New Hampshire Public Utilities Commission

DR 96-150

ELECTRIC UTILITY RESTRUCTURING

ORDER ON REQUESTS FOR REHEARING, RECONSIDERATION AND CLARIFICATION

ORDER NO. 22,875

March 20, 1998

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I. INTRODUCTION

On February 28, 1997, the New Hampshire Public Utilities Commission (Commission) issued a Statewide Electric Utility Restructuring Plan (the Plan) and five related interim stranded cost orders (ISC orders) pursuant to RSA 374-F.[1] The Plan and ISC orders implemented the policies of RSA 374-F by, *inter alia*, requiring electric utilities to provide unbundled, open access delivery services so that retail customers would have the ability to purchase electricity from competitive suppliers. Under RSA 374-F:4, I, New Hampshire consumers must have retail access no later than July 1, 1998. The Plan was designed to achieve three primary objectives: first, it articulated the Commission's general blueprint to implement RSA 374-F; second, it announced generic policy statements consistent with the Commission's delegated authority under RSA 374-F; and third, the Plan established utility compliance filing requirements pursuant to RSA 374-F:4, III. The Plan also established voluntary working groups to make further

[1]See, RSA 374-F:4, II. The Plan was issued by Order No. 22,514. Interim stranded cost charges were set by Order Nos. 22,509-22,513 for Connecticut Valley Electric Company (CVEC), Concord Electric and Exeter & Hampton Electric Companies (collectively, the Unitil Companies), Granite State Electric Company (GSEC), Public Service Company of New Hampshire (PSNH) and the New Hampshire Electric Cooperative (NHEC).

recommendations to the Commission on how to implement particular policy decisions.

In conjunction with the Plan, the Commission issued a legal analysis that addressed numerous matters, including claims by utilities that the Commission's authority to implement RSA 374-F was limited by various sources of State and federal law. Among the issues addressed in the Commission's legal analysis were those concerning implementation of the Legislature's stranded cost policies, the unbundling of utility services and state-federal jurisdictional issues regarding the provision of retail transmission.

The ISC orders applied the stranded cost policies set forth in RSA 374-F to each utility based upon a particular cost recovery mechanism articulated in the Plan. This mechanism relied on a "benchmark" approach for setting interim stranded cost charges that compared the average retail rate of each jurisdictional utility to the average retail rate for all electric utilities in the region. Any electric utility whose retail average rates exceeded the regional average rate was afforded a lower level of stranded cost relief than those utilities whose average rate was at or near the regional average.

This order addresses all outstanding motions for rehearing or clarification relative to the policies or legal positions articulated in the Plan except those portions of the Plan or Legal Analysis that specifically addressed the PSNH Rate Agreement entered into with the State of New Hampshire as part of its bankruptcy reorganization.[2] Accordingly, this order affirms, clarifies and modifies the generic policy statements, supporting legal analysis and compliance filing requirements announced previously in the Plan. In addition, this order reaffirms the ISC

[2]The Commission notes that it has filed a Request for Interlocutory Rulings with the New Hampshire Supreme Court concerning certain aspects of the Rate Agreement. This order does not address any issue related to the Rate Agreement raised in that request.

orders of Connecticut Valley Electric Company (CVEC), Granite State Electric Company (GSEC), the New Hampshire Electric Cooperative, Inc. (NHEC) and the Unitil Companies (Unitil). The Commission will issue a separate rehearing order addressing PSNH's ISC charge based on the information presented at the rehearing and incorporating the final policies and decisions articulated herein, as well as the response of the New Hampshire Supreme Court to our Request for Interlocutory Rulings.

Finally, the Commission announces herein the initiation of utility-specific compliance proceedings and several rulemaking dockets, and also reports on the status of various activities, both at the State and regional level, which are related to the implementation of RSA 374-F.[3]

II. PROCEDURAL HISTORY

[3] An update of the regional effort to reform the New England Power Pool (NEPOOL) is contained in Appendix A. An update of the various Commission-sponsored working groups is contained in Appendix B.

The Commission received 14 timely motions for rehearing or clarification concerning the Plan and ISC orders.[4] By Order No. 22,548 (April 7, 1997), the Commission suspended and stayed portions of the Plan and ISC orders pending further evaluation of the issues raised in these requests. The Commission also granted requests for further public hearings on one generic policy issue and several PSNH-specific issues. See, Order No. 22,576 (April 30, 1997). The policy issue concerned whether utilities should continue to administer ratepayer-subsidized energy efficiency programs. The PSNH-specific rehearing issues related to its ISC order; specifically, they related to whether that order (and the Plan) will cause PSNH to breach certain debt covenants and whether the Plan violates the 1989 Rate Agreement executed by PSNH and the State of New Hampshire.

[4]A list of the parties filing such requests, individually or collectively, is contained in Appendix C.

The rehearing proceedings were originally scheduled for May 1997 but were continued on two occasions at the request of a number of parties, including the State of New Hampshire, who sought to participate in a confidential mediation process overseen by the United States District Court of Rhode Island.[5] See, Order Nos. 22,599 (May 22, 1997) and 22,664 (July 21, 1997). The Commission conducted a hearing on energy efficiency on October 9, 1997. The PSNH- specific rehearings began in November 1997; legal memoranda were filed on December 19, 1997. The Commission also accepted comments on issues concerning transition service and affiliate transactions as requested by some parties.

III. DISCUSSION

A. Procedural Matters

The Plan and ISC orders culminated a nine-month generic investigation which the Commission initiated to fulfill its statutory responsibilities under RSA 374-F. That law instructed the Commission to develop a statewide industry restructuring plan and establish ISC charges for each utility no later than February 28, 1997. RSA 374-F:4, II. Consistent with these dual objectives, the Commission segmented the docket into two procedural phases: the first phase allowed parties to comment on generic policy matters; the second phase was dedicated to setting utility-specific ISC charges. The Commission employed panel-based legislative type procedures to address generic policy questions and separate utility-specific adjudicative

[5]The mediation process was prompted by a lawsuit filed by PSNH on March 3, 1997. See, PSNH, et al. v. Patch, et al., N.H. Civil Action No. 97-97-JD, R.I. Civil Action No. 97-121L.

proceedings to set ISC charges in accordance with RSA 541-A:31-36.

1. Rehearing Requests - Procedural Matters

Each of the electric utilities subject to RSA 374-F, with the exception of NHEC, assert on rehearing that the procedures employed by the Commission were inadequate or legally insufficient. PSNH and CVEC argue that the Commission erred by not utilizing formal adjudicative procedures to address every issue raised by RSA 374-F. GSEC asserts that the Commission should have conducted a formal rulemaking. Unitil claims that the Commission was required to conduct every part of this docket through either formal adjudication or rulemaking.

The foregoing entities also assert other miscellaneous procedural errors. PSNH argues it had inadequate discovery rights and was improperly foreclosed from presenting testimony, cross-examining witnesses and presenting rebuttal evidence. PSNH also claims that one of the Commission's decisional employees "evidenced an appearance that he has committed to a highly adversarial position" and that certain unspecified violations of the statutory standards of conduct set forth in RSA 363:12, III, IV and VII prejudiced the company. CVEC complains that the Legislature left too narrow a time frame for the Commission to process the momentous matters involved in this case, leading to procedural deficiencies and "pre-ordained results" in the Plan. Unitil complains that it was improperly denied the opportunity to discover the legal or statutory basis for the Commission's legal analysis.

The Office of Consumer Advocate (OCA) argues that the Commission allowed PSNH more procedural protections than other interested parties, including a greater opportunity to submit testimony on the Rate Agreement.

2. Commission Conclusions - Procedural Matters

We have addressed previously most of the procedural issues raised in the aforementioned rehearing requests. By Order No. 22,244 (July 22, 1996), we rejected PSNH's contention that it was entitled to a formal adjudicative process to resolve "each and every issue" in this proceeding.[6] In that order, we announced our intention to use adjudicative procedures to establish utility-specific ISC charges and panel-based, legislative style procedures to explore generic policy issues. We affirm those decisions and reiterate our position that we were not required to employ formal adjudicative procedures, or a formal rulemaking, before issuing generic policy statements in the Plan.[7] In addition, we reject any new claims advanced on rehearing that the procedures afforded throughout this docket were legally inadequate. We were, and are, satisfied that all parties were given an adequate opportunity to build a comprehensive record upon which the Commission could rely to develop these generic policy statements. The processes employed throughout this docket went beyond what was constitutionally required or contemplated by the Legislature when it enacted RSA 374-F. In affirming our prior decisions on these matters, we have nonetheless decided, *sua sponte*, to clarify both the nature and intended purposes of the Plan in the following section.

B. Nature of the Plan

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[6] See also, Order Nos. 22,316 (September 17, 1996) and 22,364 (October 16, 1996).

[7] By formal adjudication, we mean evidentiary hearings with attendant procedural safeguards such as the right to discovery, to testify under oath and to cross-examine witnesses.

The Legislature instructed the Commission to "undertake a generic proceeding to develop a statewide industry restructuring plan...[and] after public hearings, issue a final order no later than February 28, 1997." RSA 374-F:4, II. Since the Legislature did not define the term "statewide plan", it afforded the Commission wide latitude. As stated in the Introduction, the Plan was intended to serve three primary functions: to articulate the Commission's general restructuring blueprint; to issue generic policy statements; and to establish utility compliance filing requirements consistent with those policy pronouncements. In essence, the Plan simply announced the Commission's blueprint for implementing RSA 374-F; it did not supplant the underlying policy directives of RSA 374-F. Nor was it intended to supersede RSA 374-F. It was instead, the implementation tool for the legislative mandate upon the State's electric utilities to provide open access services so that consumers could purchase electricity from competing suppliers no later than July 1, 1998.

Although the Legislature did not explicitly require it, we issued, as part of the Plan, generic policy statements. We recognized the need to implement some of those broad policies through formal rulemaking proceedings. We recognize further, however, that some policy objectives could be advanced only within regional or federal forums.[8]

The Plan, even as modified by this order, therefore, should not be construed as the

[8] For instance, we recognized the need to restructure the New England Power Pool (NEPOOL) to enhance wholesale competition and to accommodate retail choice initiatives in New Hampshire and in many neighboring states; however, we acknowledged that such goals had to be advanced through cooperative regional efforts and in proceedings before the Federal Energy Regulatory Commission (FERC).

Commission's final declaration of its ongoing responsibility to enforce the mandates of RSA 374-F. Rather, the Plan provides parties with policy guidance in certain areas and requires utilities to submit compliance filings consistent with those policies.

C. General Policy Considerations

We affirm the fundamental rationale and objectives in the Plan which require us to develop and implement sound public policy. The passage of RSA 374-F has not altered the Commission's fundamental responsibility under RSA 363:17-a to balance the interests of customers and utilities. It has imposed upon us the new responsibility of developing and implementing policies that will encourage a competitive retail market for electricity services. The Legislature clearly instructed us to design and implement policies to achieve that particular objective when it stated the purpose of RSA 374-F this way:

> The most compelling reason to restructure the New Hampshire electric utility industry is to *reduce costs* for all consumers of electricity *by harnessing the power of competitive markets*.

RSA 374-F:1, I (emphasis added). Thus, although we continue to recognize the competing interests of consumers and utility shareholders, we must do so within the framework of an overall policy to promote a competitive market for retail electric services.

We firmly believe that the legislative mandate to implement pro-competitive policies will yield long-term benefits for consumers and the State. Although substantial opportunities exist for consumers to enjoy short-term gains, we believe that it is appropriate to develop sound, long term policy while achieving near term rate relief consistent with RSA 374-F.

We recognize that the desire to avoid litigation may lead some parties to enter into "settlement agreements" by collectively proposing changes to the policies announced in the Plan as modified herein.[9] Generally, the Commission encourages parties to seek consensual resolutions to contested issues. We do not intend to foreclose those opportunities in this or related proceedings. Parties to any such proposal, however, should be mindful that the Commission cannot abdicate its statutory responsibilities which include laying the groundwork for an effective competitive market for retail generation and ancillary energy services and achieving near term rate relief. In order to approve any settlement proposal, we must be satisfied that it substantially adheres to the Legislature's policies as articulated in RSA 374-F. In particular, we will carefully scrutinize any proposal to ensure that it does not compromise the substantial and long-term benefits which will accrue to the State through sound industry restructuring policies in exchange for modest short-term gains or an agreement that minimally complies with the language but not the long-term purposes of RSA 374-F. With or without settlement agreements, we will do everything within our delegated authority to ensure that utilities comply with the requirements of RSA 374-F by July 1, 1998.

D. Open Access Requirements

RSA 374-F authorizes and directs the Commission to require New Hampshire's electric utilities to provide retail customers with unbundled, non-discriminatory transmission and distribution services no later than July 1, 1998. See, RSA 374-F:4, I. We affirm our commitment to enforce unbundled, non-discriminatory transmission and distribution services,

[9] In fact, we note that one such proposal was recently filed in this docket. We have opened a separate proceeding to consider the issues raised by that filing. See, DR 98-012, Granite State Electric Company.

although, as discussed below, we have vacated our prior directive concerning the filing of retail transmission tariffs. Accordingly, we hereby direct each jurisdictional electric utility to file proposed distribution tariffs with rates, terms and conditions that are consistent with RSA 374-F and our discussion below. As noted above, the ISC portion of PSNH's proposed tariffs will be established in a separate order. The Commission will review and, if necessary, require modification of these tariffs within the compliance proceedings required by RSA 374-F:4, III. Unless the Commission orders otherwise, these tariffs shall be effective on or after July 1, 1998.

E. Rate Unbundling Requirement

In the Plan, the Commission directed all jurisdictional utilities to unbundle their 1996 retail revenue requirements into the three functional categories of generation, transmission and distribution.[10] The Commission directed utilities to further separate distribution revenue requirements into distribution, metering, billing, customer services and conservation and load management (C&LM) functions. Pursuant to the Plan, utilities are required to distinguish between transmission and distribution revenue requirements in accordance with the FERC's seven factor test. The Commission also directed utilities to develop transmission and distribution (T&D) revenue requirements consistent with the following principles:

- T&D rates must exclude all generation-related operation and maintenance expenses;
- T&D rates must exclude all costs associated with wholesale and retail marketing activities; and

[10]Plan at 37, fn. 27.

- T&D rates must reflect appropriate allocations of administrative and general expenses.

As part of utility compliance filing requirements, we also directed utilities to submit a cost-of-service study which unbundles 1996 test year revenue requirements based on the foregoing criteria.

No rehearing requests were filed relative to these requirements. We will modify the Plan, however, to the extent that it addressed transmission rates and tariffs. As explained in §III, J of this Order, we will no longer require electric utilities to file transmission tariffs and will limit our regulation to distribution rates and tariff terms. Accordingly, we herein affirm our directive that utilities submit, as part of their updated compliance filings, 1996 cost-of-service studies which allocate 1996 test year revenue requirements to each rate class using the cost allocation techniques underlying existing bundled rates.[11] The development of transmission rates will be subject to FERC's jurisdiction.

F. Scope of Unbundled Services

In the Plan, the Commission stated that although it would require utilities to fully unbundle retail *rates* for all customer classes, it would unbundle *services* on a more limited basis during the transition to a competitive retail market. The Commission acknowledged that some parties favor unbundling and opening to competition all identifiable services that no longer exhibit monopoly characteristics; however, we decided that it was more appropriate to require an

[11] In Appendix D we have updated utility compliance filing requirements to include 1997 data.

achievable level of unbundling at the outset of competition and that a more comprehensive separation of competitive services should be deferred to a later date. The Plan requires utilities to unbundle only generation and energy billing services for all customers at the onset of competition but requires further unbundling (specifically metering services) for large customers, which we define as any customer whose maximum demand exceeds 100 kW in any three successive months. The Commission established a working group to further explore the technical issues associated with implementing this metering unbundling policy decision.

1. Rehearing and Clarification Requests - Unbundled Services

Several parties requested clarification relative to the Commission's policy requiring unbundled metering and billing services. CVEC states that, in light of the Commission's decision to unbundle both metering and billing services for all customers over 100 kW "[p]resumably...the meter previously supplied by CVEC would have to be removed, and CVEC would no longer have any responsibility to provide meters to these large customers." In addition, CVEC assumes that customers will be responsible for any undepreciated meter investment (and billing service systems) that becomes stranded as a result of the Commission's policy.

GSEC argues that the Commission's metering policies raise many new questions. For example, GSEC points to the Commission's requirement that all customers whose maximum demands exceed 100 kW shall have hourly metering (Plan at 22). Such a requirement, according to GSEC, leaves unanswered issues surrounding the ownership of metering equipment, responsibility for meter accuracy and testing, coordination of information flow among competitive suppliers, Independent System Operator (ISO) - New England, distribution companies and customers, loss allocations, metering services for default customers, stranded costs associated with metering equipment, and the right of distribution companies to meter for their own services and other unspecified concerns. GSEC suggests that many of these issues cannot be resolved before the legislatively imposed retail access date and GSEC, therefore, asks that the Commission establish a separate schedule for unbundling metering and related services.

According to PSNH, the Commission's policy on metering exceeds its statutory authority by precluding PSNH from obtaining its own data for delivery system usage, thus denying the distribution company the right to perform essential services for these customers. PSNH also asserts that the Plan fails to acknowledge that estimated hourly loads are much less accurate than actual hourly load meter readings. According to PSNH, the Plan "misconstrues" the study conducted by GSEC.

2. Commission Conclusions - Unbundled Services

a. Metering and Billing

Throughout this order, a large customer will be defined as one whose maximum monthly demand exceeds 100kW whereas a small customer is one whose maximum monthly demand is less than or equal to 100kW.[12] The following policies will be reviewed one year after their implementation which we expect will be July 1, 1998 or soon thereafter. The primary focus of

[12] Distribution companies may utilize existing procedures to determine a customer's maximum demand or propose customer rate classifications that are consistent with the above threshold requirement. The maximum demands of new customers shall be reviewed after the first year of service to verify that the demand classification was correct. We herein clarify that an "above 100kW customer" is one whose monthly maximum demand exceeded 100kW in at least three months of any consecutive 12 month period.

the Commission's review will be to determine: (a) whether distribution companies should remain obligated to provide metering services to large customers who choose not to obtain those services from competitive (non-utility) providers, and (b) whether load estimation is an adequate alternative to measured data for customers whose metering equipment does not meet the standard described below. Before fully explaining our decisions in this area, we provide a brief summary of our conclusions in the following two paragraphs.

We affirm our decision to allow competitive providers[13] to offer energy billing services to all customers effective on the retail competition date. Competitive providers may also provide meters and metering services to large customers who choose that option. However, competitive metering will not begin before appropriate metering standards have been adopted through rulemaking. By authorizing the competitive provision of meters and metering services for large customers, we are encouraging the development of a competitive market for ancillary services, starting with the most sophisticated, energy intensive customers.

We also affirm our decision to require distribution companies to provide meters and metering services to small customers until we see evidence that those services can be better provided by the competitive market. Although we do not believe it would be practical to allow all customers to purchase meters and metering services competitively at the time of retail competition, we will consider proposals for limited pilot programs designed for small customers. Phasing in the competitive provision of metering products and services will provide for a more orderly transition to retail competition and to allow small customers an opportunity to learn more

[13]Including distribution company affiliates.

about these options.

PSNH argues that RSA 374-F does not authorize the Commission to unbundle metering and billing services for any customer. We disagree. RSA 374-F:1, I states, in pertinent part, that “[i]ncreased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require unbundling of prices and services....” and at §3, III states that “services and rates should be unbundled to provide customers clear price information on the cost components of generation, transmission, distribution, and any other ancillary charges.” Additionally, §3, IV requires the Commission to “monitor companies providing transmission or distribution services and take necessary measures to ensure that no supplier has an unfair advantage in offering and pricing such services.” We conclude that the Legislature authorized us to unbundling ancillary services, including metering and billing, recognizing such unbundling to be a critical step in the development of a competitive market for energy services.[14]

In the Plan, we required that metering equipment for large customers be capable of recording hourly loads and being read remotely each day in order to reduce the error associated with the hourly load estimation process. This new standard would have taken effect on the retail competition date. After further consideration, we have decided that until we have completed our review we will leave open the date by which metering equipment used by large customers must comply with the new standard. Prior to this review, distribution companies must

[14]Presently the Legislature is considering HB 1368, which would prohibit competitive metering and billing for all customers until the later of July 1, 2000 or the date that competition is certified to exist, as defined in RSA 38:36. If enacted, HB 1368 would obviously affect the recommendations of the working group and our decisions in this area.

estimate the hourly loads of large customers who choose not to purchase metering products and services competitively and whose existing metering equipment does not meet the new standard. These changes will provide for a more orderly transition to a competitive market for metering products and services and minimize the need for additional metering investments by distribution companies.

If a customer changes from one competitive energy supplier to another, we require the existing meter to be left in place for 60 days or until another meter is installed by the new competitive supplier. A replacement meter that meets the above new standard must be installed by the end of the 60 day grace period unless the old and new suppliers can reach a mutually acceptable solution. These requirements do not apply to large customers who, prior to our review, continue to use their existing metering equipment. We clarify that meter testing will remain the sole responsibility of distribution companies and that the connection of metering equipment at primary voltage levels must be performed by qualified individuals. We also require distribution companies to install, when requested, customized meters and/or ancillary metering devices of competitive providers in a timely and cost effective manner. Distribution companies will be compensated for the reasonable costs of providing such services, pursuant to a Commission approved tariff.

With respect to billing, we clarify that distribution companies will retain the responsibility to bill all customers for distribution services. Competitive suppliers, or their designated agent(s), will assume the responsibility for billing customers for the energy services they provide. However, for the convenience of the customers, we will require distribution companies to offer competitive suppliers the option of including their unbundled energy charges on a single consolidated bill, prepared by the distribution company. Again, the distribution company would be compensated for this billing service pursuant to a Commission approved tariff.

b. Advanced Metering Networks

Both competitive suppliers and distribution company affiliates may install advanced metering networks employing automated meter reading technology. An advanced metering network consists of two or more meters that communicate with a remote station utilizing wireless or telephone based technologies. Meters used in an advanced metering network must be able, at a minimum, to record hourly data and be read remotely.

Distribution companies seeking to install advanced metering networks must obtain prior Commission approval. In reviewing any such application, we will evaluate the potential for stranded metering investments and anti-competitive effects.

c. Cost Recovery Issues

We clarify that metering costs, appropriately allocated for the relevant classes including large customers who choose not to acquire metering products or services competitively, will be recovered via unbundled distribution charges. We reiterate that distribution companies must undertake all reasonable efforts to mitigate fixed costs not recovered as a result of customers switching to competitive providers. Distribution companies may recover the non-mitigatable portion of those costs through the annual reconciliation of stranded costs and revenues for the large customer rate classes.

d. Acceptance and Installation Standards

To ensure accurate calibration, appropriate installation and reliable operation, we will require the development of acceptance and installation standards for all metering equipment. We ask the metering working group to develop appropriate standards, which we will consider in a rulemaking. Those standards must accommodate new technologies. All competitive providers that intend to install their own custom meters or ancillary metering devices must first have the equipment acceptance-tested by the relevant distribution company. As we noted above, no competitive metering will be allowed for any customer until the Commission's administrative rules on metering have been enacted. All metering equipment must comply with Commission rules.

G. Vertical Market Power

In the Plan, we found abundant evidence that incumbent electric utilities possess the ability to exercise vertical market power and could disadvantage unaffiliated suppliers by using revenues from regulated functions to cross-subsidize unregulated functions and by offering affiliates access to preferential pricing arrangements or customer information. We concluded that divestiture was the best safeguard against such conduct. Specifically, we observed:

> The shared ownership and control of generation, transmission and distribution assets provides both the opportunity and the incentive for management of regulated companies to favor competitive affiliated suppliers. The implementation of affiliate transaction rules insufficiently restricts the incentive to exercise market power. We believe the corporate ties between regulated and competitive functions must be severed in order to eliminate this incentive. In our view, the only way to sever these corporate ties is through divestiture. We define divestiture to mean that an existing utility may no longer provide competitive and

non-competitive services.[15]

To implement this policy, we decided to limit future electric distribution utility franchise rights. We required any incumbent electric utility that sought to retain its regulated distribution functions to submit a plan under which it would divest its generation and aggregation/marketing functions by the end of a two-year transition period. We stated, however, that during the two-year transition, we would allow an affiliate of a distribution company to offer competitive products and services provided that the utility satisfactorily demonstrated that it had implemented sufficient safeguards to prevent anti-competitive behavior.

1. Rehearing Requests - Vertical Market Power

On rehearing, each jurisdictional electric utility objects to the Commission's policy statements concerning the ability of utility-affiliates to compete for retail customers within their respective service territories. Most claim that RSA 374-F did not delegate authority to the Commission to implement such a prohibition and that in any case, such a policy would be constitutionally invalid. According to these utilities, the Commerce Clause of the United States Constitution precludes the Commission from prohibiting utilities' affiliates from competing for retail customers within their service territories.

NHEC objects to any order requiring NHEC to divest its generation and "aggregation/marketing functions" because such action: (a) may deny NHEC the ability to mitigate its costs associated with its ownership interest in Seabrook and Maine Yankee; (b) is inconsistent with previous Commission conclusions relative to NHEC's ability to provide

[15]Plan at 21.

aggregation services for its members; and (c) is unlawful and unreasonable given the nature of NHEC's specific purchase power contracts.

CVEC contends that its parent, Central Vermont Public Service Company (CVPS), is a Vermont public utility which is not subject to the Commission's jurisdiction. CVEC states that both it and CVPS have "expressed a willingness...to minimize the risk of anti-competitive conduct" through codes of conduct and affiliate transaction rules.

GSEC argues that the Commission lacks the statutory authority to prohibit a GSEC affiliate from providing competitive services within GSEC's service territory. Moreover, GSEC contends that, even if such authority existed, such a prohibition "runs counter to the statutory goal of creating a robust competitive market and does not serve the public interest."[16] GSEC asserts that the "public interest" standard in RSA 374:26 does not provide the Commission with authority to withdraw a utility's ability to operate in an otherwise lawful manner in the state. GSEC also argues that such a policy could stifle competition by reducing the number of competitive suppliers and would directly reduce the market value of a distribution company.

The Governor's Office of Energy and Community Services (ECS) states that, in order to "maximize competition" as a means to lower costs, utility-affiliates should be permitted to compete for retail customers within their affiliate's service territory. According to ECS, the Commission should implement a code of conduct and then continue to monitor vertical and horizontal market power issues.

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[16] GSEC Motion at 11.

2. Commission Conclusions - Vertical Market Power

We continue to believe that divestiture (i.e., separate ownership of generation from transmission and distribution) is the most effective way to eliminate vertical market power; however, we will vacate our decision to prohibit retail marketing affiliates of an electric distribution utility from offering competitive services to customers within the franchise service territory of the distribution utility. We will permit retail marketing affiliates to compete for retail customers in their distribution utility's franchise territory, but only after we approve an appropriate code of conduct to protect against anti-competitive behavior. We reiterate, however, that distribution utilities may no longer offer generation-related services to their customers and we will require corporate unbundling consistent with our express authority to do so. See, RSA 374-F:4, VIII. In addition, our decision on this issue applies with equal force to NHEC, the State's only member-owned electric utility. We believe that NHEC should be subject to the same corporate unbundling and code of conduct requirements established for New Hampshire's other utilities.

We grant this relief on rehearing primarily for practical purposes. We have decided to defer any ultimate public good determination on this issue until we are better able to assess the efficacy of the protections proposed by various parties. We remain very concerned that, absent divestiture and the preceding prohibition against retail marketing affiliates of electric distribution utilities, affiliates may gain an unfair advantage over other market participants. Consequently, we will require utilities and their affiliates to operate in strict accordance with the code of conduct that the Commission will establish in a generic rulemaking proceeding. In addition, retail affiliates will be subject to Commission oversight and information disclosure requirements which will be addressed in this rulemaking docket. Furthermore, such affiliates must comply with the rules we adopt in the supplier registration rulemaking. We will monitor the efficacy of these protections closely to determine whether vertical market power abuses occur; if they do, we will take appropriate action and implement additional protections.

Although we have decided to modify the Plan in the foregoing manner, we nonetheless affirm our authority to place conditions on future electric distribution utility franchise rights to accommodate the retail access policies of RSA 374-F. See, Plan at 28. We do not accept the argument that we can only limit the scope of services that a utility may offer after a finding of inadequate service pursuant to RSA 374:28. Fundamental to our regulation of a distribution utility is a determination of the type and quality of services provided. Such a determination will change over time with advances in technology, changes in customer needs and the development of competitive markets for energy services. The enabling legislation we are required to implement expressly authorizes the Commission to require "that distribution and electricity supply services be provided by separate affiliates." RSA 374-F:4, VIII.

In addition to the foregoing express authority under RSA 374-F, the Commission has been delegated incidental authority to take actions necessary to implement the policies of RSA 374-F. See, RSA 374-F:4, VIII ("The Commission is authorized to order such charges and other service provisions and to take such other actions that are necessary to implement restructuring..."). Even before the enactment of RSA 374-F, the Commission had the authority and duty to prescribe terms and conditions on franchise rights whenever it would serve the public good. RSA 374:26. That authority has a special application to these circumstances because our delegated mandate is to promote competition not to perpetuate monopolies. As the

New Hampshire Supreme Court stated:

> ..[L]egislative grants of authority to the PUC should be interpreted in a manner consistent with the State's constitutional directive favoring free enterprise. Limitations on the right of the people to "free and fair" competition"...must be construed narrowly, with all doubts resolved against the establishment *or perpetuation* of monopolies. RSA 374:26 thus should not be interpreted as creating monopolies capable of outliving their usefulness.

Appeal of PSNH, 141 N.H. 13, 19 (1996) (emphasis added) (internal citation omitted).

In this case, we have identified specific circumstances where electric utilities may exploit their privileged status to inhibit the development of a competitive retail electricity market. We will implement special protections to mitigate these anti-competitive practices. Should we determine these special protections are insufficient, we will impose additional pro-competitive measures.

In light of the foregoing, we will initiate a rulemaking to establish affiliate transaction rules which will govern the conduct and relationships between regulated utilities and their unregulated affiliates. Several other jurisdictions, notably Massachusetts and California, have issued rules governing affiliate transactions. As we considered affiliate transaction rules, we saw value in using the rules adopted by one of those jurisdictions as a starting point for the rulemaking proceeding we would initiate on affiliate transactions. We have chosen to use the rules adopted by California as the initial document for the rulemaking docket we intend to open, however, we would caution parties that our decision to do should in no way be interpreted to mean that we have prejudged this issue.[17] Rather it reflects our recognition of the July 1, 1998

[17]The California rules were announced in "Opinion Adopting Standards of Conduct Governing Relationships Between Utilities and Their Affiliates," CA PUC Decision 97-12-088 (December 16, 1997).

implementation date mandated by RSA 374-F and will help expedite the rulemaking proceeding. Parties interested in participating in the affiliate transaction rulemaking docket should contact our Executive Director. Copies of these affiliate transaction rules will be posted on the Commission's web page.

H. Trade Name Prohibition

In the Plan, we prohibited utility-affiliates from marketing to customers by using a trade name that resembles that of the distribution company.[18] On rehearing, several utilities challenge that policy based on their assertion that it violates the commercial free speech protections of the First and Fourteenth Amendments of the United States Constitution.[19] Without addressing the merits of those constitutional claims, or in any way agreeing that the claims have merit, we have decided to vacate the blanket prohibition against the use of such trade names.[20] We are persuaded that until we have more experience with the marketing practices of generation suppliers, including those who are affiliated with distribution companies, we should not, at the outset of competition, act to bar the particular marketing practice of name usage. Notwithstanding the foregoing, competitive suppliers will nonetheless be required to comply with applicable registration, disclosure and consumer protection rules, some of which may have

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[18] See, Plan at 53.

[19] See, Unitil Motion, ¶ 5(c); PSNH Motion, ¶ 57.

[20] In fact, we note that the California Commission concluded that the First Amendment would not bar the Commission from prohibiting an affiliate's use of the utility's name and logo if the Commission concluded that such action was appropriate to further the interests of promoting a competitive market. See CA PUC Decision 97-12-088 at 42.

an impact on the manner in which suppliers advertise. In taking this action, we have simply decided to impose a less rigid approach to address the consumer protection and market power concerns which we expressed in the Plan. However, we will require a competitive supplier who utilizes such a trade name to disclose its affiliation(s) with regulated utilities and provide the additional disclosures that may be required by our affiliate transaction rules.

I. Regulation of Distribution Services

In the Plan, the Commission noted that it would continue to regulate electric distribution utilities whose primary duty would be to provide retail customers with open access distribution services.[21] In addition, we required electric distribution utilities to maintain their obligation to provide metering, billing and customer services for all customers whose peak loads do not exceed 100 kW. The Plan also provides that for those customers whose peak load exceeds 100 kW, metering, energy billing and customer services will be provided competitively. As noted above, we have modified this to some degree in this order.

[21]Under the Plan, this duty encompasses the obligation to connect customers, deliver energy and capacity, restore service following outages and extend service lines consistent with Commission approved tariffs. See Plan at 86.

The Plan also provides that distribution services will be regulated exclusively by the Commission and that rates for retail distribution services will be set in accordance with traditional cost of service principles. We explained that some form of performance based rate-making may be appropriate for distribution companies in the future; however, before implementing such methodology, the Commission must further examine the costs of providing distribution services. For rate-setting purposes, we adopted FERC's seven-factor technical test to demarcate, but not delineate, distribution and transmission facilities.[22] As part of compliance filing requirements, we directed utilities to determine the revenue requirement for individual rate classes using the allocation methodology underlying retail rates currently in effect.[23] We further directed utilities to include in their compliance filings a breakdown of distribution costs into specific cost categories, such as customer service, operations and maintenance, capital replacements/additions and metering and billing. We invited utilities to propose alternative rate design methodologies as part of their compliance filings, although we advised that any such filing should include an analysis of the rate impact(s) of such alternatives.

Finally, we observed that the return on equity (ROE) component of the distribution company's revenue requirement should reflect its reduced risk.

1. Rehearing Requests - Regulation of Distribution Services

Several entities argue that the Commission improperly made generic findings regarding the ROE component of regulated distribution rates. According to CVEC, distribution

[22] See, Plan at 16.

[23] According to the Plan, distribution rates were to be based on 1996 revenue requirements. In Appendix D we have updated utility compliance filing requirements to include 1997 data.

companies face the risk of entry by competitors and uncertainty regarding cost recovery for newly ordered competitive functions. CVEC argues that its cost of capital should reflect these risks.

PSNH contends that the Commission must set the appropriate level of return on equity in utility-specific rate proceedings based on financial market requirements.

CVEC also asks for clarification on whether an investment made today will be recoverable in the future if that part of its operations in which the investment is made becomes competitive in the future.

2. Commission Conclusions - Regulation of Distribution Services

We reaffirm the policy announced in the Plan to set the rates, terms and conditions for distribution services within the compliance proceedings for each utility. We clarify that the ROE component of distribution rates will be set based on traditional rate making principles. For compliance filing purposes, we direct each utility to use the last Commission-approved ROE for an electric utility, 10.2%; however, we will adjust that component of distribution rates based on the outcome of individual rate cases. <u>See</u> Order No. 22,537 in DR 96-170.

We cannot provide CVEC with its requested clarification concerning whether investments made to provide distribution services will be fully recovered through regulated rates. That issue will be addressed in a future distribution company rate case applying appropriate ratemaking principles.

J. Regulation of Retail Transmission Services

In the Plan, the Commission announced a general policy decision to defer to the jurisdictional paradigm established by FERC in Orders Nos. 888 and 888-A with respect to the provision of unbundled retail transmission services.[24] However, the Commission also directed transmission-owning utilities to develop and file with this Commission special retail tariffs for New Hampshire customers before filing such tariffs with FERC. In establishing this filing requirement, the Commission determined that it was necessary to shape the terms and conditions of retail transmission because many parts of FERC's *pro forma* tariff are inappropriate for retail transactions. The Commission recognized the risk that inconsistent retail transmission policies could be developed by the different state regulatory authorities in the New England region and that FERC would be the appropriate final authority to establish the rates, terms and conditions of retail transmission. Under this approach, the Commission assumed FERC's ultimate authority to regulate retail transmission service but determined that the Commission had the authority to review and, if necessary, require modification to proposed retail transmission tariffs before requiring the filing of such tariffs at the FERC. The Commission acknowledged that any modifications must conform with the policies and principles enunciated in the FERC's Open Access Rule.

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[24] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996); and Order No. 888-A (Order on Rehearing), 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stat. & Regs ¶ 31,048 (1997).

1. Rehearing Requests - Retail Transmission Services

On rehearing , PSNH, Unitil, GSEC and CVEC challenged this aspect of the Plan. Although each of these parties casts its argument in a slightly different fashion, all contend that the Federal Power Act (FPA) preempts the Commission from requiring utilities to make retail transmission filings here or at FERC.

In addition to the foregoing, GSEC argues that it is under no obligation to provide retail transmission services. GSEC states that it owns no transmission facilities, that such facilities are owned by GSEC's affiliate, New England Power Company (NEP), and that NEP has filed open access tariffs pursuant to the directives of FERC's Order No. 888. GSEC states that NEP's open access tariffs will be made available to its retail customers only if a voluntary restructuring plan is successfully developed between NEP and GSEC.

Cabletron Systems Inc. (Cabletron) and the Retail Merchants Association (RMA) jointly filed a motion urging the Commission to consider an alternative approach to "assure that there can be no colorable challenge based upon federal preemption that might delay implementation of the retail access program." Cabletron/RMA Motion at 9.

2. Commission Conclusions - Retail Transmission Services

In the Plan, we assumed FERC's ultimate jurisdiction over retail transmission services but asserted that we possessed the legal authority to review and require modification to proposed retail transmission tariffs as a condition to future grants of authority to operate a monopoly electric distribution service in this State. We explained that the Commission has the statutory authority to define utility franchise rights through the imposition of such conditions, stating:

> ...[T]he Commission has the authority to establish the conditions under which a utility provides service in this state. The right to own and operate transmission facilities in New Hampshire is obtained only through the permission of the Commission. The Commission can and will condition that continued permission on the transmission owner's willingness to make a filing at FERC for retail transmission service consistent with the terms and conditions established by the Commission.[25]

We continue to believe that the Commission possesses broad statutory authority to impose new conditions on electric utility franchise rights in order to promote competition or mitigate anti-competitive practices in that industry. Even before the enactment of RSA 374-F, the Commission had a statutory duty to institute such policies whenever it would serve the public good. See, Appeal of Public Service Company of New Hampshire, 141 N.H. 13 (1996). In short, we affirm our belief that electric utilities in this State possess no vested right to operate a monopoly franchise free from the imposition of new standards or conditions which are specifically designed to promote free and fair competition in the retail market for electric services.

[25]Plan, Legal Analysis, at 124.

On the other hand, this particular compliance filing requirement may unnecessarily create confusion over the respective jurisdictional roles of the Commission and FERC. In previous orders, we expressed an intent to work within the jurisdictional paradigm established by FERC in its Open Access Rule.[26] We remain encouraged by FERC's stated desire for a cooperative regulatory regime which accommodates both state and federal policy concerns. During our retail competition pilot program we identified several provisions of the FERC's *pro forma* tariff that were inconsistent with retail transactions, and FERC promptly granted a waiver of those provisions.[27] In Order 888-A, FERC reiterated its willingness to modify the *pro forma* tariff to accommodate state retail access initiatives.[28] Although the procedural path to seek such modifications is not entirely clear, FERC has indicated that it intends to address such state requests on a case-by-case basis.[29] Id.

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[26] See e.g., Restructuring New Hampshire's Electric Utility Industry: A Preliminary Plan, DR 96-150 (September 10, 1996).

[27] New England Power Company, 76 FERC ¶ 61,008 (1996).

[28] Order 888-A, FERC Statutes and Regulations, ¶ 31,048 (1997) at 30,215.

[29] In addition, FERC has signaled its clear intention to order "indirect" retail transmission with respect to facilities over which state commissions may have no jurisdiction. Order 888-A,

FERC Statutes and Regulations at 30,215. We reiterate that in the event that New Hampshire retail customers are denied appropriate transmission services after the start date for retail competition, we will not hesitate to seek an order from the FERC or take other action consistent with the jurisdictional approach outlined by FERC in Orders 888 and 888-A.

After weighing the competing considerations with respect to this issue, we have decided to modify the policy decision announced in the Plan to the extent that it requires utilities to develop specially tailored retail transmission tariffs before making such filings at FERC. Instead, filings by utilities (or their affiliates) will now be voluntary. We will not require utilities or their affiliates to submit for our review and approval new tariffs specifically designed for retail transmission in New Hampshire. However, we strongly encourage jurisdictional utilities to cooperate with the Commission and other interested stakeholders in developing appropriate retail transmission tariffs at the state level. In the absence of cooperation, we will take such action as is necessary to ensure that retail competition is not blocked by utilities denying customers access to appropriate transmission services.

Finally, we announce our intention to schedule technical sessions to allow interested parties to discuss the applicability of the FERC's *pro forma* tariff to retail transactions and the possible modifications thereto that may be appropriate to accommodate New Hampshire retail customers. Participation in these technical sessions is voluntary, although parties should be on notice that the results of these sessions may form the basis of generic waiver requests by the Commission at FERC. Utilities willing to cooperate with the Commission and its Staff in developing retail transmission tariffs tailored for New Hampshire customers should file their proposed tariff with the Commission as part of the updated compliance filing requirements. In the event that a utility declines to file such a tariff on a voluntary basis, it should so inform the Commission in its updated compliance filing.

K. Interim Stranded Cost Recovery

The Commission has been authorized and directed to set an ISC charge for each utility as part of a “generic restructuring order...[and] without a formal rate case proceeding.” RSA 374-F:4, II. The stated purpose of this legislative directive is “to facilitate the rapid transition to full competition. ” RSA 374-F:4, VI(a). ISC charges are to remain in effect for a two-year period following the implementation of utility compliance filings. Id. By statute, ISC charges can establish no legal, factual or policy precedent concerning subsequent requests for “final” stranded cost recovery. RSA 374-F:4, VI(b). See also RSA 374-F, V (authorizing “final” recovery only in the context of a rate case proceeding) .

Each utility’s ISC charge must meet the following criteria: first, it must reflect the Commission’s preliminary determination of an “equitable, appropriate, and balanced measure of stranded cost recovery”; second, it must “take[ ] into account the near term rate relief principle”; and third, it must be “substantially consistent” with the Legislature’s interdependent policy principles. RSA 374-F:4, VI(a). The Commission must make a public interest finding before putting an ISC charge into effect. Finally, RSA 374-F:4, VI(b) provides that any utility may seek adjustment of the ISC charge “at any time based on severe financial hardship.”

The near term rate relief principle provides, in part, as follows:

> The goal of restructuring is to create competitive markets that are expected to produce lower prices for all customers than would have been paid under the current regulatory system. Given New Hampshire’s higher than average regional prices for electricity, utilities, in the near term, should work to reduce rates for all customers. To the greatest extent practicable, rates should approach competitive regional electric rates.[30]

The interdependent principle in RSA 374-F that deals with stranded cost recovery provides, in part:

[30] RSA 374-F:3, XI.

> In making its [stranded cost] determinations, the [C]ommission shall balance the interests of ratepayers and utilities during and after the restructuring process. Nothing in this section is intended to provide any greater opportunity for stranded cost recovery than is available under applicable regulation or law on the effective date of this chapter.[31]

The Plan adopted a generic "benchmark" rate setting methodology for determining ISC charges. This approach was specifically designed to implement the Legislature's directives concerning the establishment of ISC charges. Briefly, the approach called for the following steps. First, the Commission compared the bundled rates for each New Hampshire utility to the average bundled rate for all New England utilities. Utilities whose bundled rates were at or below the New England average were allowed full stranded cost recovery on an interim basis. In the case of utilities whose bundled rates exceeded the regional average, we established a bundled rate target at a level which was actually *above* the regional average, and it was this rate target from which the ISC charges were derived. We set the rate target for high cost utilities at a level above the regional average to minimize the financial impact on those high-cost utilities; however, by raising the rate target we also reduced the possible savings which customers would otherwise realize during the period the ISC charges were in place.

The ISC orders implemented the regional average approach on a utility-specific basis. For utilities with rates below the regional average (GSEC, Unitil), the approach yielded an ISC that provided 100% stranded cost recovery. For utilities with rates that exceeded the regional average (PSNH), the approach yielded an ISC that produced less than 100% recovery. CVEC and NHEC both presented case-specific circumstances which were addressed in their ISC orders.

[31] RSA 374-F:3, XII (a).

In PSNH's case, the Commission set an ISC charge effectively lowering retail rates to within 108% of the regional average. We explained that such an outcome was consistent with the applicable statutory standards and stated as follows:

> In setting these [interim stranded cost] charges, we must be guided by RSA 374-F which requires us to determine rates which are equitable, appropriate, and balanced and in the public interest...The Legislature also stated that restructuring should produce rates that to the greatest extent practicable approach competitive regional electric rates. This suggests that rate differences between New Hampshire utilities and investor-owned utilities in other New England states, which puts New Hampshire at a competitive disadvantage relative to its neighbors, should be a key consideration in the setting of stranded cost charges.[32]

We specifically refuted PSNH's claim that all utility investors should have a reasonable expectation to earn a return on their investment, irrespective of the retail rates a company charges and stated as follows:

[32]Plan at 59 (internal quotations omitted).

> In New Hampshire, utilities have always faced the risk that retail competition would be substituted for cost of service rate regulation. It should be of no surprise that investors of a utility which has maintained its rates, hence costs, at or below the regional average views the risk of competition much differently than a high cost utility...In light of the fact that electric utilities in this State have always faced the prospect of retail competition, it should come as no surprise that those companies with rates significantly in excess of regional rates would be the most vulnerable to competition. In other words, this Commission has always possessed the legal authority and duty to allow electric service to be provided through a competitive market rather than monopoly providers. See, Appeal of Public Service Co., 141 N.H. 13 (1996). Those companies with the highest rates should have reasonably anticipated their relative vulnerability as compared to companies with rates at or below the regional average. The regional average approach simply reflects the level of risk which investors in New Hampshire's electric utilities should reasonably have anticipated.[33]

In sum, we concluded that the regional average approach was both equitable and consistent with the "manifest policy of the Legislature as articulated in the near term rate relief principle."[34]

1. Rehearing Requests - Interim Stranded Costs

a. ISC Charge Methodology

Several utilities challenge the statutory basis for using the regional average benchmark to set ISC charges. CVEC contends that "RSA 374-F...which is in any event of dubious validity, does not contain any affirmative authority for a regional rate cap for purposes of limiting stranded cost recovery." CVEC Motion at 36. PSNH argues that the approach violates RSA 374-F:1 by reducing costs for consumers of electricity via an uncompensated taking of private property rather than by harnessing competitive markets. Unitil argues that the regional average ISC approach is an overly broad and vague standard that may result in an

[33] Plan at 83.

[34] Plan at 82.

arbitrary and capricious level of stranded cost recovery.

b. "Takings" Arguments

Each jurisdictional utility, with the exception of NHEC, argues on rehearing that the Commission's approach for implementing the stranded cost policies of RSA 374-F is inconsistent with their purported rights under the "Takings Clause" of the United States Constitution and the analogous protections under the New Hampshire Constitution. These entities allege similar constitutional violations will occur if they are compelled to offer retail customers unbundled transmission and distribution services on the asserted basis that such action will constitute a non-consensual physical occupation of their private property.

CVEC alleges that "[t]he Commission's decision and RSA 374-F, as applied to CVEC with respect to stranded costs, constitute unlawful takings of private property...[as] these determinations unfairly frustrate, and are utterly inconsistent with, the reasonable expectations of CVEC, CVPS and investors ."[35] According to CVEC, "the existence of a satisfactory end result is what precludes further inquiry as to whether an unlawful taking has occurred...[and] the Commission has no basis for asserting a satisfactory end result with respect to CVEC, and further inquiry is thus appropriate."[36]

PSNH alleges that the Plan (and the PSNH ISC order) "violate the state and federal constitutional provisions outlawing uncompensated takings of property in that near-term

[35]CVEC Motion at 42-43.

savings to customers are produced solely by confiscation of the private property of investors."[37]

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[36]Id at 44.

[37]PSNH Motion at ¶ 10.

Unitil contends that "the Commission's abrupt change in rate making methodology (retaining 'original cost' for distribution and transmission services and moving to 'fair value' for generation services), without consideration of providing cost recovery for utility expenditures...may deprive utilities of their property without just and reasonable compensation."[38] Unitil cites as authority for its right to stranded cost recovery the United States Supreme Court decisions in Duquesne Light Co., v. Barasch, 488 U.S. 299, 307 (1989) and Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

According to GSEC, the Commission erroneously "consistently rejected the constitutional arguments under the takings clause of the New Hampshire and United States constitutions...[and] [a]s a result...failed to recognize fully the constitutional implications of its orders in this case."

In contrast to the foregoing claims, several non-utility entities argue that the Commission's analysis should be clarified by making an express finding that the utilities possess no constitutional right to receive *any* stranded cost recovery and that the sole basis for any such relief is RSA 374-F. According to Cabletron and RMA, the Commission did not address whether removal of electricity price restrictions can result in a taking; specifically, Cabletron and RMA argue as follows:

> ...the Legislature has mandated the removal of regulation of the price of generation and the setting of rates by the marketplace. Where the marketplace, rather than government action, causes loss of property value or an inability to

[38] Unitil Motion at 4.

recover costs, there can be no taking.[39]

Cabletron and RMA urge the Commission to clarify the Plan by explicitly declaring that utilities have no constitutional basis to complain if the Commission exercises its discretion and grants a utility less than full stranded cost recovery.

c. Federal Power Act/Preemption Claims

Each jurisdictional utility, with the exception of NHEC, claims on rehearing that the ISC charges established by the Commission must specifically incorporate anticipated purchase power costs associated with existing FERC-approved wholesale power contracts. Several of these entities also suggest that the Commission must pass through to retail customers the stranded costs incurred by a wholesale supplier who no longer provides wholesale service to an electric utility because of load losses caused by retail access.

GSEC argues that its all-requirements contract with NEP is subject to FERC's exclusive jurisdiction, "including the full recognition and recovery of costs associated with industry restructuring." GSEC argues that absent a voluntary restructuring, GSEC would be required to pay NEP stranded costs pursuant to FERC's Order No. 888 as affirmed in Order No. 888-A. GSEC asks the Commission to (a) fully recognize the preemptive effect of the [FPA] and Order Nos. 888 and 888-A, (b) withdraw the directive for GSEC to give notice under its wholesale contract with NEP, and (c) approve the voluntary and timely restructuring of the NEP-GSEC wholesale power contract.

CVEC makes similar claims and contends that as long as its wholesale rate schedule with CVPS remains in effect, the Commission is prohibited from preventing the retail

[39]<u>See,</u> Cabletron/RMA Motion at 28.

recovery of those wholesale costs. According to CVEC, unless FERC authorizes the termination of its existing rate schedule with CVPS, CVEC must continue to purchase full electric requirements from CVPS, and CVEC may not be prevented from recovering these wholesale costs from its retail customers.

PSNH argues that the Commission's approach will cause a "trapping" of costs in violation of the "filed rate doctrine" under the FPA. Unitil makes a similar claim and alleges that the Commission is prohibited from denying full recovery of power costs billed to Unitil's distribution companies through operation of the FERC-approved Unitil System Agreement.

2. Commission Conclusions - Interim Stranded Costs

a. Introductory Comments

As previously noted, the Commission is required to set ISC charges so as "to facilitate the rapid transition to full competition." RSA 374-F:4, VI(a). Our restructuring orders thus far (including this one) address only ISC claims; final stranded cost recovery issues must await another day. We note that ISC determinations establish "no legal, factual, or policy precedent with respect to the final determination of stranded cost recovery." RSA 374-F:4, VI(b).

The distinction between interim and final stranded cost determinations guides the Commission's review of the rehearing requests. Accordingly, this section addresses the rehearing requests which challenge the "generic" stranded cost policies used to set <u>Interim</u> stranded cost charges.

The Legislature's ISC policies are designed to achieve two distinct but related objectives. The Commission must equitably allocate between utilities and customers the risks and burdens associated with the transition to retail competition. The Commission has made a preliminary determination, which is reflected in the various levels of ISC recovery allowed, that a greater opportunity for full ISC recovery should exist for utilities: (1) whose current bundled rates are reasonably close to the regional average rate and/or (2) who engage in voluntary restructuring activities, such as generation asset divestiture, to accommodate the implementation of retail access.

This preliminary determination dovetails with the goal of achieving near term rate relief in a way that facilitates the "rapid transition to full competition." RSA 374-F:4, VI(a). The Commission's preliminary ISC determinations for utilities whose rates exceed the regional average benchmark show this goal was addressed. Customers of those utilities are the intended beneficiaries of the near term rate relief purpose of the law. We believe that a rapid transition to competition will spur higher cost utilities to improve efficiencies and to mitigate stranded costs. Both objectives were met by allowing recovery of some, but not all of the claimed stranded costs.

We believe that the regional average benchmark approach is conspicuously well-suited to achieve the Legislature's policy objectives. Moreover, such an approach is clearly supported by the United States Supreme Court's decision in Permian Basin Area Rate Cases, 390 U.S. 747 (1968). For utilities with costs lower than the benchmark, the use of rates based on the regional average will permit recovery of 100% of estimated stranded costs and acknowledge that these utilities have satisfied an important objective of keeping New Hampshire electric rates competitive with those throughout New England. For higher-cost utilities, setting preliminary rates above the benchmark but below 100% recovery of stranded costs gives them an incentive to improve their operations so as to achieve competitive pricing.

Although individual utility ISC charges could be set as part of a "generic restructuring order...[and] without a formal rate case proceeding," RSA 374-F:4, II, we did examine the effects of the regional average price benchmark separately on each utility. Order Nos. 22,509-13. Where the Commission determined an adjustment was justified, the ISC charges were set above the regional average benchmark to give partial recognition to claimed potential hardship. This approach encourages utilities to mitigate stranded costs, RSA 374-F:3, XII(b) and (c), and offers relief from claimed hardship of the transition. As required by RSA 374-F:4, VI(b), where "severe" financial hardship can be shown, we will not rule out the possibility that other adjustments may be allowed.

We stand by our finding that the regional average benchmark serves as a helpful measure in determining the appropriate balance between utilities and consumers; thus, it complies with the statutory directive to "balance the interests of ratepayers and utilities during the restructuring process." RSA 374-F:3, XII(a).

The regional average benchmark thus represents a sound generic methodology for establishing ISC charges based on the various public interest objectives that the Commission must meet under the statute. As explained in the Plan's legal analysis (pp. 10-12), use of regional pricing has a sound ratemaking pedigree, making its use as a benchmark for ISC charges appropriate. Nonetheless, any generic approach, including the regional average benchmark here, must have a "safety-valve" mechanism to avoid unintended consequences in specific cases.

The Commission recognizes the need for a waiver procedure under which ISC charges for an individual utility could be based on an asset-by-asset application of the statutory recovery standards. The statute provides a waiver mechanism where a utility demonstrates "severe financial hardship" from the application of general ISC charges. RSA 374-F:4, VI(b).

This waiver mechanism responds to PSNH's request for rehearing. The Commission has already granted PSNH's request to rehear its ISC based partly on its contention that the use of the regional average benchmark will require the write-off of certain regulatory assets. This contention contrasts with the Commission's finding that PSNH's combined rate for ISC charges and transmission and distribution services would yield revenues sufficient to meet its cash needs and produce a pre-tax return on equity of 10.88%. In its ISC rehearing request, PSNH raised further complex issues prompting the Commission to request interlocutory rulings of law from the Supreme Court. Those matters will be dealt with in a separate order. For purposes of this rehearing order, however, the important point is that the law's waiver procedures are fully operational, and they give us sufficient discretion to adjust the level or methodology of setting ISC charges for severe financial hardship. RSA 374-F:4, VI(b). The availability of this statutory procedure to consider deviations from general application of the benchmark in individual cases of severe financial hardship negates any claims that the benchmark should be abandoned as inequitable.

Application of the benchmark also follows established rate regulation principles: this Commission has always possessed the legal authority to allow electric service to be provided through a competitive market rather than by monopoly providers. <u>Appeal of Public Service Co.</u>, 141 N.H. 13 (1996). In competitive situations, low cost companies are more likely to recover all of their costs than are high cost companies. Our orders reflect that principle, but allow some extra relief to high cost utilities. Thus, the availability of the “severe financial hardship” waiver offers the possibility of further relief without the need to abandon the benchmark altogether.

In summary, given the preliminary and transitory nature of the statutory mandate for setting ISC charges, the benchmark offers an administratively efficient and objective measure against which to balance the interests of consumers and utilities, as the law requires. The Commission's ISC orders have already made some adjustments to the benchmark approach for equitable reasons. In the case of PSNH, its initial ISC order reflected an adjustment. Upon rehearing, we have identified the need to change the manner in which its ISC charges are set. We have decided to fashion a cost-based ISC charge for PSNH which is designed to avoid the accounting problems identified by PSNH and others during the rehearing process. Further details concerning PSNH will be addressed in a separate order.

We conclude that the regional average approach is both equitable and consistent with the interdependent policies that the Legislature charged the Commission to consider. Accordingly, the Commission denies the rehearing requests that seek to overturn the benchmark adopted to make ISC determinations. In our view, the approach is fully consistent with the Legislature's express intent as well as with constitutional requirements. This approach still leaves room for the opportunity to provide a “severe financial hardship” waiver where appropriate, as in PSNH’s case.

b. “Takings” Claims

The Commission rejects the "physical takings" arguments advanced by utilities as a general prohibition against application of the open access requirements of RSA 374-F. Although incumbent utilities will be obligated to offer retail customers with open access transmission and distribution services,[40] they will be compensated for the costs of providing these services through regulated rates. Utilities will be entitled to rates for such service consistent with well-established constitutional principles that provide for the return of, and return on, property devoted to providing those services.

Should utilities feel that a particular rate for an open access service is noncompensatory, we have no doubt that they will challenge that rate. Until such a concrete challenge is brought, however, it cannot be assumed, as the rehearing requests do, that rates for such service will necessarily be unconstitutional. Accordingly, the Commission denies the rehearing requests seeking to prohibit the open access provisions from going into effect on claims that an impermissible taking of property will occur.

The rehearing requests also contend that the Takings Clause of the United States Constitution (and the commensurate New Hampshire Constitutional protections) require the Commission to set ISC charges based on criteria beyond the stranded cost recovery principles set forth in RSA 374-F. In essence, these parties contend that they possess a constitutional right to receive an ISC charge that will guarantee recovery of 100% of their claimed stranded costs

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[40] New Hampshire utilities do not have a legal right to use their monopoly wires services to exclude other power suppliers from accessing retail customers. See Appeal of Public Service Company of New Hampshire, 141 N.H. 13, 22 (1996)("That the [C]ommission may have historically interpreted the public good as requiring monopolies in the provision of retail electric service does not preclude it from adopting a new paradigm based on changing concepts of what the public good requires").

despite the statutory directive which requires an "equitable, appropriate and balanced measure of stranded cost recovery." RSA 374-F:4, VI(b).

These contentions, if correct, would undermine the validity of RSA 374-F itself. Such contentions face very steep, if not insurmountable, hurdles given the extremely broad powers that the Legislature possesses to set laws regarding utility regulation: "It cannot seriously be contended that the Constitution prevents state legislatures from giving specific instructions to the utility commissions. We have never doubted that state legislatures are competent bodies to set utility rates." Duquesne Light Co. v. Barasch, 488 U.S. 299, 313 (1989).

In this case, the Legislature has offered very detailed instructions on factors to be considered, objectives to be achieved and the weight to be given in making ISC determinations. RSA 374-F:4, VI. On their face, those instructions do not violate constitutional standards, but attempt to achieve a balance among the utility and consumer interests affected by the transition to full competition.

In addition, the Commission has not found a constitutional right which overrides the statutory instructions, as the utilities suggest, so as to require us to allow recovery of all claimed stranded costs regardless of the risks or burdens associated with the transition to competition. Neither the United States nor the New Hampshire Supreme Courts have divined a constitutional right that protects regulated utilities from the effects of competition. To the contrary, "it is not the mandate of the constitution to rejuvenate the value of the investments of a company whose zenith of opportunity has been eclipsed by the operation of economic forces." Petition of Public Service Company of New Hampshire, 130 N.H. 265, 277 (1988) (internal quotation marks and citation omitted). The Commission thus denies rehearing of those challenges asserting a constitutional right to recover all stranded costs in all cases. We affirm our intent to implement RSA 374-F by allocating, through ISC charges, the risks and burdens associated with stranded costs in a manner that best serves the law's several public interest goals.

While there is no constitutional protection against the risk of competition, RSA 374-F does require that the Commission make preliminary determinations about stranded cost recovery based on appropriately balanced, equitable grounds during the transition period to restructuring. In general, full recovery of all claimed costs is not guaranteed by rate regulation. See 130 N.H. at 277 ("where the balancing of consumer interests against those of investors causes rates...insufficient to ensure the continued financial integrity of the utility,...the utility has encountered one of the risks that imperil any business enterprise, namely the risk of financial failure") (citation omitted).

The Commission's balancing of interests in its ISC orders does, however, weigh the need for continued financial integrity in the calculus of how ISC charges should be set. For those utilities permitted to recover, on an interim basis, 100% of stranded costs, continued financial integrity is not an issue. In cases where some evidence of financial hardship was shown, adjustments above the benchmark level were granted. Finally, the waiver procedure permits further relief where a utility can show "severe financial hardship" under RSA 374-F:4, VI(b). Thus, consideration of utilities' need for continued financial integrity has been accommodated in the Commission's approach.

It must also be reiterated that the ISC charges are being set at a time when stranded cost issues remain in a fluid state. At this early stage in the transition to full competition, utility claims for stranded cost relief are based on speculative estimates of market values. For example, it has been claimed that utilities who choose to divest their generation facilities will realize revenues that are well below the book costs of those facilities. However, recent initiatives by utilities in the region to auction their non-nuclear generation assets have yielded prices that substantially exceed the book costs of

those assets. In short, the exact level of stranded costs cannot be known until such a sale is consummated.

The present uncertainty warrants the two stage approach to stranded cost recovery found in the law. At this time, the presence of these unknowns limits the Commission to making preliminary determinations about <u>interim</u> stranded cost recovery that will have no legal, factual or policy precedent as to how the Commission can, should or will deal with final stranded cost questions. Again, in this situation, the law establishes interim objectives of near-term rate relief, improving New Hampshire's competitive price position in the region, and easing the transition to full competition, but not of fully resolving all stranded cost issues.

Until utilities have complied with the restructuring mandates, the exact scope of the stranded cost claims (or if there will be any claims) will not be known. At that time, with a more fully developed picture than is available now, the Commission can address those claims consistent with the statutory objectives for making a final determination of stranded cost recovery. Consequently, the Commission denies those requests for rehearing that rest on speculative assumptions about what stranded costs might result from restructuring as premature.

We turn next to Cabletron/RMA's request for clarifications. First, these entities ask the Commission to make an explicit finding that New Hampshire's electric utilities have no constitutional right to any stranded cost recovery once price regulation for generation services is removed. Second, they urge the Commission to articulate a generic rationale for stranded cost recovery based, not on constitutional principles applicable to ratemaking, but on the State Constitution and RSA 374-F.

As noted above, our policies regarding ISC recovery derive fundamentally from the policy objectives embodied in RSA 374-F, which require a balancing of ratepayer and utility interest in setting ISC charges that are equitable, appropriate and in the public interest. RSA 374-F:3, XII(a). The Commission interprets these provisions as requiring consideration of the financial impact of our ISC determinations on utilities, irrespective of whether such consideration is required by the United States or New Hampshire Constitutions. Thus, it is unnecessary to explore what rights utilities might have been able to command in the absence of such statutory provisions. On this basis, we decline to issue a declaratory ruling addressing the lower constitutional peripheries of utility stranded cost determinations.

Cabletron/RMA's second request seeks to have the Commission identify a rationale for allowing interim stranded costs based on the State Constitution and RSA 374-F, rather than on federal constitutional principles, which Cabletron/RMA contend no longer apply once market forces set prices. This request rests on two faulty assumptions.

First, the request implies that the standards applicable under the State Constitution or under RSA 374-F are different from those required by the federal Constitution. We do not agree: the standards set in RSA 374-F:3, XII(a) and RSA 374-F:4, VI(a) requiring that stranded cost determinations be "equitable, appropriate, and balanced" coincide with federal constitutional requirements. E.g. FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 582 (1942).

Second, Cabletron/RMA's request, taken to its logical conclusion, would limit the recovery of fixed generation costs to amounts which would be received through market prices. To adopt such a conclusion, the Commission would have to ignore the explicit statutory language requiring that we "determine rates" for stranded cost recovery. RSA 374-F:1, III, 374-F:3, XII(a) and 374-F:4, VI(a). The Commission cannot abdicate express responsibility assigned to it by the Legislature.

To the extent that Cabletron/RMA's request seeks to have larger consideration be given to market prices in setting ISC (or final stranded cost) charges than might be given in setting rates for a fully regulated utility, the Commission believes that its regional average price benchmark fulfills that role as part of the balancing required by the statute. In the ISC orders, the Commission measured each utility's average bundled rate against the benchmark to determine whether an adjustment was appropriate. In the Commission's view, an adjustment was warranted where a utility's rate exceeded the benchmark, and thus violated the statutory goals of improving New Hampshire's competitive position and providing near term rate relief. Thus, larger consideration has been given to market forces in setting ISC charges than is the case under traditional rate regulation.

For these reasons, Cabletron/RMA's second requested clarification is denied.

c. Federal Power Act/Preemption Claims

We reaffirm our decision to address on a case-by-case basis the recovery of stranded costs associated with existing wholesale purchased power obligations. Until those determinations are made, however, we have not prospectively barred any utility from recovering unavoidable costs associated with wholesale purchased power obligations. The key is that such costs be unavoidable, and the statute places "an obligation [on utilities] to take all reasonable measures to mitigate" such costs, including renegotiation of existing contracts. RSA 374-F:3, XII(c). This provision as well as traditional prudence principles compel utilities to terminate, sell, assign or renegotiate their existing purchased power contracts to minimize or, if possible, avoid costs and liabilities associated with these contracts.

Our decision to defer making final determinations on a utility-specific basis does not preclude recovery of unavoidable purchased power expenses. Rather, the Commission has taken the utility-specific approach on this question to evaluate the mitigation efforts undertaken by each utility. Because mitigation efforts will vary on a case-by-case basis, this approach is the only means for us to comply with the statutory directive of limiting recovery to unavoidable purchased power costs that are claimed as stranded.

3. Rehearing Requests - Decommissioning Costs

CRR seeks clarification regarding the Commission's stranded cost policies as they relate to the ability of utilities to collect nuclear decommissioning charges. Specifically, CRR urges the Commission to clearly state that "stranded cost recovery for decommissioning will be for the liability incurred as of the day of customer choice, not for any increase in that liability as a result of operation beyond that date."[41]

4. Commission Conclusions - Decommissioning Costs

Absent a change in RSA 162-F, the current law on decommissioning, we continue

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[41]CRR Motion at 5.

to believe that the Commission must provide for the recovery, through a non-bypassable wires charge, of the estimated costs to safely decommission the Seabrook nuclear facility at the end of its energy producing life. As to the request by CRR that such recovery be limited to the costs incurred as of the retail access date, we note the practical difficulty of determining which decommissioning cost increases are the result of operating the facility after the retail access date and which are due to changes in the decommissioning cost estimate prior to competition. That complication notwithstanding, we agree with CRR that on-going costs of nuclear generation, including incremental increases in the cost to decommission the facility, could appropriately be considered a generation-related variable cost. In theory, at least, these costs could be subject to market forces like any other generation-related cost. Given the critical health and safety concerns raised by nuclear decommissioning, however, we are not prepared to rely solely on the market to collect decommissioning funds, and we would not advocate a change to RSA 162-F that would do so.

In the Plan, we called for decommissioning expenses to be collected as a non-bypassable wires charge, apportioned to those distribution companies that currently have an ownership share in Seabrook. Collecting decommissioning expenses according to a company's ownership share that had been developed in an era of combined generation, transmission and distribution utilities raises interesting questions in a restructured environment. Even at present, before retail competition is in place, we are faced with one joint owner of Seabrook that has no distribution function and therefore cannot collect its decommissioning expenses in a wires charge, which has raised concerns at the Nuclear Regulatory Commission (NRC) about that joint owner's assurance of funding its decommissioning obligations. The NRC concerns and the larger issue of assurance of funding of all joint owners' decommissioning obligations in a restructured era have been the subject of lengthy investigation before the Nuclear Decommissioning Finance Committee, which continues to explore these issues.

We also are concerned about the impact on stranded costs if we, or the Legislature, were to adopt a decommissioning funding mechanism that left collection of decommissioning expenses to market forces rather than relying on a wires charge. Our expectation is that the value which could be attained for nuclear entitlements in a utility asset sale would be greatly diminished if there were no separate wires charge mechanism to collect decommissioning expenses. A diminished sale price for nuclear entitlements means higher stranded costs.

Finally, we must recognize that nuclear decommissioning is a regional issue, as the Seabrook joint owners are located throughout New England. This is an issue that must be addressed on both a state-specific and region-wide basis. We intend to work with our counterparts within the New England Conference of Public Utility Commissioners (NECPUC) to seek regional solutions where appropriate.

We also commit to working with the Legislative Oversight Committee on Electric Utility Restructuring and other relevant legislative committees to examine the workings of the current decommissioning law in the context of a deregulated generation market. Until there is a change to RSA 162-F, it would not be responsible to modify the current approach to the collection of decommissioning costs.

5. Rehearing Requests - Exit Fees

CRR requests that the Commission reconsider whether customers who choose to self-generate should pay an exit fee rather than pay stranded cost charges when and if they actually utilize back-up services. According to CRR, the Commission's policy would violate RSA 374-F because it would allow self-generation customers to 'bypass" stranded cost charges. In addition, CRR argues that the ability to avoid stranded cost charges in this manner will result in cost-shifting between large customers, who are the most likely customers to self-generate, and small commercial and residential customers who will have to assume the stranded cost burden avoided by self-generation customers. CRR suggests that the Commission impose a demand charge for self-generation customers except in the case of those customers who are completely and permanently disconnected from the grid.

6. Commission Conclusions - Exit Fees

We affirm our decision prohibiting the use of exit fees to recover stranded costs from self-generation customers who either abandon the grid totally or receive back-up/maintenance services. CRR apparently agrees with that decision as it relates to the use of exit fees, but contends that self-generation customers who retain the right to access the generation market for back-up power should pay for that right through a demand-based stranded cost charge. As noted in the Plan, the opportunity to self-generate has always been a fundamental right of New Hampshire electric customers. Further, because utilities have been compensated for that risk through allowed equity returns, we do not accept the premise that self-generation actually produces stranded costs.[42] Therefore, CRR's proposal to recover a greater share of

[42]It is worth noting that the FERC in Orders 888 and 888-A declined to provide wholesale power suppliers an opportunity to recover costs from wholesale customers' costs "associated with the normal risks of competition, such as self-generation, cogeneration, or loss of load, that do not arise from the new, accelerated availability of non-discriminatory open-access transmission." Order 888-A, at 30,361.

stranded costs from self-generation customers is in effect an attempt to alter the historic responsibility for power system costs. We decline to do so. We also point out that our policies on this issue and on the recovery of costs stranded as a result of C&LM programs are consistent, albeit for a different reason. Customers who remain on the grid but avail themselves of energy efficiency opportunities (whether funded directly or through contributions from other customers) are avoiding stranded costs that otherwise would have been recovered through regulated per kWh rates. In effect, these customers have chosen to meet a portion of their energy service needs through "off-grid" means. If we were to apply CRR's recommendation consistently, customers would no longer have the incentive to reduce their electric bills by installing energy efficiency measures. The same argument could be applied to customers who switch to natural gas or propane for their heating or manufacturing needs but continue to take grid service in order to power lighting and appliances.

7. Rehearing Requests - QF Costs

The Wood-Fired QFs and Concord Cooperative seek several clarifications relating to PSNH's on-going obligations to purchase energy and capacity pursuant to certain rate orders issued by the Commission. These entities seek clarification on the following subjects: whether PSNH's current obligations will change or remain the same after they are "assumed" by the distribution company serving PSNH's customers; the manner in which the assumption of PSNH's obligations will take place; whether a reduction in demand for default service will affect the obligation of a distribution company to purchase QF supplies; whether PSNH's obligations to purchase excess energy from the QFs will remain unchanged; whether PSNH has an on-going obligation to provide the Wood-Fired QFs back-up power services; and a clarification with respect to the support relied upon for the Commission's finding in the Plan that "it is unlikely that the output by QFs will be sufficient to meet the total load of default power service." Plan at 89.

GSHA seeks similar clarifications to those requested by the Wood-Fired QFs. Specifically, GSHA seeks clarification relative to a distribution company's on-going QF obligations when default service demand drops below the aggregate output of QF power serving the utility.

8. Commission Conclusions - QF Costs

We reaffirm our intent to implement RSA 374-F:3, XII(b) which provides that "utilities should be allowed to recover the net nonmitigatable stranded costs associated with...power acquisitions mandated by federal statutes or RSA 362-A." We decline at this time to address the Wood-Fired QFs' request for specific findings relative to PSNH's ongoing obligations under certain long-term rate orders. We reiterate, however, that it is not our intent to disrupt or impair any legal rights and obligations which were created as a result of the rate orders, RSA 362-C or the Public Utility Regulatory Policies Act, 16 U.S.C. § 824-a(3) (PURPA). On the other hand, we do not view RSA 374-F as an opportunity for QFs to enhance any such rights. Utilities have a statutory duty to mitigate all possible generation stranded costs, including those associated with existing QF obligations. However, nothing in the Plan or this Order shall affect the existing rights and obligations of QFs and utilities.

L. Special Contracts

In the Plan, the Commission observed that at least fifty large customers of PSNH or NHEC receive discounted rates through special contracts that were approved pursuant to RSA

378:18 or 378:18-a. The Commission recognized the potential adverse effects that special contracts might have on retail competition, but agreed with PSNH and others who argued that utilities should continue to honor these contractual commitments after the retail access date. The Commission did, however, direct utilities with special contract customers to unbundle their rates into the primary unbundled service components (i.e., distribution, transmission, stranded cost and generation). The Plan also required utilities to deduct from their overall stranded cost revenue requirement the discount associated with these contracts. Finally, the Plan directed utilities to include in their compliance filings a proposal for continuing to supply the energy needed to meet the requirements of special contract customers.

1. Rehearing Requests

PSNH contends that the Plan violates RSA 378:18-a, IV by “imputing to PSNH the difference between regular tariffed rate and the special contract rate.” In addition, PSNH alleges that the Commission’s decision interferes with these special contracts by requiring PSNH to divest its generating assets and purchased power contracts.

CVEC alleges that the Commission’s special contract policy is unfair and contrary to the Legislature’s intent in RSA 378:18-a, IV.

2. Commission Conclusions - Special Contracts

We decline to modify our decision relative to special contract issues. For the reasons provided in the Plan, we disagree with PSNH and CVEC that our decision violates RSA 378:18-a, IV. We also disagree with PSNH’s argument that our decision will “interfere” with existing special contracts. There is no evidence to support PSNH’s implicit assumption that the market price of energy to serve special contract customers will be greater than the average costs associated with PSNH's current generation portfolio. Similarly, CVEC has provided no evidence to support a claim that contributions to fixed costs under the special contracts will be lower under our policy than currently exists today.

M. Default Power Service

In the Plan, we noted that some customers may choose not to participate in the retail market, and that some competitive suppliers may not extend offers to certain customers. Consequently, we developed a conceptual framework which would require incumbent utilities to provide customers with "default" generation service by procuring power supplies through a competitive bidding process and/or spot market purchases. One possibility, under such an approach will be default service customers to pay the average price of the winning default power bids. We specifically found that it would be inconsistent with our mandate under RSA 374-F to set regulated rates for such service:

> Continuing to offer service to customers at rates fully regulated by this Commission does not benefit customers and is inconsistent with RSA 374-F:3, III. It is clear to us that the load of those customers who either choose not to participate or who are unable to participate in the market must be opened up to competition. If it is not, independent competitive suppliers, marketers, brokers and aggregators will be disadvantaged and, consequently, competition will be inhibited. Our vision of default service is consistent with the development of a competitive marketplace. The continued provision of a fully regulated service option, as proposed by the various proponents of [price regulated] service, fails to accomplish that result.

Plan at 88. Moreover, although we recognized the need for such a service, we noted that the prolonged use of default power service under the above-described model may have the unintended result of promoting wholesale rather than retail competition.

Under the Plan, we found that it was appropriate to require distribution companies to "administer" default power service. We based our decision on our belief that many customers "may resist the shift to competition because of the additional effort involved in arranging their own power supplies." Plan at 89. We also found that such an approach would minimize customer confusion and simplify the administration of QF contracts, which we required distribution companies to use to meet default loads.

1. Rehearing Requests - Default Service

CVEC asserts on rehearing that the default power requirement is "deficient" because it does not include a specific cost recovery mechanism for administering QF contracts. PSNH argues that the "profitless" pass-through of administrative costs contemplated in the Plan will fail to provide an incentive for PSNH to achieve the lowest possible market cost of power and will result in an uncompensated taking of PSNH's property.

2. Commission Conclusions - Default Power Service

In the Plan, we established a new service obligation on the part of incumbent utilities, i.e., to serve as the administrator of default power service. We loosely defined this service as unbundled generation service that does not require customers to deal directly with competitive suppliers. The purpose of this new service was to ensure that customers who "choose not to choose" would be provided with a reliable, market-based power supply. For the reasons explained below, it is essential for us to supplement our prior discussion and amend the Plan to the extent that it placed power supply obligations on incumbent utilities.

The model for providing default service which we established in the Plan required incumbent utilities to make new wholesale power purchases (as a result of a competitive bidding process) and to resell that power to default customers. With the exception of QF obligations, we expressly prohibited utilities from utilizing existing power supply arrangements to meet the needs of default customers. Our objective was to allow all customers, including those whose participation in the retail market is delayed or interrupted, to realize cost savings available in the competitive power market.

Since we issued the Plan, however, we have identified several potential problems associated with this approach which may seriously undermine the foregoing policy objectives. Primarily, we are concerned that the approach articulated in the Plan may provide former wholesale requirements suppliers with the opportunity to seek recovery of stranded costs at FERC beyond those which this Commission might allow.[43] This opportunity could arise only if we require incumbent utilities to administer default service in a manner which would involve such utilities becoming an unbundled transmission customer of their former requirements supplier. While we disagree that default service obligations on the part of incumbent utilities would trigger any wholesale stranded cost liability, we are nonetheless concerned about the potential for such disputes.

Secondly, we are concerned that the default service paradigm established in the Plan could be misconstrued as merely an extension of the incumbent utilities' historic obligation to provide bundled energy service to retail customers at regulated rates. We disagree: we intend

[43]In fact, CVEC's parent and current requirements supplier, Central Vermont Public Service Corporation (CVPS), has already advanced this argument at FERC in support of a request for wholesale stranded cost relief in connection with its proposed termination of the CVPS-CVEC requirements contract. See Central Vermont Public Service Corporation, FERC Docket No. ER98-1440-000.

default service to provide a temporary safety net for customers who "choose not to choose" and to complement retail competition by imposing a new more limited obligation on the part of incumbent utilities to ensure that all customers receive energy service.

Although we disagree that the default service paradigm articulated in the Plan represents an extension of a utility's historic service obligation, we will vacate that part of the Plan and instead entertain proposals from competitive suppliers to serve the energy requirements or demands of default customers. We will no longer require incumbent utilities to purchase power on behalf of any retail customer, including default customers. We invite additional comments from parties on specific models under which third-party suppliers would serve default customers directly as a result of a competitive bidding process. Those comments should be submitted by April 6, 1998. Following a review of these comments, we will issue a separate order addressing bidding parameters. We will also consider specific proposals by distribution companies to serve default customers provided that such proposals would not trigger stranded cost filings at FERC. Any proposal to serve the customers within a specific utility's service territory should be submitted within that utility's compliance proceeding. We will also consider proposals to provide default service on statewide basis.

This decision requires us to revisit our policy concerning the use of QF power to supply energy to default customers. See Plan at 89-90. Specifically, we direct utilities to resell energy and capacity purchased under QF agreements into the wholesale power market as part of their overall obligation to mitigate above-market costs. Specific proposals should be included in compliance filings.

Based on the foregoing, the specific requests for clarification filed by PSNH and CVEC are moot.

N. Transition Service

1. Comments on Transition Service

By letter dated January 12, 1998, the Commission allowed the parties an opportunity to submit comments on “transition service,” which is a new service that has been proposed by various parties to supplement the provision of default service.[44] Governor Shaheen, Cabletron, Enron, GSEC, OCA, PSNH, RMA and Unitil submitted written comments, which we summarize below.

a. Nature of the Service

GSEC states that transition service should be an optional service that “is similar in kind and quality to what [customers] receive today, but which would also offer them the benefits of a competitive generation market.” The OCA believes that transition service should be an unbundled service and that the names of suppliers should be displayed on customer bills. PSNH describes transition service as a “full service option” for customers who choose not to select a competitive supplier. PSNH does not specify whether its service should be bundled or unbundled.

With the exception of Enron, all commenters appear to advocate the same transition service paradigm, that is, a service administrator (either a distribution company or an

[44]In the Plan, we did not adopt the term “transition service”; however, as we explain below, the proponents of this service seek to implement the same features that characterize default service.

independent third party) would acquire sufficient power in the wholesale market through a competitive bid and then resell that power at regulated rates to retail customers. Enron, by contrast, would eliminate the "middle-man" and allow competitive suppliers to bid to serve all or parts of the transition service load directly. Under Enron's proposal, transition service would become a pure retail transaction.

b. Eligibility

GSEC and PSNH state that all customers who "choose not to choose" should be eligible for transition service. The OCA and PSNH believe that transition service customers should be able to terminate service at any time, but should not have an unlimited right to return. The OCA proposes a 120 day window, beyond which customers must take default service or purchase directly from competitive suppliers. PSNH proposes that only residential customers be allowed to return, provided they do so within 90 days after choosing a competitive supplier.

PSNH proposes that transition service be offered for a period no shorter than three years and no longer than seven. Transition service customers should also be eligible, according to PSNH and the OCA, for default service at the end of the transition service term. GSEC believes that the service should serve as a transition tool and provide customers with an incentive to move to the competitive market. In order to accomplish that goal, GSEC recommends that the term be limited to three to five years with annual caps that escalate over time placed on the price of energy.

c. The Need for Transition Service

GSEC contends that customers should have the option of taking transition service because service choices and quality information may be in short supply in the early years of retail competition. GSEC also suggests that the region's current tight capacity situation may make it difficult for some customers to obtain attractively priced energy supplies in the competitive market. Price guarantees can be secured, according to GSEC, by the establishment of annual caps on the price of energy. PSNH concurs and suggests that all utilities negotiate "backstop" agreements with power suppliers so as to limit transition service energy prices consistent with specified "overall rate targets". Customers taking default service would not, according to PSNH, receive these price assurances. The Governor also believes that it may be appropriate in some circumstances

to limit transition service prices in order to guarantee customer savings and smooth the path to competition.

Unitil contends that the establishment of a below-market, standard offer service similar to those offered in Rhode Island and Massachusetts would deter the emergence of new competitors in New Hampshire, impede the development of fair and efficient energy markets, and increase costs for future customers. Concurring, Enron asserts that the adoption of inappropriate market proxies in other jurisdictions has delayed the transition to full competition. If a price cap is deemed to be a necessary component of transition service, Enron suggests that the Commission utilize either the LaCapra market price estimates or the average clearing prices for energy, capacity, and ancillary services available through the regional power exchange.

d. Power Supply Issues

All commenters agree that power supplies for transition service should be acquired through a competitive bid. GSEC states that bidders must be "qualified" but does not specify the qualification requirements. The OCA states that suppliers should register with the Commission to provide transition service and must commit to a strict code of conduct. Enron believes that affiliates of a distribution company should be prohibited from bidding if the distribution company administers the bid. PSNH, on the other hand, believes that adequate safeguards can be developed to protect against affiliate abuses. The Governor suggests that it may be appropriate to limit the involvement of affiliates in the bid process.

Unitil believes that a market-based transition service can be implemented without overturning existing multi-state settlements. By requiring all utilities to put transition service out to bid, and directing those with guaranteed below-market power supply agreements to auction the rights to that power and credit the profits against stranded costs, Unitil argues that customers can enjoy both the benefits of the competitive market and the benefits of favorable power supply agreements.

PSNH and Enron also made suggestions to reduce stranded costs through the bid process. PSNH suggests that if the bid produces prices below its proposed backstop level, the resulting power cost savings should be used to reduce stranded cost charges instead of transition service charges. Enron proposes the establishment of bidding criteria that encourage bidders to include in their bids up-front payments. The up-front payments from winning bidders would then be used to offset stranded costs. Enron also supports the proposal in the Governor's September 29, 1997 legal and policy memorandum to mandate the selection of at least three bidders.

e. Administration

GSEC and PSNH believe that transition service should be administered by distribution companies. The OCA contends that the provision of transition service by distribution companies raises important jurisdictional and anti-competitive concerns and suggests that an independent third party be selected for each service area. In the alternative, the OCA argues that distribution companies should offer an aggregation service and not take title to the power.

f. Implementation Issues

Unitil argues that whatever policy the Commission adopts on transition service, it must be applied uniformly in all service areas. A piecemeal approach to transition service, according to Unitil, would balkanize the emerging competitive market and thwart competition. GSEC, on the other hand, believes that the Commission's transition service policy should allow terms and conditions to vary from utility to utility. The Governor believes that the Commission's policy should encourage consistency across distribution companies, while allowing room for utility-specific negotiations.

2. Commission Conclusions - Transition Service

We begin with the question of whether there is a need to add a transition service option, particularly in light of the availability of default service. After carefully reviewing the comments of parties on this subject, we have concluded that our new model for default service can achieve the same objectives as those advocated by proponents of transition service. In both service models, the power supplies to meet the needs of default power customers would be acquired through a competitive bidding process. More importantly, the reason for establishing such a service is the same as that which caused us to create default service: to allow retail customers to realize some of the benefits of competition without requiring them to deal directly with competitive suppliers.

Some commenters believe that transition service is necessary to achieve other objectives, in particular, stable and predictable energy prices. We disagree. This argument appears to be premised upon an assumption that our default model cannot achieve these pricing goals. On the contrary, default service model can achieve these objectives through the use of appropriate bidding rules and selection criteria. One way, for example, is to require bidders to submit bids which include prices that are known in advance and do not vary significantly over time. For all of these reasons, we believe it is unnecessary to add a third service option at this time.

In light of the foregoing observations, we will address the outstanding comments concerning transition service as a supplement to our prior discussion on default service. From this point forward, however, we will no longer refer to a separate default service, believing that transition service more accurately depicts the nature and availability of the service added herein.

We continue to believe that transition service should be available for no more than 60 days to large customers who have made the transition to the competitive market, and who for one reason or another, find themselves temporarily without a supplier. However, because of the anticipated need to educate small commercial and residential customers about retail access, transition service will be available to those customers for at least one year period beginning on the date that competition commences and continuing until such time as the Commission makes the determination that such transition service is either no longer necessary or should be modified as the result of experience with the competitive market.

In our view, large customers have the ability to make informed decisions and there will be competitive suppliers who will be ready to serve them. The evidence in our pilot program reinforces this observation, and we believe the predicted modest level of market activity in other New England states over the next few years may benefit New Hampshire customers. We are particularly concerned that broadening the availability of transition service to large customers would hinder retail competition and would send the wrong signal to potential competitors about the State's policy objectives which are clearly articulated in RSA 374-F. Accordingly, we affirm our decision to allow only those customers with maximum demands of less than 100 kW to use transition service at the start of retail competition.[45]

We decline Enron's invitation to prohibit affiliates of distribution companies from participating in the transition service bidding process if the service is administered by the distribution company. As discussed above, we are no longer requiring distribution companies to administer this service. Also, we believe that the interests of those customers and non-affiliated competitors can be adequately protected by appropriate affiliate transaction rules. We agree, however, with the suggestion to limit the percentage of transition service load that any single supplier can serve in each distribution company's service area.[46]

We agree with Unitil that any policy on transition service should be applied uniformly statewide. It would be unfair to potential competitors (including affiliates of other

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[45]See, Plan at 91.

[46]Though we decline to specify at this time the maximum percentage, we believe that there should be multiple suppliers to address potential market power concerns.

distribution companies) and harmful to retail customers to allow one utility to incorporate features in its transition service that limit the ability of competitors to compete while requiring others to fully open their markets. While we understand the desire to establish predictable prices for transition service, we question the wisdom of achieving that objective by placing artificial constraints on the outcome of a competitive bidding process. The Legislature has decided that retail competition will lead to a more efficient industry structure and reduce costs to customers in the long term. As a general matter, artificial restrictions on the ability of competitors to compete and on the ability of customers to choose are inconsistent with the Legislature's policies and inevitably will lead to higher costs in the long term. We reaffirm our commitment to rely upon market forces to achieve the policy goals articulated by the Legislature in RSA 374-F.

O. Energy Efficiency

As part of the Plan, the Commission examined whether distribution companies should continue to plan and administer ratepayer subsidized energy efficiency programs after the implementation of retail access. This issue received extensive comment from parties both supporting and opposing the continuation of such programs. In the Plan, the Commission announced its intention to phase out ratepayer-subsidized conservation programs within two years of implementation of retail choice. We stated our belief that cost-effective energy efficiency programs have been and will continue to be valuable but focussed on the role of the regulated distribution company in a retail choice environment. We found that today's programs, based predominantly on long-term avoided cost projections of *generation*, would not be appropriate for a distribution company to administer. See Plan at 111. We stated our belief that industry restructuring would lead to the increased development of competitive markets for energy efficiency services and that ratepayer-subsidized programs administered by distribution companies could impede the development of this continually evolving market. Plan at 112.

1. Rehearing Requests - Energy Efficiency

CLF, on behalf of itself and others who are part of the Electric Utility Restructuring Collaborative (collectively, CLF), GSEC and the Governor's Office of Energy and Community Services (ECS) disagree with our findings on energy efficiency and filed for rehearing. Cabletron opposed ECS's motion for rehearing.

CLF states that in passing RSA 374-F, the Legislature gave the Commission specific directives concerning public policy issues such as energy efficiency, renewable energy resources and the environmental effects due to restructuring. In CLF's opinion, the Plan violates those directives and results in "unsound and unreasonable" policy which the Commission should reconsider. CLF disagrees with many of the Commission's findings, especially the two-year phase out of utility sponsored programs, and argues that the Plan did not address market barriers, lost opportunities, or the lack of incentives for energy efficiency programs. Based on RSA 374-F:3, X, CLF argues that the Plan violates the mandate of the Legislature and wrongly focusses on the distribution company and its avoided costs upon which to measure the cost effectiveness of energy efficiency programs. CLF argues that utility sponsored energy efficiency programs are for the benefit of ratepayers and society, generally. The Commission's current benefit-cost test, the Total Resource Cost test, is appropriate, therefore, to evaluate energy efficiency programs. CLF agrees with the Commission's observation in the Plan that the State's experience in the last few years with utility sponsored energy efficiency programs, with one exception, has been disappointing, but believes this is because not enough utility-sponsored programs have been approved and funded.

CLF urges the Commission to adopt a 3.2 mills per kWh wires charge to fund energy efficiency programs and a 0.3 mill per kWh charge for renewables commercialization and to establish working groups to recommend to the Commission how to best implement commercialization programs for energy efficiency and renewable resources. CLF also asked that the Commission revise the Plan to support comparable emissions standards for all power plants.

We granted the rehearing requests to address a number of specific issues concerning energy efficiency: market barriers, market-based incentives, the appropriate benefit-cost test, program administration, and impact on near-term rate relief. See Order No. 22,576 (April 30, 1997).

We received written comments and testimony from a number of parties and Commission Staff concerning energy efficiency and environmental and renewable energy issues. Additional comments were received from current and past members of the Legislature and from an energy services company. The Commission took evidence in a full day of panel discussions on October 9, 1997.

2. Comments on Energy Efficiency and Other Public Policy Issues

a. Market Barriers

The proponents of continued electric utility funding for energy efficiency programs, CLF, GSEC, ECS, Save Our Homes Organization (SOHO), National Association of Energy Service Companies (NAESCO) and the Northeast Energy Efficiency Council (NEEC), argue that market barriers exist which prevent or impede the full development of private market-based energy efficiency services; utility sponsored and ratepayer-subsidized programs are necessary, therefore, to reduce or eliminate the market barriers. Those market barriers most often cited include the high discount rates of customers, the uncertainty of benefits associated with energy efficiency products, the split incentives between users of energy and the owner or builder of the facility, the high initial cost of the product and the information and transaction costs associated with energy efficiency products. Some parties cited the absence of including all the environmental costs of supply-side options in the price of the product as a market barrier for customers to choose energy efficient products.

Most of the comments focused on the market barriers faced by residential and small commercial customers and the need to keep ratepayer funded programs during a transitional period as a way to reduce the market barriers. CLF, CRR and ECS propose funding levels they believe are necessary to reduce market barriers during the transition. GSEC proposes funding programs for its customers as they are funded today.

Others, such as Staff and LighTec, disagree. LighTec states that the “[l]argest single barrier to the growth of a competitive energy service’s industry ... will be an improperly planned and implemented rebate program.” LighTec believes that utility owned energy service companies have distinct advantages in providing programs to their distribution company affiliates. LighTec does not believe any ratepayer subsidies are needed for energy efficiency programs; in fact, LighTec states that subsidies can harm more than help energy efficiency programs.

Staff questions the market barrier argument on a number of grounds. Arguing that this market is, and has always been, subject to some degree of competition, Staff contends there is no market failure in this area, and, consequently, there is no reason for the Commission to assert regulatory power over this segment of the economy. Staff equates the market barrier argument with the "infant industry" argument often used by countries to protect uncompetitive industries in trade agreements. Staff does state, however, that the existence of market barriers is an empirical question, ultimately, and one that could use more study.

Unitil fully supports a transition to a competitive market for a non-subsidized, market-based energy efficient services industry. Unitil states that continuing ratepayer-subsidized DSM programs may itself be a market barrier to reaching a fully developed market for energy efficiency products. Unitil supports a working group to identify market barriers and recommend solutions to reduce or eliminate those market barriers in as short a time as possible.

NHEC believes its non-profit status as a member-owned utility gives it a different perspective on energy efficiency and the market barriers faced by its members. NHEC states that large energy service companies are not interested in providing services to NHEC's rural service territory and, therefore, NHEC-sponsored programs provide a valuable mechanism to reduce information barriers faced by its members.

b. Market-Based Incentives

CLF and others believe market-based incentives work well to support and complement utility sponsored programs. They cite upgrades to building codes and the disclosure of accurate and clear information as necessary and helpful for successful market-based programs. NAESCO believes that a properly structured, ratepayer-funded standard performance contract is the best way to support and encourage the private energy efficiency market. A standard performance contract would use direct interaction between suppliers and customers of energy efficiency products as well as serve as a valuable educational mechanism.

c. Cost-Effectiveness Test

CLF, GSEC, ECS and others believe energy efficiency programs should be viewed and evaluated from a societal perspective which includes all societal costs and benefits such as avoided transmission and distribution costs as well as the benefits associated with avoided generation. Staff argues the Commission should maintain its current methodology, the Total Resource Cost test; GSEC argues for the electric system test. A number of parties believe this is an issue that could be better addressed by a working group.

Staff described the five basic benefit-cost tests used to evaluate energy efficiency programs. Due to the adverse effect of utility sponsored programs on non-participants and the market, Staff supports the use of the Rate Impact Measure test during the two-year phase out period.

d. Program Administration

NAESCO believes that, to reach a vibrant private energy efficient marketplace, adoption of strong affiliate standards of conduct are necessary. LighTec argues that an affiliate of either the distribution or supply company should not be associated with the administration of energy efficiency funding due to the potential conflicts; an independent third party should be used. Because of its unique utility status, NHEC believes that it should administer programs for its members. GSEC also believes utilities should administer utility sponsored Demand Side Management (DSM) programs as well as be allowed to participate in regional market transformation efforts. ECS stresses that certain concerns about programs impeding private market development, such as the equitable treatment of rebates, are due to program design and not a reason to eliminate public support for cost-effective energy efficiency programs. ECS believes that one goal of a working group should be to ensure that private market initiatives are not hindered by utility-sponsored programs.

e. Impact on Near-Term Rate Relief

Staff examines the sensitivity of rates to various levels of utility-sponsored energy efficiency programs. Staff's quantitative analysis, based on PSNH rates and funding, indicates that near-term rate relief is seriously harmed depending on the level of funding and the recovery by utilities of lost fixed costs.

NHEC believes its DSM programs, whose costs account for 1% of its rates, should be continued because they provide an excellent return to members, both those that benefit directly and those that do not. NHEC does not quantify that return, however. GSEC states that funding would be at its current levels and designed to provide rate reductions to all its customers though it does not elaborate on how, in a competitive retail market, all distribution customers would benefit.

3. Commission Conclusions - Energy Efficiency and Other Public Policy Issues

Based on the extensive record before us, we affirm, in part, and vacate, in part, our positions in the Plan regarding utility sponsored energy efficiency programs, renewable energy and the environmental aspects of electric utility restructuring. In taking this action, we note the language of RSA 374-F:3, X which states:

> Restructuring should be designed to reduce market barriers to investments in energy efficiency and provide incentives for appropriate demand-side management and not reduce cost-effective customer conservation. Utility sponsored energy efficiency programs should target cost-effective opportunities that may otherwise be lost due to market barriers.

We continue to believe that the most appropriate policy is to stimulate, where needed, the development of market-based, not utility sponsored and ratepayer funded, energy efficiency programs, a principle that the Legislature incorporated into RSA 374-F. However, the Legislature has also recognized the value of some utility sponsored energy efficiency programs, which we believe our plan must address.

We recognize that the transition to market based programs may take longer than the two-year period we mandated in the Plan, though we continue to believe that such a transition period is an appropriate policy objective. We also recognize that there may be a place for utility sponsored energy efficiency programs beyond the transition period, but these programs should be limited to "cost-effective opportunities that may otherwise be lost due to market barriers." We believe that efforts during the transition toward market-based DSM programs should focus on creating an environment for energy efficiency programs and services that will survive without subsidies in the future.

We still need to determine what is the appropriate test for determining "cost-effectiveness." We are not prepared today to choose among the methodologies available for determining cost-effectiveness. We recognize and would like others to recognize that cost-effectiveness in a competitive energy environment differs from the way cost-effectiveness has been viewed previously. We believe that the best way to proceed is to create a working group, as advocated by a number of parties, to help us develop standards for evaluating energy efficiency programs as outlined in more detail below and to assist us in designing an appropriate cost-effectiveness test that we will apply to future programs. Until we receive guidance from the working group on an appropriate cost-effectiveness test, we will continue the use of the TRC test, based on the use of a market price as the proxy for avoided cost, to evaluate DSM programs. We direct utilities to cap their program funding at existing levels until we have received and ruled upon the working group's recommendations. Funding includes direct program costs, lost revenues and utility financial incentives.

We emphasize that the working group will need to take a fresh look at utility sponsored energy efficiency programs, one that, in the words of ECS should "build in obsolescence wherever possible" and "transform markets." We can not emphasize enough our belief that these programs must complement the new energy markets, and not hinder their development. This will be true of programs that will be allowed during the "transition" away from most utility sponsored programs, as well as programs that will survive that transition because they would "otherwise be lost due to market barriers." These guidelines should assist utilities and our Staff in preparing and reviewing DSM programs in the interim as well as to assist the working group in helping us to prepare for a very different future. We also believe that it is appropriate to move as quickly as possible from the payment of lost revenues as part of any DSM program. Finally, we reaffirm our position in the Plan that distribution utilities should, at a minimum, undertake energy efficiency programs that avoid more costly distribution system alternatives.

We note that the Legislature is considering HB 587. HB 587 would limit for some distribution utilities the total systems benefit charge for energy efficiency and low income energy assistance programs. If enacted, it would obviously affect the working group's recommendations and our decisions in this area.

With these guidelines in mind, we ask the working group to address the following:

- what is the appropriate cost-effectiveness test for future program evaluation and whether there should be a different standard to evaluate cost-effectiveness of transformation programs.

- what, if any, market barriers exist, and what the alternatives are to reduce or eliminate these barriers during the transition to market-based programs. We believe the working group and others should recognize the effect our public education program may have on reducing informational barriers.

- how the Commission can quantitatively evaluate the effects of these alternatives during the transition.

- what "market transformation" initiatives are needed to stimulate market development of energy efficiency products and services.

- for each market barrier identified, provide a measure(s) that the Commission can use to evaluate the significance of the market barrier as well as how the Commission will know when the barrier is no longer significant.

- what level of funding is appropriate for low-income energy efficiency programs and does sufficient funding exist in the $13.2 million low-income system benefits charge to use for energy efficiency programs for eligible low-income customers. We remind the working group and others that the $13.2 million low income fund was intended not only to make bills affordable but also to encourage conservation and energy efficiency to make bills manageable. Plan at 95.

- what the effects are of utility-sponsored programs on rates and how will the costs of these programs be collected through rates.

- whether all large commercial and industrial customers should contribute to utility-sponsored DSM programs, even if they do not participate in the programs or receive transition service.

We believe a diverse group representing utilities, low income assistance advocates, energy service providers and conservation and environmental groups, as well as representatives of affected public agencies such as ECS, the State's Air Resources Division, and OCA would contribute significantly to resolving the issues we outlined above. Interested parties should contact our Executive Director.

We have also considered the requests for a renewables commercialization program and the imposition of certain environmental regulations on all fossil generation sources participating in New Hampshire's retail choice market. We will deny both requests. While we understand the rationale for such requests, and may agree in principle with the suggestion to make old and new plants meet the same emissions levels as a way to rectify certain infirmities in the Clean Air Act Amendments of 1990, we reaffirm our position in the Plan that the setting of incentives and standards for compliance with air quality regulations should be left to the United States Environmental Protection Agency and the New Hampshire Department of Environmental Services. To the extent energy efficiency programs are used in the future as offsets to more costly environmental compliance programs, we believe the enactment of such programs will serve to further the development of cost-effective, market-based programs.

P. Supplier Registration

On May 22, 1997, we received a recommendation for supplier registration requirements from the working group which was established to consider that issue. We have reviewed the proposed requirements and find them to be an appropriate starting point for a rulemaking on supplier registration. Accordingly, we will open a rulemaking docket to address the issue of supplier registration and related consumer protection issues. Parties interested in participating in the rulemaking proceeding should contact our Executive Director.

Q. Public Education Plan

In our Plan, we established a working group to advise us on the development of a public education program and stated that we would hire a consultant to put the program together for us. On December 19, 1997, our consultants, HighPoint Communications Group and Gregory S.

Franklin Associates, submitted a proposed plan for a public education program which the working group recommended we adopt. RSA 374-F:3, II states that "the commission should ensure that customer confusion will be minimized and the customer will be well informed about changes resulting from restructuring and increased customer choice." We have reviewed the plan, given consideration to the recommendation of the working group and the comments received from the parties and find that the proposed plan meets the legislative directive.

Although the cost of implementing a statewide public education program is substantial, we continue to believe that a comprehensive public education program is essential to the smooth transition to a competitive market. The research conducted by our consultants during the development of the public education plan furthers supports this belief and strengthens our conviction that a public education program is an integral piece in the successful opening of the competitive market. We have looked at what other states have done in terms of public education and believe the proposal from our consultants is comprehensive and cost effective. We have done some comparisons of the cost of the plan proposed by our consultants, on a per capita basis, to those proposed and adopted elsewhere and find the proposed program reasonable and affordable. Accordingly, we will adopt the proposed plan submitted to us by our consultants and direct the public education working group to move forward with the development of a request for proposals to solicit bids for the implementation of the program.

How the public education program will be funded still remains outstanding. RSA 365:37, II permits us to assess the utilities for costs of experts or other assistants hired by the Commission. While many suggestions have been made regarding funding, we believe that the simplest and most appropriate method of funding the program is through a utility assessment.

We direct the utilities to include in their compliance filings proposals for the recovery of the public education costs assessed against them.

IV. CONCLUSION

Based on the foregoing, the Commission's February 28, 1997 Plan is clarified and modified as stated herein. Unless otherwise specified in this order, the Plan is affirmed. Finally the Commission affirms the ISC orders for Connecticut Valley Electric Company, Inc. (Order No. 22,809), Granite State Electric Company (Order No. 22,511), New Hampshire Electric Cooperative, Inc. (Order No. 22,513) and Unitil Power Corporation (Order No. 22,510).

By order of the Public Utilities Commission of New Hampshire this 20th day of March, 1998.

Douglas L. Patch Chairman	Bruce B. Ellsworth Commissioner	Susan S. Geiger Commissioner

Attested to:

Thomas B. Getz
Executive Director and Secretary

APPENDIX A

UPDATE ON REGIONAL ACTIVITIES: NEPOOL REFORM

In RSA 374-F:3 XIII., the Legislature recognized the need to reform the New England Power Pool (NEPOOL) to enhance competition and complement industry restructuring on a regional basis and directed the Commission to work with other New England and northeastern states, where possible, to accomplish the goals of restructuring. In the Plan, the Commission identified strengths and weaknesses of NEPOOL's reform proposal and discussed its commitment to working with other New England states to develop, where possible, consistent and mutually beneficial policies and requirements to ensure that the institutions established to facilitate competition in the region can successfully do so. The Commission has worked closely with other New England states to identify elements of NEPOOL's proposal which were likely to impede the development of competition in New Hampshire or the region. Through the New England Conference of Public Utility Commissioners (NECPUC), the Commission provided NEPOOL with suggestions to improve the proposed market model, focusing on two broad areas: the structure, governance and financing of the ISO and issues relating to market power.

On February 20, 1997, the Commission, through NECPUC, filed comments with the FERC supporting NEPOOL's proposed ISO on an interim basis and requesting that FERC instruct NEPOOL to develop a permanent funding mechanism that assures budget independence, such as a transaction based fee. NECPUC also expressed concern that, as proposed, the ISO would disseminate information provided to it by NEPOOL Participants in accordance with the NEPOOL Information Policy. Our concern was assuaged somewhat by the fact that the ISO ultimately had the authority to change pre-existing System Rules and Procedures when it determined that such a change was necessary. We continue to believe that the ISO should establish its own information policy that ensures that non-NEPOOL market participants are not disadvantaged by information flow to NEPOOL Participants.

On the same day that the Commission issued its Plan, the FERC accepted for filing the NEPOOL restructuring proposal and made it effective, subject to refund, after a nominal suspension, on March 1, 1997. The FERC order allowed NEPOOL to begin taking service under the proposed transmission tariff by March 1, 1997, in compliance with Order 888. However, the FERC deferred action on the merits of the filing, leaving many disputed issues unresolved.

On June 25, 1997, the FERC conditionally authorized the establishment of an ISO by NEPOOL and made an interim finding that the transfer of control of jurisdictional transmission facilities owned by the public utility members of NEPOOL to the ISO was consistent with the public interest under section 203 of the Federal Power Act. Some of the conditions which FERC placed on its approval required the ISO to: lower the definition of an affiliate from 50% to 10% ownership; adopt a self-funding mechanism; ensure that ISO employees are financially independent of market participants by divesting any financial interests in market participants; and eliminate the restriction limiting NEPOOL membership to New England entities.

FERC also conditioned its approval on NEPOOL's agreement to modify the Interim ISO Agreement to obligate (rather than simply authorize) the ISO to review the long-range system assessment and transmission construction plans of NEPOOL Participants. In addition, FERC's ISO principle number 6 requires that ISOs be able to take operational actions to relieve system constraints within the trading rules established by the governing body. Although NEPOOL stated that the ISO would administer the proposed bid-based power exchange, NEPOOL failed to file bid-based rules. Consequently, FERC deferred action on this aspect of NEPOOL's filing.

On May 1, 1997, NEPOOL supplemented its restructuring proposal by filing market power mitigation principles and procedures which would be applied during transmission constraints. In essence, when the ISO dispatched a resource out of economic merit during a constraint, the ISO would apply two screens: a market structure screen, intended to evaluate competitive alternatives to the dispatched resource, and a price screen, intended to identify whether the price of the resource has been raised substantially, persistently or repeatedly (during constraints). NECPUC retained two consultants to evaluate NEPOOL's proposal and to conduct independent studies of market power in New England. A fundamental conclusion of both consultant reports[47] was that the NEPOOL analysis relied upon questionable assumptions, was biased and inconclusive. More analysis was needed before the New England electric generation markets could be opened to competition.

As we indicated in the Plan, the Commission favors a collaborative approach to NEPOOL restructuring, and has worked with NECPUC, NEPOOL and with the newly formed ISO to improve the proposed market model. In addition, we directed our staff to work with NECPUC to engage NEPOOL and the ISO in intensive discussions regarding the market power monitoring and mitigation proposal to better understand the areas of and reasons for disagreement. In our comments at FERC, we identified several important questions which we believed must be answered before we could support a request for market based rates and which guided staff's discussion with NEPOOL and the ISO. Specifically, these questions included:

[47] Both consultant's reports were submitted to FERC with NECPUC's comments and request for a technical conference.

What should the ISO monitor? What triggers or benchmarks are relevant in each of the product markets? What information will be available to the ISO to assist it in monitoring the market? How much, if any, of that information should be kept confidential? Will stakeholders be permitted to audit the monitoring data? Should monitoring reports be prepared, and if so, who should have access to the reports and the underlying data?

On December 19, 1997, NEPOOL filed with FERC, a market monitoring, reporting and market power mitigation proposal in support of market rules. This latest proposal by NEPOOL reflects the dialogue among NEPOOL, the ISO and NECPUC.

As stated in the Plan (at 34), this Commission has a vital interest in ensuring that the prices determined through the power exchange (PX) are not subject to manipulation. This requires the implementation of rules that promote economically efficient trading and an entity both authorized and obligated to monitor activities in the evolving competitive marketplace. The Commission believes that the proposal developed by NEPOOL and the ISO represents a sufficient starting point. This support is conditioned on the parties continuing to work to build consensus and resolve the issue of appropriate sanctions for physical withholding of capacity and failure to comply with market power monitoring or mitigation orders of the ISO. We also believe that additional work must be done to clarify how the ISO will identify anomalous behavior by a generation supplier. Although NEPOOL and the ISO assert that their proposal contains both structural and behavioral components, we believe their proposal's value lies in its review of participant behavior. Although market share numbers provide some indication of the degree of competition in a market, we believe they are insufficient to evaluate whether the changes that have taken place in the market serve the public interest. Consequently, we believe that the ISO, in keeping with its obligation to evaluate the efficiency and competitiveness of the markets, be required to include in its reports, analyses of the relationships between bid and clearing prices to marginal costs.[48] Further, decisions regarding the recoverability of stranded costs by each state in the region will affect the bidding decisions of suppliers and, therefore, may affect the market price as determined by the power exchange. Consequently, it is appropriate for the ISO to consider these issues as it evaluates the developing market.

In addition, because we continue to assert authority over market structure issues as they affect New Hampshire, we believe any reports the ISO makes available to NEPOOL Participants, FERC or other regulatory agencies should be made available to this Commission. This also means that the Commission maintains its right to examine the activities of the ISO/PX as they pertain to the competitiveness of the markets and how they develop. In this regard, we expect that the ISO will be responsive to our requests for relevant information, should such a need arise. We recognize that as the competitive market develops, certain production and financial data will become increasingly sensitive. Consequently, we believe appropriate confidentiality arrangements should govern the treatment of competitively sensitive information.

On January 21, 1998, the NEPOOL Executive Committee advised the FERC that the ISO would be unable to complete the rules, computer software and other arrangements necessary to operate under the proposed new market provisions by the expected April 1st date. On February 9, 1998, the ISO announced a target of the fourth quarter of 1998 for start-up of the new

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[48]We note that the NEPOOL members have agreed, among other things, to provide the ISO with marginal cost data, heat rates, and such other information as the ISO determines is necessary for effective market monitoring.

competitive wholesale market. We will continue to engage in appropriate dialogue with the ISO and NEPOOL and offer advice and guidance to assist them in achieving the goal of implementing the structures necessary to ensure competitive and efficient markets while maintaining a safe and reliable system.

APPENDIX B

SUMMARY OF WORKING GROUP ACTIVITIES

The Commission's February 28, 1997 Plan called for the establishment of several working groups to address a variety of issues such as supplier registration, low income assistance, public education, energy mix disclosure requirements, competitive metering and electronic data interchange standards. The efforts of these groups are essential to the successful implementation of retail choice in New Hampshire, and the groups have moved forward with their tasks despite the federal litigation. The summaries below reflect the activities of the various working groups to date.

Supplier Registration Working Group

In its Plan, the Commission found that "one of the most effective and reasonable methods available for ensuring disclosure of information is the imposition of registrations requirements" and that "registration requirements should also provide suppliers with an incentive to behave responsibly". Plan at 103. On March 18, 1997, an organizational meeting for the supplier registration working group was held. The group, which was comprised of representatives of Enron, AllEnergy, EnerDev, Granite State Electric Company, Public Service Company of NH, NE Electric System, Cabletron, the Community Action Agencies, the Governor's Office of Energy and Community Services, NH Legal Assistance, the Electric Restructuring Collaborative, the Office of Consumer Advocate and the Commission Staff along with Representative Clifton Below, met regularly during the spring. On May 22, 1997, the supplier registration working group submitted draft rules to the Commission which addressed registration requirements as well as consumer protection requirements for competitive suppliers.

The draft rules recommend the Commission establish a minimum demonstrable level of financial resources for competitive suppliers and require the disclosure of information that would be helpful to consumers when choosing a supplier. While aggregators are not required to register with the Commission, notification of intent to provide aggregation services is required by the proposed rules. The rules address the telemarketing concerns that were raised by consumers and other commenters during the Commission's restructuring proceedings. Rules prohibiting the unauthorized transfer of service along with notice provisions for terminating service are also included. Finally, sanctions for a supplier's failure to comply with the rules are outlined.

The Commission has opened a rulemaking document for consideration of the draft proposal submitted by the working group and will be scheduling a public hearing on the proposed rules in the upcoming weeks. The proposed rules can be viewed on the Commission's web page at www.puc.state.nh.us.

Public Education Working Group

Recognizing that a comprehensive public education program was essential to the smooth transition to a competitive market, the Commission authorized the formation of a working group and the hiring of a consultant to assist it in its public education endeavors. The working group, consisting of representatives of Granite State Electric, NH Electric Cooperative, Public Service Company of NH, Unitil, Enron, the City of Manchester, the Electric Restructuring Collaborative, the Governor's Office of Energy and Community Services, NH Legal Assistance, the Institute for Cooperative Development, the Office of Consumer Advocate and the Commission Staff, issued a request for proposals on April 9, 1997 requesting proposals for the provision of outreach, educational and communication services related to the development of a public education campaign. The working group conducted interviews with the four bidders and submitted a recommendation to the Commission that the contract be awarded to HighPoint Communications Group/Gregory Franklin Associates (HighPoint). After conducting its own interviews, the Commission followed the recommendation of the working group and selected HighPoint.

HighPoint worked closely with the working group during the fall and submitted its proposed public education program to the Commission on December 15, 1997. On December 17, 1997, the working group submitted its recommendation to the Commission, endorsing the plan submitted by HighPoint and recommending the Commission adopt the proposed plan. On January 12, 1998, the Commission notified all the parties that it had reviewed the proposed public education plan submitted by HighPoint and believed it to be a comprehensive, well designed program that met the goal of providing residential and small business consumers with the information and tools needed to make an informed choice in a restructured electric industry. The Commission determined that it was appropriate, however, to provide an opportunity for comments on the proposed plan before issuing any ruling. Comments on the proposed plan were due by February 5, 1998. Two parties, Enron and Unitil, submitted comments. The Commission has considered the comments it received from the parties along with the recommendation of the working group and has, in this order, adopted the plan submitted to it by HighPoint/Franklin. An RFP for the implementation of the public education plan will be forthcoming.

The foundation for the public education program is an integrated communication plan whose effectiveness comes from the synergies created through the use of a wide range of integrated, interdependent communications strategies. Research was used extensively to insure the plan was based on actual market awareness, interest and opinion. Benchmark surveys, focus groups, individual and group interviews and media analysis were used to determine the key issues, audiences and attitudes this program needed to address.

The program focuses on two major audiences, residential consumers and small businesses within New Hampshire. Its objective is to provide these audiences with the information and understanding they need to make an informed, knowledgeable energy choice. In addition, the plan is designed to enable consumers to understand that with choice comes a range of economic, environmental and social implications and directs them to other resources that can further educate them on these issues.

The program, which is based on a series of measurable awareness, understanding and empowerment objectives, has four primary objectives: to enable New Hampshire consumers to make informed, knowledgeable assessments of their electric energy options in the state's new competitive electric energy marketplace; to enhance state-wide understanding of the concepts, principles and processes of retail electric competition within all target audiences so that polarized positions are minimized and appropriate, effective and accurate discourse of these changes is enabled and encouraged; to position the New Hampshire Public Utilities Commission as the neutral, most reliable resource and knowledgeable voice concerning the new competitive electric marketplace; and to minimize marketplace confusion and reduce the potential for marketing abuses. The program timetable has a kick-off date approximately 60 to 90 days prior to the introduction of retail choice and an end date approximately 24 months after the implementation of retail choice. The public education plan can be viewed on the Commission's website at www.state.puc.nh.us.

Low Income Working Group[49]

In keeping with the Legislative directive that "programs and mechanisms that enable residential customers with low incomes to manage and afford essential electricity requirements should be included as a part of industry restructuring", the low income working group is developing a program to provide assistance to low income customers. The working group, which includes representatives of NH Legal Assistance, the Governor's Office of Energy and Community Services, the Electric Restructuring Collaborative, Connecticut Valley Electric, Granite State Electric, NH Electric Cooperative, Public Service Company of NH, Unitil, the Office of Consumer Advocate and the Commission Staff, issued a RFP for an administrator for the low income program and has been negotiating the terms of the contract with the CAP agencies, the sole respondent to the bid. While the low income working group has not yet submitted its final recommendation to the Commission, it recently submitted a status report outlining, in general terms, its proposed assistance program.

As described in the February 24, 1998 status report, the proposed low income energy assistance program is a fixed credit payment program. The guiding principle behind the program is to bring bills down to an affordable level thereby motivating participants to change their

[49] There is pending legislation which proposes limiting the amount of the systems benefit charge which could be used for a low income energy assistance program to 1.5 mills per kWh. It also proposes that the authority of the Commission to fund a low income energy assistance program through the systems benefit charge be terminated on June 30, 2003.

payment habits and make regular and timely payments on their utility accounts. The proposed energy assistance program defines affordable bills as those which are equal to 4% of income for general use customers and 6% of income for electric heat customers. The proposed energy assistance program provides benefits to participants based on historical usage and income. In order to be eligible for the program, a participant's income must be equal to or lower than 150% of the federal poverty level.

For example, a four person household earning $12,000 per year (75% of the federal poverty level), with a general usage electric bill of $75 per month currently pays 7.5% of its income towards the electric bill. Under the energy assistance program, this same household would receive a monthly credit of $35, bringing the bill down to $40 per month or 4% of the total household income.

The working group's status report recommends the CAP agencies administer the proposed program. It also endorses the participation of the Governor's Office of Energy and Community Services in the fiscal oversight of the program, a role the office currently plays now for the federally funded low income heating energy assistance program. The Governor's Office of Energy and Community Services, as part of its fiscal oversight responsibilities, would monitor the dollars collected versus the dollars obligated in benefits to participants. It would also reconcile the dollars collected versus the dollars credited by the utilities.

The working group expects to submit its completed program proposal to the Commission by April 3, 1998.

Electronic Data Interchange Working Group

In order to facilitate the efficient and reliable transfer of data between regulated distribution companies and non-regulated providers of competitive services, the Commission in its Plan authorized the establishment of an Electronic Data Interchange (EDI) Working Group whose purpose was to develop a consensual plan for the transmission of electronic information among distribution companies and competitive power suppliers. The Working Group met for the first time on April 8, 1997 and has met on numerous occasions since. The group is comprised of representatives from Connecticut Valley Electric, Granite State Electric, NH Electric Cooperative, Public Service Company of NH, Unitil, the Commission Staff, AllEnergy, Enron, Green Mountain Energy, Strategic Energy Limited, Wheeled Electric Power Company, Unitil Resources, Xenergy, Eastern Utilities Associates and Granite State Energy.

One of the first actions of the working group was to create two subgroups, the Business Rules Subgroup and the Implementation Subgroup. The task of the Business Rules Subgroup is twofold: to reach agreement on a standard set of data transactions that meet the basic needs of all market participants; and to formulate business rules for each standard transaction. In an effort to reach consensus on these issues, the subgroup has examined the relationships between customers, competitive suppliers and distribution companies as they are anticipated to be at the start of retail competition. Substantial agreement has been reached on a set of data transactions that correspond to the anticipated business relationships, and the subgroup is currently finalizing description of the business rules that will govern their use. These rules will apply to each distribution company and all registered suppliers of competitive products and services.

The Implementation Subgroup's primary task is to review the technologies and services available for transferring large quantities of electronic data and to make recommendations which meet certain technical standards and ensure the timely implementation of retail choice in 1998.

Those criteria include data security, system reliability and the recoverability and archiving of data. The subgroup is also responsible for developing recommendations on the format of the electronic files. Both of these tasks are substantially complete.

The EDI Working Group recommends that competitive suppliers attend a mandatory training session that will introduce the attendees to the regulatory and operational requirements of the retail electric market in New Hampshire. In addition, each competitive supplier will be required to demonstrate its capability to electronically send data to and receive data from each distribution company in whose service area it intends to offer competitive services. The training and testing manuals to implement these requirements are still being developed.

The EDI Working Group expects to submit its final report to the Commission by April 2, 1998. A draft of the report can be viewed on the Commission's website.

Metering Working Group

The metering working group was formed to develop standards for the competitive provision of metering services to customers whose maximum demand is in excess of 100 kW. The first metering working group meeting was held on March 21, 1997, and the working group met approximately 10 times thereafter. Participants in the metering working group included representatives from Unitil, Connecticut Valley Electric, Peregrine Energy Group on behalf of CellNet Data Systems, Enron Capital and Trade, Granite State Electric, PJA Energy and Public Service Company of New Hampshire.

The working group has focused on how to best implement metering technologies and standards, within a competitive energy marketplace, for customers whose maximum demand exceeds 100kW. Topics that were discussed at the working group meetings included:

1) Definition of a > 100kW customer.

2) Load estimation, allocation, and reporting requirements.

3) Data availability, format, and timeliness.

4) Default metering services.

5) Possible barriers to fair competition.

6) Meter accuracy and testing.

7) Meter accuracy dispute resolution.

8) Stranded costs associated with metering equipment.

9) Theft of service issues.

10) National Electric Code requirements.

11) Tax legislation affecting meters (HB 602)

12) Service disconnects and restoration.

13) New metering technologies.

14) Load estimation and reconciliation.

15) Multiple meter logistics.

16) Customer choice versus forced compliance.

Within the context of the meetings, many concerns, issues and items requiring clarification were raised prompting the compilation of a “Clarifications & Issues” document that was submitted to the Commission on August 28, 1997. The Commission’s response to the various issues raised in the working group’s August 28, 1997 request for clarification have been addressed within the body of this Order. See Commission Conclusions - Unbundling; Metering and Billing at 8.

Disclosure of Resource Mix and Environmental Characteristics of Power Working Group

RSA 374-F:3; VIII requires that increased competition in the electric industry be implemented in a manner that supports and promotes the goal of environmental improvement. In the Plan, the Commission found that, although the parties to this proceeding held different views regarding the role that the Commission should play in environmental improvement, the environmental improvement principle indicates support for "market-driven approaches." Plan at 113. The Commission stated

> although...environmental improvement is an indispensable public good for which the state and the nation must make adequate provision, we do not find it appropriate to independently establish environmental improvement policies related to electric generators selling power in New Hampshire. Plan at 116.

The Commission established a working group to discuss issues related to the disclosure of resource mix and the environmental characteristics of power and charged the group with developing a recommendation to the Commission regarding the disclosure of the energy resource mix and labeling. The Commission further stated:

> We also believe ... that customers benefit from requirements that suppliers disclose information regarding the environmental characteristics of the power in their resource mix ... We will also request that the working group evaluate the feasibility of requiring suppliers to disclose the environmental impact of the power in their resource mix.

Plan at 118.

The first meeting of the working group occurred on March 19, 1997. Additional sessions were held on March 27, April 10, 18 and 23, 1997. Representatives from the Commission Staff, the Office of Consumer Advocate, the Governor's Office of Energy and Community Services, New Hampshire Department of Environmental Services - Air Resources Division, the

Regulatory Assistance Project,[50] the Conservation Law Foundation, the Center for Energy and Economic Development, Green Mountain Power Corporation, New Hampshire Electric Cooperative, New England Electric System, Public Service Company of New Hampshire, Granite State Hydro Association, Enron and Bellwether Solutions participated in the process. The Legislature was represented by Representative Clifton Below.

At the working group sessions, several proposals were presented for consideration. Two, the "Green Tags" proposal developed by Enron and Green Mountain Power's "Green Disclosure Standards", were discussed first at a session of the working group and have since been discussed at the regional and national level.

Agreement on a number of guiding principles for disclosure was reached at the April 17 meeting. The working group believes that customers should receive disclosure information that is accurate, simple, understandable, objective and verifiable. Whatever system or systems ultimately chosen should not be subject to "gaming," which can be generally thought of as the ability of retail suppliers to evade detection of false or misleading sales claims due to "loopholes" in the accounting/settlements process. A universal or standard format for customers is preferred. How to best achieve those principles at a reasonable cost is still a matter for further debate and

[50] RAP is manager for the New England Pilot Project on Consumer Disclosure, an effort sponsored by the National Council on Competition and the electric industry to engage New England regulators and stakeholders to reach, if possible, a consensus on disclosure for the New England region. RAP attended two of the working group sessions and provided valuable input on disclosure, but neither endorsed nor dismissed any particular proposal.

study. Nonetheless, the efforts of those involved in the working group will prove valuable as New Hampshire and the other New England states move closer to the day when all customers will have the opportunity to choose their retail electric supplier.

The working group submitted the following recommendations to the Commission: the Commission should impose a moratorium of 12-18 months on disclosure in order to review and analyze information and data collected through the NEPOOL Settlements process; the working group should convene a meeting with the public education working group and the winner of the public education bidding process to ensure the need for expanded customer information and education, including information on the environmental aspects of electricity production is met; the Federal Trade Commission/ Attorney General/Stakeholders collaborative should establish disclosure guidelines of environmental claims; the Commission should encourage, to the extent feasible, regional consistency in disclosure; and the feasibility of a “green tag” concept as an element of claim verification in green market development should be pursued.

The Commission agrees with the working group recommendation that, where feasible, regional consistency in disclosure requirements should be pursued. Although we recognize that each New England state will be developing its own information disclosure policy, we believe a regional approach is in the public interest for two reasons. First, such an approach will assist consumers in comparing suppliers’ offers, thereby enabling consumers to make informed decisions about electricity suppliers in the region. Second, such an approach will reduce supplier expenses attributable to compliance with different state requirements which, in turn, will lower the cost of electricity in the region. Consequently, we directed our Staff to participate in workshops organized by the Regulatory Assistance Project. Those workshops were part of a seven month effort undertaken by the Regulatory Assistance Project to work with public utility commissions and other stakeholders in New England in an effort to develop a uniform regional approach to consumer information disclosure. The culmination of that effort was RAP's paper entitled *Uniform Consumer Disclosure Standards for New England: Report and Recommendations to the New England Utility Regulatory Commissions* which included model disclosure rules. In addition, our Staff continues to work with NECPUC to consider other disclosure alternatives and to discuss the feasibility and costs of the various alternatives with the newly created independent system operator. As a result of their review process, the NECPUC staff developed model disclosure rules that built upon the RAP proposal; those model disclosure rules will serve as the basis for initiating a disclosure rulemaking proceeding in New Hampshire.

APPENDIX C

LIST OF PARTIES REQUESTING REHEARING,

RECONSIDERATION OR CLARIFICATION

Public Service Company of New Hampshire (PSNH)

New Hampshire Electric Cooperative, Inc. (NHEC)

Enron Trade and Resources, Inc. (Enron)

Concord Regional Solid Waste/Resource Recovery Cooperative (Concord Cooperative)

Bio-Energy Corporation, Bridgewater Power Company, L.P., Hemphill Power and Light Company, Pinetree Power, Inc., Pinetree Power - Tamworth, Inc., and Whitefield Power and Light Company (Wood-Fired QFs)

Concord Electric Company and Exeter & Hampton Electric Company (Unitil)

Cabletron Systems, Inc. (Cabletron)

Retail Merchants Association of New Hampshire (RMA)

Granite State Energy, Inc./AllEnergy Marketing Company, L.L.C.

Granite State Hydropower Association (GSHA)

Governor's Office of Energy and Community Services (ECS)

Office of Consumer Advocate (OCA)

Connecticut Valley Electric Company (CVEC)

Conservation Law Foundation (CLF)

Campaign for Ratepayer Rights (CRR)

Granite State Electric Company (GSEC)

APPENDIX D

REVISED COMPLIANCE FILING REQUIREMENTS

In accordance with RSA 374-F:4, III, each jurisdictional utility, except PSNH, shall submit, for Commission approval, a compliance filing no later than May 1, 1998 consistent with the Plan (Order 22,514), as modified by this order.[51] Utilities may address further issues on a voluntary basis.

Utility compliance filings must, at a minimum, include the following information:

1. A proposed plan to transfer or assign to a non-utility affiliate (a) owned generation facilities, (b) non-QF purchases power contracts, and (c) aggregation/marketing functions.
2. A proposed plan to implement the affiliate transaction rules adopted by the Commission. For compliance filing purposes, utilities should use the Commission's draft rules referenced in Section G,2 of this rehearing order.
3. Documentation showing that the proposed designation of transmission and distribution facilities as state-jurisdictional distribution facilities or FERC-

[51]Although this is the Commission's final order concerning rehearing requests related to the Plan, we are constrained by the temporary restraining order issued March 21, 1997 in the <u>PSNH v. Patch</u> litigation to stay the compliance filing requirements as applied to PSNH until

jurisdictional transmission facilities meets the FERC's seven-factor test.

4. A cost-of-service study which separates 1996 revenue requirements into the three functional categories of generation, transmission, and distribution. The distribution revenue requirement shall be further sub-divided into distribution, metering, billing, and customer service; the resulting sub-divisions must be allocated to rate classes based on the allocation methods underlying existing bundled rates. Utilities must identify any changes to previously approved cost allocation methodologies.

5. Proposed tariffs specifying the rates, terms and conditions for unbundled distribution service to each rate class for service rendered on or after July 1, 1998. Distribution service tariffs shall include separate charges for (a) consumption tax, (b) energy efficiency programs and (c) low income customer programs. Distribution service tariffs may also include the non-bypassable stranded cost charges approved by the Commission in Orders Nos. 22,509 (CVEC), 22,510 (Unitil), 22,511 (GSEC), and 22,513 (NHEC). Revised ISC charges for PSNH will be set in an order to be issued.

6. A plan to mitigate stranded costs consistent with RSA 374-F:3, XII(c).

7. A proposed method for categorizing customers as "small" or "large" as those terms are used in the Plan (i.e., customer's maximum demand less than or greater than

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further order.

100 kW).

8. The proposed terms and conditions governing the provision of standard and consolidated billing services to competitive suppliers. Under the standard billing option, a customer receives two bills: one for distribution service from his/her utility and a second bill from the competitive supplier for generation service. Under the consolidated billing option, a customer receives a single bill from the distribution company for distribution service and generation service provided by a competitive supplier.

9. A proposed plan to implement the electronic data interchange requirements of the Plan as amended by this order. Such plan shall be consistent with the recommendations of the Electronic Data Interchange Working Group.

10. A proposed plan to implement the low-income customer policies described in the Plan and the Working Group recommendations.

11. A proposed plan to meet the energy service needs of special contract customers.

12. Proposed tariffs specifying the rates, terms and conditions of an unbundled distribution service to special contract customers for service rendered on or after July 1, 1998.