THE FERC, STRANDED COST RECOVERY, AND MUNICIPALIZATION.

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I. INTRODUCTION

Wholesale and Retail Electric Deregulation and Stranded Costs

This article examines practical and theoretical issues in the application of the Federal Energy Regulatory Commission's (FERC or Commission) formula for calculating stranded costs. We demonstrate that the formula is not well-suited for accurate estimates of stranded cost in one of its two basic applications; the acquisition by a governmental unit of existing private utility's distribution system in a portion of that utility's service area, or "municipalization."[1] In the new lexicon of stranded costs, this is known as a "retail-turned-wholesale" (RTW) case.

The Commission's Order No. 888 and successor Orders No. 888-A, B, C[2] constitute the single largest step taken to date to introduce greater

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1. M.J. Doane and D.F. Spulber, *Municipalization: Opportunism and Bypass in Electric Power*, 18 ENERGY L. J. 333-361 (1994).

2. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, III F.E.R.C. STATS. & REGS. ¶ 31,036, 61 Fed. Reg. 21,540 (1996) [hereinafter Order No. 888]; Order No. 888-A, F.E.R.C. STATS. & REGS. ¶ 31,048, 62 Fed. Reg. 12,274 (1997) [hereinafter Order No. 888-A]; Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997), *order on reh'g*[hereinafter Order No. 888-B]; Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998), *order on reh'g*

competition into wholesale electric power generation. Emboldened by the successes of natural gas deregulation,[3] Order No. 888 set forth a vision of an industry with competitive, price-unregulated generators sending their power through a common-carrier-style transmission network.[4] Transmission systems would be open to all wholesale buyers and sellers under regulated terms and conditions that guaranteed equal access. These systems would also be monitored and enforced by the FERC and FERC-approved self-regulatory structures. The rates for local power distribution, according to the FERC, would continue to be set by state public service commissions, rural electric cooperatives, public power authorities and other distributors not subject to state PSC jurisdiction.[5]

Order No. 888 required each public utility that owned transmission systems to file an "open access" transmission tariff which met certain detailed standards of non-discrimination and pricing.[6] The Commission believed that broader transmission access would facilitate more competition between power generators, bringing the discipline of lower cost and greater efficiency to the portion of the power industry that builds and operates power plants.[7]

The Commission recognized that increased competition could cause some existing generation utilities to lose sales, making it impossible for these entities to recover their investment.[8] The Commission decided that electric utilities which offered transmission access were entitled to collect

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[hereinafter Order No. 888-C] (citations herein are to the FERC Reports).

3. Daniel F. Santa, Jr. & Clifford S. Sikora, *Open Access and Transition Costs: Will the Electric Industry Transition Track the Natural Gas Industry Restructuring?,* 15 ENERGY L. J. 273-321 (1994).

4. The electric utility industry may be divided into three main stages of production: generation, transmission, and distribution. Briefly, generation creates electricity in large quantities, transmission moves large quantities to major distribution centers (substations) near consumers, and distribution moves smaller quantities from substations to individual users. When a utility is engaged in the sale of electricity to retail consumers, that utility has traditionally been regulated by state public service commissions. However, power generation sold to other utilities at wholesale and unbundled transmission services fall under the jurisdiction of the Federal Energy Regulatory Commission under the Federal Power Act (16 U.S.C. § 824a (1998)). For more explanation, see PETER FOX-PENNER, ELECTRIC UTILITY RESTRUCTURING: A GUIDE TO THE COMPETITIVE ERA. Vienna, VA: Public Utility Reports, 1997, chapters 2,4,5. [hereinafter FOX-PENNER]

5. Order No. 888, *supra* note 2, at 31,770-85.

6. Order No. 888, *supra* note 2, at 31,732-67.

7. Order No. 888, *supra* note 2, at 31,651-2.

8. As the Commission explained in its Notice of Proposed Rulemaking, *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, F.E.R.C. STATS. & REGS. ¶ 32,507, at 32,867, 59 Fed. Reg. 35,274 (1994).

> The Commission notes that new generating capacity can be built and operated at a cost that is less than many utilities' current embedded generating cost. This simple fact of current economic conditions is encouraging many users to seek access to the new lower cost sources of supply. Utilities traditionally have been obligated to serve all retail customers within their franchise territory and all wholesale requirements customers to whom they have contractually agreed to provide service. The have constructed or contracted for generating capacity sufficient to meet these service obligations. If existing customers leave their current utility suppliers, the utilities may not be able to recover all of their prudently incurred costs.

the costs of generating plants that could not be recovered from the competitive wholesale market, or so-called stranded costs. Noting that the costs of most of these plants were explicitly approved by state or federal regulatory authorities, and were already being paid by electric consumers, the Commission stated:[9]

> We also will decline to require a utility seeking stranded cost recovery to shoulder a portion of its stranded costs. Such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[10] Although the Commission allowed such an approach with regard to a natural gas pipeline's take-or-pay cost,[11] we did so only as an extraordinary measure given the nature of the take-or-pay problem and the prevailing environment at that time. We returned to traditional principles when, in issuing Order No. 636, we authorized pipelines to recover all of their prudently incurred gas supply realignment costs...[12]

In its rulemaking, the Commission recognized that stranded wholesale costs directly attributable to open access transmission could arise through two major avenues.[13] The first scenario occurs when a FERC-regulated "wholesale requirements" customer ceases to take service from its historical power supplier in favor of other suppliers who can now reach that customer through open access transmission. Since the historical supplier had a Commission-imposed obligation to plan for that customer, the historical supplier may have incurred costs to fulfill its obligation to that customer that could be stranded. This avenue, which we refer to as the "wholesale requirements" customer scenario, is not discussed further in any detail.[14]

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9. Order 888, *supra* note 2, at 31,802-31,803. *See also*, Walter R. Hall II, *Securitization and Stranded Cost Recovery*, 18 ENERGY L. J. 363 (1997).

10. *See, e.g.,* Maryland v. Louisiana, 451 U.S. 725, 748 (1981); Office of Consumers' Counsel v. FERC, 914 F.2d 292 (D.C. 1990); National Fuel Gas Supply Corporation v. FERC, 900 F.2d 350, 342, 347-51 (D.C. Cir. 1990). (Original Footnote)

11. In Order No. 500, the Commission provided that if pipelines absorbed from 25 to 50 percent of their take-or-pay settlement costs, they could recover an equal amount from their firm sales customers in the form of fixed charges. Any balance could be recovered in the form of a commodity rate surcharge or a volumetric surcharge on total pipeline throughput. Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, III F.E.R.C. STATS. & REGS. ¶ 30,761, at 30,787, 52 Fed. Reg. 30,334 (1987). *See also* Order No. 528, *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, 53 F.E.R.C. ¶ 61,163, at 61,597 (1990). Moreover, we offered pipelines an important quid pro quo for absorbing take-or-pay costs under Order Nos. 500 and 528-B a special presumption that they had been prudent in incurring their take-or-pay liabilities. (Footnote in Original)

12. *See* Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation*, III F.E.R.C. STATS. & REGS. ¶ 30,939, at 30,461(1992). (Original footnote abbreviated).

13. Generating plants may also be stranded if state public service commissions implement retail competition. This is the same economic phenomenon; the sole difference is the immediate triggering event. We discuss the fact that the measurement of stranded costs should be consistent at the state and federal levels in Section II and III, *infra*.

14. Many of the points we make concerning stranded costs in municipalizations also apply to the wholesale requirements customer scenario. Retail-turned-wholesale stranded costs proceedings at the Commission include *City of Las Cruces, New Mexico*, F.E.R.C. Docket No. SC97-2-000; *City of Alma,*

The second stranded cost scenario occurs when a group of customers within a utility's historical, exclusive service area form a new distribution utility, perhaps by acquiring the existing distribution system.[15] As a distributor, this entity could then purchase generation from other suppliers, other than the pre-existing, integrated utility supplier. The Commission called this scenario "retail-turned-wholesale," although it is often referred to as "municipalization" as well because the customer group that seeks to leave its present system is often owned or organized by a city, town, or county.[16]

The Commission promulgated an approach to measuring and awarding stranded costs that seemingly employed a simple and specific formula.[17] Because the formula is based in part on the revenues the firm would have earned from the departing customer, the Commission called its approach the "revenues lost" approach. Importantly, the Commission held that this formula should be used for both stranded cost scenarios, wholesale requirements customers and RTW.[18] Rejecting almost all suggested modifications to this formula, the Commission held that a single, simple formula was best for both jobs. The Commission said:

> We recognize that some commenters oppose the revenues lost approach as imprecise. However, any rate-making method that relies on estimates will be subject to forecasting error. Moreover, in direct response to the commenters concerns, we have gone to great lengths in this rule to provide specificity with respect to the calculation of the components of the formula.[19]

At the same time, the Commission insisted that utilities in RTW scenarios were also entitled to full stranded cost recovery.

II. POLICY DEBATES CONCERNING THE RECOVERY OF STRANDED COSTS

The possibility that costs incurred by private, regulated firms may not be recoverable due to a broad shift in government policies is certainly not a new phenomenon. In the U.S., the earliest form in which government policies could directly affect investors was probably the issuance of governmental debt itself. In 1790, Treasury Secretary Alexander Hamilton proposed that pre-Constitutional national debt be redeemed by re-issuing bonds backed by newly constitutional federal tax revenues in place of state

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Michigan, F.E.R.C. Docket No. SC97-4-000, and *Village of Lakewood, New York*, F.E.R.C. Docket No. SC98-2-000.

15. Franchises are discussed in FOX-PENNER, *supra* note 3, at 95 and in H. Reiter, *Protecting Competition for the Market: The Role of Franchise Competition Between Public and Private Distributors of Electricity in a Restructured Power Industry*, Mimeo (April, 1998) (available from the author).

16. A number of state public service commissions and other participants disagreed with the Commission's assertion that it had jurisdiction over RTW stranded costs. Order No. 888, *supra* note 2, at 31,817-8.

17. The formula is discussed in Part III, *infra*.

18. Order No. 888, *supra* note 2, at 31,818-9.

19. Order No. 888, *supra* note 2, at 31,840-1.

backed securities whose repayment was seldom certain. According to historian John Steele Gordon:

> The reason was simple. If the government of the moment could decide, on its own, to whom it owed past debts, any government in the future would have a precedent to do the same. Politics would control the situation, and politics is always uncertain. There is nothing that markets hate more than uncertainty, and they weigh the value of stocks and bonds accordingly.[20]

Among other recent instances, stranded costs occurred in connection with natural gas deregulation during the 1980's, a fact discussed at some length in Order No. 888.[21]

In essence, the arguments in favor of stranded cost recovery center on the concept recognized by Hamilton, namely that government's reneging on commitments to investors is an unwise, unfair, and ultimately costly exercise.[22] Arguments against stranded cost recovery draw on several assertions, including: fairness to utility ratepayers and the lack of guaranteed recovery of utility investments, utility imprudence, adverse incentives, and other considerations.[23] As of this writing, at least eighteen states are deregulating retail electric sales.[24] In many of these states, the recovery of stranded costs has been debated vigorously, with most states electing policies of full, or almost full, recovery.[25]

This article is not intended to present or analyze the economic, political, or other pros and cons of allowing the full recovery of stranded costs. The debate over *whether* to allow stranded cost recovery is already well-documented. Moreover, in this particular instance after extensive deliberation, the Commission has clearly articulated a policy of allowing full cost recovery. The objective of this article is to examine the extent to which the Commission's stated objectives and policies concerning stranded costs can be met through the careful application of its own stranded cost formula.[26]

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20. GORDON, J.S., HAMILTON'S BLESSING 26-7 (1997).

21. Order No. 888, *supra* note 2, at 31,789.

22. THE ECONOMIC REPORT OF THE PRESIDENT, U.S. Government Printing Office, 186,(Feb. 1996), and J.G. Sidak and D.F. Spulber, *Deregulatory Takings and Breach of the Regulatory Contract*, 71 N.Y.U. L. REV. 851 (1996).

23. Arguments for and against stranded cost recovery are reviewed in FOX-PENNER, *supra* note 2, at ch. 16.

24. The 18 states are Arizona, California, Connecticut, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, New Hampshire, New York, Oklahoma, Pennsylvania, Rhode Island, Vermont, Virginia. The status of retail electric competition is summarized by a number of organizations on an ongoing basis, including, DOE *Energy Information Administration* <http://www.eia.doe.gov>, the *National Association of Regulatory Utility Commissioners* (NARUC) <http://www.narue.org> and the *LEAP Letter* <http://www.spratley.com>.

25. Stranded cost policies in the states are also changing or being formulated in detail for the first time. For state regulations on stranded cost recovery in more detail, see *infra* Section III.

26. Furthermore, we limit our discussion only to generating plant stranded costs. The main categories of individual stranded cost components include: generating units, fuel purchase contracts, purchased power agreements, non-utility generation and PURPA contracts, regulatory assets, decommissioning costs for nuclear and non-nuclear power plants, and labor retraining and transition costs.

III. THE OBJECTIVES UNDERLYING THE COMMISSION'S STRANDED COST POLICY

The Commission's main objectives, as described in Order No. 888 and No. 888-A, as well as in its Notice of Proposed Rulemaking on Stranded Costs, include computing stranded cost obligations (SCOs) accurately, avoidance of cost-shifting, avoidance of undue complexity, appropriate deference to state regulatory authorities, and reduction in uncertainty and delay for customers who may face SCOs.[27] The Commission's determination that it favored stranded cost recovery, however, was only the beginning of its actual policy. Among other things, the Commission needed to decide which types of stranded costs were jurisdictional. The Commission also needed to determine the allowable methods for measuring these stranded costs: how costs should be apportioned to all past, present and future customers, and how its methods should mesh with other related state and federal policies.

The application of its detailed policy (embodied in its formula and the rules for applying it) produces a specific dollar sum of stranded costs owed by a specific customer who leaves a jurisdictional utility. This is the customer's stranded cost obligation. In adopting its approach, the Commission acknowledged that the approach was not designed solely to maximize accuracy, but rather to balance the need for accuracy against other important objectives. As the Commission noted in rejecting suggestions that its approach include "true-ups," or periodic recalculation of SCO over time:

> The revenues lost formula is based on a one-time snapshot approach. We favor this approach over the true-up approach because it creates certainty and will produce reasonably accurate results. True-ups, on the other hand, while theoretically more accurate, require periodic recalculation of stranded costs, which creates ongoing uncertainty and disputes. In addition, true-ups will result in additional transaction costs. We believe that an approach that provides certainty and establishes cost responsibility up front is best for what is fundamentally a transition issue.[28]

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27. *See e.g.*, Order No. 888, *supra* note 2, at 31,840, where the Commission said,

> The formula balances a number of goals, including: (1) Ensuring full recovery of legitimate, prudent and verifiable stranded costs; (2) requiring the utility to mitigate stranded costs; (3) providing certainty for departing generation customers; and (4) creating incentives for the parties to renegotiate their existing requirements contracts or otherwise settle stranded cost claims without resort to litigation.

28. Order No. 888, *supra* note 2, at 31,842. In addition, the Commission also evidenced concern for the prevention of cost-shifting in the context of utilities with stranded cost obligations in multiple jurisdictions. Order No. 888, *supra* note 2, at 31,826. In such cases, the Commission will consider amending jurisdictional agreements to prevent interstate shifts of stranded costs. Order No. 888-A, *supra* note 2, at 30,411. Finally, the Commission makes it clear that it will not allow responsibility for retail stranded costs to be shifted away from retail customers via FERC-jurisdictional transmission rates. Notice of Proposed Rulemaking, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities*

On the other hand, the Commission acknowledged that accuracy was important, as in this discussion of the importance of direct assignment is in providing accurate stranded costs estimates:

> Direct assignment will result in a more accurate determination of a utility's stranded cost than would an up-front, broad-based transmission surcharge. This is because the stranded cost for any customer is finally determined only if the customer actually leaves a utility. Moreover, there is no stranded cost unless the then-current market price of power for the period that the utility reasonably expected to continue serving the customer is below the utility's cost. Thus, because the circumstances of each departing customer will be known, the amount of any stranded cost liability can be determined with reasonable accuracy.[29]

The notion that its stranded cost policies should require all customers to pay for the costs incurred to serve them, so that others would not be required to pay them, appears central to the Commission's policy. The Commission calls the avoidance of cost-shifting from the customers responsible for the costs to other parties its "primary concern" in the calculation of stranded costs in RTW situations.[30] The Commission amplifies this finding by saying:

> Indeed, we are particularly concerned that the failure to assign stranded cost responsibilities to customers that have access to alternative suppliers will leave captive customers exposed to the risk of greater cost burdens, thereby shifting to captive customers the costs that were originally incurred for the benefit of the (typically larger) customers who have the flexibility to take early advantage of competing power suppliers.[31]

An intention to avoid cost-shifting is also repeatedly noted in the Commission's Notice of Proposed Rulemaking (NOPR) on stranded cost.[32]

The Commission believed it was preventing cost-shifting by adopting an approach centered on the direct assignment of costs to the departing customer. The Commission noted that direct assignment is the only approach consistent with the long-established principle of assigning cost based on cost causation, i.e., that all customers should be responsible for repaying costs incurred to provide service to them. Avoidance of cost-shifting is also an important means of ensuring that rates are just and reasonable not only from the standpoint of utility customers, but also from the standpoint of investors, whose returns are diminished if shifted costs cannot fully be recovered.[33] The importance of maintaining utility financial

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and Transmitting Utilities, III F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,127, 60 Fed. Reg. 17,662 (1995).

29. Order No. 888, *supra* note 2, at 31,798.

30. Order No. 888-A, *supra* note 2, at 30,407.

31. Order No. 888-A, *supra* note 2, at 30,355. The Commission also mentions the importance of the avoidance of cost-shifting in Order No. 888, *supra* note 2, at 31,789, 31,798, 31,799, and 31,812.

32. Notice of Proposed Rulemaking, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilites and Transmitting Utilities*, III F.E.R.C. STATS. & REGS. ¶ 32,514 at 33,095-100, 33,108-109, 33,127, 60 Fed. Reg. 17,662, at 17708, 17697 (1995).

33. Because of the significance of such [stranded] costs to the utilities that would face them may be great (and the prospect of not recovering such costs could erode utilities' ability to attract

integrity was also acknowledged in the Commission's open access NOPRs.[34]

Additionally, the Commission made clear that the computation of SCO should be based on a representative share of the total system serving that customer.[35] An approach that allocates average portions of the system to all customers—sometimes called a slice of system allocation—best ensures that uneconomic costs are allocated fairly to all customers, wholesale and retail, whether or not they choose to leave bundled service.[36]

The Commission also expressed concern for the closely-related phenomenon of evading SCO obligations entirely. The Commission recognized the possibility that some customers may be able to avoid entirely their legitimate stranded cost obligations, whether imposed by state or federal authorities. To prevent this, the Commission "reserv[ed] the right to address such situations on a case-by-case basis."[37]

The Commission's decision to address jurisdiction shopping was well-founded, given its concerns about cost-shifting. Forum-shopping occurs only when a customer with a stranded cost obligation has an opportunity to obtain a determination (or evade entirely) the obligation in more than one forum. If one such avenue of determination more accurately computes that customer's SCO and the other is likely to underestimate it, rational customers will choose the latter forum. This, in turn, may induce cost-shifting onto other customers, unfair low returns to the customer's

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capital and be very detrimental to a diverse array of utility shareholders), we believe that we have a responsibility to allow for the recovery of such costs. Order No. 888, *supra* note 2, at 31,790.

34. *Supplemental Stranded Cost Notice Of Proposed Rulemaking*, III F.E.R.C. STATS. & REGS. ¶ 32,514 at 33,108 (1995):

> In addition, allowing direct assignment of stranded costs will ensure that there are no stranded costs left to be borne by the remaining customer base or by the shareholders. This, in turn, will ensure that the financial health of the industry is not placed in jeopardy. If some customers are permitted to leave their suppliers without paying for costs incurred to serve them, this may cause an excessive burden on the remaining customers (such as residentials) who cannot leave and therefore may have to bear those costs. Moreover, the prospect or lack thereof for recovering such costs from ratepayers could erode a utility's access to capital markets or significantly increase the utility's cost of capital. This higher cost of capital could precipitate other customers leaving the system which, in turn, could cause others to leave. Such a spiral could be difficult to stop once begun.

Id.

35. In response to ELCON's argument that it is not clear how departing wholesale customers who signed contracts in 1985 could have "caused" utilities to incur uneconomic assets such as expensive nuclear facilities that were planned and ordered in the 1970s, we note that customers taking requirements service generally pay an allocated share of total embedded costs, including the cost of investments made before the customer began service. This pricing principle is consistent with the method that Order No. 888 adopts for calculating a departing customer's stranded cost obligation. The revenues lost approach is not an asset-by-asset approach. Instead, it is an approach that looks at a utility's current rates, which are based on all the utility's assets, which may include both high cost and low cost generating facilities of various ages, and relies on the presumption that the fixed costs allocated to departing customers under their current rates are properly assignable to them. Order No. 888-A, *supra* note 2, at 30,378 n. 586.

36. Order No. 888-A, *supra* note 2, at 30,413-4, 30,434.

37. Order No. 888, *supra* note 2, at 31,819.

utility, or both. The converse applies to a utility with stranded costs and where one forum is likely to overestimate stranded cost obligations or has a more favorable policy.

In effect, cost-shifting occurs automatically when stranded costs are not computed with sufficient accuracy.[38] Forum-shopping occurs when there are more than one forum for resolving stranded costs, SCOs are computed differently among the forum, and parties are comfortable guessing the likely direction of the error. Simply put, uncertain and/or inaccurate stranded costs create the incentive to search for cost-shifting opportunities, including forum-shopping.

In its Supplemental Stranded Cost NOPR, the Commission noted that "we anticipate state approaches to retail stranded costs not unlike our approach. . . ."[39] Still, more specifically, the Commission emphasized its ability to adopt precisely the same "calculation methodology" as a state uses:

> We clarify in response to SoCal Edison's request that the Commission has the discretion to defer to a state stranded cost calculation methodology. However, because we recognize that state retail access plans may present questions that need to be addressed on a case-by-case basis, we will consider whether to exercise that discretion on a case-by-case basis.[40]

In summary, the Commission's objectives of prevention of cost-shifting, prevention of forum-shopping, reduction of uncertainty, speedy resolution, and deference to state authority are stated clearly and often eloquently in its Order. As demonstrated, the nature of stranded costs in the case of retail turned wholesale are such that these objectives can be met only by a very careful application of the Commission's stranded cost formula.

IV. MEASURING ACTUAL AND ESTIMATED STRANDED COSTS

The Concept of Stranded Costs

There has been relatively little debate, at the Commission or in state public utility proceedings, as to the conceptual definition of stranded generating plant costs as opposed to their measurement. Stranded generating plant costs are simply the fixed costs[41] of a generating plant that

38. As the Commission notes, the costs of serving customers and repaying investors is reflected in present rates. If, as a result of miscalculation, a customer no longer pays its share of the costs incurred to serve it, these costs do not simply disappear. Instead, they are borne by one customer group, other customers or they are unrecovered. If costs are not recovered, the short fall must be made up by investors.

39. Notice of Proposed Rulemaking, *Promoting Wholesale Competition Trough Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, III F.E.R.C. STATS. & REGS. ¶ 32,514, at 33,127, 60 Fed. Reg. 17,662 (1995). The Commission further noted that, in response to its request for comments, state regulatory authorities provided little in the way of specific calculation procedures.

40. Order No. 888-A, *supra* note 2, at 30,668.

41. The variable or operating costs of a plant, such as fuel, labor, materials and maintenance

have been expended, and that cannot be recovered by the owners on future sales revenues from the plant following a particular regulatory change.[42]

Conceptually, measuring this difference is straightforward. Suppose, for example, a utility builds a plant that costs $50 million and can produce 100,000 MWh per year for ten years.[43] The plant was expected to sell to regulated customers at a cost-based rate that would enable the plant's owners to recover their $50 million investment. Thus, the owners anticipate a total present value revenue of $50 million, plus out-of-pocket operating and maintenance costs also recovered via additional revenues beyond the $50 million.

On the day it is completed, regulators announce that the plant is deregulated and free to sell into a competitive market. An objective observer of the situation immediately projects that the plant can earn, in total, a net present value of $40 million from sales to the competitive market. If the government's policy is to compensate for stranded costs in this instance and investors are to be fairly compensated for their original investment, they should be paid $10 million in stranded costs ($50 million - $40 million).

The difficulties in implementing a stranded cost policy do not arise from these straightforward concepts, but rather from the prospective *measurement* of stranded costs before all information can be known. In the simple example above, we know everything about this plant: its cost, lifetime, annual output, and allowed return each future year under regulated operation. With this information, we can compute the earnings investors in the regulated plant would have earned, but for the change in regulation. We also know similar data for operation of the plant under competition: plant life, plant output, plant capital and operating costs, and most importantly, the price the plant is expected to fetch from unregulated sales over the life of the plant.

Whether or not anyone can forecast these perfectly, it is essential to recognize that actual or "true" stranded costs are not determined by today's regulators. True or actual stranded costs are the difference between what present and future regulators would have allowed in earnings and what a plant earns without regulation, i.e., when prices (and

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capital expenditures, are usually assumed to be recoverable. This is because the rational owners of a power plant will not operate the plant unless they are *at least* paid their operating costs. If the plant is not run, variable costs are avoided. Therefore, plant owners either will not incur variable costs or will offset them with energy market revenues, yielding no stranded variable costs. The same is not true of past capital costs. The owners of plants must repay capital whether or not their plant operates. For generating plants, it is precisely the inability to avoid past capital costs that gives rise to stranded costs.

42. Historically, not all regulatory changes have imposed the costs of the change on investors honoring past policies. In Order No. 888, the Commission explained its rationale for awarded stranded costs in this instance at length. It also stated that it would consider only those costs imposed as a result of its own specific open access policies as stranded. *See generally* Order No. 888, *supra* note 2.

43. This plausible, but fictitious example is a 100 MW plant that costs $500 per kW and operates 1000 hours per year.

therefore asset values) are set competitively. Regulators control, at most, one-half of this equation; the other half is determined by the marketplace. Thus, if the objective is to achieve an opportunity for full cost recovery, it is necessary to forecast *accurately* what actual stranded costs are expected to be and set *allowed* stranded costs as close as possible to *expected* actual stranded costs.

The FERC's Approach to Stranded Costs

The FERC ruled in Order No. 888 that before a utility would be permitted to recover stranded costs, it would be required to demonstrate that it had a reasonable expectation of continuing to serve the departing customer.[44] Where such a reasonable expectation exists, the Commission determined that the stranded cost obligation of a departing generation customer should be determined on a present value basis through the use of the following "revenues-lost formula:"[45]

$SCO = (RSE - CMVE) \times L$

where:

RSE (Revenue Stream Estimate) is the average annual revenues from the departing generation customer over the three years prior to the customer's departure,[46] less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same three years under its new wholesale transmission tariff.

CMVE (Competitive Market Value Estimate) is an estimate of the amount that the host utility can expect to receive by selling the released capacity and associated energy.

L refers to the period of time the utility could have reasonably expected to continue to serve the departing generation customer. L is sometimes referred to as the "expectation to serve period."

The formula was developed primarily for the purpose of calculating the stranded cost obligation of a wholesale requirements customer that was purchasing power under a long-term power purchase contract executed prior to July 11, 1994. In that context, the Commission believed that most of the parameters used to calculate the stranded cost obligation should be readily identifiable and not subject to dispute. That is, the customer represents a discrete, metered load on the utility's system. The utility's rates are on file at the FERC, and therefore RSE can be easily

44. Order No. 888, *supra* note 2, at 31,831.

45. Order No. 888, *supra* note 2, at 31,839. This formula is codified in the FERC's regulations at 18 C.F.R. § 35.26(c)(2)(iii) (1998). The regulations also require that the stranded cost obligation of a departing customer should not exceed the amount the customer would have contributed to the fixed costs of the utility if it had remained as a customer. Order No. 888, *supra* note 2, at 31, 840. The customer's contribution to fixed costs for this purpose was defined as RSE less variable costs.

46. Order No. 888 provides that if a customer's rates changed during the relevant three-year period, then RSE should be calculated using the customer's most recent 12 months of revenue. Order No. 888, *supra* note 2, at 31,840.

calculated.[47] Similarly, the transmission-related deduction from RSE may be calculated by applying the utility's established rates for transmission service and mandatory ancillary services to the customer's historical loads prior to its departure. The termination date of the customer's contract will frequently provide a convenient means of determining the end date of L.[48] Finally, while there may be disagreement regarding the competitive market value of the power the customer would have purchased, the FERC provided an opportunity for the customer to market or broker a portion or all of the released capacity and associated energy if it believes that the utility has underestimated CMVE in order to increase its stranded cost recovery.

In the case of stranded costs caused by retail-turned-wholesale customers, the FERC in Order No. 888, declared itself the "primary forum" for their recovery[49] and stated: " we will require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer, and will apply the same procedures for determining stranded cost obligation, as that required in the case of a wholesale requirements customer."[50] As noted earlier, the FERC adopted this policy to limit forum-shopping and duplicative litigation of the issue.[51]

By taking jurisdiction over RTW stranded costs, but also using the very same formula,[52] the Commission effectively asserted that this formula

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47. Where the customer's rates are cost-of-service formula rates, the calculation of RSE may require preparation of estimates of the utility's costs if the stranded cost obligation is being calculated several months in advance of the contemplated departure date. In contrast, no such problem arises if the rates contain established demand and energy charges.

48. The existence of a notice period for termination of a wholesale power sales agreement creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the termination date. Order No. 888, *supra* note 2, at 31,831. However, a utility has an opportunity on a case-by-case basis to demonstrate that the history of the parties' relationship created a reasonable expectation that the utility would continue to serve the customer after the termination of the contract. Order No. 888-A, *supra* note 2, at 30,422-3.

49. The first retail-turned-wholesale stranded cost case to come before the FERC is *City of Las Cruces, New Mexico*, F.E.R.C. Docket No. SC97-2-000. In an order issued on Aug. 1, 1997, FERC Chairman Hoecker and Commissioner Massey, who had previously dissented to the exercise of jurisdiction by the FERC over the stranded cost obligation of retail-turned-wholesale customers when Order No. 888 was adopted, agreed to set the Las Cruces case for hearing. *City of Las Cruces, New Mexico*, 80 F..E.R.C. ¶ 61,160 at 61,700 (1997).

50. Order No. 888, *supra* note 2, at 31,819.

51. The FERC also asserted that it had jurisdiction over recovery of stranded costs that were caused by state retail access programs. However, it declined to exercise this authority unless the relevant state regulatory agencies did not have authority under state law to address stranded costs when retail wheeling is required. Order No. 888, *supra* note 2, at 31,824-6.

52. Although the same general methodology is followed in establishing the stranded cost obligation of a departing retail-turned-wholesale customer as that applicable to a departing wholesale customer, certain variations were adopted in Order No. 888. Factors such as whether state law awards exclusive service territories and imposes a mandatory obligation to serve are among the issues to be considered in determining whether the utility reasonably expected at the time it incurred its costs that the retail-turned-wholesale customer would continue to receive bundled retail service. Additionally, when calculating stranded costs of a retail-turned-wholesale customer, subtraction of distribution-system related costs from RSE may be appropriate. Order No. 888, *supra* note 2, at 31,839, n 863.

was "good enough" to attain its objectives in RTW situations. As theory and practice demonstrate, this is true only if the formula is very carefully applied.

Alternative Methods of Stranded Cost Estimation

Approximately eighteen states have adopted retail electric competition.[53] Many more have studied or are considering the same. In almost every such state, stranded cost recovery has been studied and in many states a specific measurement approach has been proposed or adopted.[54] A majority of the states use an approach that differs substantially from the FERC approach, though there are many variations and feature differences between states as well.

Many states use an approach that begins by attempting to measure stranded costs as the difference between the book value (BV) and the market value (MV) of a utility's generating plants.[55] There are several main computational options associated with a measurement of this type. These can be summarized as follows:

Measurement of the Value of the Generator After Deregulation, or Market Value (MV)

One way to set the value of a power plant selling into a competitive market is to estimate the net present value (NPV) of all operating profits or free cash flow the plant can expect to earn from power sales over its life. To do this, one must forecast power prices along with costs of operating the plant over its life and then compute the NPV of all future operating profits. Alternatively, one may auction off the generator and let the market set its value. Finance theory holds that the winning bidder should pay a price equal to the NPV of future operating profits discounted at the appropriate rate. An auction of a plant whose output is (or is about to become) price-unregulated effectively causes auction participants to place a value on that plant today by creating their own estimate of future annual

53. Arizona, California, Connecticut, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, New Hampshire, New York, Oklahoma, Pennsylvania, Rhode Island, Vermont, Virginia. *See infra* Appendix A.

54. With varying degrees of specificity, fifteen states have adopted estimation methods for stranded generation costs. *See infra* Appendix A.

55. More precisely, stranded costs are the difference between the value of a power plant to investors under regulation versus its value under deregulation. In either case, modern financial theory teaches that the value of a plant is the net present value of the after-tax free cash flow expected by investors in the plant. Under regulation, the net present value after-tax cash returned to investors is the book value of the plant plus earned return, which we assume is equal to allowed return. Under deregulation, the cash return to investors is the net after-tax cash earned from deregulated sales of power (and other power plant outputs), less out-of-pocket costs. We caution against confusing the price of electricity sold from plants with the value of the plant itself. The two concepts are related because the price of power from the plant is a determinant of the revenues the plant earns. Costs are subtracted from those revenues to determine operating profits, the present value of which, over a plant's remaining life, is the value of the plant.

prices and operating profits.[56] While such a market estimate may or may not prove to be correct over time, this approach eliminates the need for regulators to adopt a forecast and thus later be accountable for forecast errors. However, it creates the need for utilities to divest their generating units, which is a major strategic decision. Approaches in which plants are sold are often called "market valuations," whereas approaches that rely on estimates of future sales revenues earned by the present owners are sometimes called "administrative determinations."

One-Time Versus Ongoing Measurement of Stranded Costs.

If a deregulated power plant is not auctioned, the present owners will continue to sell deregulated power at competitive market rates for years to come. Rather than make a prospective one-time estimate of the value of the plant based on the forecasted value of that plant's output, it is possible simply to examine actual sales and profits in each future year. These may be compared to a presumed case of operating under regulation to compute stranded costs. While this approach reduces the incentive to game the estimate of market price, it also prolongs regulation and may reduce incentives of plant owners to make improvements that involve taking risks.

Top-Down Versus Bottom-Up.[57]

"Top-down" stranded cost methods begin with the total revenue requirement or average rate for all generating plants, while bottom-up methods examine the revenue requirement for each plant and compare it to that plant's potential sales revenue. As an illustration, suppose for a particular year that average regulated rate for *all* of a utility's generating plants were known to be 10 cents a kilowatt-hour (kWh), and all plants together produce and sell 50 million kWh each year (ignoring losses). Required revenues for this group of plants would be $5 million in total, and this could be compared to market revenues earned on the same 50 million kWh sold competitively. This is the so-called "top-down method," because it presumes that the total revenue stream estimate can be known without inquiring into its component parts.

Alternatively, regulators could examine each of the utility's power plants, determine each plant's revenue requirement, the time profile of its output, competitive prices for the plant output, and do an individual plant stranded cost computation. If all of the data were correct, the sum total output and required revenues should be the same for the two cases. Why, then, is there any distinction between these approaches?

If both approaches are implemented fully and correctly over the entire remaining lives of the stranded generators, there would be no

56. Plant values may be set by a variety of transaction mechanisms other than an auction. As an example, one or more generating plants can be made into a separate company that is sold or "spun off" from the present owner.

57. The third issue of stranded cost measurement is also referred to as "revenues lost" versus "asset-by-asset."

difference. However, this equivalence can hold only if in the top-down method one recomputes revenue requirements and output separately *for each year*, since the number of generators that are stranded declines over time as plants are depreciated and eventually retired from service. Since required revenues can change significantly each year for generators, but aggregate rates often do not, the unadjusted top-down approaches are inherently inaccurate.

Appendix A summarizes state policies on stranded cost recovery, including specific approaches to measurement where one has been developed. The strong majority of approaches eschew top-down or revenues-lost methods. Most states also declare that they will attempt to estimate and provide utilities with an opportunity to recover all or most stranded generation costs.[58]

Estimating Stranded Costs With One-Time, Administrative Approaches

Before turning to a specific comparison of the Commission's stranded cost obligation formula and more accurate alternatives, several differences between state-authorized retail access situations and RTW stranded cost situations should be acknowledged. First, state stranded cost determinations generally stem from a situation in which all of the plants of a utility are exposed to competition. In RTW situations, a portion of a utility's system is stranded by a customer group that commences to buy competitive wholesale power. The rest of the system continues under state regulation unless state legislators separately enact retail choice.

In theory, this difference should make RTW stranded cost determination a bit easier. In a state stranded cost determination, regulators must forecast years of earnings that would have arisen under a regulatory regime that is being abolished as well as under a newly or not-yet-established competitive market. In contrast, RTW measurements require a comparison between revenues earned by a representative portion of the system selling into a competitive wholesale power market (which is slightly older and arguably better understood than a competitive retail market) and revenues earned by the same assets under continued regulation.

The second underlying difference in the two stranded cost scenarios is that RTW departures may strand distribution or possibly even transmission assets, whereas state retail choice scenarios typically do not strand distribution assets. Under state retail choice schemes, the existing distribution system remains regulated and is used by all competitive sellers to deliver power. If rates are designed properly, revenues associated with these assets do not change under state choice schemes. However, in RTW scenarios, the fate of the existing distribution system is uncertain. In the remainder of this article, we remove stranded transmission and

58. There are increasing signs of opposition to these policies, but so far few have changed. For example, a referendum to disallow stranded cost recovery has qualified for the ballot in California, and a network of advocacy groups around the U.S. has formed to oppose stranded cost recovery.

distribution costs from our discussion and focus entirely on the methods of measuring stranded generation costs.

Finally, it should be noted that while only fixed (or capital) costs can be stranded, stranded cost calculations often examine revenue streams that include operating costs such as fuel and variable operations and maintenance expense. This inclusion is appropriate where generation operating costs can be assumed to be the same in the stranded and non-stranded scenarios and therefore do not affect estimated stranded costs.

A comparison of the alternative state approaches to the measurement of stranded generation costs that are closest to the FERC approach highlights the aspect of the Commission's approach that must be applied carefully in order to yield accurate results. First, the Commission explicitly rejected recomputation of SCO, or "true-ups," as more information was revealed.[59] Therefore, one time stranded cost measurement methods are comparable to the FERC's. Second, the FERC does not require the sale of a power plant to establish its market value, so administrative methods are more comparable than divestiture methods.

The approach that meets the measurement conditions analogous to those chosen by the Commission is a one-time, administrative process with neither plant divestiture nor true-ups. This well-established, or "conventional," measurement method is used by many of the state public service commissions that are implementing retail competition.[60] The conventional method calculates the present value of the after-tax difference between book value and estimated market value in an administrative proceeding. This method employs six general steps:[61]

First, determine the plants that are stranded. The only plants that can be stranded are those that exist (or are fully committed to and under construction) when a utility begins the transition from its traditional obligation to serve to a competitive environment. Future generation investments and obligations (other than maintenance capital additions to existing plants[62]) required to serve customers cannot be considered stranded. If utilities do not expect to recover at least the present value of these costs, these investments will not be made. It, therefore, is not possible for the costs of future plants to be stranded.

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59. Order No. 888, *supra* note 2, at 31,835-6. Interestingly, the Commission's approach parallels its treatment of avoided costs under PURPA. In this instance, however, state Commissions implemented the specific formulas, and states soon evolved from administrative determinations to "market-determined" processes. See Peter S. Fox-Penner, *Regulating Independent Power Producers: Lessons of the PURPA Approach*, 12 RESOURCES AND ENERGY 117-41 (1990).

60. See Appendix A. This same method may employ future recalculations of stranded costs to compare price forecasts to actual experienced prices over time. The use of such "true-up" procedures does not affect the initial application of the approach.

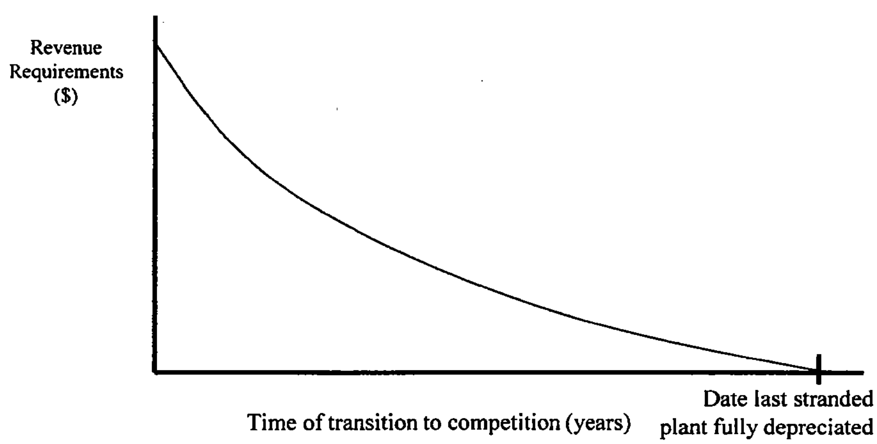
61. Recall that this procedure and the associated discussion applies only to generating plants.

62. Future maintenance capital expenditures at reasonable levels for existing plants are necessary to estimate stranded costs. For example, any bidder in a generation auction will deduct such future capital expenditures along with other O&M costs from expected revenues in determining the free cash flows, and thus the value of the plant.

Second, determine the remaining revenue requirements for all such generating plants as of the date of transition. These figures are summed for each plant operating in each year of its expected operation, and then present-valued. Finally, these results are discounted to the present by means of a risk adjusted, after-tax cost of capital. Under standard regulatory accounting, the net present value of all revenue requirements, less the operating costs of the units, is the net book value of the plant. For any set of generating plants going forward, revenue requirements are generally a steadily declining function. This is because the number of generating units stranded declines over time as plants reach the end of their useful lives and because traditional utility revenue requirements are the sum of depreciation, return, taxes, and operating costs which decline for a plant as it gets older and its book value (hence aggregate annual depreciation and return) declines to zero. Normal stranded plant revenue requirements therefore have a downward sloping shape shown in Figure 1. Note that revenue requirements, while declining, continue until the last plant existing on the day of transition is fully depreciated.

FIGURE 1

The Profile of Regulated Revenue Requirements for Stranded Generating Plants



Third, estimate the amount of electricity that this group of plants can produce in each year. This amount diminishes over time as plants both wear out and are dispatched less frequently after efficient new plants come in line.

Fourth, forecast the sales price of power in future years and the gross revenues the group of plants can earn.[63] This should take into

63. This is *identical* in concept to estimating the competitive market value of power sold from the

consideration whether a particular plant is a peaking, intermediate, or baseload plant because the competitive market is expected to price electricity hourly and show considerable peak price intensity.

Fifth, subtract from gross competitive revenues the estimated full operating costs of the power plants to obtain the net revenues to the owner of the plant. The present value of these operating profits is the estimated market value of the plant under competition.[64]

Sixth, compare the book value, computed in step two, to the market value from step five, in present value terms. The difference is the total stranded cost for all generators as of the date of transition to competition.[65]

Whether one totals the individual components or starts with the sum, total SCO is always the composite (algebraic sum) of stranded costs that is measured for all generators owned by a single utility as of the date of transition.

Structural Differences Between the FERC Formula and the Conventional Method for Stranded Cost Calculation

From the outset, the Commission has recognized that the revenues lost formula approach is imprecise. There is an undeniable appeal to the Commission's objective of avoiding undue complexity in the stranded cost computation. However, the particular form of simplification the Commission has adopted produces reasonably accurate stranded cost estimates only if it is applied very carefully. The variables in the revenues-lost formula attempt to mimic those in the inherently more accurate alternatives, but the underlying design of the formula differs. Hence, each of the magnitudes, (RSE, CMVE, and L) in the revenues-lost equation must be chosen to produce a reasonable end result, *i.e.,* an accurate SCO.

The first major structural difference between the FERC formula and the conventional method, arises from the Commission's use of a revenue stream estimate. This RSE remains at a fixed level over time, rather than declining with expected revenue requirements for the group of stranded plants. This introduces dramatically different time profiles for revenue requirements and RSE, as shown in Figure 2.[66] The conventional method will be a more accurate approach to estimating revenue requirements with the passage of any substantial period of time.

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plant, or CMVE in the FERC formula discussed *infra.*

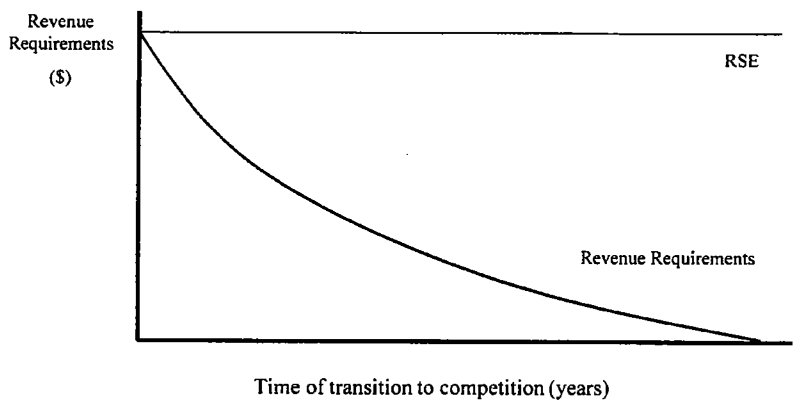
64. This traditional method of asset valuation is often referred to as the discounted cash flow (DCF) method. Recently, more sophisticated methods of plant valuation (such as the use of option pricing) have been proposed for valuing these types of assets, but have not been used in stranded cost determinations to any significant extent.

65. It is possible that some power plants have market values higher than book values, and therefore have negative stranded costs. In this instance, these gains are usually netted against stranded costs, reducing the latter. *See* Appendix A, *infra.*

66. In theory, in the first year of transition, the generation-only portion of RSE equals generation revenue requirements. As a result, both the RSE and revenue requirements begin at the same level in Figure 2.

FIGURE 2

Comparison of Unchanging "RSE" and Actual Stranded Plant Revenue Requirements



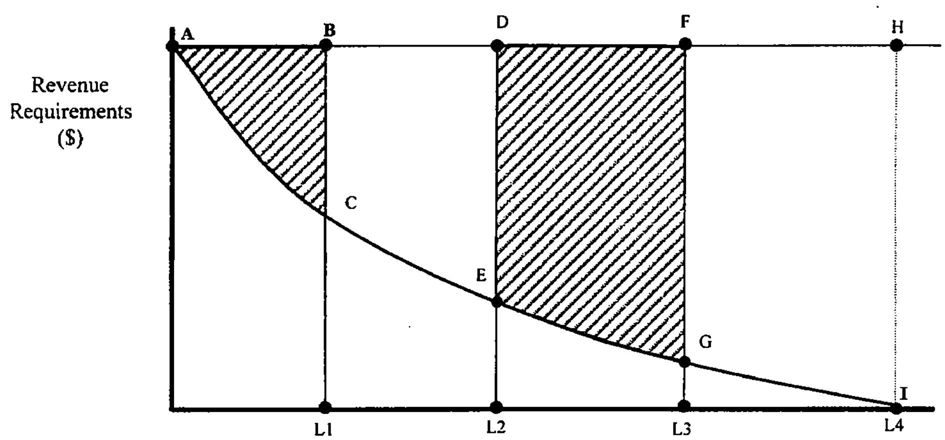
Once the revenue components of both the revenues-lost and the traditional stranded cost calculation methodologies have been determined, the competitive market value estimate is subtracted from each. The CMVE used in the revenues-lost and in the conventional approach is the same. Therefore, after the same CMVE is deducted from the annual revenue streams in each of the two stranded cost approaches, the difference shown in Figure 2 will persist.

The different measure of revenue requirements yielded by the FERC revenues-lost formula and the more accurate conventional method makes it important for both methods to use *appropriate* sequence lengths, each yielding accurate totals of present value numbers. However, the Commission's policy on setting the length of the annual sequence for stranded cost is to base L on a subjective determination of the period over which the utility had an expectation to serve the departing customer. In effect, the Commission makes it possible to select an L, irrespective of whether L yields an accurate SCO, as determined by a more accurate conventional method.

Two examples illustrate that the timing differences between the RSE and the revenue requirement annual stream mean that the subjective selection of L can produce enormous differences in SCO between the FERC and the conventional formulas. In Figure 3, we show the time profile of an RSE and estimated revenue requirement for a hypothetical departing municipality. For the same time profile as in Figure 2, suppose the Commission selects among four L's, labeled L_1-L_4, along the horizontal axis of Figure 3. If the Commission were to choose L_1, the revenue differences would be the comparatively modest triangular area ABC. If L_2 were chosen, the difference would grow to area ADE; L_3 would produce a difference of AFG, and L_4 would yield AIH.[67]

FIGURE 3

Impact of Commission-Determined "L" on Purely Methodology-Induced Differences in SCO



To illustrate the large combined impact of different revenue requirement estimates and the improper selection of L, consider the example of a hypothetical utility with the following characteristics:

- The customer departs the system on the first day of year 1;
- RSE at the time of departure equals $100 per year;
- The traditional stranded cost revenue requirements equal $100 today, steadily declining by $10 per year until year 11, at which time the assets are all retired; and
- CMVE is $10, in all years from 1 to 10.

The discount rate is assumed to be zero in order to remove the need for present value calculations. In this case, actual stranded costs are equal to $450, which is equal to the sum of the difference between the revenue requirement and CMVE in every year.[68] For each year, the vertical difference in dollar terms between the revenue requirement and the

67. To keep Figure 3 simple, we have not shown CMVE which must be identically subtracted from either of the two revenue streams. However, this does not change our point as CMVE is identically subtracted either from RSE or revenue requirements to get stranded costs. We also note that the areas shown in the figures are reduced to present value when SCO is computed under any approach.

68. This is calculated as the average revenue requirement over the period ($55) multiplied by 10 years less the total CMVE of $100 ($10 for 10 years).

CMVE is equal to the amount of costs stranded in that year. This amount declines evenly throughout the period from $90 in year 1 to $0 in year 10, while the (RSE - CMVE) term remains constant over time, neglecting the fact that the annual stranded cost will decline from year to year. These results are shown in Table 1.

In this example, the choice of an L can have a dramatic effect. Given *actual* stranded costs of $450, the only way for the revenues lost formula to arrive at the actual stranded cost is if the expectation to serve is determined to be five years.[69] If the L is determined to be three years, the FERC revenues lost formula method determines that the stranded cost obligation is $270, not $450. At the same time, an L of seven years will yield a SCO of $630. Finally, if one assumed an expectation to serve equal to the life of 10 years, the stranded cost would increase to $900.

In conclusion, the Commission should not employ a formula that uses an initially true, but fixed, RSE and the correct CMVE, and then select an arbitrary L to compute the SCO.[70] If the objective of the calculation is to compute an accurate stranded cost and prevent the shifting of this cost to other customers or utility investors, the overarching rationale for selecting an L is that it approximates the period required for the utility to recover its stranded costs from departing customers.[71]

Displacement and Load Growth as Alternative Measures of CMVE

One point of consensus in stranded cost policies is that utilities should pursue all reasonable measures available to reduce or "mitigate" stranded costs. When a customer group departs from a utility, leaving that utility with excess capacity and the attendant stranded costs, the most direct

69. The Commission formula of (RSE - CMVE) x L is equal to ($100 - $10) x 5 years, or $450.

70. The Commission seemed almost to admit this in Order No. 888-A but declined to change its formula. *See* Order No. 888-A, *supra* note 2, at 30,427:

> In response to petitioners requesting an RSE based on estimates of future revenues for the reasonable expectation period (L), we continue to believe that an approach based on estimates of future revenue streams would engender countless disputes over the RSE component in the formula with little, if any, added accuracy. These would in effect be rate cases that attempt to litigate not what costs were during a test year based on audited accounting data, but what costs will be, based on speculation about future fuel costs, employment levels, capital costs, and so on. In contrast, we believe that the use of present revenues will produce fair results and minimize litigation of RSE. This is appropriate for a transition period cost recovery charge that needs to be settled quickly for market participants to make business decisions about future wholesale sales and purchases. Our approach minimizes transaction costs and provides greater certainty with respect to the RSE term in the formula.

As this section shows, the Commission finding that alternative revenue streams would add little accuracy is predicated on its correct interpretation of L in each instance.

71. Given the inconsistencies between the revenues lost and traditional stranded cost approaches, there is one way to ensure that the Commission's approach determines an accurate level of stranded costs. This approach would set the L in the revenues lost formula equal to a value, L*, that would equate the outcomes of the revenues lost and more accurate stranded cost methodologies. This approach would ensure that the formula used in Order No. 888 does not lead to inaccurate estimates of stranded costs.

means of mitigating the stranded cost is to sell the capacity on the market at the highest possible price. This reasoning is inherent in the Commission's formula: lost revenues are to be mitigated by the revenues received from the sale of the stranded capacity and/or the power generated by the stranded capacity, so the SCO is reduced by CMVE, the revenues gained from mitigation via sale of power.[72]

A number of more complex mitigation alternatives are sometimes possible. Some state proceedings have explored mitigation in detail. Order No. 888 discusses the use of load growth as a mitigation possibility. To fit within its formula, this form of mitigation simply provides another way of choosing CMVE. In addition, there is another alternative method of setting CMVE known as *displacement*.

Each of these approaches provides a specific alternative method of computing a number that plugs the CMVE variable into the Commission's revenues-lost formula. As with all the other aspects of applying the formula, use of these alternative approaches must be done carefully if accurate stranded costs are to be determined and cost-shifting avoided.

To illustrate the concept of displacement, consider a utility that has zero sales growth and is presently purchasing 500,000 MWh per year[73] of power for its needs, at $20/MWh, and an RTW customer group of 500,000 MWh per year has decided to leave the system. There are no changes in the utility's rates under any conditions; they are $30/MWh.

If the customer group leaves, the utility sells 500,000 MWh less power to its remaining customers and receives $15 million per year less in revenue. However, the utility also eliminates the power purchase, reducing its costs by $10 million. Since the utility has lost $15 million in revenue, but has to pay $10 million less in power costs, it would seem that its stranded cost is $5 million.

The basic idea underlying this example is sound. Any utility with stranded costs must do everything it can to reduce (mitigate) stranded costs without shifting or absorbing them. However, the treatment in this example is faithful to the Commission policies, if and only if, two conditions apply. First, the purchase power expense must be avoidable in its entirety, i.e., there must not be a demand charge or capacity payment that continues for the utility. If there is a fixed payment, only the variable portion of the purchase should be used to perform the CMVE computation.

The second condition is that the avoidable portion of the power purchase must be higher in price than the highest average net revenue the utility can earn selling owned capacity in the market place. If, for example, the utility can sell the 500,000 MWh formerly sold to the departing group for a total of $12 million, it should continue the $10 million purchase and instead sell the released power. This could reduce its stranded cost to $3 million.

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72. Order No. 888, *supra* note 2, at 31,840-2.

73. Approximately 100 MW at a 57% load factor.

In Order No. 888-A, the Commission also allowed for the possibility that load growth on the system could mitigate stranded costs.[74] To understand this concept and its implementation within the revenues-lost formula, consider the following example: Suppose 5% of a utility's customers leave that utility's system, thereby causing stranded costs, and at the same time, sales to the *remaining* system customers grow 5%. Have any costs actually been stranded? Is the utility back where it started from, having only enough capacity to serve its native load?

The Commission's rules appear to allow this reasoning to be applied, though only under certain specific conditions:

> We clarify that our stranded cost policy does take into account the effects of load growth and excess capacity. The formula is used to calculate the value of stranded costs only if the Commission determines that the utility has proved it has legitimate, prudent, and verifiable stranded costs. For example, it must pass our reasonable expectation test before the formula applies. However, costs may be stranded only if they are not fully recovered from another customer; that is, the released capacity may be either left unsold or resold at a price below full embedded cost.
>
> The resale may be either to a new third-party customer or to remaining native load. If the released capacity is resold to a third-party customer at full embedded cost-based rates, then no costs would be stranded and the formula would not have to be used. Released capacity would also be considered as "resold." If its cost is subsequently (and without delay) included in the rate base of the utility's retail and wholesale native load. It may be included if it is needed, in the judgment of the appropriate state or federal regulatory body, for native load growth plus reliability reserve. In this case the cost is not stranded if it is fully recovered in the cost-based rates paid by native load. If the full embedded cost rate is paid by the new purchaser for the capacity released by the departing customer, the parties may argue either that there is no stranded cost or that the formula produces a stranded cost obligation of zero because CMVE equals the embedded-cost rate that the utility charges its wholesale and retail native load customers; hence RSE equals CMVE.[75]

In this passage, the Commission seems to say that it is acceptable to resell more expensive capacity when a departing customer is leaving the system precisely to escape from the remaining system, and therefore increasing the proportion of high-cost power in the mixture remaining for which ratepayers must pay. When commentators suggested to the Commission that these policies were contradictory, the Commission disagreed.[76] However, the Commission held that this approach could only

74. *See generally*, Order No. 888-A, *supra* note 2.

75. Order No. 888-A, *supra* note 2, at 30,440.

76. In Order No. 888-B, the Commission clarified its position with respect to load growth, stating:

"In short, the revenues lost approach already takes account of the marketability of the released capacity and appropriately incorporates load growth associated with remaining retail and wholesale customers and does not contradict the cost responsibility principle set forth in Order Nos. 888 and 888-A." Order No. 888-B, *supra* note 2, at 62,106.

be used if the full costs of the capacity released by the departure and then redirected to the rest of the customers were recoverable from remaining ratepayers subsequently (and without delay).[77]

To mathematically analyze the proper use of this method of determining CMVE, it is necessary to decide how existing generating plants and purchase power contracts are allocated to the departing customer group versus remaining customers. On this point, the Commission states clearly that the capacity released by a departing customer should be viewed as a representative fraction of the entire utility's generating plants and resources: "[a]s an initial matter, we note that there are rarely separate retail and wholesale generating facilities. Retail customers and wholesale requirements customers get energy from the same facilities, each buying a 'slice of the system.'"[78]

In connection with a discussion clarifying the ability of a departing customer to attempt to sell the capacity released by its own departure, the Commission similarly expressed its view that the ordinary way to view the capacity released by a departing customer was as an average system resource of average cost.[79] The Commission appeared to base this reasoning not only on the realities of system operation, but also on the mathematical fact that cost-shifting is avoided and costs apportioned fairly only by assuming that the departing and remaining customers are each responsible for proportionate shares of the complete set of existing generating plants and other system fixed costs existing as of the date of departure.

The combination of a policy in which average system costs are allocated to all customers, and a policy that allows remaining embedded costs are allocated to load growth, allowing the departing customer to escape with zero stranded costs, yields a mathematical conundrum. Mathematically, one cannot allow load growth to absorb all costs if the overarching policy is to avoid shifting costs, allocated equally to all customers, onto remaining customers.

The intuition underlying this result is obvious. For either the utility's growing system or for the municipality if it breaks away, the next increment of power obtained is going to be lower in cost than the existing average. This is the reason why stranded costs exist in the first place. If the customer group stays part of the utility and the latter supplies its next increment of load growth with cheaper power, the benefits of this cheaper power are shared by all customers. If instead, the municipality leaves, it supplies itself entirely with cheaper power and the remaining customers no longer have an opportunity to blend power from their existing high-cost resources with new low-cost supplies, thus lowering costs. This result is

77. Order No. 888-A, *supra* note 2, at 30,440.

78. *Id.* at 30,414. The term slice of system is utility industry jargon for an equal fraction of each and every generating plant owned by the system, effectively blending plants with different operating attributes and costs into one system-wide composite.

79. Order No. 888-A, *supra* note 2, at 30,433-4.

demonstrated via a detailed mathematical example in Appendix B.

V. CONCLUSION

This article raises a series of points concerning the Commission's implementation of its policy of providing an opportunity for utilities offering open access to fully recover all prudent, legitimate, and verifiable stranded costs. First, the formula the Commission chose to compute stranded cost obligations for departing retail-turned-wholesale customers, if not applied with exceptional care, can be extremely inaccurate. While the Commission recognized that its formula was imperfect, and struck what it believed to be a conscious balance between complexity, certainty, and accuracy, the formula shows vast inaccuracies in the RTW case. Such inaccuracies threaten the Commission's core policy objectives: providing full stranded cost recovery, discouraging forum-shopping, and preventing cost-shifting from one customer group to another.

Second, the Commission's formula could be made serviceable by careful application. For this to occur, the Commission cannot treat the length of the "reasonable obligation period" or "L," as something to determine by *ad hoc* judgment. Instead, the Commission must determine "L" so as to yield a stranded cost number that is consistent with *actual* stranded costs as best as can be determined. To do anything other than this is to produce a stranded cost obligation that simply does not equal the actual stranded cost. This could result in either investors and/or the remaining native load customers paying the difference between actual stranded costs and those estimated by the formula.

Moreover, the inherent inaccuracy of the formula can be substantially exacerbated by interpreting apparently conflicting portions of Order No. 888 to say that a utility with stranded costs should absorb *all* of the stranded costs associated with its future load growth, allowing departing customers to shoulder none. Such an application of the Commission's formula produces the mathematical certainty that costs will be shifted onto remaining customers or investors. Either of these results violate the essence of the Commission's policy.

Given the differences between the Commission's approach and the conventional methods used to estimate stranded costs more accurately, the Commission is faced with a clear opportunity to reaffirm its stranded cost recovery policy or to retreat from it substantially. On the one hand, the Commission faces increasing political opposition to stranded cost recovery, at least in some quarters, as well as arguments by the public power community that "high" stranded cost exit fees will prevent municipalization and franchise competition.[80] However, the Commission also undoubtedly understands that sound regulatory and economic policy rests on governments honoring their commitments with respect to long

80. *E.g.*, Harvey L. Reiter, *Why the FERC Should Preserve and Encourage Municipalization as a Viable Competitive Alternative to Private Distribution of Electricity*, AMERICAN PUBLIC POWER ASSOCIATION, January 1998.

term, irreversible capital investments made in the public interest. Utilities and their investors have the right and duty to oppose every possible move of the Commission that would subvert its stated policy by applying its revenues-lost formula without appropriate care.

Apart from the fundamental merits of stranded cost recovery, inadequate care in applying the Commission's formula, in this RTW situation, will have harmful repercussions beyond the jurisdiction of the FERC. As states struggle to find the political will to award stranded costs, any appearances of retreat by the federal government will undoubtedly add to what already threatens to become a "race to the bottom," where federal and state regulators are pitted against each other to see who can lower rates fastest by failing to pay stranded costs.

Conversely, a decision to apply its formula with the care necessary to yield an accurate determination of the stranded cost obligation is not a decision to damage public power. It is a decision to assure that new suppliers do not unfairly benefit by shifting costs to remaining IOU customers or shareholders. In an era in which most electric consumers are being given *individual* retail choice, it is not clear why efforts to replace one exclusive retail generation supplier for a city or town with another (perhaps public) one makes good public policy. This does not deny the important and legitimate role for aggregators to which customers can voluntarily subscribe in a retail choice environment—a role that public power may quite successfully fulfill. The purchasing of a distribution system purely to avoid stranded cost payments is precisely what the Commission should discourage, even if it wishes to encourage public supply alternatives in a competitive industry.

From the proceedings before the Commission and in many state regulatory agencies, the legacy of stranded costs has been a bitter and unhappy one. Absent extreme care, the application of the Commission's formula to RTW stranded cost assessment is destined to add greatly to this misery.

FIGURE X

Retail Rates vs. Revenue Requirement of Existing Assets & Obligations

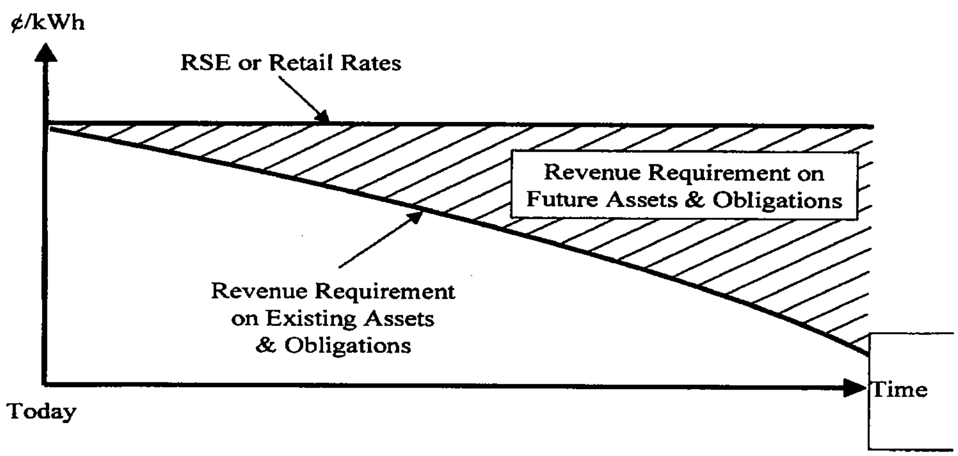
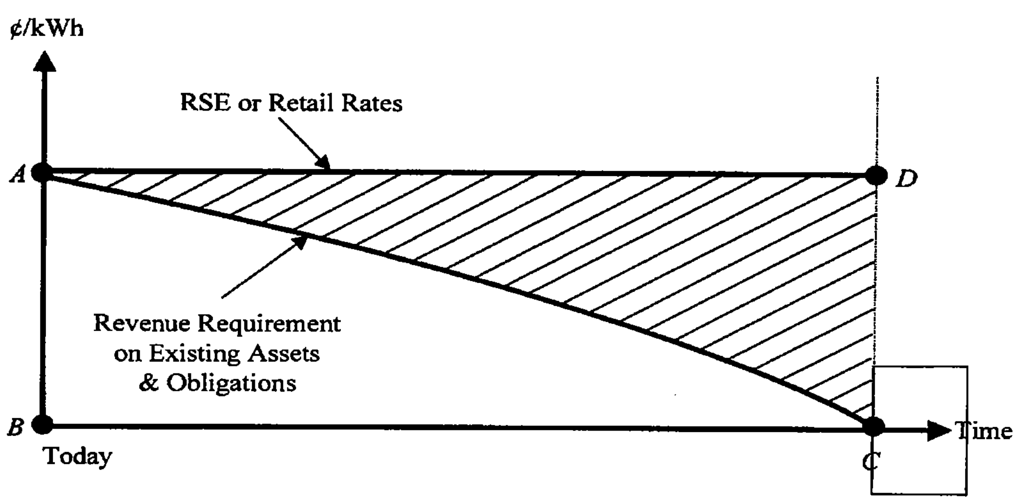


FIGURE Y

Comparison of Revenues Lost & Traditional Stranded Cost Methodologies



Appendix A

State	Status of Retail Choice	Policy on Stranded Cost	Method of Estimating Stranded Generation Cost	Source
Arizona [2]	The Governor is expected to sign a bill passed in May, 1998, that would allow for the opening of a competitive electricity market. No entity may have more than 40% of the state's total generating capacity. Arizona Corporation Commission (ACC) approved plan for retail competition which is phased in from January, 1999, to January, 2001. H.B. 2663 speeds up access to December 1999, and deregulates public power as well.	ACC plan has 100% Stranded Cost (SC) recovery only if utilities fully divest generation. Customers will incur or receive any positive or negative SCs. After ten years, if stranded costs remain, they will be shared with shareholders.	SCs are defined as the difference between market based prices and the regulated cost of power as stranded costs. The State allows utilities to choose from: 1) divestiture/auction methodology; 2) transition revenues methodology. Specifications about these methodologies are also included.	H.B. 2663
California [1]	The Legislature enacted A.B. 1890, which was signed by into law on September 23, 1996. The PUC issued a series of Orders, starting in April, 1994, and continuing to present on implementation of the policy. All customers achieved retail access on March 31, 1998, (three months delayed because of problems starting the Power Exchange and ISO).	Stranded "transition" costs are the net value of generation or restructuring assets whose book value exceeds market value. Ratepayers pay SC which can be collected without increasing rates or rate caps and before 2002, with exceptions.	SC largely estimated using sales price of voluntary divestitures. Some administrative determination, e.g. employee transition. Some reconciliation to the actuals, e.g. nuclear decommissioning and PPCs.	CPUC Decision 96-12-088, December 20, 1996.
Connecticut [1]	In July, 1995, the Connecticut DPUC issued a final report calling for deregulating generation and gradually moving into retail competition. Enacted legislation provides for 35% of customers to use competitive retailers by January, 2000, 100% by July, 2000.	A Competitive Transition Assessment will be used to pay the principal and interest on rate reduction bonds, all reasonable expenses related to financing, and an electric company stranded costs.	Utilities may divest nuclear and non-nuclear generation and calculate SC as Net Book Value – Market Value.	R.B. 5005, signed into law April 29, 1998.

Illinois [1]	H.B. enacted that provides for rate cuts for ComEd and Illinois Power and accords residential customers full choice for their generation supplier by May, 2002. Customers who choose an alternative will pay transition costs until 2006.		The lost revenues formula is used. Amount lost when the customer leaves system determined. "Lost" value = Regulated tariffs – delivery service charge – market value of energy. Transition charge = "lost" value – mitigation factor.	H.B. 362
Maine [1]	Legislation enacted into law in May, 1997, allowing retail competition by March, 2000.	Verifiable and unmitigable costs made uneconomic as a result of the restructuring and determined b the commission can be recovered from ratepayers. Includes all nuclear decommissioning.	Mandatory divestiture of all generation, except QF and nuclear, establishes the market value, which is compared with the net book value. Corrections made every three years where administrative estimates are involved.	Act to Restructure the State's Electric Industry, H.P 1274 – L.D. 1804, approved by the Governor on May 29, 1997.
Maryland [2]	PSC issued order on December, 1997, establishing phased retail access July, 1999, to July, 2000.	Utilities allowed to recover SC and filed plans March, 1998.	TBD	Order in Case No. 8738, December, 1997.
Massachusetts [1]	Commission issues Order initiating restructuring in August, 1995. Path breaking settlement reached by New England Electric System (NEES) and Massachusetts Attorney General in September, 1996, included full divestiture of generation. Law passed validating these policies in December, 1997. Open access for all on January, 1, 1998 (later postponed until March 1, 1998). Standard offer at 10-18% below previous rates.	Full divestiture of generation and PPA to be offered exactly for full recovery of SC.	Net book value – divestiture based market plan.	Electric Utility Industry Restructuring Offer of Settlement by NEES, October, 1996. Act Restructuring the Electric Industry in Massachusetts, November, 1997.
Michigan [2]	MPSC order in June, 1997 phased access March, 1998.	Full recovery of SC using existing fees through 2007.	Bottom-up calculation for five categories of potential stranded costs.	MPSC Order in Case No. U-11290, June, 1997, and MPSC staff report, December, 1996.

Montana [1]	Legislation enacted in May, 1997, allowing retail access for large (>1MW) customers by July, 1997, and as soon as feasible and by July, 2002, for all others (with exemptions).	Transition costs mean utility's net verifiable generation-related cost, including cost of capital, that become unrecoverable as a result of retail access.	Transition costs determined by Commission, using estimates of market value, appraisal by third parties, or by competitive bid sale.	S.B. 390, enacted into law May, 1997.
Nevada [1]	Law directs PUC to establish competitive retail market by December, 1999.	PUC to determine recoverable SC, no guarantee.	PUC to determine SC based on six factor test, General method of asset by asset SC determination is endorsed.	A.B. 366 enacted July, 1997.
New Hampshire [1]	May, 1996, H.B. 1392 passed setting timetable for PUC to establish competition by 1998. February, 1997, final PUC plan passed calling for competition by January, 1998. March, 1997, PSNH filed lawsuit to stop plan on grounds of SC recovery. Federal Judge has issued injunction blocking implementation of plan until issue is resolved in courts. Plan is currently before New Hampshire Supreme Court.	Benchmark price of energy for average regional utility will determine if utilities get full recovery of SC. Costs above this level will not be recovered, unless utility present justification as to why its costs were legitimately above this level.	Divestiture required within two years of competition to sell at retail rates. Interim SC will be in place for two years. Utilities are directed to establish a stranded cost reconciliation account for each customer class.	"Restructuring New Hampshire's Electric Utility Industry: Final Plan" PUC – DR 96-150 February 28, 1997.
New Jersey [2]	BPU released a Energy Master Plan for restructuring in April, 1997, with phase in of restructuring beginning of October, 1998, and full competition in July, 2000. Legislative session ended in July, 1998, without restructuring bill passed. BPU plan now has been modified to push restructuring time table back six months. Four IOUs filed restructuring plans in July, 1997.	BPU plan says utilities should be given opportunity to recover SC, but this must be balanced with desire to give customers near term benefits of 5-10% rate reduction. Presumptive cut off point for SC shall be date of last base rate case prior to issuance of report. Securitization will be allowed, but limited.	Under BPU plan, utilities will submit SC filings with their own market valuations and sensitivity analysis. BPU reserves the right to require divestiture. BPU will determine MTC on a utility by utility basis. MTCs will be in place for 4 to 8 years.	Docket No. EX94120585YNJBPU Restructuring the Electric Power Industry in New Jersey – Findings and Recommendations, April 20, 1997.

New York [2]	The Public Service Commission issued an order in May, 1996, that called for retail competition to begin in the state by early 1998. The order directed each utility to file a company-specific restructuring plan, and all such plans have been approved by the commission. Several utilities have begun to offer retail choice to a subset of their customers.	The Commission's order said that utilities should have a reasonable opportunity to recover stranded costs but that this objective must be balanced against other goals, such as lower rates and economic development.	The calculation of SCs has been determined individually for each utility as part of their restructuring proposal.	Public Service Commission Opinion No. 96-12, May, 1996.
Oklahoma [1]	Legislature passed S.B. 500 in April, 1997, and made slight amendments in timetable with S.B. 800 in May, 1998. OCC task force will study various issues and report Legislature's Joint Electric Utility Task Force. All studies will be completed by October, 1999.	Recovery of an "appropriate amount of prudently incurred, unmitigable and verifiable stranded costs." Each utility shall propose a plan with a recovery time of three to seven years designed so that the CTC does not cause total energy costs to exceed the amount paid on April 25, 1997.	Not yet determined. Utility Task Force will study issue of stranded costs.	S.B. 888, May, 1998.
Pennsylvania [1]	Legislature enacted H.B. 1509, which was signed into law on December 6, 1996. Utilities filed restructuring plans in 1997, and orders have been issued on individual cases from December, 1997, to present. Access to begin January 1, 1999.	Stranded costs are the net present value of costs that traditionally would be recoverable under regulation, but may not be recoverable under competition. SC recovery should not raise rates and should be recovered in seven years (with exceptions).	Stranded costs are determined through an administrative process, based on an asset by asset evaluation. Divestiture cannot be ordered. The key variable is the forecast of market prices. Book lifetimes have been used for the duration.	Electricity Generation and Competition Act, H.B. 1509.
Rhode Island [1]	Legislature enacted the first restructuring statute in August, 1996. Access began for all customers on January 1, 1998. However, the Stranded Offer for customers who stay with incumbent utility is so low that very little competition exists.	In connection with the transition to competition, public utilities should have the reasonable opportunity to recover transitional costs associated with commitments prudently incurred in the past pursuant to their legal obligation to serve.	Generation assets, regulatory assets, and above market fuel contracts are determined by administrative process or voluntary divestiture. Nuclear decommissioning, PPCs, and employee transition costs are trued-up to actual values.	The Utility Restructuring Act of 1996.

Virginia [1]	Legislature passed H.B. 1172 in April, 1998, creating timetable for restructuring. ISO and PX shall be created by January, 2001, by SCC and interested parties. Limited competition starting by January, 2002, with full retail competition by January, 2004.	"Just and reasonable net stranded costs shall be recoverable." General Assembly will define these SC and thereafter will regulate their recovery.	Not yet determined.	H.B. 1172 – April 15, 1998.
Vermont [2]	The Public Service Board issued a restructuring report and order (Docket No. 5854) in December, 1996. The order calls for retail access to be phased-in starting in early 1998 and completed by the end of that year. This order has not been implemented due to the absence of corresponding legislation. Several restructuring bills were considered in the 1998 session, but none were passed.	The Board proposes a sharing of stranded costs between utilities and customers. The ultimate allocation of stranded costs will depend on the circumstances of individual cases and on the effectiveness of utility efforts to mitigate their potentially stranded costs.	An administrative, bottom-up calculation, where one calculates the stranded cost for each generation-related Asset. Utilities will be required to submit estimates of market prices and the potential stream of their stranded costs through the year 2025.	Report and Order, Docket No. 5854.

[1] Restructuring Legislation Enacted
[2] Comprehensive Regulatory Order Issued

APPENDIX B: DEMONSTRATION OF COST SHIFT CAUSED BY THE LOAD GROWTH METHODOLOGY

The example shown in this appendix illustrates the fact that using the Load Growth Methodology for calculating stranded costs creates a shifting of costs away from departing customers. In particular, the existence of a retail rate freeze does not prevent a shifting of costs, but merely assigns the shifted costs to utility shareholders rather than to remaining ratepayers, who might bear the costs in the absence of a rate freeze.

Table B1 shows a very simplified example for a hypothetical utility under four different scenarios regarding stranded costs. Throughout this example, several simplifying assumptions have been employed to isolate and make it easier to observe the effects of interest. The assumptions include:

Fuel cost is constant at $3/MWh; it does not escalate

The market value of power (CMVE) is constant at $4/MWh; it does not escalate

Load growth causes no change in system operation; all growth is served with purchased power

Load growth is constant at 5% per year

Load factor is same for departing and remaining customers (57%)

The weighted average cost of capital (WACC) is 10%

The retail rate is constant at $10/MWh (under assumed rate freeze) in all but the last scenario

RSE is equal to the retail rate

Each panel of Table B1 shows the revenues from native load, revenues earned by selling released capacity and energy into the competitive market, and stranded cost payments from departing customers, as well as variable costs (including fuel), purchases and depreciation for each scenario. Each panel shows the return to investors, including stranded cost recovery, as the difference between revenues and costs, and shows the present value of the five-year return stream.

Panel A of Table B1 illustrates a base case against which to compare the other cases; it reflects the case in which no customers depart, and shows a present value to investors of $10.8 million. This example assumes a retail rate freeze; rates are constant at $10/MWh. This panel shows the customer rates and shareholder return that the state commission (or other regulatory body) deemed appropriate in setting rates. Thus it serves as the standard against which a stranded cost settlement should be measured in light of the FERC's opposition to cost shifting B when judging the allocation of costs and benefits, costs should not be shifted from their allocation in Panel A.

Panel B shows the departure of an RTW customer equal to 10% of original system load. Generation and purchases are the same as in the base case, and the excess energy is sold at the market price, CMVE.[81] The departing customer's stranded cost obligation (SCO) is calculated as the difference between RSE and CMVE, multiplied by the released energy in MWh.[82]

Panel C shows the same customer departing, but in this case the departing customer's SCO is calculated according to the load growth methodology, which reduces the released capacity by the amount of increase in remaining load. Line C8 shows that by year 4 the entire released capacity is consumed by load growth, and the SCO goes to zero. It is obvious from this example, however, that since rates for remaining customers are held constant under the rate freeze, this amounts to a shifting of costs (relative to the base case) from departing customers to utility shareholders. In fact, in this example, departing customers absorb all the benefits of load growth up until load growth consumes the full released capacity, causing a significant deterioration in shareholder value.

Panel D illustrates that the retail rate freeze does not affect the fact that the load growth methodology causes a cost shift. It shows a scenario that uses the load growth methodology to calculate SCO, but in which there is no rate freeze, and rates for remaining customers are increased to hold shareholders harmless (with respect to Scenario B). This causes a 5.5% rate increase for remaining customers. This scenario is similar to that in Panel C, except that costs are shifted to remaining ratepayers rather than to shareholders. In either case, however, the use of the load growth methodology to calculate SCO allows departing customers to avoid paying their share of stranded costs, and imposes those costs on either remaining ratepayers or utility shareholders.

81. Equivalently, purchases could be reduced to reflect lower energy demand, but since purchases and sales of released capacity both occur at CMVE, this would create no ultimate difference, and holding purchases constant with respect to the base case facilitates comparison with the base case.

82. Note that even this methodology does not yield complete recovery for shareholders, because the amount of released capacity and energy is based on the departing customer's size at the time of departure, and is not increased to account for the departing customer's load growth. In order to fully compensate shareholders with respect to the base case, it would be necessary to calculate stranded costs based on a growing load. However, this is contrary to the FERC's intention as expressed in Order 888, and so the stranded costs calculated here are based only on the customer's size at departure.

Table B1

Load Growth Methodology Causes Cost Shift

Retail Rate Freeze Does Not Prevent Cost Shift

Panel A: Without Customer Departure								
No Stranded Costs				**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
A1	Revenues	Native Load	MW	1,000	1,050	1,103	1,158	1,216
A2		Sales to Native Load	GWh	5,000	5,250	5,513	5,788	6,078
A3		Average Rate for Native Load	$/MWh	10.00	10.00	10.00	10.00	10.00
A4		Native Load Revenue	$000	50,000	52,500	55,125	57,881	60,775
A5		Released Capacity & Energy	GWh	0	0	0	0	0
A6		Market Price (CMVE)	$/MWh	4.00	4.00	4.00	4.00	4.00
A7		Released Capacity & Energy Revenue	$000	0	0	0	0	0
A8		Stranded Cost Recovery	$000	0	0	0	0	0
A9		Total Revenue	$000	50,000	52,500	55,125	57,881	60,775
A10	Costs	Fuel and other Variable Costs	$000	15,000	15,000	15,000	15,000	15,000
A11		Purchases	$000	0	1,000	2,050	3,153	4,310
A12		Depreciation	$000	35,000	35,000	35,000	35,000	35,000
A13		Total Cost per MWh	$/MWh	10.00	9.71	9.44	9.18	8.94
A14		Total Costs	$000	50,000	51,000	52,050	53,153	54,310
A15	Return to Investors, incl Stranded Cost Recovery		$000	0	1,500	3,075	4,729	6,465
A16	PV of Return, incl Stranded Cost Recovery		$000	$10,794				
Panel B: With Customer Departure								
Stranded Costs by Correct Methodology				**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
B1	Revenues	Native Load	MW	900	945	992	1,042	1,094
B2		Sales to Native Load	GWh	4,500	4,725	4,961	5,209	5,470
B3		Average Rate for Native Load	$/MWh	10.00	10.00	10.00	10.00	10.00
B4		Native Load Revenue	$000	45,000	47,250	49,613	52,093	54,698
B5		Released Capacity & Energy	GWh	500	525	551	579	608
B6		Market Price (CMVE)	$/MWh	4.00	4.00	4.00	4.00	4.00
B7		Released Capacity & Energy Revenue	$000	2,000	2,100	2,205	2,315	2,431
B8		Stranded Cost Recovery	$000	3,000	3,000	3,000	3,000	3,000
B9		Total Revenue	$000	50,000	52,350	54,818	57,408	60,129
B10	Costs	Fuel and other Variable Costs	$000	15,000	15,000	15,000	15,000	15,000
B11		Purchases	$000	0	1,000	2,050	3,153	4,310
B12		Depreciation	$000	35,000	35,000	35,000	35,000	35,000
B13		Total Cost per MWh	$/MWh	10.00	9.71	9.44	9.18	8.94
B14		Total Costs	$000	50,000	51,000	52,050	53,153	54,310
B15	Return to Investors, incl Stranded Cost Recovery		$000	0	1,350	2,768	4,256	5,819
B16	PV of Return, incl Stranded Cost Recovery		$000	$9,715				

Table B1

Load Growth Methodology Causes Cost Shift

Retail Rate Freeze Does Not Prevent Cost Shift

				Year 1	Year 2	Year 3	Year 4	Year 5
Panel C: With Customer Departure								
Stranded Costs by Load Growth Methodology								
C1	Revenues	Native Load	MW	900	945	992	1,042	1,094
C2		Sales to Native Load	GWh	4,500	4,725	4,961	5,209	5,470
C3		Average Rate for Native Load	$/MWh	10.00	10.00	10.00	10.00	10.00
C4		Native Load Revenue	$000	45,000	47,250	49,613	52,093	54,698
C5		Released Capacity & Energy	GWh	500	525	551	579	608
C6		Market Price (CMVE)	$/MWh	4.00	4.00	4.00	4.00	4.00
C7		Released Capacity & Energy Revenue	$000	2,000	2,100	2,205	2,315	2,431
C8		Stranded Cost Recovery	$000	3,000	1,650	233	0	0
C9		Total Revenue	$000	50,000	51,000	52,050	54,408	57,129
C10	Costs	Fuel and other Variable Costs	$000	15,000	15,000	15,000	15,000	15,000
C11		Purchases	$000	0	1,000	2,050	3,153	4,310
C12		Depreciation	$000	35,000	35,000	35,000	35,000	35,000
C13		Total Cost per MWh	$/MWh	10.00	9.71	9.44	9.18	8.94
C14		Total Costs	$000	50,000	51,000	52,050	53,153	54,310
C15	Return to Investors, incl Stranded Cost Recovery		$000	0	0	0	1,256	2,819
C16	PV of Return, incl Stranded Cost Recovery		$000	$2,608				
Panel D: No Rate Freeze; Investors Held Harmless								
Stranded Costs by Load Growth Methodology				Year 1	Year 2	Year 3	Year 4	Year 5
D1	Revenues	Native Load	MW	900	945	992	1,042	1,094
D2		Sales to Native Load	GWh	4,500	4,725	4,961	5,209	5,470
D3		Average Rate for Native Load	$/MWh	10.00	10.29	10.56	10.58	10.55
D4		Native Load Revenue	$000	45,000	48,600	52,380	55,093	57,698
D5		Released Capacity & Energy	GWh	500	525	551	579	608
D6		Market Price (CMVE)	$/MWh	4.00	4.00	4.00	4.00	4.00
D7		Released Capacity & Energy Revenue	$000	2,000	2,100	2,205	2,315	2,431
D8		Stranded Cost Recovery	$000	3,000	1,650	233	0	0
D9		Total Revenue	$000	50,000	52,350	54,818	57,408	60,129
D10	Costs	Fuel and other Variable Costs	$000	15,000	15,000	15,000	15,000	15,000
D11		Purchases	$000	0	1,000	2,050	3,153	4,310
D12		Depreciation	$000	35,000	35,000	35,000	35,000	35,000
D13		Total Cost per MWh	$/MWh	10.00	9.71	9.44	9.18	8.94
D14		Total Costs	$000	50,000	51,000	52,050	53,153	54,310
D15	Return to Investors, incl Stranded Cost Recovery		$000	0	1,350	2,768	4,256	5,819
D16	PV of Return, incl Stranded Cost Recovery		$000	$9,715				