WHEELING AND THE OBLIGATION TO SERVE

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I. INTRODUCTION

This article explores a number of issues raised by the seeming inconsistency between customers' demands for the right to shop for electricity and the utility's obligation to provide the facilities needed to meet all the electric requirements of the customers in its service area. The relevance of these issues obviously hinges on the transmission access scenario that one envisions and on the regulatory or legislative changes necessary to move toward that end. Here the focus is on some of the problems raised by a particular open transmission access scenario—one in which utilities would be subject to a regulatory requirement to provide transmission service to their wholesale customers and at least to their large retail industrial and government customers in order to permit those customers to shop for electric supplies. In such a scenario, there would be a two-tier electric utility industry structure. At one level, potential switching customers could use transmission access to shop for their requirements among alternative suppliers of power, including other existing utilities, independent generating companies or cogenerators. The market would determine the prices and other terms and conditions under which such power could be obtained. At the second level, captive or core customers would continue to be served by the local utility at regulated rates.

A customer-access-to-transmission policy would expose utilities to major potential load shifts and thus raise significant obligation to serve problems. Implementation of a customer wheeling policy presumably would require legislative action aimed at clarifying federal versus state jurisdictional questions and determining the circumstances under which regulators would be empowered to order wheeling. Rational consideration of any such legislative initiative must come to grips explicitly with the obligation to serve issues which are the subject of this article, rather than leaving them for resolution by the courts at some later date.[1]

It should be clear that providing transmission access to facilitate customer shopping for electricity raises a number of other important issues addressed only partially or not at all in this article. Examples of such issues include: (1) would competition induced by customer wheeling ultimately

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1. As used throughout this article, the term "obligation to serve" means specifically the obligation to supply the capacity and energy requirements of customers within a utility's geographic service area, including the obligation to provide future power supply service. This is distinct from the obligation that may be imposed on the utility to meet the customer's need for transmission service to enable it to shop for electricity from other utilities.

increase or reduce the average price of electricity to all customers collectively?; (2) would cooperation among utilities be discouraged by customer wheeling and, in turn, how would any reduction in cooperation affect the reliability and efficiency of electric supply?; (3) would customer wheeling adversely affect operating reliability by diminishing direct utility control over power flows?; (4) would the overall burden of regulating the industry be reduced or increased by customer wheeling?; (5) what role would government-owned and cooperative utilities play in such markets?; and (6) last, but certainly not least, what would be the expected effects of such shopping on potential switching customers, captive customers, and utility stockholders?[2] Each of these questions is sufficiently critical that it must be confronted as a necessary part of rationally considering proposals to provide transmission access to customers.

Any time the prospect of opening up transmission access to allow customer shopping among utility suppliers is discussed, the obligation to serve problem quickly surfaces. The "problem" as seen by utilities has a number of dimensions: (1) that allowing shopping without a substantial notice period violates the existing regulatory contract (consisting of a utility obligation to make the investments required to provide service on demand, presumably matched by a reciprocal customer obligation to take service) and thus inappropriately imposes stranded investment costs on captive customers and/or utility stockholders; (2) that breaking the traditional regulatory contract will inject substantial uncertainty into the planning process, thereby raising costs and possibly creating capacity shortages in the future; (3) that in any event, in order to make economically rational decisions, both the utility and the potential switching customer must know what obligation the utility will have to supply the remaining requirements of customers who seek to obtain only a portion of their needs through shopping and how any regulated partial requirements rate will be set; (4) that the terms and conditions under which utilities must provide transmission service must be clearly specified; and (5) that rational decisionmaking also depends upon the utility and the potential switching customer knowing in advance whether the local utility will have any obligation to serve returning customers in the future. An overriding utility concern is that should the switching customer's alternatives turn sour at any point, political pressures will result in imposing on the local utility a *de facto* obligation to take the customer back and supply its requirements at regulated rates without adequate (or any) additional compensation, thus exacerbating planning problems and subsidizing switching behavior at the expense of utility stockholders and small captive customers.

The obligation to serve problem as seen by potential switching customers is very different. It may be summarized as follows: (1) that while there may now exist a utility obligation to serve, individual customers never have had an obligation to take service and, therefore, there is no regulatory contract to prevent shopping around; (2) that competitive markets will cause supply to be

2. For a description and preliminary evaluation of many of these and numerous other issues raised by customer-access-to-transmission proposals, see R. Frame & J. Pace, Approaching the Transmission Access Debate Rationally (1987) (available from National Economic Research Associates, Inc.).

more responsive to demand than will any regulatory contract and will reduce electricity costs rather than lead to increases; (3) that since procuring alternative supplies for all of the customer's requirements may not be feasible, the local utility must have an obligation to continue supplying partial requirements service at regulated rates; (4) that because transmission is a natural monopoly, the local utility must have an obligation to expand its facilities as necessary to provide transmission service to potential switching customers at cost-based rates; and (5) that if the switching customer wishes to return to the local utility supplier in the future, it should be treated like any other "new" customer at that point and thus enjoy the benefit of the utility's readiness to serve at standard regulated rates. In any event, as viewed by customers, because some bulk power markets may cease to be effectively competitive in the future even with open transmission access, some obligation to serve at reasonable rates must be available to prevent customers from being exploited.

A review of these positions suggests that the obligation to serve problem has three temporal dimensions: (1) problems associated with the need to deal with the costs of utility investments already made to satisfy the obligation to serve imposed by the existing regulatory system; (2) problems raised by uncertainty over the extent of the local utility's obligation to provide continuing service under existing terms and conditions and to furnish partial requirements power and transmission service to customers that are permitted to pursue competitive alternatives; and (3) problems arising if and when switching customers wish to retreat from the market at some future point and return to regulated utility service.

The remainder of this article explores each of these facets of the obligation to serve problem with the aim of identifying where the real problems lie and assessing how and to what extent they may be solvable. The next section provides a brief overview of the conclusions. The sections following that present the details.

II. Overview of Conclusions

The conclusions suggested by the remainder of this article may be summarized as follows.

1. It seems indisputable that both the local utility and potential switching customers must know the rules of the game in advance in order to make rational decisions. Proposals to open up transmission access in order to permit customers to shop for electric power should not be permitted to ignore the obligation to serve problem. Reasonable open access scenarios must spell out how stranded investment costs will be handled, what future obligations to serve, if any, are envisioned, why such obligations should exist, and what pricing rules should apply for service rendered pursuant to any such obligations.

Reliance upon the current set of regulatory and legal institutions to deal with the obligation to serve problem would be perilous. Any argument in favor of eliminating or substantially limiting the obligation to serve potential switching customers must face the reality that if the supply situation tightens up in the future and, as a result, competitive electricity prices begin to rise sharply, regulators will face intense political pressure to allow the switching customers to return to regulated rate service. Potential switching customers are likely to be large influential commercial and industrial concerns that pose the threat of substantial local employment and tax base losses if they do not receive the rate and service adequacy protection they seek. In short, the legal and political climate within which utilities operate gives credence to their concern that even with open access, they will continue to shoulder a *de facto* obligation to serve, thus placing them and their nonshopping customers in a no-win position.

To address this concern, any open access plan should be contingent on an explicit legislative delineation of the remaining regulatory jurisdiction over electricity sales to switching customers. The process of legislative compromise should not be allowed to result in a mandate for open transmission access, while leaving obligation to serve problems to be dealt with by state regulators or courts. Compelling open access without coming to grips realistically and effectively with the obligation to serve issues that such access would entail would be a serious policy mistake.

2. As an integral part of any rational open access plan, reasonable transition rules would need to be specified in order to address stranded investment problems in a way that motivates efficient decisionmaking and minimizes income transfers from utilities and their captive customers to potential switching customers.

The legal/equitable basis for concern with stranded investment costs is clear-cut, particularly at the retail customer level. Utilities have been compelled to make substantial long-lived investments in order to satisfy explicit obligations to serve retail customers and in return, as part of the regulatory bargain, typically have been granted *de facto* exclusive rights to serve in defined territories at rates designed to cover all prudently-incurred costs. Accordingly, the legal/equitable argument against allowing potential switching customers to avoid embedded costs incurred on their behalf seems especially compelling when applied to retail customers. It also seems reasonably plain that utilities have in reality shouldered an obligation to meet the needs of wholesale customers as well. Once service to such customers is initiated, the utility cannot terminate its obligation to satisfy their continuing requirements, absent an order of the Federal Energy Regulatory Commission (FERC or Commission).[3]

The stranded investment problem raises more than just "fairness" issues, however. Any open access scenario that allows embedded costs incurred to satisfy the utility's obligation to serve to be shifted from potential switching customers to captive customers or utility stockholders will induce uneconomic shopping and economically inefficient consumption decisions. Clearly, if shopping appears attractive to potential switching customers only because they can impose sunk costs on the utility's other customers or its stockholders, then such shopping should not be encouraged.

To address some of these problems, obligating potential switching customers to pay stranded investment costs during a transition period defined by

3. Indiana & Michigan Elec. Co., 12 F.E.R.C. ¶ 61,007 (1980).

market conditions might be considered. The basic objective would be to avoid inducing inefficient shopping and large income transfers in markets currently glutted with capacity. Instead, if customer shopping is to be promoted, sensible public policy suggests that it be done when market supply and demand are more nearly in balance and therefore when market prices would more accurately reflect the long-run marginal cost of electricity. In these circumstances, customers could make more informed choices between a regulated rate system and a market-determined system. It is important to note that a stranded investment obligation based on *market* demand and supply conditions is not the same thing as one based on *utility-specific* demand and supply conditions. Thus, even if potential switching customers were liable for stranded investment costs for a period of time based on average demand and supply conditions in the region, particularly high-cost or capacity-excess utilities might not recover all stranded investment costs. If customer access to transmission is pursued, public policymakers must decide whether such a compromise strikes a reasonable balance between the competing interests of potential switching customers and those of the utility and its captive customers.

3. In unregulated markets, many of which are substantially less than perfectly competitive, there is no obligation to serve. Suppliers in unregulated industries are free to enter or exit markets as they please. Customers get only what suppliers are willing to sell voluntarily. Those desiring certainty of supply can use various contracting or insurance options to obtain needed supply assurance. Unregulated markets, of course, do not always smoothly match capacity to customer needs. Instead, periods of excess capacity and periods of tight capacity, with attendant price swings, are characteristics of many markets. These are imperfections that must be accepted or dealt with by contracting if free markets are to be relied upon.

In unregulated markets, the attention devoted to supply assurance is greatest where future supplies are relatively risky or their riskiness, however small, threatens to impose relatively large costs on purchasers. This is likely to be the case when: (a) the good cannot be stored so that inventories cannot be used to cushion current supply disruptions; (b) the good is essential so that doing without it would be very costly; (c) there is little flexibility to expand output in the short run; and (d) a relatively long period is required to install additional capacity. Where these characteristics predominate, there is a substantial need for long-term take-or-pay contracts, option contracts, or vertical and horizontal integration of various functions within individual firms in order to provide needed supply assurance.

4. Legally imposed obligations to serve are fundamentally inconsistent with the notion of customers shopping in competitive bulk power supply markets. If electric transmission access were to be opened up to customers, it should be only after concluding that bulk power markets will be effectively competitive[4] and therefore that no obligation to serve potential switching cus-

4. At this point, there is no consensus regarding the prospects for achieving effective competition in bulk power markets. Any rational proposal for customer access to transmission must be contingent on a showing that such competition can be expected to exist and will be relied upon as the primary means for securing electric supplies.

tomers will be imposed on any supplier.

By definition, market processes will match capacity and switching customer demands. Moreover, if effective competition is obtainable, it can be expected to goad power suppliers to minimize cost in the short run and exploit available technologies in the long run. However, there are a number of reasons to question whether a two-tier power supply market would operate very smoothly or produce more efficient outcomes. Individual power suppliers undoubtedly would find it more difficult to forecast demand than now is the case. As a result, periods of capacity excess or tightness could be expected and, given the characteristics of electricity supply and demand, this could produce substantial spot price swings. Private contracting between customers and suppliers may not provide an efficient way to address this problem. Switching customers might find it necessary to enter into relatively inflexible long-term contracts in order to assure supplies at predictable prices and enable suppliers to support the construction of long lead time, capital intensive generating units with low-cost financing. This may be contrasted with the present "regulatory contract" system which gives individual customers the flexibility to vary their electricity demands and simultaneously provides the utility with the security of supplying a reasonably predictable aggregate demand in a defined territory. Whether unregulated markets relying upon spot transactions and private contracting would produce a more efficient outcome than that achieved when suppliers and customers operate under a regulatory contract is unclear. Beyond this, problems posed by overt or inadvertent impacts of regulation on the unregulated market in a two-tier system are likely to be considerable. Necessary regulatory control over the allocation of costs between the utility's regulated and unregulated operations, as well as control over new power supply facilities exercised through state siting and certification processes, pose a significant threat to the efficient operation of deregulated power markets.

These uncertainties about possible market outcomes suggest several things. First, if there is at least a good prospect that the present regulatory contract offers the most efficient solution to matching customer and supplier requirements, then that option ought to be retained. Potential switching customers should have the option to stay within the existing regulated rate system rather than be forced into a market environment that may be economically inefficient as well as hostile to their interests. Alternatively, as some have suggested, if the aim is to introduce a greater measure of competition, a better approach may be one that retains the existing utility obligation to serve and customer obligation to take service (thus there is no customer wheeling), but requires utilities to procure all needed new generating capacity competitively.[5]

5. *See* KEYSTONE ELECTRICITY WORKING GROUP, KEYSTONE ELECTRICITY DRAFT (1987); Statement of Charles J. Cicchetti before the Commonwealth of Massachusetts, Department of Public Utilities, on behalf of Boston Edison Co., No. 86-36 (June 12, 1987); Statement of William W. Berry before the Federal Energy Regulatory Commission concerning implementation of the Public Utilities Regulatory Policies Act in Washington, D.C. (Apr. 16, 1987); Testimony of Alfred E. Kahn before the Vermont Public Service Commission on behalf of Central Vermont Public Service Corp., No. 5201, Petition for Approval of a Statutory Merger and for a Declaratory Ruling (Nov. 7, 1986).

Second, if potential switching customers choose to forsake the present system and use transmission access to shop for power, they should be prepared to accept the market risks associated with the choice. They should not be allowed to reenter the regulated rate system later on the same terms as other "new" customers if market outcomes turn sour. It is difficult to be sympathetic to the potential switching customer's argument in this regard, if they have been given a *choice* between the regulated rate system and a deregulated market system. Customers who seek the right to shop now when excess capacity generally exists and, at the same time, demand a legally enforced right to return to service in the future at embedded cost-based rates simply want to have the best of both worlds (leaving the worst of both worlds to the utility and its remaining customers).

Third, uncertainties about the long-run efficiency implications of a customer wheeling scenario reaffirm concerns about the wisdom of any public policy aimed at opening up transmission access to customers in the presence of the current power supply capacity glut, unless (as argued herein) some requirement is imposed on switching customers to pay stranded investment costs while the capacity excess is worked off. Providing customers with the chance to escape sunk costs incurred on their behalf not only will encourage shopping that yields no short-term efficiencies, but will entice customers into an unregulated market offering dubious long-term benefits.

5. As suggested above, if a customer wheeling scenario were to be implemented, potential switching customers should be given the option to stay in the present regulatory system. However, their choice must be unambiguous. The utility's obligation to serve customers opting in would be equivalent to its obligation to serve captive customers. Given this, to share the benefits of a regulated rate system on a par with captive customers, potential switching customers opting in should be required to provide long-term assurance of their position. Such customers might be compelled to sign requirements contracts with, for example, minimum ten-year rolling notice provisions in order to continue to enjoy the benefits of traditional rate and obligation to serve regulation. These contracts need not be as inflexible as it might seem at first from the customer's point of view. It would not be necessary for the customer to specify and commit to pay for defined amounts of electricity. Rather the customer would commit only to take whatever its electricity requirements (if any) might be from the local utility for the duration of the contract. In short, in order to enjoy the benefits of the regulatory contract, the customer would be asked to agree to abide by that contract and forgo shopping until the specified notice provisions were satisfied. The proper notice provision should be related to the time required for utilities to absorb or sell off generating capacity no longer needed to supply switching customers. This will depend on capacity expansion lead times, the rate of growth of nonswitching load and the relative size of potential switching customers. Given five- to ten-year capacity expansion lead times and thirty-year or longer generating plant lives, a case could be made for requiring very substantial notice provisions.

The treatment of new customers in the potential switching class should parallel the treatment of existing customers. If existing customers are given the one-time choice to opt into or out of the regulated rate system, new customers can be given this same choice when they initially establish service. This should satisfy court- or commission-imposed antidiscrimination standards in that all existing and new potential switching customers would have been given the same choice: either to sign long-term contracts with the local utility and thereby opt into the regulated rate system, or to shop for their electricity requirements in deregulated markets.

While a customer choice system has certain key advantages, it is not without problems. Administering such a system will require distinguishing between "old" customers who have made the regulated/unregulated rate choice and "new" customers who have a new option to select how they will satisfy their electricity requirements. Events such as plant closings, significant expansions of a customer's electricity requirements and ownership changes would complicate the administrative process. These definitional problems can be handled (though inevitably in ways subject to controversy), but some distortions seem unavoidable. In particular, if customers can obtain a new regulated/unregulated rate option by closing down operations in one area and moving to a new location (in another utility's service area), that flexibility can be used to game the two-tier system or be employed as a threat to compel the local utility to make rate concessions. In addition to this, giving new customers a choice of the manner in which they wish to be served necessarily will increase the uncertainty of utility demand forecasts.

6. Because of the prospect that some bulk power markets may not prove to be effectively competitive in the future even with open transmission access, it may make sense to provide switching customers with some safeguard against exploitation. However, it is important that the safeguard price not be set so low as to cause *de facto* subsidization of switching customers by captive customers. A system conceptually similar to that currently employed in the railroad industry may be appropriate. In the railroad case, if the shipper demonstrates that it is a captive customer (that sufficient competitive transportation alternatives do not exist), then a regulated ceiling price is established for service to that customer.[6] Modified for the electric utility industry (which has a long history of relying upon split-the-savings arrangements between parties with equal bargaining power), the obligation to serve policy might be stated as follows: if the switching customer demonstrates that it does not have reasonable access to alternative supplies, then the local utility shall have an obligation to extend service to the customer as soon as feasible at a ceiling price halfway between the long-run marginal cost to the local utility of providing the required service and the (presumably higher) customer's cost of meeting its own requirements. However, any such safeguard policy must distinguish between "tight" markets with temporarily high prices[7] and noncompetitive

6. The ceiling price is based upon the cost of providing stand-alone rail service to the captive customer or to it and other similarly situated shippers as a group. *See* Coal Rate Guidelines, Nationwide, 48 Fed. Reg. 8362-64 (1983).

7. It is important to stress that "temporarily" high prices could prevail for a considerable period of time as suppliers might require a number of years to adjust their capacity expansion plans to respond to unforeseen market conditions.

markets in which supply responses cannot be counted upon to bring prices and costs into reasonable alignment over time. Customers who shop in order to enjoy the benefits of low prices in "soft" markets should not be protected from unpleasantly high prices in tight markets.

7. The general arguments against imposing any obligation to serve on utilities if customers are allowed to shop for competitive power supplies also apply to the obligation to provide partial requirements service. There is little basis for allowing customers to shop for pieces of their requirements and simultaneously compelling utilities to serve any remaining requirements at regulated rates. Setting cost-recovering partial requirements rates under those circumstances is extremely difficult. Deregulated markets may be able to provide needed partial requirements services, although some services—in particular, load-following and backup services—may be available at acceptable costs only from local utility suppliers in the short run. If one wished to maximize the customers' flexibility, still have a tractable regulated rate sytem and minimize the chance of disturbing system operations, customers might be given a single partial requirements option—that is, to purchase a fixed block of baseload power in deregulated markets and obtain the remaining requirements from the local utility at regulated rates. The local utility would provide partial requirements "load-following" service; the customer could shop for a discrete block of capacity; and transactions costs and operating problems would be minimized since a constant amount of power would be scheduled into the local utility's control area. In addition to this, requiring utilities to supply backup power for local independent generators may make sense. If this is done, it will be necessary to craft backup power rates with considerable care, both to compensate the utility properly for the service rendered and to induce independent suppliers to plan for and maintain optimum levels of generating unit reliability.

8. If the provision of transmission service to potential switching customers is a natural monopoly, then that service must be comprehensively regulated. Transmission service prices as well as the terms and conditions under which such service must be made available to potential switching customers will have to be controlled. In order to assure the functioning of effectively competitive markets, regulators would need to have the authority to compel the expansion of transmission capacity in order to accommodate actual and expected wheeling requests. Determining when such facility expansions are required and how they should be paid for seems likely to entrap regulators, utilities and potential switching customers in endless debate and is alone a problem of such complexity as to shed doubt on the viability of open transmission access. These transmission service obligation and pricing problems may be the Achilles heel of customer wheeling proposals.

Many other aspects of the obligation to serve problem can be solved, at least in principle, by giving customers a choice between the present regulated rate system and an unregulated system, and unequivocally imposing on switching customers the costs of their shopping. However, transmission remains an indispensible, necessarily regulated and complex part of the puzzle. While it is premature to say that transmission pricing and service obligation problems are unsolvable, it can be said with confidence that they presently are unsolved. Again it is crucial that this area not be ignored in public policy debates. Reasonable open access scenarios must specify who will regulate the transmission obligation to serve, how transmission capacity will be measured, how it will be decided when expansions of that capacity are needed, what degree of flexibility (in terms of reaching different alternative suppliers) and reliability must be provided, how transmission capacity expansion plans will be implemented, and how their costs will be shared among potential switching and captive customers.

III. Establishing the Rules of the New Game in Advance

There can be no excuse for entering into a public policy debate on opening up transmission access to customers without specifying clearly and in advance what the rules of the new game will be. The ability to address open transmission access questions rationally hinges on knowing how stranded investment costs will be handled, as well as identifying the nature and extent of any future obligations suppliers will be forced to accept. If potential switching customers believe that they can have the benefit of market-determined rates in the short run (escaping all stranded investment costs) and regulated average cost-based rates in the long run, then they are in a no-lose position. Correspondingly, utilities and their captive customers are in a no-win position. Failing to specify the rules in advance serves only to obscure a balanced appraisal of the costs and benefits of widespread wheeling.

A failure to address obligation to serve problems will affect more than just the fairness of the new game to various players. How stranded investment costs will be handled in any customer wheeling environment must be made explicit in order to minimize potentially serious distortions of customer decisionmaking and to deal with the potential repercussions of shifting large costs to captive customers and/or utility stockholders. What supplier, if any, will have an obligation to serve potential wheeling customers in the future and under what terms and conditions must be spelled out in order to minimize adverse effects on future utility investment planning. Since relatively few utilities now confront an immediate capacity expansion need, it is unlikely that vagueness about any future obligation to serve will lead to widespread capacity planning problems in the short run. In the long run, however, if the local utility receives ambiguous messages regarding its obligation to serve switching customers, it may feel compelled to plan for their needs. At the same time, if neighboring suppliers serving switching customers are unsure of their legal ability to terminate service to such customers when contractual arrangements expire, they also may feel the need to plan for those same customers' requirements. Alternatively, uncertainty may result in neither supplier making provisions to serve the switching customers' needs. Vagueness about the obligation to serve can only exacerbate long-run capacity planning problems.

Reliance upon the current set of regulatory and legal institutions to deal with the obligation to serve problem seems perilous. The FERC still has failed to deal adequately with the costs of take-or-pay obligations which have been stranded by its open access policy in the gas industry.[8] Beyond this, existing federal and state laws and regulations offer little guidance as to how future obligation to serve problems will be resolved. At the federal level, although considerable uncertainty surrounds the issue, the imposition of service obligations appears to hinge on the "public interest" as seen by the then-current FERC, and its perceptions of the public interest obviously may change over time.[9] Up to this point, decisions of the FERC have demonstrated an unwillingness to impose symmetric obligations on suppliers and customers. Suppliers have been barred from terminating service when contracts expire, but customers have been held to have no obligation to take service other than that which might be embodied in relatively short-term contracts.[10] At the state level, the ability of regulators to modify electric utility obligations to serve in response to changed competitive conditions apparently has not been tested. However, given that public utility obligations to serve are deeply rooted in common law and generally codified in state regulatory statutes, significantly altering future utility obligations to serve through state regulatory actions is likely to prove difficult and, if attempted, subject to prolonged litigation.

Perhaps even more important, the political realities of electric utility regulation should not be overlooked. At the present time when most regions are characterized by excess generation capacity, it seems relatively painless to suggest that any moves toward opening up transmission access to customers should be accompanied by limitations on the utility's obligation to serve such customers in the future. But it must be recognized that if generation capacity gets tight in the future and electricity prices to switching customers begin to rise sharply in response, regulators will be subject to enormous political pressure to reimpose on utilities an obligation to serve switching customers at regulated rates. The switching customers are likely to be large influential commercial and industrial concerns that can pose the threat of large employment and tax base losses on the local economy if their demands for rate relief are not met. State regulators may find it very difficult not to yield to such pressures.

In short, the legal and political climate within which they operate gives credence to the utilities' concern that, even with open transmission access, they would continue to shoulder a *de facto* obligation to serve, thus distorting the decisions of potential switching customers, while placing utilities and their captive customers in a disadvantageous position. The best that can be done to address these concerns is to insist not only that open access proposals spell out the future service obligations envisioned, but that any proposed limits on the obligation to serve be embodied in legislation preempting the authority of regulators to reimpose broader obligations in the future. The importance of not allowing the process of legislative compromise to produce a mandate for open access, while leaving obligation to serve problems to be addressed another day by another body, cannot be overemphasized.

8. *See* Associated Gas Distribs. v. FERC, 824 F.2d 981, 1021-29 (D.C. Cir. 1987).

9. *See* Bouknight & Raskin, *Planning for Wholesale Customer Loads in a Competitive Environment: The Obligation to Provide Wholesale Service Under the Federal Power Act*, 8 ENERGY L.J. 1, 1-5 (1987).

10. *Id.*

IV. Wheeling, the Regulatory Contract and Stranded Investment Problem

The "regulatory contract/stranded investment" problem has been viewed primarily as a legal or equitable one; however, its handling can have potentially important efficiency consequences as well. It should be noted at the outset that a utility's investment can be "stranded" in any of several ways if customers are given transmission access. First, customers may leave the local utility system and meet their requirements with purchases from neighboring suppliers. In this case, capacity constructed to meet the switching customer's needs literally could be idled and the fixed costs associated with that stranded investment by necessity would be shifted to captive customers and/or utility stockholders. A second and more likely case is that customer switching would not actually result in idling capacity on the local utility system, but rather would leave the utility with only one option to reemploy that capacity—that is, to sell power to other suppliers in the coordination market at prices below the levels required to cover its fixed investment cost. Third, customers may not actually switch suppliers. Instead, the availability of transmission access may force the utility to reduce its prices to levels below those that cover its fixed investment costs (but more than cover its current out-of-pocket costs) in order to induce potential switching customers not to change suppliers. In either of the latter two cases, fixed investment costs are stranded and still must be shifted to captive customers and/or utility stockholders even though the local utility's capacity continues to be used. Any of these situations poses a stranded investment problem. In short, as defined here, a stranded investment problem exists whenever opening up transmission access results in the local utility's inability to recover from potential switching customers the fixed costs of capacity prudently constructed (under the existing regulatory rules of the game) to meet their needs.[11]

There can be no serious question that utilities generally have been compelled to make substantial long-lived investments[12] in order to satisfy explicit obligations to serve retail electric customers. As previously noted, the obligation of public utilities to serve all customers on a nondiscriminatory basis is grounded in common law and typically enacted in state public utility statutes. Further, in order to protect the public interest when essential public utility

11. Conversely, there is at most only a temporary stranded investment problem if the local utility has a reasonable prospect of recovering its fixed costs in the foreseeable future through power sales to potential switching customers or other suppliers at market rates. By definition, however, the incentive for customer switching will be greatest when market prices are expected to be below regulated rate levels and thus when utilities are least likely to be able to recoup stranded investment costs. Moreover, regardless of anticipated market conditions, such recoupment will not be possible if switching customers gain the right to return to the local utility and be served at standard regulated rates.

12. Typical generating plant lives are 30 to 40 years. *See* Federal Power Commission, The 1970 National Power Survey pt. IV, ch. 1, at 29 (1972). On average, utilities have invested $3.04 in electric plant for every $1.00 of annual revenues. This contrasts with an average investment of only $0.53 per dollar of revenue for all manufacturing industries. (Calculated from data in Energy Information Administration, Financial Statistics of Selected Electric Utilities 1985 at 12, 15 (1987), and U.S. Bureau of the Census, Quarterly Financial Report for Manufacturing, Mining and Trade Corporations, Fourth Quarter, 1986 (1987)).

services are involved, it is well recognized that comprehensive price regulation necessarily must be accompanied by the power to assure the provision of adequate service by utilities. This, in turn, rests upon the ability of regulatory authorities to mandate that utilities reasonably anticipate future demands and undertake capacity expansions designed to meet those demands at least cost. It is also true that those obligations have been accepted by utilities in return for certain reciprocal rights as part of a regulatory bargain or contract—to wit, that the utility will be given a reasonable opportunity to earn a fair rate of return on its investment. This opportunity typically has been provided by granting utilities *de facto* exclusive retail service rights in all or most of their service territories and establishing rates for service within that area with the avowed aim of covering all prudently incurred costs.

Except as sometimes specified in contracts with large customers, individual retail customers never have had an obligation to take a specified level of electric service from their local utility. Individual customers have always been able to reduce their electricity use by conserving, or switching to other energy sources, self-generating, or leaving the area altogether, without having to compensate the local utility for stranded investments. Potential switching customers can be expected to rely upon this as support for the proposition that they have no obligation to take service and that the utility never had, and does not now deserve, protection from load swings. However, this argument ignores one key aspect of the typical retail regulatory bargain—that is, that pursuant to franchises or certificates of convenience and necessity, it has been almost universally true that if the customer purchases electricity at its present location, it must purchase it exclusively from the franchised or certificated local utility. It is this legal obligation to take service (if at all) from the local utility which would be abridged if retail customers were permitted to use transmission access to shop for electricity supplies. Whether the utility's franchise or certificate rights can be so abridged without just compensation is a legal question beyond the scope of this article.

Utility and customer obligations may be somewhat different in the wholesale power arena. The Federal Power Act has been construed to give the FERC relatively broad authority to require utilities to provide wholesale service. Commission decisions have demonstrated, at least in some cases, that the FERC will compel the furnishing of wholesale services not voluntarily provided in circumstances where the Commission believes the "public interest" so requires. Apparently, however, wholesale customers are not viewed as having any reciprocal obligation to take service. FERC decisions suggest that the utility supplier's only protection against stranded investment problems lies in obtaining proper contractual notice provisions. In a recent case where the FERC focused on proper notice provisions, it found a five-year provision to be reasonable.[13]

The regulatory contract/stranded investment argument also relies heavily upon perceptions of "fairness." Utilities and their captive customers justifiably may view it as unfair to change the rules in the middle of the game. This

13. Kentucky Utils. Co., 37 F.E.R.C. ¶ 61,299 (1986).

unfairness seems particularly acute in cases where utility investments were undertaken in direct reliance upon load forecasts or projected operating levels furnished by customers now seeking the right to shop. One response is that any "deregulation" scenario by definition is likely to involve significant changes in the ground rules and substantial resulting income transfers. The last decade has demonstrated that such changes have been tolerated when efficiency-based arguments in favor of deregulation become compelling or when the complexities of a partial regulation/partial competition system become overwhelming.[14] The regulatory contract equity argument does suggest two propositions, however. The first is that the burden of proof should be on the proponents of changing the rules in the middle of the game to demonstrate that the new game in fact will be better for society as a whole. The second is that serious attention ought to be given to working out transition mechanisms to minimize income transfers between potential switching customers and captive customers or utility stockholders.

Abrogating the existing regulatory contract also may have significant negative efficiency implications unless local utilities are compensated for stranded investments. If potential switching customers can obtain marginal cost-based (presumably lower) rates from surrounding suppliers but must pay traditional embedded cost-based rates if they remain with their local utility, they will have an artificial inducement to switch suppliers and thereby escape sunk costs incurred on their behalf. If the local utility is permitted to respond to competitive offers by reducing rates to potential switching customers, then those customers will enjoy rates more nearly reflecting marginal costs, while captive customers or stockholders bear the full burden of utility costs in excess of current marginal costs. To illustrate, assume that the utility's average cost (which includes the fixed costs associated with investments made in the past to meet anticipated customer needs) is 5.0 cents per kilowatt-hour, while its current marginal cost is 3.0 cents per kilowatt-hour. A utility serving two equal-sized customer classes in a world of regulated average cost pricing might charge each 5.0 cents per kilowatt-hour. All else being equal, opening up transmission access to one customer class could be expected to drive rates to that class toward the 3.0 cent level (assuming that surrounding suppliers also have marginal costs of approximately 3.0 cents per kilowatt-hour) and, if the utility is to recover all its costs, drive rates to the captive customer class upward toward 7.0 cents per kilowatt-hour. Economic efficiency is extremely unlikely to be served in that case. It is widely recognized that efficiency would be better served by distributing the fixed cost burden over all customers in a manner inversely proportional to the elasticity of their demand for electricity.[15] As a general proposition, wholesale customer demand elasticities can be

14. However, it is not clear that the magnitude and direction of the income shifts (for example, in the telecommunications industry) were fully appreciated in advance, nor is it clear that there would have been adequate support for the restructuring had the potential income transfers been recognized.

15. *See* Baumol & Bradford, *Optimal Departures from Marginal Cost Pricing*, AM. ECON. REV., June 1970, at 265; Ramsey, *A Contribution to the Theory of Taxation*, ECON. J., Mar. 1927, at 47. The elasticity of demand is a measure of the responsiveness of the demand, for a particular good or service to changes in the price of that good or service. For example, if a ten percent price increase leads to an eight percent reduction in quantity demanded, the elasticity of demand is −0.8. When addressing the efficiency

expected to approximate those of captive customers, while the demand elasticities of large industrial customers probably exceed those of captive customers only by relatively small amounts, perhaps -1.2 to -1.0 (unless self-generation costs are competitive with embedded cost-based rates).[16] Under these circumstances, there is no efficiency-based justification for creating one class of favored wholesale/large industrial customers to avoid stranded investment costs and receive the full benefits of marginal cost-based rates, while captive customers cover all additional embedded costs. To return to the two-customer class example, if the potential switching customer class had a demand elasticity of -1.2, while the captive class had a demand elasticity of -1.0, cost-recovering economically efficient prices would be 4.8 cents per kilowatt-hour to the first group and 5.2 cents per kilowatt-hour to the second group. Permitting open transmission access to produce a 3.0 cent per kilowatt-hour rate to potential switching customers and a 7.0 cent per kilowatt-hour rate to captive customers would seriously distort consumption decisions.[17] All else being equal, these inefficiencies could be avoided by requiring potential switching customers to pay a 1.8 cent per kilowatt-hour stranded investment cost if they switched to another supplier. This would have the twin virtues of promoting economic efficiency and minimizing the shifting of cost burdens to other customers and/or utility stockholders.

In summary, as an integral part of any rational open transmission access plan, reasonable transition rules would need to be specified in order to address stranded investment problems in a way that motivates efficient decisionmaking and minimizes income transfers from utilities and their captive customers to potential switching customers. For example, utilities might be required to file tariffs for wholesale and large industrial customers separately specifying short-run marginal costs by time of day and the additional demand and energy charges needed to meet the utility's average cost-based revenue requirement. Any potential switching customer leaving the system would be permitted to avoid the local utility's short-run marginal costs, but would be required to

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properties of the so-called inverse elasticity rule, it is important to note that the relevant elasticity is that related to the potential switching customers' total demand for electricity, as distinguished from the much higher elasticity of their demand for electric power offered by an individual supplier when there are competitive alternatives.

16. K. Anderson, The Effects of Electric Prices upon Demand—A Survey, 12, table 3 (Dec. 1985) (on file at the Public Service Company of New Hampshire).

17. It would be naive to overlook the possibility that captive customer rates might not be permitted to rise and that the losses associated with lower rates to potential switching customers would simply be imposed on utility stockholders. Thus, the end result could be a 3.0 cent price to potential switching customers, a 5.0 cent price to captive customers and a substantial loss imposed on utility stockholders. In effect, in such a case, policymakers would have decided that it was appropriate for the utility to recover on average only 4.0 cents per kilowatt-hour and absorb losses of 1.0 cent per kilowatt-hour. While this may be deemed an inequitable result, it is difficult to say much about its effects on economic efficiency, particularly if losses can be imposed on utility stockholders without adversely affecting the future costs of capital to the industry. We can say that in the situation posited here, given that the utility is permitted to recover 4.0 cents per kilowatt-hour, the price of power to potential switching customers (3.0 cents per kilowatt-hour) is inefficiently low relative to the captive customer price (5.0 cents per kilowatt-hour). Efficient prices based on a 4.0 cent average recovery would be 3.9 cents to the potential switching customers and 4.1 cents to the captive customers given the demand elasticities we have assumed.

shoulder all or (as a compromise) some declining portion of the average cost-based revenue requirement for a defined transition period. (As an obvious alternative, the customer could buy its way out of the local utility system immediately by paying a lump sum amount equal to the present discounted value of its stranded investment obligation.)

What constitutes an appropriate transition rule to address stranded investment concerns obviously is subject to debate. From the utility's perspective, anything less than full recovery of stranded investment costs unfairly imposes the remaining costs on captive customers and/or utility stockholders. From the customers' perspective, full stranded investment recovery would be equivalent to locking them into their existing supplier's embedded costs. Obviously, it is impossible to satisfy both parties. As a possible compromise, a transition period based on market conditions might be considered. The basic objective would be to avoid inducing inefficient shopping and large income transfers in markets currently glutted with capacity. If customer shopping is to be promoted, sensible public policy suggests that it be done when market supply and demand are more nearly in balance and therefore when market prices would more accurately reflect the long-run marginal cost of supplying electricity. In these circumstances, customers could make more informed choices between the regulated rate system and a market-determined system. Given this objective, the appropriate transition period would vary by region, perhaps being related to the time that each region is expected to achieve, for example, a twenty percent reserve margin (without additional generation being initiated).[18] Among other things, an advantage of a regional approach based on supply/demand balances is that it would provide a gradual basis for experimenting with market outcomes in a customer wheeling environment.

It is important to note that a stranded investment obligation based on *market* demand and supply conditions is not the same thing as one based on *utility-specific* demand and supply conditions. Given this approach, while potential switching customers would be liable for stranded investment costs for a period of time based on average demand and supply conditions in the region, particularly high-cost or capacity-excess utilities might not recover all stranded investment costs. If customer access to transmission is pursued, public policymakers must decide whether such a compromise strikes a reasonable balance between the competing interests of potential switching customers and those of the utility and its captive customers.

V. Supplier Obligations in Unregulated Markets

In unregulated markets, many of which are substantially less than perfectly competitive, there is no obligation to serve. Suppliers in unregulated industries are free to enter or exit markets as they please. Customers get only what suppliers are willing to sell voluntarily. Those desiring certainty of supply can use various contracting or insurance options to obtain needed supply assurance. Unregulated markets, of course, do not always smoothly match

18. The difficulty of defining "regions" in a logical way in order to implement such a transition mechanism should not be overlooked.

capacity to customer needs. Instead, periods of excess capacity and periods of tight capacity are characteristics of many markets. In unregulated markets, price is the ultimate mechanism relied upon to match supply and demand. When excess supplies exist, prices tend to fall, thus stimulating additional demand and discouraging investment in additional or replacement capacity. When supplies are tight, prices rise in order to discourage demand, stimulate additional production in the short run, and encourage expansion of capacity in the long run. The more inelastic the demand (because the good is prized by users and has few substitutes) or the supply (because it is difficult to expand production in a short time period), the more prolonged are the potential periods of excess or tightness and the more severe can be the price swings necessary to equilibrate supply and demand. These are imperfections that must be accepted or dealt with by contracting if free markets are to be relied upon.

Unregulated markets employ a variety of supply arrangements to function efficiently in the absence of obligations to serve. The particular contract or ownership arrangements vary from market to market depending on the characteristics of the good in question. When future supply risks appear to be small or in any event would not be costly, customers tend to rely on the operation of spot markets. If demand for the good turns out to be unexpectedly large, the spot price rises. This rations the supply anonymously among the competing purchasers, who are cut off from the market only to the extent that they are unwilling to match the price paid by other buyers. If the good is storable, inventories can be drawn down, easing the supply situation and, by the same token, tempering the increase in spot prices. The higher spot price simultaneously provides suppliers with an incentive to increase output in the short run, to the extent that the higher cost of doing so is consistent with the price purchasers are willing to pay for an immediate expansion of output. If the higher spot price persists (more precisely, if the increased demand is expected to persist), suppliers have a profit incentive to expand capacity.

Conversely, the attention devoted to supply assurance is greatest where future suppliers are relatively risky or their riskiness, however small, threatens to impose relatively large costs on purchasers. Thus, mechanisms to deal with supply risks tend to be more elaborate when:

1. The good cannot be stored, either because it is highly perishable or because (as in the case of electricity) storage is sufficiently costly that production and consumption normally must occur simultaneously. Holding an inventory is therefore not available as a strategy to deal with supply risks.

2. The good is "essential." There are no close substitutes, so difficulties in obtaining supplies would be very costly.

3. The supply of the good is highly inelastic in the short run. Thus, if demand turns out to be unexpectedly large, little flexibility exists to expand output. What supply there is must be rationed (whether by price or by some other mechanism).

4. The short run lasts a long time. Suppliers require a long lead time to install additional capacity or to obtain whatever is necessary to expand output.

Where these characteristics predominate, there is a substantial need for forward contracts or vertical and horizontal integration to provide needed supply assurance. Forward contracts can take the form of firm commitments (take-or-pay contracts or ownership participation) or merely options to buy at some stipulated price.

Take-or-pay contracts can be used to shift most or all of the risks of demand uncertainty to customers. The supplier insures that customers will not have to pay more than the price stipulated by the contract in return for the customer's agreement to take the product or pay for it anyway. A take-or-pay contract can establish with certainty the price at which service will be supplied in the future or various escalators can be employed. If the price is a fixed one, presumably based upon the supplier's best estimates of the marginal cost of satisfying the contract plus a profit margin, then the supplier bears the risk that its costs will turn out higher than expected. If the contract includes escalators based upon the supplier's incurred costs, the risks can be shifted entirely to customers. The risks can be shared by including escalators based upon general cost trends, as opposed to the supplier's contract specific costs. The key point is that the supplier's cost of satisfying a take-or-pay contract is reasonably predictable—it is equal to the long-run marginal cost of providing the required capacity.

Option contracts can provide another alternative for dealing with supply risks, although one much less frequently used than take-or-pay contracts in unregulated (nonfinancial) markets. Option contracts present a substantial source of additional uncertainty: whether the holder will choose to exercise the contract. This additional uncertainty is borne entirely by the supplier of the option, who has to be prepared to honor the contract (or buy back the option, perhaps at a substantial premium) even though the supplier's revenue is limited to the price charged for issuing the option if the contract is not exercised. Option contracts involve the establishment of two prices: (1) The option price itself which is the initial price the customer pays for the right to demand future supplies; and (2) the exercise price, which is how much the customer will pay for future supplies if he elects to take them.[19] The exercise price can be fixed or indexed. The supplier's costs have two corresponding components: (1) The initial investment made in order to be able to satisfy the option or to minimize the expected costs of meeting the option demand; and (2) the additional investment and operating costs incurred to supply the product if and when the option is exercised. The supplier could make no initial investment to satisfy option contracts. In that case, if the option is exercised, the supplier's cost of satisfying it will be its short-run marginal costs at the time. An option contract structured to reflect this strategy would have a very low option price and a very high exercise price. At the other extreme, the supplier could invest initially in capital-intensive plant designed to minimize the variable costs associated with supplying the product if the options are

19. To be nontrivial, the option contract must offer an exercise price that may vary significantly from future expected spot market prices. The option is worthwhile to the customer only if it gives him the right to obtain capacity and energy in the future at prices substantially below then-current spot market prices under plausible conditions. A meaningful option contract, therefore, necessarily is risky to the supplier since it commits him to furnish the service at prices that may turn out to be well below future market rates.

exercised. An option contract structured to reflect this strategy would contain a very high option price and a very low exercise price.

The supplier's cost of meeting its option contract obligations will depend critically upon the rate at which they are exercised. Suitable pricing requires predicting the probability that the option will be exercised and this presents formidable problems in virtually any market setting. It is undoubtedly for this reason that the use of options (outside of financial markets) appears to be relatively infrequent.

Contracting does not always provide the most efficient approach for dealing with supply assurance problems. Another alternative is to internalize transactions within individual firms—that is, to carry out a number of production and marketing functions within a single organization, rather than relying upon external market transactions. Internalization of transactions is likely to be less expensive than contracting when the transactions under consideration are complex and interdependent, when required transaction-specific investments are large, and when very long-term contracts would be required to deal with future uncertainty.[20] These circumstances make it costly to substitute contracts for common control, because contracts would be difficult to draft and would require a burdensome level of detail to ensure continuing good performance in a complex long-term relationship. Efficiency requires, therefore, that firms be free to respond to supply assurance problems not only by relying upon spot markets and forward contracting, but also by vertically and horizontally integrating when appropriate to minimize transactions costs or capture other economies.

VI. Market Performance in the Absence of the Utility Obligation to Serve

A legally imposed obligation to serve is fundamentally inconsistent with the concept of reliance upon effectively competitive bulk power markets.[21] Potential switching customers should not be permitted to demand open transmission access in the name of promoting bulk power competition and simultaneously claim service rights inconsistent with competitive markets. One obvious scenario, therefore, envisions no supplier having any legally-mandated

20. *See* Coase, *The Nature of the Firm*, 4 ECONOMICA, N.S. 386 (1937); Landon, *Theories of Vertical Integration and Their Application to the Electric Utility Industry*, 28 ANTITRUST BULL. 122 (1983); Williamson, *Transactions-Cost Economics: The Governance of Contractual Relations*, 22 J. OF L. & ECON. 3 (1979).

21. Throughout this article, there are a number of references to "effectively competitive markets." There are no bright-line tests for identifying when markets are effectively competitive. Economists sometimes have used the term "workable competition" to identify situations in which there are as many suppliers as scale economies permit, there are no artificial restrictions on entry, prices are set independently, production and distribution operations are efficient, and profits are just sufficient to reward investment, efficiency and innovation. *See* F. SCHERER, INDUSTRIAL MARKET STRUCTURE AND ECONOMIC PERFORMANCE 42 (1980). The Justice Department's current merger guidelines treat as unconcentrated and thus not generally a source of competitive concern markets with Herfindahl indices of 1000 or less. An industry with 10 or more equal-sized competitors would fall into this category. Markets with Herfindahl indices between 1000 and 1800 are viewed as moderately concentrated. An industry with six to nine equal-sized competitors would fall into this category. *See* 1984 Merger Guidelines, 49 Fed. Reg. 26,824 (1984).

obligation to provide power to customers with wheeling options. Instead, as in other unregulated markets, variations in price, along with reliance upon take-or-pay contracts, option contracts and vertical integration, would be depended upon to match capacity to the needs of switching customers. In the absence of significant market imperfections, that presumably would be the preferred choice.

As noted in the introduction to this article, however, a number of utilities argue that an unregulated bulk power supply market will fail to produce a reasonable matching of capacity to customer needs. As they see it, the almost inevitable result of substituting reliance upon profit motives for the existing regulated system will be shortages of capacity to meet potential switching customer requirements, or unacceptable price swings, as well as an unnecessary increase in the cost of producing electricity. On these grounds, they oppose customer wheeling. Some have suggested that a better alternative would be to retain the existing utility obligation to serve and customer obligation to take service, but introduce greater competition into the system by requiring utilities to procure needed new capacity competitively.[22] Utility subsidiaries would be allowed to compete in the new generation capacity market. To assure all potential suppliers of equal access to the market, utilities would be obligated to wheel power from cogenerators or independent generating companies in their territories to other utilities needing to purchase capacity.

Proponents of customer wheeling believe that direct access to alternative suppliers is needed to obtain the benefits of competition. Moreover, they argue that market forces will bring forth the needed capacity and do it more efficiently; however, they apparently want to hedge their bets by having the right to return to the regulated rate system on the same terms as other "new" customers.[23]

In the paragraphs below, we discuss how bulk power supply markets might be expected to work in a two-tier market where switching customers rely upon market forces, rather than legally-mandated service obligations, to meet their electricity requirements.

A. *Matching Supply and Demand in the Absence of a Regulatory Contract*

By definition, the market will match supply and demand, unless regulators unduly interfere with market processes. Absent an obligation to serve, it is the profit motive which would be relied upon to call forth capacity to meet the projected needs of switching customers. Variations in price will equate supply and demand in the short run and stimulate or discourage capacity additions in the long run.[24] Among other things, the efficiency of this process

22. *See supra* note 5.

23. *See* Comments of the Electricity Consumers Resource Council and The American Iron and Steel Institute, submitted to the Federal Energy Regulatory Commission, Regulation of Electricity, Sales-for-Resale and Transmission Services, No. RM85-17-000 (FERC filed Aug. 9, 1985).

24. It is important not to underestimate the role of price changes in mitigating potential supply/demand imbalances. With a short-run price elasticity of demand for electricity of approximately -0.5, all else being equal, a 20 percent price increase would lead to a 10 percent reduction in the demand for electricity and thus buy time for capacity expansion projects to be completed.

would depend on the difficulty of forecasting demand in a customer-access-to-transmission world and on the cost of dealing with additional uncertainty.

In a customer wheeling world, the individual supplier's ability to forecast demand inevitably would be eroded. However, as is true in many unregulated markets, a substantial amount of information about future expected demand and supply could be developed to provide suppliers with a rational basis for planning. Suppliers could utilize such information as a basis for constructing capacity speculatively or, alternatively, could rely upon contracts with customers to support construction plans.

The aggregate demand for electricity in a region is unlikely to be substantially less predictable than now is the case. This follows from the fact that the potential switching customer's electric requirement itself is no less certain when there are wheeling opportunities than when there are none. Competition would tend to discourage the sharing of load data by suppliers[25] and thus reduce the accuracy of regional forecasts, but regulators presumably could mitigate this problem by requiring all suppliers to furnish relevant information so that regional load forecasts could be produced and reviewed by others. Given the availability of reasonable amounts of data, independent services undoubtedly would be available to provide existing and potential suppliers with regional electricity demand forecasts, by customer class and by industry.

The key change introduced by customer wheeling would be that the demands of potential switching customers could be shifted among suppliers (including utilities, independent generators and cogenerators) in reasonably close proximity to the customer. Thus, individual suppliers would need a basis for forecasting the portion of the total regional demand for electricity that they may be able to capture. Given that rival capacity plans would tend to be very visible (because of the required siting and environmental approvals as well as the need to coordinate generation and transmission planning), an individual power supplier could form reasonable judgments about competitive demands unlikely to be met by others. If that supplier then decided to go ahead with plans to fill the gap, its announcement would signal others and tend to discourage overbuilding.[26] In short, it seems inevitable that the market would contain a significant amount of information concerning demand projections and capacity expansion plans, thus providing a basis for rational planning by individual firms.

It should be noted that if the unregulated market were a very thin one—that is, if relatively few customers in a region elected to shop for power, the demand forecasting problem would be exacerbated. Predicting the demands of a small number of industrial customers (as opposed to predicting the demands of a large number of diverse customers) can be especially difficult.

25. Utilities today typically rely upon statistical estimation techniques and information gleaned directly from large customers to develop system load forecasts. These forecasts are subject to review by various regulatory bodies and are shared with surrounding utility systems in order to produce regional demand forecasts.

26. One potential problem in such an environment is that competing suppliers might file a number of applications to construct capacity without any real intention of going through with all of the proposed projects.

To overcome this, individual suppliers seeking to serve such customers either would have to rely upon long-term contracts with those customers to assure a market for any capacity built to serve them or, less likely, depend upon reselling capacity to other suppliers in the area if direct sales to switching customers do not turn out as planned. It also should be noted that if new customers moving into the area were given the option to elect regulated utility service (see Section VII below), the local utility would face a unique capacity planning problem. It would be obligated to stand ready to serve all new customers locating in its territory if they so choose, but would have no assurance that any of those customers will elect to be served by it. To deal with this, the utility would need to predict the outcome of new customer elections based upon its forecasts of regulated versus market prices for power. However, the utility and/or its captive customers necessarily would bear the costs if the forecast sales to new customers did not materialize because those customers selected alternative suppliers.

Increases in the uncertainty of demand could be expected to produce several market responses. First, suppliers could respond to increased uncertainty by speculatively constructing shorter lead time and lower capital cost/higher operating cost capacity than historically has been the case. In return for accepting more risk, suppliers would require higher expected rates of return on their investment. Thus, it is often asserted that without the assurances provided by the regulatory contract, the "right" types of capacity no longer will be forthcoming—in particular, relatively large, long lead time, low-cost generating units will not be built and the overall cost of electricity will rise as a result. Second, suppliers and potential switching customers could respond to uncertainty by making substantial use of forward contracts to assure needed supplies and minimize unexpected costs. Relatively long lead time, capital-intensive units could be supported by such contracts if that were seen as the economic choice. Indeed, if potential switching customers observed that lower cost units were being constructed to meet captive customer demands because of the utility's ability to rely upon a regulatory contract, the potential switching customers presumably could offer explicit contracts to induce suppliers to build the same types of units to meet their needs.

Whether the operation of such spot and contract markets would result in a more or less efficient industry structure is very much open to debate. Proponents of increased reliance upon the market may question whether large, capital-intensive generating units represent the most economic choice for society and, in any event, whether regulated utilities will build such units in the future. In the current regulatory and market environment, utilities already are strongly motivated to rely upon shorter lead time and lower investment cost generating units. In many cases, large, capital-intensive baseload units already have been removed from capacity expansion plans. While this could raise the cost of electricity in the long run, arguably the damage already has been done.[27] Beyond this, the presumption that large, capital-intensive units

27. It is certainly possible that the regulatory contract will be renewed—that is, that utilities and their regulators will enter into explicit agreements regarding the amounts and types of new capacity that will be built and the cost of such capacity that will be recoverable from customers. If this happens, large scale

are desirable is open to question, especially if such units appear to be the economic choice only in a regulated monopoly environment. If such units do not survive in unregulated spot or contract markets, then perhaps that demonstrates that they do not represent truly efficient choices. Moreover, increases in capital costs in unregulated power supply markets can be seen as an appropriate price to pay for shifting greater risk from customers to suppliers.

These arguments in favor of reliance upon market processes to determine the economic structure of the power supply overlook several key features of electricity markets, however. Electricity possesses all the characteristics identified in Section V above as calling for great attention to supply assurance—it cannot be stored, it is essential, the ability to expand output in the short run is very limited, and a substantial period of time is required to install additional production capacity. Additionally, electric generating units typically have a thirty- to forty-year life so that capacity excesses can take a very long time to work off. Furthermore, because the production of electricity is very capital intensive, consumers stand to benefit substantially if the costs of capital can be reduced by minimizing supplier risks without shifting undue risks to individual customers.

Given these characteristics, private contracting between customers and power suppliers may not provide a very efficient means for organizing the industry.[28] To minimize suppliers' risks, individual customers might be required to project their own demands and enter into detailed, relatively inflexible, long-term contracts for power supply. With generating plant lead times of five to ten years and decades-long plant lives, the required contract length might substantially exceed the typical industrial customer's own planning horizon. In a customer-wheeling world, therefore, the customer's only choice would likely be to rely upon relatively short-term arrangements embodying higher costs reflecting the supplier's greater risk, or to enter into contracts that outlive the customer's own planning horizon and depend upon being able to resell those contracts in a secondary market to gain a measure of flexibility. In contrast, the present system of organizing the industry based upon a regulatory contract can be seen as dealing with supply assurance problems in an extremely efficient manner. The regulatory contract permits individual customers to vary their electricity consumption and to enter or leave the area as their needs dictate. At the same time, it provides the electric supplier with a relatively predictable aggregate demand to meet, based upon its *de facto* exclusive right to supply all the requirements in a defined geographic area.

The potential advantages of competition should not be overlooked, of course. As a general proposition, competition provides suppliers with a powerful stimulus to minimize cost in the short run and to exploit available technologies in the long run. If effective competition could be introduced in power supply markets, the advantages of competition might outweigh the disadvan-

generating units can be expected to reappear in capacity expansion plans where they provide the lowest-cost option.

28. For a description of some of the potential efficiency problems raised by contracting for power supplies, see P. JOSKOW & R. SCHMALENSEE, MARKETS FOR POWER 109-27 (1985).

tages associated with customer reliance upon spot transactions or long-term contracts and thus yield a net gain in efficiency. However, it is certainly not clear that the balance favors a customer shopping world. This is especially true given that it may be possible to obtain many of the benefits of competition by having utilities procure new generating capacity from independent suppliers operating in competitive markets, while at the same time retaining the benefits of the regulatory contract (by reaffirming the utility's obligation to serve and the customer's obligation to take service from the local franchised utility). There is simply no clear case for relying upon a market structure including customer access to transmission to call forth the "right" amounts or types of capacity or to minimize long-run costs. This is true even if regulators do not interfere overtly or inadvertently in "unregulated" power supply markets. This subject is addressed next.

B. Partial Regulation and the Operation of Market Forces

As indicated at the outset of this article, the market structure envisioned by the proponents of customer wheeling is a two-tiered one: captive customers continue to be served by the local utility at regulated rates, while potential switching customers have the option of shopping for power in markets that are not directly regulated. In the paragraphs below, some of the problems that might arise in such a mixed market structure are explored. The concern that prompts this discussion is that if regulators interfere with profit expectations in unregulated power supply markets, then efficient supply responses in those markets will be disrupted. If this were to happen, then serious capacity shortages could result or excess capacity costs could be unnecessarily incurred.

The regulator can affect the unregulated operations of utilities in numerous ways. Several of these are discussed below.

1. The Cost Allocation Process

The process of cost allocation can move costs directly from the regulated to the unregulated portion of the utility's operation.[29] Suppose for example that the utility currently has sales of 100 kilowatt-hours per year and that its total embedded cost of service is $5.00. Thus, its average embedded cost per kilowatt-hour is 5.0 cents. Suppose also that the utility's marginal cost of additional sales is 3.0 cents per kilowatt-hour (for sales with exactly the same load factor and load pattern as existing sales). If the utility sells power to a new class of deregulated customers, even at rates in excess of the additional costs of supplying them, it will not necessarily make a profit. To see this, assume that the utility sells ten kilowatt-hours to deregulated customers at a price of 4.0 cents per kilowatt-hour, which is 1.0 cent above its marginal costs. The addition to its total costs is thirty cents, revenues from the additional sales

29. For a discussion of problems posed by regulator interference in the competitive market, see H. Roseman, Mixing Competition and Regulation (Feb. 12, 1986) (NERA Electric Utility Conference, Scottsdale, Ariz.). The example presented in the text below is a variant of one developed by Roseman.

are forty cents, and therefore the utility appears clearly to have engaged in a profitable transaction.

The cost allocation process can undermine this result, however. The regulator now observes that the utility's total costs have risen to $5.30. Clearly, since regulated sales now comprise 90.91% of total sales (100 out of 110 kilowatt-hours), the inclination may be to allocate that same percentage of the utility's total costs to the regulated business. Now 90.91% of the $5.30 total cost is $4.92. If that is determined to be the regulated cost of service, since there are still 100 kilowatt-hours of sales to captive customers, a regulated rate reduction from 5.0 cents per kilowatt-hour to 4.82 cents per kilowatt-hour is called for. At the new rates, the utility is selling 100 regulated kilowatt-hours at 4.82 cents per kilowatt-hour, for revenues of $4.82, and it is selling ten kilowatt-hours of unregulated power at a rate of 4.0 cents, for revenues of $0.40. Total revenues therefore are $5.22, but total costs are $5.30. Thus, although the utility seemed to be selling additional kilowatt-hours at a profit, it ended up losing money. The result is that the cost allocation procedure reduced the total costs allocated to the regulated business by eighteen cents. This reduction in the total costs allocated to regulated sales effectively increased the costs which must be recovered from unregulated sales. In this situation, if the utility makes unregulated sales at a rate less than its average cost of service, it will lose money by doing so, regardless of how its unregulated rate compares with its true marginal cost.[30]

The upshot of this example is that through the cost allocation process, regulators can exercise significant control over the rates that utilities must get for "deregulated" sales if the utility is not to lose money on them. It is also important to recognize that the regulator will have a variety of cost allocation methods to choose from in order to determine the costs to be recovered from captive customers. There may be a natural inclination to choose the method that minimizes the regulated cost of service and thereby places the biggest implicit cost burden on unregulated sales. This, of course, will make it more difficult for the utility to make money in the unregulated portion of the business.

These considerations suggest that the cost allocations inherent in a partial regulation/partial competition system may significantly interfere with the operation of market forces in the deregulated market. Some of these problems could be avoided if competitive operations were carried out by separate subsidiaries employing separate facilities to provide service, or if one could do a once-and-for-all allocation of generating plant costs between the regulated and unregulated sales. While such divisions can be attempted, the intrinsic problem is that the utility's generation and transmission system is planned and operated as a single functioning unit. Therefore, the cost allocation problem is unlikely ever to be perfectly resolvable.

30. Note that if marginal costs are above average costs and if costs are reallocated using the method described in the text, the utility could sell power to switching customers at rates below its marginal costs and still make a profit.

2. The Determination of the Cost of Capital

Another way in which costs may be shifted between potential switching customers and captive customers is through the handling of cost of capital issues. If the additional uncertainties generated by competition for potential switching customers serve to increase the overall cost of capital to the utility, then to determine the cost of service for the utility's regulated core business, regulators will have to distinguish between the relative degree of risk associated with the capital devoted to its core and competitive services. While this may be difficult to do "scientifically," it is probably feasible for regulators to make reasonable judgmental adjustments to account for risk differences. Thus, for example, the regulator might continue to rely upon a market-derived cost of equity for the enterprise as a whole, but impute to the competitive business a debt/equity capital structure more typical for firms operating in competitive markets. Alternatively, the capital costs incurred by entirely independent generating companies may be observable. While the handling of the capital cost problem presents some of the same potential for mischief as the more general cost allocation problem, this is an issue that regulators increasingly must come to grips with in any case as more and more utilities diversify into nonutility lines of business.

3. The Determination of Appropriate Reserve Margins

Costs can be shifted between the regulated and unregulated parts of a utility's operation through the regulator's treatment of the appropriate level and cost of reserves. Suppose it is the case that there exists a range of reasonable reserve margins (say from fifteen to twenty percent) which the regulator can be expected to accept and reflect in the rates paid by captive customers. The utility's interest might be in planning for a twenty percent reserve margin. If no unexpected competitive opportunities rise, the twenty percent reserve margin cost will be borne by captive customers and they will receive service reliability commensurate with those reserves. However, if additional opportunities arise to take on switching customers profitably, the utility could do so without incurring the regulator's wrath until reserve margins are reduced to fifteen percent. Presumably the capacity sold to switching customers will be removed from the captive customer rate base in the next rate proceeding, but it remains true that captive customers would have borne a portion of the cost of holding capacity for switching customers. The cost shifting also can go the other way, of course. Even though the utility has, say, an overall twenty percent reserve margin, the regulator may decide (after the fact) that only a fourteen percent margin is required for captive customer service and thus allocate the excess to the unregulated business. The extent to which this is a problem depends on one's view of how tightly the range of desirable reserve margins can be specified. While this may pose some problems, it would seem that the specification of appropriate reserve margins can be done with sufficient precision to avoid serious cost shifting in this way.

4. The Certification of New Generating Facilities

States now routinely exercise control over the construction of large new generating units by requiring that various certificates be obtained before the units can be built. As part of the certification process, the specific site chosen for the plant must be approved. But beyond this, the size and type of unit to be constructed may be tightly controlled by requiring the "need for power" to be shown, as well as mandating that the unit to be constructed minimize environmental impacts and be demonstrably more economical than other alternatives available to meet that need. Such certification procedures clearly are more akin to central planning than to a market-driven supply system. Unless states are willing to give up regulation of all nonenvironmental aspects of new generating plant construction when that plant is planned to serve unregulated requirements, there exists a significant probability of disrupting supplies to switching customers.

C. Implications

For a number of reasons discussed above, a two-tier (captive customer/potential switching customer) power market may not operate very smoothly and may not produce more efficient outcomes in the long run. Customer requirements undoubtedly would be more difficult (though not impossible) to forecast in a market with no regulatory contract. Given this, as in other unregulated markets, periods of excess capacity or tightness of supply could be expected and, recognizing the characteristics of electricity supply and demand, this could result in substantial spot price swings. Alternatively, switching customers might find it necessary to enter into relatively inflexible long-term contracts in order to assure supplies at predictable prices and enable suppliers to support the construction of long lead time, capital-intensive generating units with low-cost financing. This may be contrasted with the present "regulatory contract" system which gives individual customers the flexibility to vary their electricity demands and simultaneously provides the utility with the security of supplying a reasonably predictable aggregate demand in a defined territory. Whether unregulated markets relying upon spot transactions and private contracting would produce a more efficient outcome than that achieved when suppliers and customers operate under a regulatory contract is unclear. Beyond this, problems posed by overt or inadvertent impacts of regulation on the unregulated market in a two-tier system are considerable.

These uncertainties about possible market outcomes suggest several things. First, if there is at least a good prospect that the present regulatory contract offers the most efficient solution to matching customer and supplier requirements, then that option ought to be retained. As some have suggested, a better approach may be one that retains the existing utility obligation to serve and customer obligation to take service (thus there is no customer wheeling), but introduces greater competition into the system by requiring utilities to procure all needed new generating capacity competitively. If a customer wheeling scenario is pursued, the regulatory contract option should not be eliminated. Instead, any customer-access-to-transmission scenario should provide for potential switching customers to have the option to stay within the existing regulated rate system. Customers should not be forced into a market environment that may be economically inefficient as well as hostile to their interests.

Second, if potential switching customers choose to forsake the present system and use transmission access to shop for power, they should be prepared to accept the market risks associated with the choice. They should not be allowed to reenter the regulated rate system on the same terms as other "new" customers if market outcomes turn sour. As a general proposition, it is difficult to be sympathetic to the potential switching customers' argument in this regard. For some customers, continued regulation may be the desired choice. They can be given the option to stay in the regulated system. For other customers, complete deregulation may be the right choice. If customers are given a *choice* between the protection of regulation or the protection afforded by unregulated market forces, there is no reason to give them a third choice that mixes regulation and competition, but is so difficult to manage well. If potential switching customers doubt that an unregulated market would be effectively competitive, they can compare the imperfections of that market with the imperfections of the existing regulatory system and choose what is best for them. There is a great deal of merit to the position that this is the best one can do in an imperfect world and that customers should be given an all or nothing choice. A more moderate position would be to provide potential switching customers with a relatively limited safeguard to be applied only when bulk power markets prove to be seriously noncompetitive.

Third, uncertainties about the long-run efficiency implications of a customer wheeling scenario reaffirm concerns about the wisdom of any public policy aimed at opening up transmission access to customers in the presence of the current power supply capacity glut, unless (as argued in Section IV above) some requirement is imposed on switching customers to pay stranded investment costs during a transition period while the capacity excess is worked off. Providing customers with the chance to escape sunk costs incurred on their behalf not only will encourage shopping that yields no short-term efficiencies, but will entice customers into an unregulated market offering dubious long-term benefits. When electricity supply and demand are more nearly in balance, customers can make better informed decisions regarding the benefits of shopping for power in unregulated markets or remaining within the existing regulated system.

VII. The Option to Stay with the Present System of Regulation

As a part of any open access scheme, existing customers in the potential switching class should be given an option to stay within the present regulated rate and obligation to serve system. However, their choice should be unambiguous. There are a number of reasons for giving customers this choice. First, and most important, since one cannot be sure that unregulated markets will produce better outcomes than continued reliance on a system involving reciprocal utility obligations to serve and customer obligations to take service, it seems clearly inappropriate to push customers out of the regulated system.

Second, changing the rules in the middle of the game can be just as inequitable to customers as it is to utilities. Third, many customers in the potential switching class may have neither the skills nor the inclination to procure electric supplies competitively.[31] Finally, an advantage of allowing customers to choose how they want to be treated is that the class of switching customers is self-selected, and some but not all, potentially difficult class definition problems therefore are avoided.

Customers opting to stay in the existing system should be compelled to make the choice clear cut and long term. The utility's obligation to serve customers opting in would be equivalent to its obligation to serve captive customers. Presumably, therefore, the utility would meet this obligation by engaging in long-term capacity planning and perhaps by installing relatively long lead time, high-capital cost generating plants. To benefit from this planning and the associated economies, potential switching customers opting in should be required to provide long-term assurance of their position. For example, such customers might be compelled to sign requirements contracts with say, minimum ten-year rolling notice provisions in order to continue to enjoy the benefits of traditional rate and obligation to serve regulation. It is important to stress that this need not be as inflexible as it might seem at first from the customer's point of view. It would not be necessary for the customer to specify and commit to pay for defined amounts of electricity. Rather, the customer would commit only to take whatever its electricity requirements (if any) might be from the local utility for the duration of the contract. In short, in order to enjoy the benefits of the regulatory contract, the customer would be asked to agree to abide by that contract and forgo shopping until the specified notice provisions were satisfied. The proper notice provision should be related to the time required for utilities to absorb or sell off into other markets generating capacity no longer needed to supply switching customers. This will depend on capacity expansion lead times, the rate of growth of nonswitching load and the relative size of potential switching customers. The ten-year notice provision adopted for discussion purposes in this article admittedly is somewhat arbitrary. Given five- to ten-year capacity expansion lead times and a thirty-year generating plant life, a case could be made for requiring substantially longer notice provisions.

It should be noted that if the class of potential switching customers could be reasonably identified and if one could have confidence in the superiority of a deregulated approach, legitimate questions could be raised about the appropriateness of allowing potential switching customers to opt into the system. In some respects, the argument for allowing existing potential switching customers to stay in the system is the same as the utility's argument for recovery of stranded investment costs. In each case, the party's position is founded importantly upon avoiding inequitable income transfers resulting from mid-game rule changes. Where the change would disadvantage the utility and its captive customers, the utility seeks protection through recovery of stranded investment costs. Where the change would disadvantage the customer, the cus-

31. Customers could overcome this problem by retaining agents to arrange for power supplies.

tomer seeks protection via a right to retain its regulated rate position. What is sauce for the goose is sauce for the gander! If utilities are given no stranded investment protection, why should customers be given any embedded-cost rate protection? Alternatively, if utilities are provided with a limited stranded investment recovery period as discussed in Section IV above, why should customers not be provided with only a matching period of regulated rate protection? For example, at the end of a defined transition period, all regulation of bulk power rates to potential switching customers (other than wheeling rates) might be eliminated. Potential switching customers at that point would retain only a ceiling price safeguard available when bulk power markets were shown to be seriously noncompetitive (see Section IX below).

The treatment of new customers in the potential switching class should parallel the treatment of existing customers. If existing customers are given the one-time choice to opt into or out of the regulated rate system, new customers can be given this same choice when they initially establish service. On the other hand, if a class of switching customers is identified and the decision is made to shift existing customers into the competitive market, then this obviously would apply to new customers as well. In that case, new customers in the potential switching class would not be permitted to opt into the present system of regulated embedded cost-based rates.

Parallel treatment of existing and new customers has several obvious advantages. It meets the potential switching customers' argument that they only want to be treated like any other new customer if they choose to return to their local supplier. Moreover, this approach should satisfy court- or commission-approved antidiscrimination standards in that all equivalently-situated customers would be treated alike. All existing and new customers would have been given the identical one-time choice of opting in or out of the system.

While a customer choice system seems preferable on balance, such a system does pose difficult definitional problems and may unavoidably distort some customer decisionmaking. For example, if an existing switching customer is acquired by another entity, is the new concern a "new customer" with a new option to select service at regulated rates? Under any reasonable system, the answer must be "no." This suggests that the choice to be a switching customer or a regulated rate customer must attach to the premises, rather than to the corporate identity of the customer. Thus, as long as the operation is not substantially changed, any new owner would be bound by the previous owner's decision regarding regulated versus competitive electric service. Another problem concerns expansions of existing customers' operations. Is the expansion a "new" customer with a new regulation/competition choice? The practical answer might be "yes" only if the electrical requirements of the expanded operations and the original operation are physically separate and separately metered. While these definitional problems can be handled (though inevitably in ways subject to controversy), some distortions seem unavoidable. In particular, if customers can obtain a new regulated/unregulated rate option by closing down operations in one area and moving to a new location (in another utility's service area), that flexibility can be used to game the two-tier system or be employed as a threat to compel the local utility to make rate concessions. In addition to this, as noted earlier, giving new customers a choice of the manner in which they wish to be served necessarily will increase the uncertainty of individual utility demand forecasts.

VIII. A Limited Obligation to Serve Returning Customers

Because of the prospect that some bulk power markets may prove to be seriously noncompetitive in the future even with open transmission access, it may make sense to provide switching customers with some safeguard against exploitation. However, switching customers should not be given an easy means of escaping market risks they have accepted voluntarily. Moreover, it is important that the safeguard price not be set so low as to yield *de facto* subsidization of switching customers by captive customers. The Interstate Commerce Commission's (ICC) treatment of railroad rate setting to captive shippers suggests one way to meet this problem.[32] Under current conditions, rail rates remain essentially deregulated. As a general matter, railroads can charge what the market will bear. However, in the case of captive shippers, rail rates are subject to ceiling price regulation based upon the stand-alone costs of providing rail service to captive customers.[33] The ceiling price can substantially exceed a price based on fully distributed cost. In effect, the railroad is forced to set its price to captive customers at or below the price that could be offered by an alternative rail system designed to meet the needs of just those customers.

The ICC ceiling price model could be applied directly to the electric utility case. In order to trigger an obligation to serve by the local utility subject to a ceiling price constraint, the switching customer first would have to demonstrate that it is a captive customer. In essence, the customer would be required to show that the market in which it procures electricity was, but no longer is, effectively competitive. For example, this might be demonstrated by showing that the market contains only a small number of potential competitors, that there are significant impediments to new entry, that cooperative rather than competitive conduct prevails in the market and that suppliers earn persistent excess profits. Moreover, it should be incumbent upon the customer to establish that the market structure has become significantly less competitive than it was at the time when the customer opted to be a switching customer. Noncompetitive markets would have to be distinguished from "tight" markets and, admittedly, this could prove to be very difficult in practice. A noncompetitive market is one in which supply responses cannot be relied upon to bring prices and costs into reasonable alignment over time. A tight market is one in which capacity is temporarily short and prices have risen in order to discourage demand and encourage the construction of additional capacity. Such situations should be relatively short-lived (but could exist for five to ten years in this industry), and movement of the market toward equilibrium should be detectable. Customers who shop in order to enjoy the benefits of

32. *See supra* note 5.

33. In principle, the railroad is also subject to an overall profit constraint but current profits are so far below this that this constraint is not relevant.

low prices in soft markets should not be protected from unpleasantly high prices in tight markets.

Under the proposed safeguard system, if the customer made the requisite noncompetitive market showing, that would entitle it to service by the local utility as soon as feasible at the ceiling price.[34] The ceiling price could be determined as in the ICC case. A hearing would determine the cost of constructing a stand-alone electric system to serve one or a group of the now captive former switching customers and that would serve as the ceiling price.

An alternative would employ the split-the-savings concept frequently utilized in the electric utility industry. The local utility would be obligated to serve captive former switching customers at a price halfway between the utility's marginal cost of extending the service and the customer's alternative supply cost.[35] The alternative cost could reflect either the cost of self-generation by the customer or the lowest price the customer could elicit in the presumably noncompetitive bulk power supply market. Thus, if the utility's marginal cost were eight cents per kilowatt-hour, the customer's self-generation cost were fourteen cents per kilowatt-hour and the best price it could get from an alternative supplier (including wheeling costs) were thirteen cents per kilowatt-hour, the local utility would be obligated to provide service at 10.5 cents per kilowatt-hour. This system would seem to have the virtues of being understandable and administratively feasible.[36] Moreover, it would produce outcomes consistent with those that would be expected if the utility and the captive customer had equal bargaining power.

IX. THE OBLIGATION TO PROVIDE REGULATED PARTIAL REQUIREMENTS SERVICE

The discussion of the potential switching customer's right to choose to stay in the regulated rate system naturally raises a related question: can the customer elect to obtain a portion of its electricity requirements via competitive shopping and demand that the local utility supply the remaining requirements at regulated rates? Essentially the same question also arises in a different context. If the switching customer simply makes inadequate provisions with alternative suppliers to meet its requirements and thus imposes

34. Continuity of service could present problems but they should occur relatively infrequently. When the switching customer leaves supplier B to return to utility A, capacity ordinarily will be freed up on supplier B's system which could be made available to utility A to accommodate the switchover. The exception would occur if supplier B were fortunate enough to have obtained a near-term commitment for the released capacity from a new customer coming into the area. Beyond this, in a competitive environment, the possibility certainly exists that supplier B would not be willing to sell the capacity to supplier A.

35. The utility's marginal costs are assumed here to be above average embedded costs at the point when these problems are likely to arise (that is, when supplies are tight and prices generally are rising). In no case would it seem appropriate to force the local utility to take back a switching customer at rates lower than those charged to otherwise comparable customers who have stayed within the regulated embedded cost-based rate system.

36. The availability of cogeneration prices could aid in identifying stand-alone costs, although cogeneration prices may depend importantly on how facility costs are allocated between steam production and electricity production.

unintended demands on the local utility, is the local utility obligated to meet those residual demands and, if so, at what rates?

At the outset, it should be noted that the general arguments against imposing any obligation to serve on suppliers if customers are allowed to shop for competitive power supplies also apply to the obligation to provide partial requirements service. If effective competition can take place across the spectrum of needed services, there is no basis for allowing customers to shop for pieces of their requirements and simultaneously demand that the local utility be obligated to serve any remaining requirements at regulated rates. Beyond this, it seems sensible to insist that any open transmission access plan minimize the imposition of unintended residual demands on the local utility and reduce the complexity of remaining rate regulation to the extent possible.

To be more specific, the appropriateness of imposing an obligation to provide partial requirements service hinges on the answers to three questions. First, are potential switching customers likely to need partial requirements service in order to make shopping for power feasible? Second, is there a reason to believe that bulk power markets will provide competitive alternatives for satisfying discrete parts of the customers' requirements (thus justifying partial deregulation) and, at the same time, present noncompetitive conditions for meeting any remaining partial requirements service needs (thus justifying the imposition of a partial requirements obligation to serve at regulated rates)? Third, do the complexities of designing and implementing regulated partial requirements rates justify placing strict limits on any obligation to supply such service to potential switching customers?

To address the potential need for partial requirements service, it is important initially to understand the nature of the typical customer's electricity requirements and the supply system needed to meet those requirements. The typical customer's electricity requirements vary from minute to minute. They tend to be somewhat weather sensitive, to move up and down as the level of the customer's operations varies, and to change over time. Since there currently is no economically feasible means of storing electricity, the supply must vary as the customer's requirements vary. Thus, the customer requires "load-following" service. Beyond this, interruptions of supply are very costly to the typical customer, so that what is needed is highly reliable or "firm" power.

Firm load-following power is provided by integrated electric utility suppliers owning a number of generating units tied together by a transmission system and operated under common computer control. Multiple generating units provide the needed reliability when individual units are out of service and, along with the control system, provide the means for varying generator output in order to follow load variations. In some cases, telemetry has been installed to "move" a customer's load electronically to a neighboring utility control area so that the neighbor's generation can vary to follow that customer's minute-to-minute changing electricity requirements. Thus, in theory, potential switching customers could purchase their full requirements from any integrated electric supplier operating a control area adjacent to their local utility (or having contractual rights to the benefits of a control area operated by another entity). This would include most of the major utilities in the country.

How widespread use of such telemetering of varying loads to adjacent utilities would affect the operations of the current interconnected utility system is a subject that needs further study. Going beyond this, however, for a potential switching customer to be able to utilize power supplied by nontraditional unintegrated generating entities, it would be necessary to assemble a firm load-following electricity supply by putting together various types of partial requirements services. In particular, the unintegrated supplier's offering will not be usable by the typical potential switching customer unless backup power is available to provide acceptable reliability and unless a sufficiently variable source of supply is available to follow the customer's load swings. For unintegrated suppliers to play a significant role in deregulated markets, therefore, backup and load following services must be available, either in the deregulated market or from regulated utilities.

The second question focuses on the likelihood of there existing sufficient competitive sources of the needed partial requirements services in deregulated markets. If bulk power supply markets turn out to be effectively competitive as a general proposition, there is no inherent reason why all necessary services, including backup and load-following services, could not be supplied competitively. The customer or independent suppliers could install or purchase backup generation or enter into support contracts in order to deal with the reliability problem. Similarly, load-following service could be supplied either by supplemental generation and control facilities on the customer's premises or perhaps by purchases of that service from independent suppliers. Again, however, it should be noted that this could substantially increase the complexity of operating the interconnected utility network. Moreover, the local utility might enjoy significant cost advantages, at least initially, in providing load-following and backup services. Accordingly, obtaining needed partial requirements services could present a problem, at least until deregulated markets became well established and included a significant number of shopping customers and independent suppliers.

The third question addresses the complexity of setting regulated partial requirements rates in an environment where customers have substantial competitive alternatives. As a general proposition, if the customer is given the option of procuring competitively any portion of its requirements that it sees fit and demanding that the remaining residual requirements be furnished by the local utility at regulated rates, the regulators' ratesetting task will be almost impossibly complex. No matter how carefully designed are the regulated partial requirements rates—at least as long as those rates (or the revenues the utility is permitted to collect under them) are based on average embedded costs—customers with competitive alternatives are likely to be able to exploit niches in the system faster than the utility and its regulators can adjust the regulated rate. Of course, this problem is mitigated if the customer is required to commit to a particular competitive or regulated service on a long-term basis. It is not eliminated, however, if individual customers are permitted to make a variety of competitive arrangements and demand that the utility meet their varied remaining requirements at regulated rates.

The discussion above suggests that deregulated markets may be able to provide all needed partial requirements services, although some services—in particular, load-following and backup services—may be available at acceptable costs only from integrated utility suppliers in the short run. Also, shifting load-following responsibility away from the local utility may turn out to affect operations adversely. Under these circumstances, if one wished to maximize the customers' flexibility, still have a tractable regulated rate system and minimize the chance of disturbing system operations, customers might be provided with a limited regulated partial requirements option. Customers could be given the option of buying a fixed block of baseload power in deregulated markets (say ten megawatts every hour of the year) and obtaining the remaining requirements from the local utility at regulated rates. The local utility would provide partial requirements load-following service; the customer could shop for a discrete block of capacity; transactions costs and operating problems would be minimized since a constant amount of power would be scheduled into the local utility's control area at all times. (Remote telemetering would seem to be unnecessary.) Formulating appropriate rates still would be difficult because the pattern of demand each partial requirements customer would impose on the local utility would vary depending both on the customer's normal load variations and the relative size of the block of outside power it purchased. But the ratesetting problem certainly would seem to be less burdensome than would be the case if utilities were compelled to offer an unbundled menu of partial requirements services. Beyond this, at least during a transition period, it probably would make sense to require utilities to provide standby or backup power to independent suppliers so that they can market blocks of firm power. The rates for such services would have to be crafted with considerable care, however, not only to assure that utilities are properly compensated for the service provided, but to induce independent suppliers to plan for and maintain optimum levels of generating unit reliability.

X. The Obligation to Expand Transmission Facilities to Accommodate Wheeling Requests

If the provision of transmission service by the local utility to potential switching customers is a natural monopoly, then that service must be comprehensively regulated. Transmission service prices, as well as the terms and conditions under which such service must be made available to potential switching customers, will have to be controlled. In particular, in order to assure the functioning of effectively competitive markets, regulators must have the authority to compel the expansion of transmission capacity in order to accommodate wheeling requests. Such transmission service regulation would seem to present a number of formidable problems. The paragraphs below discuss some of the key ones.

When disputes arise, the regulator will have to determine whether the local utility has transmission capacity in place adequate to accommodate a given wheeling demand. This is a complex task. The capacity to import power from neighboring systems over the local utility's interconnections is not a fixed number. Instead, it is highly variable and dependent upon a number of system conditions, as well as how the interconnected systems are operated to respond to those conditions. The import capability may be limited by generation or transmission conditions on the sending system or on other systems significantly affected by potential load flows even though they are not: (1) parties to the wheeling transaction; (2) limitations on interconnection capacity itself; or (3) limitations imposed by the local utility's ability to receive power over the interconnection and maintain generation reliability (spinning and operating reserves), area voltage support (reactive power, dispersed generation), transient stability, acceptable thermal loading of transmission facilities, and minimum generator loadings. Beyond this, any time the local utility's interconnections with neighboring systems are loaded with power flows scheduled to wheeling customers, the utility has lost an important degree of flexibility in dealing with system emergencies. Restoring the needed ability to respond to contingencies when interties are heavily loaded may require substantial alterations in the operations and facilities of the local utility, thus significantly affecting generation as well as transmission costs. As a result of these considerations, a significant amount of judgment is involved in assessing a given utility's import capability. Moreover, as noted earlier, the end result of a reasoned analysis will not be a single import capability number, but a probabilistic distribution of capabilities dependent upon various potential system conditions. Resolving customer/utility disputes in this area is likely to prove to be a difficult task for regulators.

The regulator also will have to be able to determine when expansions of power import capability are justified. Major transmission expansion projects may require from three to seven years to complete.[37] Thus, the utility must be given significant advance notice of the transmission service it is obligated to supply. Moreover, the source of the power to be wheeled in must be specified. If potential switching customers want the flexibility to deal over several interconnections with a number of suppliers, redundant transmission capacity will be required to allow this flexibility.[38] In judging the need for future transmission capacity, will regulators rely upon the local utility's forecast of wheeling demands, upon the potential switching customers' expressions of interest in having wheeling service, upon rules of thumb aimed at assuring that the utility always maintains some specified firm import capability, or will potential switching customers be required to enter into take-or-pay contracts to reserve future wheeling capacity?

Since power transfer capability may be limited by conditions on utility systems not involved in the proposed wheeling transaction, to remove bottlenecks effectively, there will have to be a way to compel facility expansions on third-party systems. It is now widely recognized that the transmission of electricity often imposes significant parallel power flows on systems that are not parties to the transmission arrangement.[39] Proponents of open transmission access must address the reasonableness of imposing an obligation to expand

37. For a discussion of transmission siting and planning problems, see NATIONAL GOVERNORS' ASSOCIATION, MOVING POWER: FLEXIBILITY FOR THE FUTURE (1987).

38. The construction of duplicate transmission facilities may be hindered or prevented by applicable land use restrictions.

39. *See, e.g.*, Casazza, *Understanding the Transmission Access and Wheeling Problem*, PUB. UTIL.

transmission facilities on third-party utilities having no involvement in a proposed wheeling arrangement.

In a world with widespread wheeling options, regulators also will have to come to grips with a number of very difficult transmission service pricing problems that have not yet been addressed. For example, will wheeling rates be based on average embedded costs (as now is generally the case) or on marginal costs? Will the rate for wheeling service be based upon the customer's relative kilowatt or kilowatt-mile demand or will load flow and other studies be used to attempt to assess the burdens actually imposed on the system by a particular wheeling transaction? Will the customer be responsible for transmission load flows imposed on other systems which are not direct parties to the proposed wheeling transaction? If long-lived transmission facility investments are made to accommodate reasonably foreseeable wheeling demands, will potential switching customers be liable for stranded investment costs if they cease using those facilities? Alternatively, will the utility be permitted to depreciate those facilities over their anticipated useful life, which could be as short as the wheeling customer's power supply contract with the neighboring supplier? Given the integrated nature of the transmission and generation system, the provision of wheeling service may have substantial (and difficult to predict) effects on the local utility's generating costs. Will it be possible to craft transmission service rates with sufficient care to capture these effects? In particular, will the local utility be permitted to include in its wheeling rates standby or backup charges designed to compensate it for maintaining a generation and transmission system capable of providing continuous reliable service when interconnected system conditions limit import capacity? The resolution of these complex pricing problems necessarily determines how costs will be shared among potential switching and captive customers and whether transmission service prices will stimulate or impede efficiency-enhancing shopping by customers.

It is difficult to escape the sense that these transmission service obligation and pricing problems may be the Achilles heel of customer wheeling proposals. Many other aspects of the obligation to serve problem can be solved, at least in principle, by giving customers a choice between the present regulated rate system and an unregulated system, and unequivocally imposing on switching customers the costs of their shopping. However, transmission remains an indispensible, necessarily regulated and complex part of the puzzle. While it may be premature to say that transmission pricing and service obligation problems are unsolvable, it can be said with confidence that they presently are unsolved. Worse yet, there is little evidence that they even have been addressed seriously. Certainly proponents of open access have not focused on any of these complex problems raised by their advocacy. This is a crucial area that should not be avoided in public policy debates. Reasonable open access scenarios must specify whether a legally-mandated obligation to expand facilities to accommodate wheeling demands is envisioned and, if so, what regulatory agency will exercise the necessary control, how it will be

FORT., Oct. 31, 1985, at 35-42. W. Kersting, Does the Physical Infrastructure Exist? 8 (Sept. 12, 1986) (presented before the New Mexico State University Conference, Deregulation of Electric Generation).

determined when transmission capacity expansions must be provided and how the cost of such expansions will be spread among potential switching and captive customers.