Chapter 3

Alternative Scenarios for Increasing Competition in the Electric Power Industry

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This chapter describes the five alternative institutional and regulatory scenarios for increased competition in the electric power industry that were developed by OTA and which are used throughout this report.

INTRODUCTION

There have been many proposals for revamping the electric power industry through competition, deregulation, and restructuring, but few have been sufficiently detailed, particularly in the area of transmission systems operations, to support the kind of analysis required for this assessment.[1] *It was necessary to explore how possible regulatory futures of the electric power industry might evolve before examining the technical feasibility of expanded competition.* OTA *defined five alternative economic and regulatory scenarios to capture a reasonable range of industry futures and to form the basis of our technical analysis. The major features of the scenarios are summarized in table 3-1.*

The scenarios range from scenario 1, which makes modest changes in the regulatory procedures for approving new plant construction with no legislative expansion of transmission access, to scenario 5, which would separate the *industry into generation, transmission, and distribution sectors and impose common carrier obligations on transmission companies. Four of the scenarios would expand access to transmission services; two scenarios would allow retail customers to seek wheeling orders. The scenarios pose very different implications for the future direction of the electric power industry and its technical and institutional infrastructure. The scenarios derive* important elements from some recent proposals for regulatory reform and structural change in the electric power industry, but are not identical with any one of them.[2]

In discussing scenario implementation, OTA generalizes about how electric utilities would be affected and how State regulation might be adapted. The typical utility structure under the scenarios is the vertically integrated investor-owned utility. This model, while applicable to utilities owning over 70 percent of the our generating capacity, does not cover all of the diverse combinations of utility structure, ownership, and State regulation characteristic of the Nation's electric power industry. For many aspects of the scenarios, the ownership structure of the utility is less important than whether the utility controls and operates generating, transmission, and distribution facilities. OTA believes that these generalizations are sufficiently representative of most of the utilities and State regulatory schemes to allow us to draw supportable conclusions about the overall impacts of the scenarios.

The scenarios do not exclude public power agencies or consumer cooperatives from full participation in the competitive generation sector. Although scenarios 4 and 5 involve significant disintegration and restructuring of the electric power industry, they do not include provisions for "privatizing" Federal and other publicly owned power systems. A detailed consideration of the legal, economic, and political implications of such proposals is beyond the scope of this report.

I For background information contrasting past proposals for electric power industry reform see: Paul J-. Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electrical Utility Deregulation* (Cambridge, MA: The MIT Press, 1983); Theodore Barry & Associates, "A Study of Aggregation Alternatives in the U.S. Electric Utility Industry," December 1982, prepared for the U.S. Department of Energy, Director, Policy Planning and Analysis, Division of Electric Utility Policy (available through National Technical Information Service), DOE/RG/10295-1; U.S. Department of Energy, Office of Policy Planning and Analysis, "Deregulation of Electric Power: A Framework for Analysis, A Draft Discussion Paper, *Phase z Report,*" September 1982 (DOE/NBB-0021), prepared by the Massachusetts Institute of Technology, under contract number Ex-76-A-012295 (available through National Technical Information Service); and Edison Electric Institute, Economics Division, "Alternative Models of Electric Power Deregulation," May 1982 (prepared by NPS Energy Management, Inc.).

2For example, scenario 2 transmission access procedures are based in part on recommendations of the Electricity Consumers Resource Council, and scenario 3 includes elements of competitive bidding proposals by FERC Chairman Martha Hesse and the Keystone Electricity Forurn, among others.

Table 3-l-Summary of Alternative Scenarios

Scenario 1 Strengthening the Regulatory Bargain	Scenario 2 Expanding Transmission Access and Competition in the Existing Regulated Utility Structure	scenario 3 Competition for New Bulk Power Supplies	Scenario 4 Competition for All Bulk Power Supplies	Scenario 5 Common Carrier Transmission Services in a Disaggregate Industry Structure
• Industry consists of a mix of vertically integrated utilities, 10 Us, public power, cooperatives, Federal power authorities, self-generators, QFs, and IPPs. • Existing regulatory structure with State proapproval of new generating projects and periodic prudence reviews during planning and construction. • Negotiated transmission access arrangements • Traditional system coordination and control by integrated utilities or control centers. • Prices set by regulatory proceedings and cost of service. Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases). State oversight of retail rates and PURPA implementation. • Federal and public power agencies and cooperatives affected only to the extent State law provides.	• Industry consists of existing mix of entitles. • Existing regulatory structure with wider QF eligibility under PURPA including full utility ownership/control of QFs (may require amendment of PURPA). • New Federal wheeling authority under a public interest standard for wholesale and retail transmission access (requires amendment of the Federal Power Act). • Traditional system coordination and control by integrated utilities or control centers with contracts for unbundled services. • Prices set by regulatory proceedings . and cost of service. Transmission prices and wholesale rates set by FERC (including approval of negotiated IPP power purchases). State oversight of retail rates and PURPA Implementation. • Federal and public power agencies and cooperates affected only to the extent State law provides.	Existing mix of generating entities expanded by IPPs and unregulated utility generating subsidiaries. Existing regulatory structure with market-based rates for new competitive generation. Utilities use all source procurement for new bulk power needs. Contracts awarded to lowest cost supplier with consideration for non-price factors. • Transmission access provided by utilities as a bidding condition, or by privately negotiated arrangements, or under new Federal public interest wheeling authority (no retail wheeling). Traditional system coordination and control by integrated utilities or control centers. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Retail and transmission prices set by regulatory proceedings. Wholesale power prices set through competitive procurement except for cost-base plants built by utility as last resort supplier. State and Federal regulators oversee terms and conditions of wholesale sales. • Federal and public power agencies, and cooperatives can participate competitive generating sector to extent provided by Federal and State law and policy.	• Industry structure: Ownership of competitive generating sector segregated from transmission and distribution tiers. • New Federal and State regulatory systems. Price and entry regulation of generation sector replaced with competitive market. Continued regulation of transmission and distribution utilities and retail sales. • Revised Federal wholesale wheeling authority. Transmission utility to plan for and provide nondiscriminatory access for bulk power supplies. • Most of traditional utility system planning and coordination taken over by transmission and distribution entities. Competitive generators plan and build generation. Transmission operator assumes responsibility for bulk power system control and operation. Distribution utility retains retail obligation to serve. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Bulk power prices set by market through bidding, negotiation. Transmission and retail prices are set by regulatory proceedings. Some State and Federal oversight of competitiveness of generation markets and prudence of bulk power contracts. • Federal and public power agencies, cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.	• Ownership and control of existing integrated utility industry is disaggregate into separate generation, transmission, and distribution segments. • New Federal and State regulatory system. Price and entry regulation of generation replaced with competitive markets. Distribution utilities' services and retail prices remain regulated. Transmission prices and activities are strictly regulated. • Transmission sector operates as a common carrier providing nondiscriminatory access to all wholesale and retail customers. Reasonable renditions on reserving transmission services may be imposed. • Bulk system planning and coordination is split among generation, transmission, and distribution entities. Generators identify, plan, and build new generation in response to market signals. Transmission utility assumes responsibility for reliability of bulk system operations. Responsibility for estimating demand and securing adequate power supplies rests with distribution utilities. Unbundled bulk power dispatch, control, and transmission services provided through contracts. • Bulk power prices set by market. Transmission and retail prices are set by regulatory proceedings. Some State and Federal oversight of competitiveness of generation markets and prudence of bulk power contracts. • Federal and public power agencies, Cooperatives can participate in competitive generating sector to extent provided by Federal and State law and policy.

SOURCE: Office of Technology Assessment, 1989.

SCENARIO 1

Reaffirming the Regulatory Compact

Under the traditional "regulatory contract," a public utility is guaranteed the opportunity to recover all prudent investment committed to public use and to earn a competitive rate of return on its investment. In exchange, the utility assumes the legal obligation to provide adequate and reliable service at reasonable rates to all customers located in its exclusive franchise territory. Scenario 1 reflects the view that only modest changes in existing arrangements and institutions governing the industry are needed to assure continued adequate and reliable electric power supplies. This scenario differs from the status quo by the adoption of measures to reaffirm the regulatory compact between utilities and regulatory authorities (on behalf of utility customers) through:

1. *changes to State ratemaking policies to reduce the investment risk for new construction and to allow utilities to attract needed capital;*
2. *the modification of rules under the Public Utility Regulatory Policies Act of 1978 (PURPA) to address perceived imbalances in the implementation of avoided cost pricing for qualifying facility (QF) payments;*[3] *and*
3. *the adoption of measures to encourage greater access to transmission services for bulk power transfers and the construction of additional transmission capacity.*

Proponents believe that a major benefit of regulatory reform for utilities would be the enhanced expectation that over the long term they will be able to recover their prudent capital investment and earn a competitive return for their shareholders. At the same time, customers would be assured of adequate, reliable power supplies at reasonable rates. Some analysts speculate that reduced regulatory risks might eventually lead to savings for consumers from a lowering of capital costs of new utility construction.[4] *Some proponents of this scenario argue that more drastic reforms of utility regulation are unnecessary because the problems of the 1970s and 1980s were the result of an unfortunate and unique convergence of events and trends that are unlikely to be repeated, and that the regulatory system and domestic utility industry have largely adjusted to changed conditions. Furthermore, the flexibility with which electric utilities and the regulatory system have responded to recent financial difficulties and competitive pressures attests to the soundness of current institutions.*

Transmission access and wheeling arrangements would be negotiated between the participants on a voluntary basis. The Federal Energy Regulatory Commission (FERC) would retain its authority over transmission rates and interstate and wholesale power sales. States would exercise jurisdiction over resource planning, expansion, retail rates, and distribution. Public power agencies and cooperatives would continue to be regulated as now, subject to varying degrees of oversight by Federal and State authorities. These changes may give requirements customers greater input and oversight of power supply decisions by wholesale utilities.

Utilities would remain the primary providers of electric power under scenario 1. Cogenerators, self-generators, and independent power producers (IPPs) would continue to exert competitive pressures on utilities, but, except for PURPA qualifying facilities, alternative generating sources would not be given any special status or preference under State or Federal regulation.

Background

Much of the current interest in increasing competition in generation can be attributed to the problems encountered by the electric power industry over the past 15 years in dealing with declining growth rates, excess capacity, rising fuel costs, and steeply escalating construction costs (especially for nuclear

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[3] In some cases these changes would lower avoided cost rates, but in others it is conceivable that unrealistically low avoided cost rates would be increased.

[4] Public utility commissions might lower the authorized rate of return for utilities because of the reduced regulatory risk, but some analysts question whether preapprovals would actually lead to a reduction in the risk component of capital costs as reflected in market rates. See National Regulatory Research Institute, *Commission Preapproval of Utility Investments* (Columbus, OH: National Regulatory Research Institute, 1981, reissued 1987), hereafter referred to as "Preapprovals."

plants).[5] *Billions of dollars in new, large-baseload generating plants were canceled or deferred.*[6] *Rising utility costs and sharp rate hikes in the 1970s reversed the postwar trend of steadily declining electricity prices and prompted close regulatory scrutiny of utility performance and rate requests. Eventually regulators disallowed recovery of large amounts of imprudent utility investment in both cancelled and completed plants.*[7] *The specter of disallowances through "after-the-fact" prudence reviews contributed to a growing perception among many in the utility industry and the investment community that the long-standing regulatory compact had been seriously impaired. Many utilities felt that they were no longer assured an opportunity to recover their capital investment and eam a fair return on investment in exchange for their obligation to serve. In comparison with other industries, many utility stocks posted lower returns to investors during the early 1980s.*

Spending on new plant construction has dropped sharply in recent years. The most obvious causes are the completion of large construction projects begun in the 1970s and slow growth in electricity use. Some, however, see this drop as evidence that the industry as a whole has become substantially more risk averse and has adopted a capital minimization strategy in response to increased uncertainty over regulatory decisions and greater unpredictability in future demand growth. Some energy analysts view this hiatus in new plant construction with alarm because they fear additional baseload capacity may be needed as early as the mid-to-late 1990s if electricity demand growth increases significantly.[8]

PURPA has increased the amount of nonutility generation and cogeneration and spurred investment in and commercialization of alternative energy technologies. The competitive pressures created by the growth of PURPA cogeneration have forced many utilities to engage in aggressive cost-cutting to lower rates to avoid the loss of industrial customers. At the same time, PURPA has further compounded the uncertainties facing utilities. As implemented in some States, PURPA also has required some utilities and their ratepayers to pay for unneeded energy or QF capacity under long-term fixed-price contracts at avoided cost prices that are higher than the utilities' current marginal costs of generating electricity. Moreover, many critics of PURPA argue that it has disproportionately favored greater reliance on oil and natural gas as fuels.

Undoubtedly, some of the impacts of PURPA reflect the initial difficulties and uncertainties in implementing a complex regulatory scheme. Other problems, however, are caused by the current surplus of generating capacity and lower *fuel prices--circumstances that arguably are different from those envisioned when PURPA was enacted in 1978 in an era of rising fuel costs, projected high electricity demand growth, and fears of future energy shortages. Already, many States have initiated changes in their PURPA implementation programs to address these changed circumstances and reduce avoided costs while at the same time preserving PURPA's incentives for alternative generators.*

[5] Another reason for the interest in expanding competition is the political preference among some economists and policymakers in favor of market-based institutions and against regulated monopolies. Less reliance on regulation and greater reliance on increased competition in power supplies are seen as mechanisms for attaining the goal of economic efficiency.

[6] U.S. Congress, Congressional Budget office, *Financial* Condition *of the U.S. Electric Utility Industry* (Washington, DC: U.S. Government Printing Office, March 1986).

[7] Under many State regulatory statutes, a utility investment in a new plant must be prudent and used and useful (put intO service) before it can be placed in the rate base and costs recovered from ratepayers. Prudence reviews are regulatory examinations of the appropriateness of utility demand projections, construction practices, and management decisions and area precondition for adding a new facility to the ratebase. The reviews are typically conducted after the plant is completed. Prudence reviews have lead regulators to disallow all or part of investments in large coal and nuclear plants because of mismanagement and uncontrolled costs and, in some cases, because the completed plant proved to be excess capacity when projected demand growth did not materialize. Some industry analysts contend that prudence reviews have shifted the risks from ratepayers to shareholders and utilities and made it more difficult for utilities to commit capital for construction. Others contend that utilities and shareholders always bore these risks, but that they had historically been minimal until the highly inflationary and turbulent 1970s.

[8] For example, see: J. Steven Herod and Jeffrey Skeer, "A Look at National and Regional Electric Supply Needs," paper presented at the 12th Energy Technology Conference and Exposition, March 1985; U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, Staff Report, "Electric Power Supply and Demand for the Contiguous United States, 1997 -1996," DOE/E-0011 (Springfield, VA: National Technical Information Service, February 1988); Peter Navarro, *The Dimming of America: The Real Costs of Electric Utility Regulatory Failure* (Cambridge, MA: Ballinger Publishing Co., 1985).

From the perspective of some utilities, PURPA contributed to the further impairment of the traditional utility bargain because, while it left utilities with the obligation to assure adequate, reliable electricity service, it diminished their control over the sources and costs of generation.

Time, lower fuel prices, and lower inflation rates have abated many of the financial threats to the electric utilities.[9] There remain, however, some problems of uncertainty and delay attributed to both the regulatory process and prudence reviews of generating plant construction costs. There is some agreement among regulators and utilities that targeted regulatory reforms would help avoid the conflicts of recent years and restore a balance to the regulatory bargain by assuring the industry of recovery of future prudent investments in new facilities, if needed, while offering similar assurances to consumers and regulators that new capacity costs will be kept under control.

Implementation

The *primary responsibility for implementing scenario 1 would rest with State governments. Few changes to Federal law and regulation would be necessary. The major Federal statutory and regulatory structure governing the electric power industry today would remain essentially unaltered. In particular, PURPA, the Federal Power Act, and the Public Utility Holding Company Act (PUHCA) would be untouched and existing statutory standards would not be loosened or expanded substantially by administrative or judicial interpretations. Scenario 1 would not, however, preclude certain relatively selective, but possibly significant, changes in existing administrative rules governing industry structure and operations. For example, FERC might make minor changes or clarifications in rules governing utility avoided costs for purchases from qualifying facilities under PURPA. FERC might impose more stringent technology or efficiency standards on QFs to discourage the proliferation of "PURPA machines." Similarly, FERC could continue its efforts to encourage greater amounts of voluntary wheeling by utilities and to provide additional incentives for expanded intersystem bulk power transactions. Examples include the Western Systems Power Pool Experiment and approvals of more flexible transmission pricing schemes in individual cases.*

Transmission access and wheeling rates for wholesale and retail customers under this scenario would depend on voluntary agreements negotiated with the utilities controlling transmission facilities. FERC would oversee wheeling rates.

Federal authority to issue wheeling orders under the Federal Power Act and PURPA would remain limited. The Nuclear Regulatory Commission could order wheeling as part of licensing of new nuclear plants, however, it is unlikely that any new orders will be issued. FERC jurisdiction would largely be limited to setting wheeling rates and approving various proposals and experiments among utilities. Some States would continue to assert authority to require intrastate wheeling as a condition of State initiatives.[10] Antitrust considerations could provide some source of mandatory wheeling as part of a court order or settlement, but such wheeling orders are expected to be rare.

The current statutory split between Federal and State jurisdiction over regulation of electric utilities would remain largely undisturbed. With the existing trend toward greater use of bulk power sales, however, it is conceivable that a greater share of power costs might shift from State to Federal regulatory jurisdiction, Modified State regulatory procedures for review and approval of new plant construction would offer stronger assurances to utilities of recovery of investment than the current system. These changes would likely require State legislation and would probably include a more direct and active role by utility commissions (and the public) in the planning and oversight of new

[9] Many utilities have regained their healthy financial status and are projected to have favorable cash flows in the late 1980s-1990s. See ch. 2 of this report.

[10] The success of these efforts is open to doubt. Texas requires utilities to wheel QF power to other utilities, Texas may escape challenge *because its* transmission grid is physically isolated from other interconnected systems and thus arguably cannot be said to affect interstate transmission flows, Other States are potentially subject to FERC challenges to their authority. New York and Massachusetts require wheeling as a condition of participation in their bidding programs. Florida's attempts to require intrastate wheeling, including self-service wheeling, have repeatedly been challenged by FERC and by several Florida utilities, arguing that Federal law preempts State control over rates, and the terms and conditions of wheeling transactions. *Florida Power & Light, Petition for Declaratory Order from FERC*, EL87-19-000, filed Mar. 11, 1987.

generation sources and transmission facilities.11 Some observers believe, however, that many States would not significantly alter their existing regulatory procedures because they have already adopted similar reforms in response to the problems of slow growth rates, inflation, cost-overruns, soaring fuel prices, and excess capacity that stressed utilities during the 1970s and early 1980s.

Rolling Prudence Reviews. *One regulatory reform that addresses the utilities capital attraction problem is a proapproval process for construction of new generating and transmission facilities coupled with periodic prudence reviews.*[12] *These determinations would be in addition to State least-cost planning requirements. Regulators and utilities would agree in advance as to the need, type, cost, and rate implications of major new projects. These hearings would allow participation by consumers. Following initial approval, projects would be subject to regularly scheduled prudence reviews from inception to completion. Utilities would be assured recovery of all expenses incurred up to the most recent prudence determination, except of course for losses due to reckless, improper, or negligent actions of the utility. This process has been characterized as a "rolling prudence review" in contrast to the post-construction prudence reviews now common under many State regulatory programs.*[13] *Proapproval is not equivalent to adoption of a rate scheme that allows recovery for Construction Work in Progress* (CWIP) *in the rate base before the plant actually is in use. Under the rolling prudence concept, a new plant would become recoverable as part of the rate base only after it began operating and was determined to be "used and useful."*

If the circumstances underlying an initial approval of new capacity changed, periodic regulatory reviews could allow projects to be canceled or modified midcourse, but the utility would still be entitled to recover in the rate base the value of its prudent investment to date plus a reasonable return over any recovery period.[14] *If the utility chose to continue construction, it would receive no guarantees from that point on that the remaining costs would be allowed into the rate base. When and if the facility began operation, the public utility commission would decide whether the expenditures were prudent. Some utility executives argue that such a regulatory program would "fairly balance the risk to consumers and investors alike and give assurance of adequate and reliable supply of electric power in the future."*[15] *In effect, the traditional regulatory bargain would be restored and strengthened, but it would be more comparable to an explicit contract between the utility and the regulatory commission on behalf of the customers.*

Institution of a rolling prudence review for new construction projects would reduce the utility's management control over major investment decisions. In some States, however, there is already an extensive degree of regulatory involvement in all aspects of utility investment decisionmaking and, to some degree, this scenario would simply constitute a formal recognition of a regulatory system that already exists, except perhaps for the guarantees accorded to the utility.

A system of rolling prudence reviews is consistent with other current trends in regulatory treatment of utility resource expansion planning and construction. Other regulatory initiatives have been proposed or adopted in recent years to restore the utility's expectation that it will recover its prudent investments or to enhance its cash flow to fund construction. Examples include automatic fuel adjustment

11State regulatory authorities in Massachusetts have adopted a proapproval process for new capacity. Massachusetts Department of Public Utilities, "Pricing and Rate-making Treatment To Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities," D.P.U. 86-36-C, May 12, 1988.

12See "Presentation of Richard E. Disbrow at a Seminar for Virginia's Legislative Leadership and Energy Committee Members, Aug. 10, 1987" for a discussion of this approach. This strategy is also based in part on the remarks of Richard E. Disbrow at the OTA Workshop on Alternative Scenarios for Increasing Competition in the Electric Power Industry, Sept. 28, 1987; and on NRRI, "Preapprovals," supra note 4.

13The prime attractions of a rolling prudence scheme are that it reduces some of the risk in utility capital investments, while the expanded role in planning, approval, and scheduled project reviews offers equivalent protections and controls for regulators and consumers.

14Many State regulatory authorities have historically allowed utilities to recover the full costs of canceled plants plus a reasonable return on investment. Some States may, however, be restricted by State authorizing legislation that limits recovery to capital plant expenditures that are both prudent and used and useful, therefore requiring a facility to actually be in operation before any recovery can be placed in the ratebase. See NRRI, "Preapprovals," supra note 4.

15Disbrow, supra note 12.

clauses, incentive rates, performance bonuses *and penalties, advance caps on* construction reimbursement, and inclusion of the value of CWIP in the ratebase.[16]

Regulatory reforms aimed at reducing or shifting risk in constructing new large baseload plants may not, however, actually result in the immediate construction of any such plants. Other considera*tions such as the extent of existing reserve capacity, increased uncertainty in future demand growth, and greater volatility in fuel prices may lead utilities to conclude it is more prudent and cost-effective to build smaller increments of new generation and to buy power from other sources for the foreseeable future.*

Under scenario 1 many ongoing State regulatory initiatives could be expected to continue. State commissions would likely continue their efforts to encourage utilities to expand their bulk power procurement practices to include consideration of QFs, other utilities, and independent power suppliers.[18] Under the more standard State PURPA programs, the commissions might review previously established avoided cost rates. In some cases, lower fuel costs and existing capacity surpluses could yield lower avoided cost rates. These changes could lead some higher-cost PURPA projects to drop out. In other cases, reviews may lead to increases in existing low avoided cost rates encouraging QF development. The basic PURPA incentive structure would still remain. Utilities would still be obligated to purchase power generated by QFs at avoided cost rates. QFs would retain the protection of existing long-term capacity contracts at avoided cost pricing with host utilities,

States could continue to encourage greater coordination of utility planning and operations through centralized dispatch, power pools, and brokerage angements. The States would also continue their efforts to promote workable regional power supply planning arrangements and new means of developing needed interregional transmission capacity. Preapproval will eventually require most State regulatory agencies to increase their expertise in system planning and load forecasting.

Industry Structure. *Under scenario 1 the electric power industry would consist of the current mix of investor-owned utilities, public power agencies, cooperatives, Federal power authorities, self-generators, small power producers, QFs, and IPPs. As now, vertically integrated, investor-owned utilities will dominate the generation, transmission, and retail distribution segments of the power industry. Recent trends toward limited industry restructuring through mergers, acquisitions, and internal reorganizations can be expected to continue within the constraints imposed by existing law.*

The trend toward greater bulk power competition would continue as power suppliers, sellers, buyers, and State regulatory commissions cope with pressures from prices and technology. In some States or regions a de facto competitive market in bulk power supplies will continue to evolve if FERC maintains its "hands off' approach to reviewing these interutility transfers. Utilities will continue to increase bulk power transfers.

The role of IPPs, and especially utility-affiliated IPPs, remains unsettled because, unlike QFs, they would not be exempt from coverage by the Federal Power Act or PUHCA. Without PURPA purchase requirements, IPPs would have to compete on the underlying economics of their projects. Non-QF cogenerators and IPPs could continue to contract for the sale and transmission of power to utilities and other purchasers, however, provided suitable arrangements can be negotiated.

System Operations and Planning

Scenario 1 would have little or no impact on system operations and closely resembles the status quo. Table 3-2 summarizes the system operating requirements under the scenarios. Responsibility for

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[16] See Joseph P, Kalt, Henry Lee, and Herman B. Leonard, "Re-Establishing the Regulatory Bargain in the Electric Utility Industry," Discussion Paper Series (E-87-02), Energy and Environmenttal Policy Center, John F. Kennedy School of Government, Harvard University, Cambridge, MA, March 1987; Leland L. Johnson, Incentives *To improve Electric Utility Performance " Opportunities and Problems* (Santa Monica, CA: Rand Corp., *March 1985);* and NRRI, "Preapprovals," supra note *4.*

[17] This utility investment preference was previously noted by OTA, U.S. Congress, Office of Technology Assessment, New *Electric power Technologies: Problems and Prospects for the 1990s,* OTA-E-246 (Washington, DC: U.S. Government Printing Office, July 1985), ch. 3.

[18] This approach is different from scenario 3 which would require (he use of competitive procurement procedures for all new bulk power supplies.

Table 3-2-Alternative Scenarios: Summary of System Operations, Planning, and Developrnent

	System operation	System planning and development		
scenario	Reliability, dispatch and coordination	Generation	Transmission	Distribution
1. Strengthening the regulatory bargain.	Utility controloanter. Control of nonutility generation set by contract.	Utility obligation to plan, build, and purchase. QFs market under PURPA. IPPs negotiate contracts.	Utility responsibility.	local utility responsibility.
2. Expanding transmission access and competition in the existing regulated industry structure.	Similar to 1 with greater reliance on contractual provisions for nonutility generation control and wheeling.	Similar to 1 with expanded OF and IPP participation.	Same as 1, but States may require utilities to plan and build adequate transmission capacity for regional needs including retail wheeling.	same as 1.
3. Competition for new bulk power supplies.	same as 2.	Utility obligation to plan and secure adequate new supplies through competitive means. Generators, QFs, IPPs, and host utility affiliates.	Same as 2, but no retail wheeling obligation.	same as 1.
4. Competition for all bulk power supplies.	Transmission utility assumes bulk system control. Operational responsibilities of generators and distribution utilities set by contracts with customers and transmission utilities.	Generators pfan and build in response to perceived market needs and solicitations by transmissiondistnbution utilities.	Transmission utility obligation to plan and build adequate capacity for instate/regional wholesale needs.	local retail utility obligation to plan and contract for adequate supplies. Utility may participate in load management and conservation. Transmission utility may provide brokering services.
5. Common carrier transmission services in a disaggregate industry structure.	same as 4.	Generators plan and build in response to perceived market needs and solicitations by local distribution utilities and transmission companies as brokers.	Transmission utility obligation to plan and build adequate capacity for foreseeable needs as common carrier for regional wholesale and retail customers.	Same as 4.

SOURCE: Office of Technology Assassment, adapted from Power Technologies, inc., *Technicl Background and Considerations in Proposed Increased Wheeling, Transmission Access, and Nonutility Generation*, OTA contractor report, Mar. 30, 1988.

maintaining day-to-day system reliability and coordination of generation and transmission resources would rest with the local utility or centralized control center (under a coordination or power pool agreement).[19] *InterUtility agreements and operating practices, as well as NERC regional protocols, would continue to govern cooperative activities among utilities. Operational responsibilities and technical standards for nonutility or third-party power suppliers would be based on contract terms with the local utility. As under existing law, State regulators would have the authority to rule on the reasonableness of utility technical specifications in cases of disputes between utilities and third-party generators.*[20]

The local utility or regional control center would determine the order of dispatch, maintenance scheduling, and unit loading of utility owned or leased units. For QFs and IPP units, dispatch and scheduling would depend on contract terms with the local utility. Dispatchable third-party generators would likely be treated the same as utility sources if they demonstrate adequate reliability and availability and if unit dispatch is technically feasible. Nondispatchable third-party generators would not be subject to utility control, except as needed to preserve the stability and reliability of the system. Under this scenario, it is likely that IPPs will be dispatchable under contracts, because their options to sell power to other customers is limited. Emergency curtailments of backup service for third-party generators would be allocated according to State regulated curtailment policies.

Under scenario 1 local utilities would have the responsibility for planning and developing overall generation, transmission, and distribution requirements for the system based on their projections of future electricity supply and demand. These planning efforts most likely would be coordinated with other regional utilities and overseen by State regulatory agencies as part of the proapproval process for new plants. Regulated utilities would retain the obligation to provide adequate and reliable service for current and future needs under this and other scenarios.

In preparing generating capacity expansion plans, utilities will consider various options for securing power supplies, including potential QF sources, and *bulk power purchases from other utilities and IPPs, as well as conservation and load management strategies.*[21] *State authorities would* **generally** *approve utilities' generation expansion plans through the certification and proapproval process. QFs, IPPs, and self-generators would plan and build capacity based on their own perceptions of need and profitability.* As *eligibility requirements are tightened and avoided cost prices are lowered, sponsors might tend to abandon some of the more expensive QF projects currently planned. It is unlikely that any IPP project would go forward without a firm contract with a utility for its power output. Third-party power producers will likely be more successful in areas with low reserve generating capacity margins than in those areas with substantial amounts of existing utility generating reserves or low production costs.*

Local and regional utilities would plan and develop transmission system additions subject to regulatory approval. The pressures for increased access to transmission services to accommodate bulk power sales can be expected to continue. State and Federal initiatives toward more flexible transmission pricing may encourage some additional upgrading and expansion of transmission systems. The potential for delays and controversy attendant witb proposals for the siting and construction of new transmission lines can be expected to continue. Planning and building distribution system additions would remain the responsibility of the local utility with regulatory approval.

I Where are about 150 utility control centers in the United States. Some centers oversee the operations of individual utilities, others govern the operations of participating utilities over a region established through coordination agreements or power pools. See chs. 4 and 5 of this report for more on control area responsibilities.

20Under PURPA, utilities are required to interconnect with small power producers and QFs, and cannot impose unreasonable technical requirements to discourage access.

21Over half of the States either require utilities t. engage in least-cost planning for future electricity needs or are developing such requirements, David Berry, "Least-cost Planning and Utility Regulation''l%ldic ***Utilities*** *Fortnight/y,* Mar. 17, 1988, pp. 9-15.

SCENARIO 2

Expanding Transmission Access and Competition Within the Existing Institutional Structure

Scenario 2 would preserve most of the electric power industry's existing structure and regulatory framework, but would expand competition in the generation sector more than scenario 1 or the status quo. Scenario *2* would increase the number of potential bulk power sellers by modifying some of the size, technology, fuel, and ownership limitations for QFs under PURPA. This could largely be accomplished by changes in regulations, but eliminating all restrictions on utility ownership would likely require legislation.[22] At the same time, the ranks of prospective buyers would be enlarged by amending the transmission access provisions of the Federal Power Act *to authorize FERC to issue transmission access orders under a broad public interest standard.*[23] *These legislative changes would increase opportunities for both wholesale and retail wheeling. Utilities and large industrial retail customers could purchase electricity "off system" from traditional and nontraditional power suppliers and have it delivered to them over a more open transmission system.*

The principal mechanism for achieving increased competition in scenario 2 is the provision for both wholesale and retail wheeling. If efforts to negotiate voluntary wheeling arrangements failed, any utility (including QFs and IPPs) or a very large retail customer would have legal standing to seek a wheeling order from FERC.[24] *There would be a rebuttable assumption that the capacity to wheel exists. The utility denying the wheeling services would bear the burden of proving either a lack of available capacity or that accommodating a proposed wheeling transaction would result in a degradation of service.*[25] *The utility would be entitled to a reasonable compensation for its transmission services.*

In addition to new wheeling authority, Federal and State administrative policies intended to encourage greater competition in bulk power sales within the existing institutional structure and increased access to transmission services would be continued and expanded,

Background

Many industry analysts have argued that the regulated electric power industry would be more economically efficient if more competition were

22 PURPA provides that a qualifying facility must be "owned by a person not primarily engaged in the generation or sale of electric power (Other than electric power solely from cogeneration and small power production facilities)." 16 U.S.C. 7%(17)(C) and (18)(B). FERC has solicited public comment on several potential changes to its rules on utility equity ownership of QFs. U.S. Federal Energy Regulatory Commission, Notice of Proposed Rulemaking on Regulations Governing the Public Utility Regulatory Policies Act of 1978, Docket No. RM88-17-000, July 19, 1988, pp. 32-57.

23 For examples of this approach, see *Electricity's Future: A Special Report by the Electricity Consumers Resource Council,* July 1987. See also, the proposed "Electric Utility Transmission Reform Act of 1985" introduced by Rep. peter H. Kostmayer in the 99th Congress, H.R. 2231. The bill would have amended sees. 211 and 212 of the Federal Power Act to provide that FERC could issue an order requiring an electric utility to provide transmission services for another electric utility whenever it was found necessary or appropriate in order to: 1) conserve energy, 2) promote the efficient use of facilities and resources, 3) increase competition in the bulk power supply market, or 4) otherwise serve the public interest. The order could be granted on the application of any State commission, or public utility, or by FERC acting on its own motion following notice to affected utilities and an opportunity for a hearing. FERC could order a utility to expand transmission facilities to provide the needed transmission services, but the wheeling party would pay the capital and operating costs involved. The bill used a broad definition of a public utility as "any person, State agency, or Federal agency that sells electric energy" for its new wheeling authority, but otherwise would not expand FERC jurisdiction over these entities. H.R. 2231 expressly banned orders to deliver power to "ultimate" or retail customers. OTA'S scenario 2 would extend eligibility for wheeling services to "qualified" power purchasers to allow very large retail customers to obtain wheeling. FERC or the States would establish standards for determining which retail customers would qualify for wheeling.

24 The issue of what Constitute a very large retail customer would be left to the States. It is assumed that States would limit access to facilities that require 20 to 50 MW or more. For example, a pulp and paper mill might qualify at 20 MW in some States, but in others, facilities might require at least 200 MW (e.g., the power requirements of a large aluminum reduction plant),

25 In deciding whether to grant a requested wheeling order, FERC could consider all relevant issues including the potential impacts On utilities, captive customers, and system reliability. Thus, it is possible that, if granting a wheeling order to an industrial customer to purchase off system would impose a substantial economic hardship on the utility's remaining customers, FERC could deny the request for transmission access under its "public interest" standard.

allowed in certain segments of the industry.[26] Among the benefits of competition they cite are: better use of generation and transmission resources, a more flexible and secure power supply, increased efficiencies in utility operations, and lower prices to consumers over the long-term. In addition, utility ratepayers would have less exposure to the risks of construction cost overruns and poor plant performance as these risks would be shifted more explicitly to the shareholders of nonutility generators. A further benefit of allowing limited competition and more wheeling would be a growth in the information and experience available to assist policy makers in evaluating the technical and institutional feasibility of proposals for broader competition and economic deregulation of electric power.

Proponents note that changes in generation and transmission technologies have diminished some of the so-called natural monopoly characteristics of the electric power industry allowing workable competition to exist as a supplement to regulation. Smaller generating units are now in many cases cost-competitive with large baseload plants and have shorter lead-times. Increased interconnections and higher voltage transmission lines have made regional coordination of utility operations more feasible. With these developments, some analysts see the subregional, insulated, vertically integrated utility as fast becoming an outmoded and economically inefficient entity. In their view, an industry structure dominated by such entities: inhibits cost-savings that could be achieved with greater coordination and bulk power trades between interconnected systems; makes cooperative agreements and power pooling arrangements difficult to establish; provides unequal access to the benefits of coordination and power pools among buyers and sellers; and allows the owners of transmission lines to exercise monopoly power over their sections of the interconnected systems.[27]

The entrance of small power producers and cogenerators into the generation market under the aegis of PURPA has yielded some benefits, but it also has imposed additional operating uncertainties and costs on electric utilities.[28] Expanding the PURPA model is one mechanism for introducing limited competition into the regulated generating sector. A major advantage of this approach is that "smaller increments of increased competition can yield efficiency gains and resolve uncertainties without radically altering present institutional arrangements and risking a costly mistake."[29] At the same time, changes in the criteria for QFs would reduce what some view as inherent market distortions created by PURPA's limitation to small power producers and nonutility firms.

Federal authority to issue wheeling orders rests primarily on three sources:

1. *antitrust law (as a remedy for anti-competitive or monopolistic behavior),*
2. *the licensing power under the Atomic Energy Act, and*
3. *sections 211 and 212 of the Federal Power Act, as amended by PURPA.[30]*

Wheeling orders under antitrust law are rare, and even if a plaintiff is successful, it may take years to work out acceptable arrangements. Wheeling conditions imposed on licensees of nuclear power plants by the Nuclear Regulatory Commission (NRC) and its predecessor, the Atomic Energy Commission have been a major source for guaranteeing transmission access for requirements customers. With no new nuclear power plants on order, additional NRC wheeling orders as part of licensing conditions will be rare. It is possible that NRC might modify some

26See ELCON, *Electricity's Future,* supra note 23; William A. Brownell, "Electric Utility Deregulation: Analyzing the Prospects for Competitive Generation," *Annual Review of Energy 1984, pp. 229-262;* and F. Paul Bland, "Problems of Price and Transportation: Two Proposals To Encourage Competition From Alternative Energy Sources," 10 *Harvard Environmental Law Review 345 (1986).*

27William A. Brownell, "Electric Utility Deregulation: Analyzing the Prospects for Competitive Generation," *Annual Review of Energy 1984,* pp. 229-262.

28Id., pp. 254-255,

29Id., p. 253.

3016 U.S.C. 824j and 824k. See discussion in ch. 2 of this report.

existing licensing obligations, however.[31] Section 211 wheeling orders have been effectively precluded by the heavy burden of proof placed on applicants and the restrictive findings that must be made before an order can be issued. For example, among other things, section 211 requires a finding that existing competitive relationships, such as existing power sales arrangements, not be disturbed.[32] Other difficulties with existing FERC wheeling authority include: the fact that each wheeling application is considered separately; uncertainty over whether QFs and IPPs are included under the broad definition of a utility as any entity that generates power for sale; prohibition on retail wheeling; and Federal court decisions and FERC informal opinions that the 1978 PURPA wheeling provisions narrowed whatever inherent authority may have existed under the Federal Power Act to order wheeling to promote competition.[33]

A fourth possible source of wheeling authority is FERC's ability to "condition" its approval of some desired action on the petitioner's acceptance of certain specified requirements. This conditional authority is inherent in FERC's regulatory and policy responsibilities under the Federal Power Act and other laws.[34]

Implementation

Scenario 2 would be implemented through combined Federal and State efforts. Federal legislation would be required to amend PURPA, the Federal Power Act, and PUHCA. State legislation or regulatory action would be needed to implement the changes in Federal PURPA rules.

Changes in PURPA Requirements. Selected changes in the PURPA eligibility standards for qualifying cogenerators and small power producers would increase the ranks of potential competitors in bulk power markets.[35] PURPA vests with FERC the responsibility for establishing technical requirements for qualifying facility status, and most of these initiatives could be accomplished through changes in FERC regulations. Modifications have been suggested to the standards on the unit size, technologies, fuel types, and utility equity participation.

Size: FERC rules limit small power producers to no more than 80MW for PURPA eligibility. There is a statutory limit of 30MW for exemption from State and Federal utility regulation (including regulation under PUHCA). Under scenario 2, the size cap for small power producers would be raised, for example, to 165 MW as proposed by a former FERC chairman.[36] There are no size or fuel limits on

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[31] Ohio Edison has asked NRC to revise the wheeling obligations included in the license for its Perry Nuclear plant. The license requires Ohio Edison to wheel cheaper coal-fired power from southern Ohio to 21 municipal distributors in northeast Ohio. Ohio Edison has argued that the wheeling requirements should be dropped because the municipals no longer want to purchase the more expensive Perry nuclear power. ' 'Metzenbaum, public Power Fight Ohio Edison wheeling Request to NRC," *Energy Daily*, Apr. 4, 1988, pp. 1-2. Wheeling issues could also be raised before NRC in reviews of license assignments in mergers and acquisitions,

[32] 16 U.S.C. 824j(c)(i). See analysis of Federal wheeling authority in Alvin Kaufman, Car Behrens, Donald Dulchinos, Larry B. Parker, and Robert D. Poling, *Wheeling in the Electric Utility Industry*, Report No. 87-289 ENR (Washington, DC: Congressional Research Service, Feb. 12, 1987).

[33] See Kaufman et al., id. Similar conclusions were reached in Harvey L. Reiter, "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation Under the Federal Power and Natural Gas Acts," 18 Land and Water Law Review 1-80, 1983; National Regulatory Research Institute, *Non-Technical Impediments to Power Transfers* (Columbus, OH: National Regulatory Research Institute, September 1987); and Bland, supra note 26.

[34] The "wheeling in" and "wheeling out" p-sin the notices of proposed rulemaking would be based on FERC's conditional authority. See note 57 infra. See also the discussion of FERC's authority in ch. 2.

[35] FERC regulations define a small power producer as a facility that produces less than 80 MW of electric power at the same site through usc of biomass; waste materials; geothermal energy; or renewable resources such as wind, solar and hydroelectric resources (up to 25 percent of total energy input to QF may be oil, natural gas, or coal). 18 CFR 292.204(1988). FERC defines a cogeneration facility as "equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy." 18 CFR 292.202(c) (1988). To be a qualified facility, the small power production facility or cogeneration facility cannot be owned by a person or entity "primarily engaged in the generation or sale of electric power" (other than the power produced from the qualifying facility). 18 CFR 292.206 (1988).

[36] See Hearings Before the House Subcommittee on Energy Conservation & power. on H.R. 2992 and H.R. 2876 (1981). H.R. 2876 would have increased QF size cap from 80 to 165 MW and eliminated 30MW limit exemptions from Federal and State utility regulation. Legislation in the Senate was introduced in 1982 (S, 1885) and hearings were held. Hearings on S. 1885 before the Senate Committee on Energy and Natural Resources, Apr. 19, 1982. The rationale for this size limit is that it would allow larger QF plants but would be less than some larger utility or IPP planned modular power plants. Legislation in 1981 would have lifted overall size limits to 165 MW.

cogenerators, because they are not *primarily in* the *business* of *generating* and *selling* electricity.

Utility Equity Participation: Legislation would probably be required to allow *fill equity participa*-tion *in* QFs by *utilities* and *would be controversial.*[37] FERC rules *interpreting PURPA* have allowed utility equity participation of less than 50 percent.[38] Many utility subsidiaries are active in building QF plants, but they must do so as part of a joint venture with another nonutility firm. Under this scenario, unregulated utility subsidiaries would be able to build and own generating units outside their own service territories and sell power at PURPA avoided cost rates. FERC has solicited comments on how they might amend the existing equity ownership rules to expand utility participation in QFs.[39]

Fuel: Qualifying small power producers are limited to those that produce electricity through use of biomass, waste materials, geothermal energy, or renewable resources such as wind, solar, and hydroelectric resources. They may use oil, natural gas, or coal for up to 25 percent of their total energy input.

Technology: FERC rules require that to qualify, energy use by a cogenerator must be sequential and must meet minimum efficiency standards in thermal output. Sequential use means that the rejected heat from a power production or heating process is used in another power production or heating process. This cascading use of energy in sequential processes gives rise to the energy conserving characteristics of cogeneration.[40] Some new technologies, such as extraction turbines, do not use sequential steam to generate large amounts of power. Modifications to the technology requirements might allow additional facilities to qualify.

Operating and Eficiency Standards: FERC regulations impose different efficiency and operating standards on QF units depending on the type of fuel used. New cogeneration facilities using natural gas or oil must satisfy minimum efficiency levels intended to ensure efficiency superior to conventional utility facilities.[41] No such restrictions are imposed on waste plants or coal plants.

Easing of the above PURPA standards for QF eligibility would increase both the number and diversity of participants in bulk power markets and, combined with increased access to transmission service, would broaden the range of purchase options available to utilities and large retail customers. For those customers either unable or unwilling to assume the risks of purchasing power off system, the local utility would maintain a service obligation to either construct or acquire needed capacity to serve their power supply needs.

Revised PURPA eligibility standards could bring some IPP projects under the QF purchase obligations of utilities. At the same time, with greater variety and more competition among alternative sources, the purchasing utility's avoided costs might be driven down, thus lowering required QF payments. IPP and QF projects could use their access to the transmission system to contract with more distant utilities offering more attractive avoided cost payments. IPPs not meeting QF status requirements would still be able to seek mandatory transmission access to move their power.

Transmission Access and Wheeling—Scenario 2 involves two distinct kinds of wheeling to promote greater competition:

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[37] H.R. 2876 would also have eliminated the utility ownership restriction from the definition of qualifying cogenerators and small power producers. Lifting the utility ownership cap was strongly opposed by State regulators and QF developers. See Hearings on H.R. 2992 and H.R. 2876, supra note 36.

[38] 18 CFR 292.206 (1988).

[39] See Notice of Proposed Rulemaking on Regulations Governing the Public Utility Regulatory Policies Act of 1978, Docket No. RM88-17-000, July 29, 1988.

[40] The requirement of sequential use of energy was added by FERC in its technical definition of cogeneration and is not found in PURPA. The sequential use requirement was viewed as critical even though not statutory. See discussion in Pfeffer, Lindsay & Associates, Inc., *Emerging Policy issues in PURPA Implementation: An Examination of Policy Issues Related to Federal and State Efforts to Encourage Development of Cogeneration and Small Power Production Under Title II of PURPA*, March 1986, prepared for the U.S. Department of Energy, Office of Coal & Electricity Policy, ch. 11.

41 Under the Power Plant and Industrial Fuel Use Act of 1978, utilities were largely precluded from building new plants burning oil Or natural @s without a special exemption, because these were believed at the time to be scarce fuels. In 1987 Congress *repealed the* act fuel restrictions for new utility baseload plants.

1. *wholesale* wheeling—providing transmission services to utilities and nonutility generators for the sale of power for resale (mostly involving sales to utilities); and
2. *retail wheeling-transmitting* power from other generators (utilities, QFs, IPPs) to ultimate consumers, which would also allow "self-service" wheeling among facilities owned by a QF or a self-generator.

Expanded transmission access under scenario 2 would increase the market access of both potential buyers and sellers of electric power and lessen the dominance of the utilities controlling the transmission grids.

Scenario 2 would amend the Federal Power Act to change the definition of those eligible to seek wheeling orders and modify the process through which FERC can order wheeling.[42] The restrictive findings required by existing law, which effectively preclude issuance of wheeling orders in most cases, would be replaced by a more flexible "public interest standard. " If efforts to negotiate voluntary wheeling arrangements failed, any utility (including QFs and IPPs) or large retail customer would have legal standing to seek a wheeling order from FERC. There would be a rebuttable assumption that the capacity to wheel exists and any utility denying wheeling services would bear the burden of proof of showing that there is either a lack of capacity or a degradation of service that would result from the proposed wheeling transaction. The wheeling utility would be entitled to a reasonable compensation for its transmission services.

In deciding whether to grant a requested wheeling order, FERC could consider all relevant issues including potential impacts on utilities, captive customers, and system reliability. Thus, it is possible that, if a wheeling order allowing an industrial customer to purchase off-system[43] would impose a substantial economic hardship on the utility's remaining customers, FERC could deny the request for transmission access under a public interest standard. (The customer, of course, would always retain the option of self-generation, which would still leave the utility with the same problem of recovering its investment from a smaller pool of ratepayers.) Providing retail customers with access to transmission would provide them with a bargaining tool in seeking to negotiate rate concessions from their retail supplier.

The principal constraints on a customer purchasing off-system under scenario 2 would be the availability of transmission capacity, and any specific contractual provisions with the existing utility supplier on minimum take and termination notice conditions. Arrangements for backup or standby power supplies would have to be negotiated with the host utility, perhaps with review by appropriate regulatory authorities.[44] In some cases the customer would have to negotiate contracts for provision of unbundled control area services provided by the local utility.

Industrial customers going off-system for their power needs would have to negotiate some stand-by or maintenance service arrangement with their native utilities if they were to expect any sort of service obligation. They may also have to negotiate some provisions for later reconnection to local utility service if State regulations do not already provide for this. The contracts between large retail customers and alternative suppliers would likely be more detailed and complex than their previous agreements with a host utility. Many of the services that had been supplied as part of traditional electric power service would now have to be contracted for specifically. Contracts that involve wheeling agreements with third parties will also require more stringent delineations of technical and operating specifications and responsibilities.

Scenario 2 also would encourage the development of new initiatives to provide greater economic incentives to utilities to wheel voluntarily. FERC could, for example, establish affirmative guidelines for the approval of transmission agreements that

[42] See the ELCON proposal and Kostmayer bill, supra note 23. The Federal Power Act defines an electric utility as any entity that generates electric power for resale-some have questioned whether that definition brings QFs and IPPs within the class of parties with standing to seek mandatory transmission orders under existing law. The proposals would also extend standing to FERC, State agencies, Federal power agencies, and large power consumers/purchasers.

@Off system" refers t. purchases from a power supplier other than the native or host utility currently serving the industrial customer.

[44] Some States already require utilities to provide backup services at nondiscriminatory rates.

might encourage wheeling, such as allowing more flexible pricing of transmission services, requiring compensation of other affected parties (such as other utilities experiencing unintended flows or parallel path problems), permitting auctioning of transmission services, establishing strict timetables for negotiating transmission agreements, and expediting their own review of transmission rates and agreements.[45] FERC might also cooperate in providing guidance and technical assistance to State regulators in pricing and contracting procedures for unbundled transmission and control services.

State Initiatives. Because States have the primary responsibility for implementing PURPA under guidelines established by FERC, the States would have to revise their rules and procedures to accommodate the expanded eligibility for QF status. States would have the lead role in implementing changes that permit large retail customers to purchase off system in intrastate transactions. Federal law would not preempt any State laws that characterize an IPP, self-generator, or QF engaged in retail sales as a public utility subject to regulation. States might require instate utilities to wheel power from other instate utilities and nonutility generators to large retail customers.

It is possible that the existing balance between State and Federal regulation could be maintained somewhat if Federal legislation expressly allowed delegation to the States of the authority to implement intrastate retail wheeling under FERC guidelines. State involvement might also be the most politically effective means of implementing retail wheeling because of the substantial equity and fairness considerations involved in weighing the interests of large customers in wheeling power against both the economic impacts on the local utility and the interests of other customers. Placing the decision-making responsibility in State hands would move the process closer to the parties that potentially would be most affected by the order.

System Operations and Planning

System reliability and coordination remains the responsibility of the local control center as in scenario 1. Operating requirements for QFs and IPPs would be specified in contracts. System *operations* would likely be affected more than in scenario 1 as there would be a need to accommodate a greater diversity of generating sources and delivery points.

Dispatch, maintenance, and unit loading operations and procedures would be similar to scenario 1, except that loading and dispatch of transmission accessors not subject to direct utility control would be determined by contracts among the generator, its customers, and the wheeling utility. The wheeling utility would have to adjust its operations to counter any increased uncertainty created by having nondispatchable generators on the system. (Of course, the wheeling utility could impose reasonable technical conditions and charges on the nondispatchable generators and their customers to provide this service.)

Emergency curtailments of service would be allocated according to State-regulated curtailment policies and contracts (same as in scenario 1). For outages of nonutility wheeled power, curtailment and backup power would be based on standby service contracts with the local utility.

Planning and developing generating capacity would be very similar to scenario 1. Under revised PURPA standards, a broader range of facilities would be eligible for QF status, and State law might require utilities to consider QFs as potential components of their capacity expansion plans. It is likely that much more QF and IPP capacity would be built under scenario 2 than under scenario 1. As the amount of nonutility generation grows, States or regional utility groups may wish to provide for direct participation by nonutility generators in the planning process.

Planning for transmission additions would be similar to scenario 1 except that State regulators may require utilities to include provisions for adequate transmission capacity for wheeling services in

45 Recent examples of these initiatives include the Western States power Pool experiment, FERC authorization for Baltimore Gas & Electric to auction off its unneeded capacity on the PJM power pool, and approval of a flexible transmission pricing arrangement between Pacific Gas & Electric and the Turlock Irrigation District, see "PG&E Offers 'New Approach' To Pricing Transmission Services." *The* Energy *Daily*, Apr. 5, 1988, p. 1.

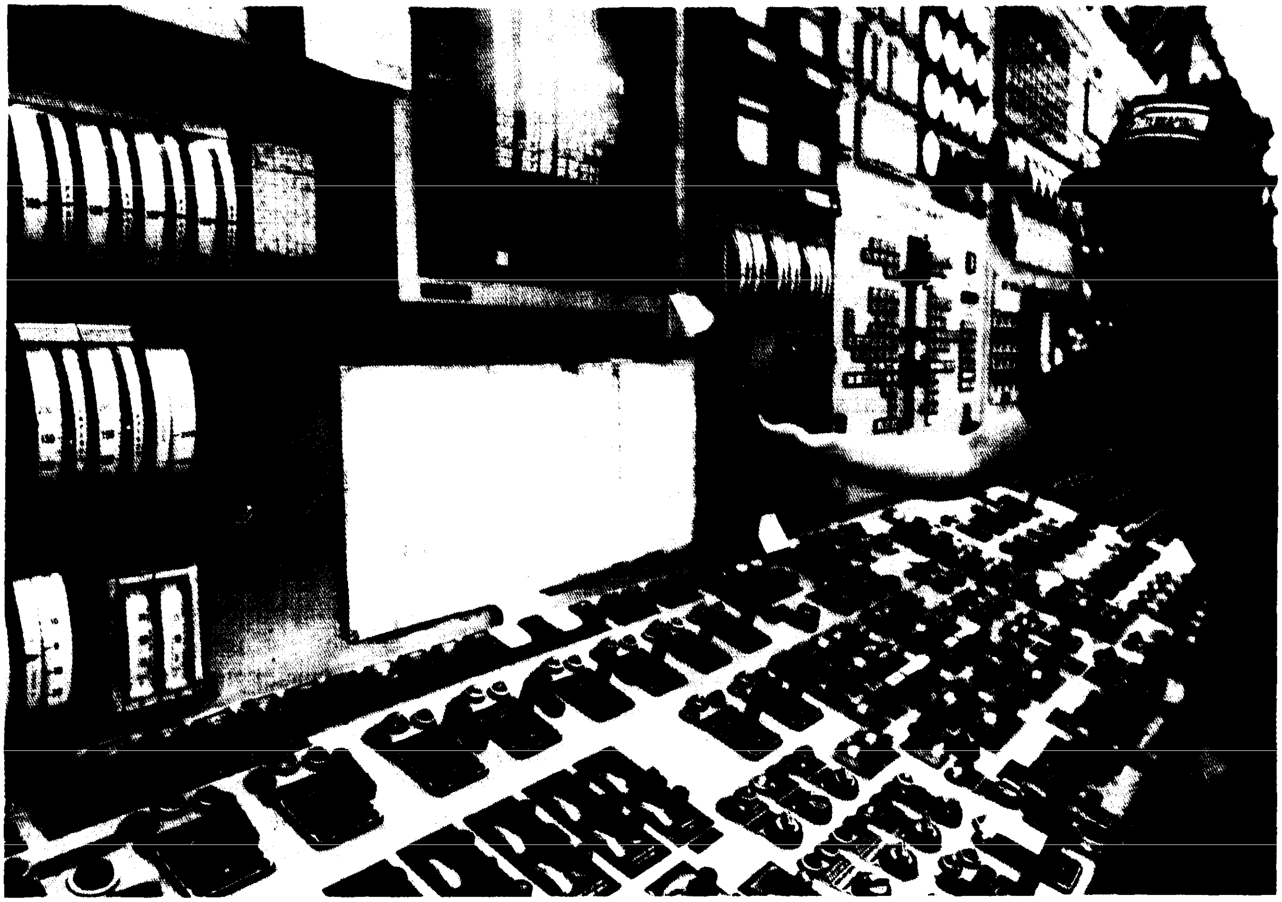

Photo credit: Dominion Resources, Inc.

Operator at the controls of a power plant

system planning. There is a possibility that some nonutility entities might build private transmission lines, but they would have no eminent domain authority and an uncertain regulatory status. FERC might order a utility to upgrade or expand its transmission facilities to implement a public interest wheeling order. States might also require utilities to expand transmission capacity to accommodate competitive sources.

Distribution additions would be the responsibility of the local utility (same as in scenario 1).

Conservation and load management plans would be developed by the local utility with oversight by State authorities. State regulators may require utilities to include consideration of savings from conservation and load management strategies as part of their least-cost planning efforts as in scenario 1.

SCENARIO 3

Competition for New Bulk Power Supplies

Scenario **3** would create an institutional and regulatory structure to support all source competition for new electricity supplies. Bulk power prices would be established through reliance on competitive market forces rather than cost-based regulation. The overall structure of regulated utilities would be maintained, but limited competition for new capacity needs would be introduced in the generation sector. The present electric power industry structure would be expanded by the entry of IPPs and unregulated utility subsidiaries, divisions, and/or spinoffs created to build and operate new generating facilities and to sell power in competitive markets. The numbers of competing buyers and sellers of electricity would greatly increase, as would the number of entities seeking access to the transmission grid.[46]

Under scenario 3, once a need for new power supplies has been certified by the appropriate regulatory authorities, an electric utility would solicit offers for new power supplies from other utilities, nonutility generators, QFs, and its own unregulated generating subsidiaries.[47] Conservation and load management strategies might also be included as competitive options in some State programs.[48] With appropriate safeguards to limit problems of self-dealing and conflict of interest, the unregulated utility subsidiaries could bid for new capacity within their own service territories.[49] Contracts for new electricity supplies would be awarded based on consideration of both price and nonprice factors (e.g., dispatchability, fuel and technology preferences, location, and relative environmental impacts).

Three mechanisms would exist for securing transmission services: 1) voluntary transmission arrangements with wheeling utilities for utilities and retail customers; 2) transmission access preconditions imposed on utility participants in bidding for competitively awarded bulk power contracts; and 3) public interest transmission orders issued by FERC which would be available only to utilities and wholesale power suppliers.

Scenario 3 would effectively create a two-tiered bulk power supply system: new power supplies under a minimally regulated, "workably competitive" market;[50] and existing generation under the current State-Federal scheme of regulated entry and pricing. Existing generating facilities, and transmission and distribution systems would remain regulated. Gradually, however, as old generation plants are replaced, the system would move toward an unregulated market in electric power generation and supply.

Background

Scenario 3 is loosely based on recent suggestions for allowing competition for new electricity sources. These proposals include those of FERC Chairman Martha Hesse[51] the Keystone Electricity Working Group,[52] and three notices of proposed rulemaking

*Although the numbers of competing suppliers and potential customers are likely to increase as a result of changes in this scenario, it is not at all clear whether the number of generators that win competitive supply contracts will increase significantly. It is conceivable that traditional utilities and large independent power producers would win many of the solicitations and that the need to integrate many new entrants into the bulk power network would be much less than if a large number of small entities won contracts to supply an equivalent quantity of bulk power. We have assumed for purposes of this analysis that competitive solicitations will yield a larger and more diverse mix of generation than under traditional regulation because that result would pose the greatest challenges for bulk power system operation and control.

47 As used here, competitive "bidding" includes not only a structured auction with sealed or firm bids, but also less structural competitive negotiations where participating vendors might be selected basal on an initial solicitation of proposals, such as, for example, the process used by Virginia Power Co. in seeking alternative power supplies described in ch. 5.

48 Among the mechanisms for including these demand side alternatives are: 1) to require utilities to consider demand side options as part of a least-cost planning before reaching a determination of new supply needs, 2) to allow demand side options to compete directly with supply options in the competitive solicitation, and 3) to hold a separate solicitation for a desired increment of demand side options.

49 If a utility chose not to participate directly in the bidding, it might compete indirectly by setting a benchmark based on its own estimate Of the costs of building the plant itself and recovering the costs under the base as the supplier of last resort.

50 As yet, FERC has not offered a clear and objective definition of what would constitute a "workably competitive market" under the Federal Power Act. Development of appropriate findings or guidelines for determining whether a workably competitive market existed would be left to FERC under scenario 3 and would be a prerequisite for implementation. A more detailed definition of the term is not needed for purposes of OTA'S technical analysis, however.

51 See, for example, "Talking Points for the Chairman," The Edison Electric Institute, Cincinnati, OH, June 10, 1987; and "Remarks by FERC Chairman Martha O. Hesse," Energy Daily's Annual Utility conference, Washington, DC, Nov. 6, 1987.

52 The Keystone Energy Forum is an informal discussion group with members from industry, government, academia, trade associations, and public interest groups. The working group meets periodically on subjects of current interest. The draft proposal ("Keystone Electricity Draft," 1/27/88) was prepared to merge concepts brought out in discussions of the electricity working group of the Keystone Energy Futures Project. Although the group discussions are largely off the record, reports about the draft appeared in the trade press. The electricity working group never reached a consensus on final conclusions or recommendations on transmission access issues. They are currently considering issues related to transmission pricing.

(NOPRs) issued by FERC in March 1988.[53] Scenario 3 is not identical with any of the proposals, however.

Chairman Hesse initially proposed the use of competitive bidding as an alternative to administrative determinations to set QF avoided cost capacity payments under PURPA. According to Chairman Hesse, modifications of existing PURPA rules to allow States to implement all-source competitive bidding on an *optional* basis and to use these results to establish avoided cost rates would also "fit PURPA into an overall electric strategy which will move us toward a more economically efficient industry."[54]

As a further initiative to expand competition, she suggested, some of the regulatory requirements on IPPs could be reduced for any IPP that is not a QF and that sells electric power in areas where it has no service franchises and otherwise lacks significant market power.[55] Eligible IPPs would receive the maximum pricing flexibility under the Federal Power Act's "just and reasonable" standard and would be relieved of certain reporting and accounting obligations because of their lack of market power. Chairman Hesse deferred discussion of transmission access and pricing issues for future FERC action.

The Keystone Group considered, but did not adopt, a draft proposal opening a utility's future bulk power needs to competition among all potential suppliers with the economic and technical capability to develop needed generating capacity. The proposal suggested that existing regulatory and statutory constraints in PURPA and PUHCA on utility ownership of new power supply projects eligible to participate in this new competitive market would be relaxed or eliminated. The existing PURPA administratively determined avoided cost pricing scheme would be replaced; competitive bidding would allow the prices to be paid by distribution utilities for new generation to be set in the marketplace. If independent generators were unable to meet a utility's need for new generating capacity, the utility would function as a "backstop" or a supplier of last resort for whatever remaining need there was for new power supplies. The utility's cost of providing such last-resort capacity would also set an upper limit on what might be paid to independent power suppliers.

Under the Keystone approach, all independent third-party suppliers would have guaranteed access to transmission service on reasonable terms (subject to availability). The draft did not provide much detail on how the access guarantees would work. Transmission access would not be available for retail customers.

In March 1988 FERC formally advanced Chairman Hesse's suggestions for greater reliance on "workably competitive markets" by issuing NOPRs that would:

1. impose additional procedural requirements for determination of avoided costs by State regulators and unregulated utilities,
2. specify acceptable forms of competitive bidding for new power supplies that could be used by States or unregulated utilities in setting avoided costs under PURPA, and
3. establish IPPs as a new category of power suppliers without market power that would be exempted from many of FERC's reporting and regulatory requirements otherwise imposed on electric utilities.

The NOPRs invited comment on two changes involving transmission. The avoided cost NOPR asked whether QFs should be allowed to construct and own transmission lines and interconnection facilities to transport their own power to purchasing

[53] U.S. Department of Energy, Federal Energy Regulatory Commission, Notice of Proposed Rulemaking on Regulations Governing Bidding Programs (18 CFR Parts 35 and 293), Docket No, RM88-5-000, Mar. 16, 1988, very brief summary published at 53 Fed. Reg. 9324, Mar. 22, 1988; Notice of Reposed Rulemaking on Regulations Governing Independent Power Producers (18 CFR Parts 38 and 382), Docket No. RM88-4-000, Mar. 16, 1988, very brief summary published at 53 Fed. Reg. 9327, Mar. 22, 1988; and Notice of Proposed Rulemaking on Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities (18 CFR Part 292), Docket No. RM88-6-000, Mar. 16, 1988, very brief summary published at 53 Fed. Reg. 9331, Mar, 22, 1988.

[54] Hesse, supra note 51, p. 3. One of the basic overall principles cited in support of her proposal was "The degree of regulation should reflect the degree of market power. Workably competitive markets should be allowed to operate with as little regulatory interference as possible." Id., at p. 4.

[55] The rationale for special treatment for this class of IPPs is presented in a FERC document, "Summary of Current Staff Proposal on PURPA-Related Issues," Sept. 11, 1987, pp. 16-19,

utilities without losing their QF exemption from Federal and State regulation as a public utility. FERC also requested comments on how to deal with situations where a QF wishes to provide wheeling services for others over its transmission lines.[56] The competitive bidding NOPR asked for comments on imposing "wheeling in" and "wheeling out" conditions on utilities participating in bidding programs.[57]

OTA's scenario 3, like the previous proposals, would open up competition for new bulk power supplies. Unlike the Hesse proposals and the FERC NOPRs, the use of competitive procurement methods would not be optional. Scenario 3 also does not require creation of special regulatory exemptions for IPPs. Scenario 3 would condition participation in competitive bidding on agreements to provide transmission access to other bidders—somewhat similar to the wheeling mechanisms described by FERC. Unlike the other proposals however, Scenario 3 would include mandatory transmission access for wholesale bulk power sales under a public interest standard similar to that in Scenario 2 and would clearly require congressional action.[58]

Implementation

Conceivably, scenario 3 could be partially accomplished through administrative actions by FERC. New rules could require States and utilities to use competitive procedures for establishing avoided cost prices for qualifying facilities under PURPA, although this may require a strained interpretation of PURPA and the Federal Power Act. (FERC proposed making competitive bidding optional for State PURPA implementation.) FERC might also formally accept market-based pricing for bulk power sales under its jurisdiction in regions where it found at least a presumption of a workably competitive market. Some observers have concluded that FERC has effectively deregulated many bulk power wales by accepting negotiated arrangements without much inquiry.

Under scenario 3, legislation would be required to expand FERC authority to order wheeling for wholesale transactions among utilities and to assure transmission access for new bulk power contracts. Changes would probably be needed in PUHCA to allow utility subsidiaries and other companies to compete as unregulated entities without coming under the more restrictive provisions of that act.

Many States would require legislation to authorize reliance on market-based mechanisms to set prices for new power sources. Legislation may be needed to vest adequate authority in public utility commissions to oversee and enforce competitive solicitations for new power supplies. A number of States including Connecticut, Massachusetts, Maine, New York, and Virginia, have already sanctioned competitive solicitations as a means of obtaining alternative electricity supplies at the lowest competitive costs. These competitive bidding processes do not, however, necessarily reflect an explicit State policy shift in favor of creating a fully competitive generating sector to replace traditional utility price regulation. Utilities can still build and receive cost of service treatment for new capacity in these States.

Regulators would become more extensively involved in approving determinations of need and in resolving disputes over contract awards under this scenario. The analytical capabilities of State commissions may need to be enhanced and expanded with additional funding and staff. It is presumed that under State competitive bidding programs, considerations of competitiveness and prudence would be addressed before the contracts were approved. Competitively established wholesale power prices would then be passed through to retail customers of the distribution utilities with only limited opportunity

[56] Docket No. RM88-6-000, supra note 53, pp. 85-95.

[57] Docket No, RM88-5-000, supra note 53, pp. 87-9], "Wheeling in" would require a utility wishing to bid on the capacity needs of another utility to agree to provide firm transmission services to the purchasing utility for successful bidders that are located within the bidding utilities service territory or that can reach one of its interconnection points. 'Wheeling out" would require a utility wishing to bid to supply its own capacity needs to provide firm transmission services to the border of its service area to unsuccessful bidders that wished to sell to another wholesale purchaser. Both forms of wheeling would be subject to "reliability and economic dispatch considerations".

[58] Some critics of the FERC competitive bidding and IPP NOPRs have argued that these actions also should be placed before Congress either because FERC lacks the explicit authority to require them and/or because they raise such significant national policy issues that they are more appropriate for legislative action. FERC Commissioner Charles A. Trabandt is one of the most vocal proponents of the latter view.

for change by State regulators.[59] In some instances regulators may reassert some control over bulk power costs by reexamining the prudence of contract rates and conditions in the context of retail ratesetting and other proceedings. State regulators might disallow full recovery of the purchased power costs if the utility's actions in selecting or negotiating the contract were found to be imprudent (e.g., if cheaper power were available elsewhere). The extent of State agency jurisdiction to review the retail impacts of wholesale contracts has been cast into doubt by a recent U.S. Supreme Court decision.

The ability of State regulators to examine the prudence of wholesale supply contracts in setting retail rates and approving supply plans was assumed in the development of this scenario. This assumption of effective State review of competitive contracts has been undercut by the U.S. Supreme Court's decision in *Mississippi Power & Light Co. v. Mississippi ex. rel. Moore, Attorney General of Mississippi* involving the dispute over the Grand Gulf nuclear plant.[60] The Court held that FERC authority over wholesale sales preempted any State commission inquiry into the prudence of the management decisions concerning the underlying power supply contract between Mississippi Power & Light, a subsidiary of Middle South Utilities, a public utility holding company, and another of the holding company's subsidiaries. Because of this preemption, the States were required to pass through the wholesale rates to their customers; all prudence issues would have to be raised by States and consumers in hearings before FERC. If extended beyond the facts of the Grand Gulf case, the Court's decision could require Federal legislation to implement scenario 3 in a form that assured effective State oversight of a utility's competitive supply arrangements.[61] Alternatively, new procedures and authority and expanded resources would be needed at FERC to provide an equivalent Federal role.

In scenario 3, State and Federal authorities would no longer *directly* control entrance into the generation sector (through certification of capacity need), nor would they set wholesale prices for power from new generating facilities. Instead, a system of competitive-bidding or negotiated contracts would establish competitive market-based rates. These competitively established bulk power prices would then be passed through to retail customers of the distribution utilities. This approach may require a preliminary finding that a workably competitive situation exists for new power transactions and continuing market oversight by State and or Federal regulators. Most probably, regulators would be more extensively involved in approving a utility's assessment of capacity needs and in resolving disputes over contract awards.

Prices for "old" power supplies would remain under existing cost-based regulation. New competitive power supply prices could reflect levels of service and other non-price factors. Prices for transmission services would continue to be regulated by FERC. Greater reliance on transmission services may increase pressure for transmission pricing based on actual measured cost of service with allowances for non-price factors[62] Alternatively, there will also be pressure from transmission owners and others to allow more flexible and value-based transmission pricing.

Under scenario 3 QFs and IPPs would be able to compete to sell wholesale power to utilities. They would not have access to the transmission system to sell power directly to retail purchasers, however,

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[59] Under existing law, FERC has jurisdiction over the prices for most wholesale power sates. PURPA exempted purchases of QF power from FERC price regulation, States have jurisdiction over utilities resource planning and construction and retail rates. States are generally required to pass through purchased power costs at FERC approved prices under the "filed rate doctrine." Without a change in PURPA or the Federal Power Act, FERC would have to approve contract prices for purchases from utilities and IPPs under a State competitive procurement program. See discussions in ch. 2.

[60] No.86-1970, June 24, 1988.

[61] Questions about the prudence of utility decisions in awarding bulk power contracts could arise later if a utility overestimated future demand and was left with a take or pay contract for unneeded electric power. The central issue would not be the contract price, but whether the utility's initial decision to purchase additional supplies was prudent and whether the full costs should be passed through to ratepayers. Another possible subsequent retail rate issue might arise over a utility prudence in signing a contract with price escalation clauses that resulted in actual contract prices that exceeded those on which the initial bid was awarded.

[62] Transmission prices are now commonly set in several ways, postage stamp rates, split the difference in savings rate, and others. See National Regulatory Research Institute, *Some Principles for Pricing Wheeled Power* (Columbus, OH: August 1987). Edison Electric Institute, Rate Regulation Department, *Terms and* Conditions *of Existing Transmission* Service *Agreements, 04-85-05, 1985.*

except to the extent that utilities controlling the grid voluntarily agreed to provide wheeling services.

Systems Operations and Planning

System reliability and coordination would be maintained as in scenarios 1 and 2 with primary responsibility resting with the local utility and/or control center. Operational requirements for nonutility generators (e.g., QFs and IPPs) would be based on contract terms with the local utility (or wheeling utilities). More formalized agreements would be needed to replace many of the current informal operating arrangements of integrated utilities and power pools as electric power supply functions are increasingly "unbundled."

Dispatch, maintenance, and unit loading schedules for the system would largely be handled by the local utility or control center. Specific dispatch and scheduling responsibilities of nonutility generators and transmission accessors would be negotiated by contracts among the generators, power purchasers, and wheeling utilities as in scenario 2.

Emergency curtailments of generation and transmission services would be dealt with as in scenario 2.

Planning and developing generating capacity additions would primarily be the responsibility of the local utility as in scenario 2. Because the States would require utilities to use a competitive selection process (including consideration of non-price factors) for new power supplies, State regulators would be more heavily involved in overseeing utility demand forecasts and determinations of capacity needs. Independent generators would be free to make their own plans for new construction based in part upon the utilities' needs and in part on their own expectations of profit.

Transmission additions would be planned and built by the public utility transmission company or division with review and approval by regulatory authorities. State rules may require utilities to plan for adequate capacity for instate wheeling of new power supplies and to consider regional transmission needs. As in scenario 2, FERC may order a utility to expand its transmission capacity to provide mandatory wheeling services.

Planning and building additions to the distribution system would remain the responsibility of the local utility.

Conservation and load management planning and implementation would be the responsibility of local utilities as in scenarios 1 and 2. State authorities may require consideration of potential contributions of conservation and load management strategies as part of utilities' least-cost planning and in approving retail rates. State regulators might also allow demand side options to compete directly in the bidding process for capacity additions.[63]

SCENARIO 4

All Source Competition for All Bulk Power Supplies With Generation Segregated From Transmission and Distribution Services

Scenario *4* would restructure the U.S. electric power industry and its regulatory institutions and create a competitive, unregulated generating sector and a structurally separate regulated transmission and distribution sector. Integrated utilities would be required to segregate generation activities, both institutionally and operationally, from transmission and distribution to limit the potential for self-dealing and cross-subsidization. Owners of existing and new generation sources would compete to sell power to regulated transmission and distribution companies. Some transmission companies could also act as power brokers or wholesalers providing bulk power supply planning, purchasing, and delivery services to distribution utilities. Purchasing utilities would be assured access to transmission services for their bulk power needs (capacity permitting).

The scenario would entail substantial rewriting of Federal and State laws governing utility regulation with greater emphasis on authority for overseeing the competitiveness of bulk power markets and regulating transmission services and power brokers. Modifications of the public utility ownership restrictions in the Federal Power Act, PURPA, and

[63] Regulators in Maine have allowed demand-side management options to compete to provide needed decrements of power capacity. In bidding conducted by Central Maine Power for 100 MW of capacity, 13 of 37 total bids were for demand-side management projects, however these projects represented only 35.6 MW out of more than 1,145 MW offered. On a price basis, the demand side projects averaged 75 percent of the utility's avoided costs, while the supply side offers averaged 97 percent of avoided costs. *Issues Review and Tracking,* Aug. 4, 1988, p. 1.

PUHCA would allow broader participation in generation markets. State regulatory schemes would also have to be overhauled to accommodate this scenario. The scenario could shift the primary locus of utility regulation from States to the Federal Government, but implementing legislation could maintain a balance by giving greater wholesale authority to State regulators. States would regulate the prices, operations, and quality of service of retail distribution companies. Transmission capacity, services, and rates would be subject to mixed Federal and State regulation.

Background

Scenario **4** is derived from proposals that would structurally disaggregate the electric power industry to allow the generating sector to become both more dependent on the discipline of competitive market forces and free from many of the pricing and entry restraints of the existing regulatory system.* Under scenario 4, the organizational structure of the electric power industry would begin to resemble that of the natural gas industry where production, interstate transmission, and local distribution are generally under separate ownership (although there are numerous cases of "upstream" and "downstream" integration).

Scenario 4 would open all power supply contracts to competition, unlike Scenario 3, which is limited to new bulk power sources. Because Scenario 4 would be applied industry wide, it would probably involve a transition period of many years to allow a gradual phase-out of rate-of-return regulation, orderly restructuring and divestiture of assets, and renegotiation of existing arrangements.[65]

Radical industry restructuring has some precedent in the recent experience in breaking up AT&T and deregulating much of the telephone industry. On a much smaller scale, several utilities have sought to revamp their internal structures to set up holding companies, split power system functions into separate subsidiaries, and create unregulated competitive generating subsidiaries.[66] But, there is no precedent for radical restructuring and deregulation of an industry similar to electric power that is characterized by long-term investment, heavy fixed costs, an obligation to serve, and which is in a period of excess capacity. The restructuring under scenario 4 raises major questions of public policy and equitable treatment of stockholders and ratepayers in allocating any increased value for existing assets.

As one benefit of removing most price and entry restrictions from the generating sector and replacing them with open competition, "there would be strong, direct incentives for efficiency in construction, and new units would be built by companies that could offer capacity at the lowest life cycle costs. '*7 The principal risk would be threats to the reliability and stability of the overall integrated systems arising from lack of or reduced coordination among competing entities. Proponents believe there would also be substantial efficiency gains in the use of all available generating units to meet regional electricity demands. In their view, these efficiency gains would not likely be achieved under the existing structure because of the disincentives to increased bulk power transfers among utility control areas, difficulties in forming power pools, and transmission capacity constraints.

64See for example, Richard J. Pierce, Jr., "A Proposal to Deregulate the Market for Bulk Power," 72 *Virginia Law Rev.* 1183 (1986); Aspen Institute, "Electric Utilities: Structure and Regulation," *Energy Policy Forum, 1986;* and William W. Berry, "The Case for Competition in the Electric Utility Industry," 110 *Public Utilities Fortnightly 13 (1982).*

65At least one proponent of a similar approach argues that mandatory divestiture and reorganization of the industry by courts and legislatures would not be needed because competitive pressures would force firms to restructure voluntarily through spinoffs, mergers, and acquisitions eventually producing the desired efficient industry structure. This process could, however, take as long as 20 or 30 years. Pierce, *supra* note 64, p. 1214.

66For example, Public Service Company of New Mexico proposed a significant corporate restructuring that would form a holding company, split most generation and transmission assets into a separate competitive subsidiary, and sell power under long-term contracts to a distribution subsidiary and its wholesale customers. The company dropped its proposal in mid- 1988 because of the criticisms raised by some State agencies and the City of Albuquerque, its largest wholesale customer.

67William W. Berry, "The Implications of Deregulation for Electric Utilities," Comment for the Reason Foundation Conference on Deregulating Public Utilities, 1987.

Implementation

Scenario 4 would require substantial changes in both Federal and State laws governing the electric power industry. The Federal Power Act's jurisdictional and procedural requirements would be substantially revised to reflect the new institutional structures with greater emphasis on creating effective mechanisms for overseeing the competitiveness of bulk power markets and regulating transmission services and power brokers. PURPA and PUHCA would also require amendment to remove statutory barriers to full participation in the competitive generating sector. This would allow utilities' generating companies to compete outside of their regional territories without coming under the full financial and operational restrictions imposed on regulated utility holding companies. Continuation of PURPA's purchase and sale obligations for alternative energy sources might also require reexamination to determine if they still were effective and/or appropriate under a changed industry structure.

The transmission and distribution segments of the industry would continue to be regulated heavily while generation would be subject only to competitive market forces, regulatory oversight, and antitrust laws. Price and entry regulation for the generation sector would be replaced with competitive markets. Generators would still be subject to environmental, siting, financial, and antitrust requirements imposed by other State and Federal laws under scenario 4 and all others. The States would regulate the prices, operations, and quality of service of retail distribution companies. State regulators would review the power purchase contracts of distribution utilities, but the effectiveness of State programs would be hindered without some mechanism to review the adequacy of competitive market transactions. Transmission capacity, services, and rates would be subject to mixed Federal and State regulation. Under this scenario there is the potential for increased Federal regulation and oversight of bulk power supplies and what were formerly intrasystem transmission arrangements. Implementing legislation could, however, provide for a more balanced Federal-State division of regulatory authority to give States greater control over intrastate activities.

Vertical integration of the electric power industry would be reduced by the separation of utility generating segments from transmission and distribution segments.[68] This could be accomplished by creating new subsidiaries or divisions, or by spinning off a new company and then "selling" the required physical plant and other assets to the new entity.[69] Segregated utility generators, QFs, and IPPs could compete to provide power supplies to transmission-distribution and local distribution companies. Age, performance, and fuels of existing units will affect the competitive strengths of the new generating companies. These competitive differences could eventually lead to a consolidation of the industry.[70]

Under scenario 4 local distribution companies would be primarily responsible for securing adequate power supplies from competing suppliers through contract solicitations and negotiations. Regulated transmission companies would own and operate the transmission facilities and be responsible for planning and building networks with adequate capacity to serve buyers and sellers in a competitive market. Transmission companies would function as regional controllers and dispatchers of generation and provide wheeling services for utilities under regulated rate schedules. They could also act as power brokers or as wholesalers linking independent generators and local distribution utilities.

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[68] Under scenarios 4 and 5, the physical division of integrated utility facilities among the newly disaggregate entities would probably not reflect a clearcut allocation of generation, transmission, and distribution facilities. It is likely that at least a portion of the transmission facilities associated with individual generating stations might be retained by the generating subsidiary. Generators might have to construct their own transmission facilities to move power to the point of delivery to the transmission or distribution companies. Similarly, transmission and distribution utilities would be able to retain or acquire small scattered generating units that provide essential system support or backup services.

[69] This financial restructuring and redistribution of assets will be a complex and controversial aspect of this scenario for utilities, shareholders, regulators, and ratepayers alike. If not handled with caution, the transactions could result in a sizable transfer of wealth and assets from the regulated sectors to the unregulated generators. There could be a tremendous incentive for owners of low cost older plains to move them as quickly as possible into the unregulated market so as to capture a greater profit than would be allowed under regulated historic embedded cost pricing. This could leave a utility's high cost plants in the regulated sector.

[70] See, for example, Joskow and Schmalensee, supra note 1, pp. 212-213.

Generators and distribution companies could seek transmission orders from FERC based on a public interest standard similar to that in scenarios 2 and 3. Unlike scenario 2 there would be no mandatory wheeling for retail customers. It is expected, however, that many generators and transmission companies would sell directly to large retail customers under arrangements for bypass or standby payments to local distribution companies.

Distribution companies under scenario 4 would retain an obligation to serve, that is, to plan for and secure adequate electricity supplies for the needs of their franchise customers. But with little or no generating resources of their own, they would be highly dependent on the willingness of independent suppliers to construct needed capacity and the availability of adequate transmission capacity to move the power. Competing generating companies would be under no legal obligation to build new capacity, but would commit to do so if and when the market price was sufficient to assure them an attractive return. Thus, in the generating sector market price signals would displace the utility's traditional service obligation as the principal mechanism for assuring the availability of adequate and reliable power supplies. The experiences of the numerous independent distribution companies that currently obtain their electricity supplies and transmission services from larger integrated utilities could provide helpful precedents.

Transmission under scenario 4 would begin to assume some of the characteristics of a common carrier, but the transmission entity would retain some discretion over who was eligible to obtain service and would not be required to provide wheeling to retail customers. The transmission company could not impose unreasonable or discriminatory conditions on transmission access. It could, for example, specify minimum operating standards to preserve system reliability and require advance notice and financial commitments to reserve firm transmission capacity.

Independent generating companies and local distribution entities would be linked by these newly created transmission entities, which would serve as regional controllers and dispatchers of generating capacity. In addition to this primary role, transmission utilities could also serve as regional power brokers which would make the market for, and be party to, contracts negotiated between independent generating companies and distribution entities. Transmission companies might also assist in the creation of secondary futures markets as a means of hedging against the added uncertainty associated with a vertically segregated industry.

Under scenario 4, transmission access would be achieved primarily through voluntary negotiations; however, the separate transmission entities would have an obligation to provide adequate transmission capacity to support the industry's new competitive structure. FERC would also have the authority to order wheeling for customer utilities on a public interest standard if satisfactory voluntary arrangements could not be reached through negotiation. With FERC'S endorsement, States might require nondiscriminatory access to transmission services as a precondition for allowing existing regulated generation, transmission, and distribution companies to participate in the new competitive system. Transmission access for retail customers would be kept on a voluntary basis.

Systems Operations and Planning

System reliability and coordination would be the responsibility of the regulated transmission company or transmission-distribution company. The transmission company would take over many of the day-to-day functions of system coordination that are now the responsibility of local utilities and control centers. Operational responsibilities of power suppliers and local distribution companies would be specified in contracts with State and Federal oversight.

Dispatch, unit loading, and maintenance schedules would be administered by the transmission utility under various contracts between power suppliers and: 1) regulated transmission companies, 2) regulated distribution companies, and/or 3) retail customers. Dispatchable generators would be controlled by the transmission company and compensated for their services according to contract terms.

Emergency curtailments for retail customers served by local distribution companies would be allocated according to State-regulated curtailment policies. For other customers, curtailments would be specified in contracts with the transmission and generation suppliers. Curtailment of transmission services will be based on contractual terms, State and Federal regulation, and system reliability considerations.

Generating Capacity Additions: Future electric supply requirements would be determined by the local distribution company through its planning processes with State oversight. Competition for supply contracts would be open to all generating sources, as in scenario 3. Independent generators would plan and build new plants based on utilities' indications of need and their own strategic plans and profit expectations. Transmission utilities could also contract for generating capacity to aid in preserving system reliability and to allow them to serve as power brokers subject to State and Federal regulation.

Transmission Additions: The regulated transmission or transmission-distribution companies would have the obligation to provide transmission capacity necessary to support wheeling needs for instate utilities. (This assumes of course that wheeling is economical and that wheeling customers are willing to pay for the additional capacity needs.) States could require transmission capacity planning to include consideration and coordination of regional transmission system needs.

Distribution additions would be the responsibility of the locally regulated distribution utility, with oversight by State authorities-same as in scenario 3.

Conservation and load management programs would be provided by local distribution companies, possibly in conjunction with transmission companies. State regulators could require consideration of potential contributions from load management and conservation strategies as part of the distribution utility's least-cost planning processes in this and other scenarios.

SCENARIO 5

Common Carrier Transmission Services in a Disaggregate, Market-Oriented, Electric Power Industry

Scenario *5* would break up the vertically integrated electric power industry by divesting generation, transmission, and retail distribution segments into separate entities. All customers (both wholesale and retail) would have the option of purchasing power from any willing supplier with the assurance that such power could be delivered under reasonable terms and conditions. Distribution and transmission services would remain tightly regulated, but entry and bulk power pricing in the electric generation segment would primarily be left to market forces.

The competitive generation segment would include formerly regulated utility generation operations, QFs, and IPPs (although such distinctions among power producers would no longer be relevant). Unlike scenario 4, ownership of generating companies would be completely severed from ownership of transmission and distribution companies. The regulated transmission companies would explicitly be required to provide transmission services as a common carrier (i.e., nondiscriminatory service based on approved wheeling tariffs to all parties requesting service) and to provide adequate transmission capacity. Wheeling to retail customers would be available, although as a practical matter it would likely be limited to very large industrial consumers. Federal and State policies might encourage greater aggregation in transmission services to create coordinated large regional transmission systems-either through mergers and acquisitions or through operational agreements among neighboring systems.

Background

Scenario 5 includes many of the key elements of the preceding scenarios including vertical disintegration of industry structure, market-based pricing of generation, and transmission access. Under scenario 5, any generator could sell to any buyer, any buyer could purchase from any seller, and the transmission company would have to wheel the power. Proponents of this radical restructuring of the industry cite a number of technological and public policy reasons for adopting this approach.[71] Chief among them are: the decline of the natural monopoly characteristics of the generating sector; the excess generating capacity in many regions; and the presumably higher social and economic costs to society

71 See for example, Philip R. O'Connor, Robert G. Bussa, and Wayne P. Olson, "Competition, Financial Innovation, and Diversity in the Electric power Industry," *Public Utilities Fortnightly*, Feb. 20, 1986, pp. 17-21; Philip R. O'Connor, "The Transition to Competition in the Electric Power Industry," Illinois Commerce Commission (presented at the American Power Conference, Chicago, IL, Apr. 22, 1985); and Matthew Cohen, Essay: "Efficiency and Competition in the Electric Power Industry," 88 Yule *Law Journal* 1511-1549, June 1979.

of "imperfect regulation" compared with "imperfect competition."

The key to having a vigorously competitive and economically efficient electric power industry lies in the evolution of new institutions and arrangements.[72] This is unlikely to be accomplished merely by allowing distribution utilities and others to shop around for the best bulk power deal without first establishing the necessary competitive market environment. Among the changes in industry regulation, operations and structure that would lead to achievement of this scenario are:

- encouraging the regionalization of utility regulation and operations by expanding the use of centralized dispatch of generating capacity within States or regions;
- creating power brokerage and auction markets;
- realigning Federal and State regulatory authority to allow States clear authority in intrastate bulk power and wheeling markets;
- creating federally approved interstate regulatory compacts for governance of central dispatch, auction, and brokerage systems; and
- assuring open and fair access to transmission systems either through mandatory wheeling or through creation of new regional transmission entities.

Implementation

Scenario 5 would require rewriting of existing State and Federal laws and regulations governing electric power generation, transmission, and distribution. Although "deregulated," the competitive generating sector would need continuing oversight to assure the existence of workably competitive markets. In addition, new contractual arrangements and industry practices would have to evolve to assure effective operations under a new disintegrated, market-based industry structure, and to preserve reliability and stability of interconnected electric power systems.

Regulators would approve the transmission company's wheeling tariffs for both utility and nonutility generators. FERC (or perhaps a regional authority) would have the power to issue wheeling orders to facilitate bulk power transfers if satisfactory arrangements could not be made with the transmission company. Wheeling rates would be designed to include adequate signals to assure construction of new transmission facilities. The transmission utility also would have an obligation to plan for and build adequate and reliable transmission capacity to serve regional needs and to accommodate interregional transfers. Wheeling customers could contract for different levels of service (e.g., firm, interruptible).

Bulk power prices would be set through competitive markets and passed through to ratepayers. Power purchases by distribution companies and retail rates would be regulated by State authorities. Retail rates and the need for and prudence of bulk power purchases by distribution companies would be regulated as now by State authorities. Rates charged by transmission companies acting as power brokers and reselling to distribution companies would also be subject to regulatory oversight to assure that there was no cross-subsidization of operations or anticompetitive practices.

This scenario would involve the mobilization and transfer of billions of dollars in utility assets to newly established entities. Because of the complexity of the transactions, it is likely that many years would be required to complete an orderly transition.[73] The essential step in achieving this scenario would be the establishment of a separate and functional common carrier transmission entity. This could be accomplished simply by spinning off the transmission assets and operations of a vertically integrated utility to a new private entity. It could also be accomplished through legislation to create federally chartered and publicly held regional transmission (and dispatch) corporations to acquire all transmission lines and facilities within a designated region.

[72] See Joskow and Schmalensee, supra note 1, at pp. 104-1 (M, for their "scenario 4" which adopts a similar approach. See also Edison Electric Institute, "Deregulation Issues and Concepts," 1981. The industry structure of scenario 5 resembles that proposed for the utility industry in the United Kingdom after privatization. See ch. 2 box 2-B. The U.S. industry and regulation structure are far more complex than the present government-run British system, so that direct comparisons with the U.K. proposal are of limited value.

[73] A detailed transition plan for achieving this sort of industry has been outlined conceptually by Phillip O'Connor, former Chairman Of the Illinois Commerce Commission. O'Connor's lo-step process would gradually transform the industry into a vertically disintegrated structure with market-based pricing of generation evolving in conjunction with regulated transmission and distribution entities. O'Connor, supra note71.

Systems Operations and Planning

System reliability and coordination would be maintained by the separate, regulated transmission company. The operational responsibilities of power suppliers and local distribution companies would be specified in contracts with the transmission company.

Dispatch, unit loading, and maintenance schedules would be determined by the transmission company in negotiation with generators and governed by contracts as in scenario 4.

Emergency curtailments of electric power and transmission services would be allocated according to contractual arrangements and/or State regulations.

Generating capacity additions would be planned and built by independent generating companies based on their strategic plans, profit expectations, and transmission and distribution utilities' indications of need, Distribution and transmission companies (jointly or separately) would project future demand and determine the desired mix of generating resources to meet those needs before soliciting contract bids from power suppliers.

Transmission additions would be planned and built by the transmission utility which would have an obligation to provide adequate and reliable transmission capacity necessary to supply the wheeling needs of anticipated customers. Regulatory authorities may require consideration and coordination of regional transmission capacity needs in planning.

Distribution additions would be planned and built by the local distribution utility as in scenario 4.

Conservation and load management strategies would be developed by local distribution companies in cooperation with transmission companies and regulatory authorities.

ANALYSIS OF THE SCENARIOS

These scenarios were used by OTA and its contractors in its assessment of the technical and institutional feasibility of expanding competition and opening up transmission access. Chapter 5 looks at the technical aspects of changing the electric power infrastructure to accommodate the scenarios and some cost and performance implications. Chapter 6 examines the regional characteristics of the electric power industry and how they might affect the successful implementation of the scenarios. Finally, chapter 8 examines policy options for resolving some of the technical and institutional problems identified in OTA'S analysis.

There are many other possible scenarios that could be used. Selection of these five reflect the best judgment of OTA staff and others about the range of possible future industry structures that may be most useful in testing the technical feasibility of adapting existing bulk power systems to change.

The five OTA scenarios were developed and analyzed for the limited purposes of this assessment. These scenarios are not intended as legislative policy options. They may not be, in some respects, the optimal or most probable policy choices in considering the creation of a new regulatory and institutional framework for the U.S. electric utility industry as a whole.

Many difficult and controversial aspects of making the electric power industry more competitive are not included in OTA's review of the technological feasibility of expanded competition and increased transmission access. We did not conduct an extensive analysis of all the legislative and regulatory changes that would be needed to implement each of the scenarios. For example, we did not analyze in detail the considerations to be addressed in deciding on whether to grant a petition for mandatory transmission access under a revised public interest standard. Nor did we address the very thorny problems of how to divide the assets and liabilities of existing utilities among ratepayers, shareholders, and regulated and unregulated subsidiaries. Issues of national energy policy were also beyond the scope of this study. Therefore, we did not examine in any detail the possible implications of changing PURPA's preference for certain classes of cogenerators and small power producers. OTA's study may, of course, help to identify many of these issues for Congress. The scenarios may also prove a useful tool for analyzing these policy options and responses.