In Wisconsin, there has been a Round Table on Electric Utility Trends and Regulatory Policy Directions initiated by Commissioner John Coughlin and meeting through the University of Wisconsin's Public Utilities Institute since January. The Roundtable recently issued a white paper that outlines key competitive issues and possible courses of action to deal with electric power competition and retail wheeling. Recently, the Wisconsin Public Service Commission also initiated an investigation into competition and the restructuring of Wisconsin's electric utilities to achieve the best balance of the commission's desired objectives. Comments were due November 1st.