Resource Insight, Inc.

Restructuring the Electric Utilities of Maryland

Protecting and Advancing Consumer Interests

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Executive Summary

In its Order No. 72938 for Case No. 8738, the Public Service Commission instituted a proceeding to evaluate issues relating to restructuring of Maryland's electric-utility industry. In addition, the Commission directed the PSC Staff to consult with all affected stakeholders regarding these issues.

The Office of People's Counsel has prepared this report to serve as the basis for discussions with the PSC Staff about the restructuring process. It presents the OPC's findings and recommendations regarding restructuring of electricity markets and vertically integrated utilities; preservation and advancement of public benefits in competitive markets; treatment of stranded costs in the transition to competition; rate unbundling; and tax-related issues. Together, these recommendations constitute the OPC's proposal for maximizing the benefits to Maryland's consumers from restructuring, while preserving the public protections and benefits that have been achieved under the current industry structure.

Experience with existing wholesale electricity markets indicates that there are likely to be significant benefits from increased competition in these markets. However, there is little experience to guide predictions of whether competition in retail markets will provide tangible benefits beyond those achievable with wholesale restructuring, or whether such benefits will outweigh the costs of restructuring the regulatory process to preserve public benefits in a competitive retail market.

Accordingly, the OPC recommends restructuring the wholesale market to create a fully competitive and efficient market for wholesale power supply. In addition, we recommend that consumers be afforded the opportunity to petition for direct access to competitive supply on a case-by-case basis. This approach will provide immediate benefits to ratepayers from wholesale restructuring, while providing the Commission the opportunity to learn from experience with the retail-access option and from experience with retail competition in other states.

Wholesale markets will not be truly competitive if utilities can exercise vertical or horizontal market power in the regional market. The OPC therefore recommends complete divestiture of the unregulated generation from the regulated distribution business. Moreover, we recommend that control of the bulk transmission system be transferred to an independent system operator that is financially and operationally independent of generators, transmission owners, and other market participants.

Maryland's ratepayers have benefited significantly from an industry structure and regulatory process that provides reliable, efficient, and relatively clean energy services while vigorously protecting consumers' rights. Restructuring of the wholesale market is unlikely to place these benefits at risk. Indeed, the restructuring process provides an opportunity for the Commission to establish the obligation for utilities to provide non-discriminatory service at reasonable rates to all consumers.

In contrast, there is a significant risk that retail competition will seriously degrade the reliability, efficiency, environmental, and consumer-protection benefits that have been achieved under the current industry structure. If the Commission or the legislature adopts retail access as the model for Maryland, the industry and the regulatory process must be restructured to preserve and perhaps enhance public benefits in a competitive retail market.

Restructuring may result in stranded investment. If so, the Commission has broad discretion in setting the appropriate level of recovery. Recovery of stranded costs should be conditioned on utility cooperation in promoting the public interest in the restructuring process.

Principles of Restructuring

The restructuring process should be guided by two overarching principles. First, a restructured industry must provide Maryland consumers access to adequate, safe, reliable, and efficient energy services at fair and reasonable prices and at the lowest long-term cost to society. Second, the electric industry should be restructured only to the extent that it improves economic efficiency, provides tangible benefits to all consumers, and serves the broader public interest.

These guiding principles give rise to the following detailed principles:

1. All customers must have the opportunity to share in the benefits of restructuring. The restructuring process must not result in cost-shifting among customer classes.
2. A restructured industry must meet or exceed existing standards of service, safety, and reliability.
3. A restructured industry must provide non-discriminatory universal service to all customers. All customers must have the opportunity to connect and take service at reasonable rates and under reasonable terms.
4. Existing consumer protection standards must be maintained in a restructured industry.
5. Provisions must be made to enable low-income customers to effectively participate in the benefits of restructuring.
6. Restructuring must preserve and advance the end-use efficiency and environmental benefits of the current system. Funding for DSM programs must be continued. Restructuring must maintain or improve the quality of the environment.
7. The right to recovery of stranded costs by utilities must not be presumed. Decisions about stranded-cost recovery should promote the public interest.
8. A restructured industry must provide non-discriminatory access to the bulk transmission system for all wholesale-market participants.
9. A restructured industry must not allow anti-competitive abuses of vertical or horizontal market power.

Market Structure

The anticipated restructuring of the electric utility industry is generally expected to convert the existing integrated utility into a set of business operations, some regulated (distribution and transmission), and others competitive (generation and perhaps energy marketing and services). This restructuring can provide significant benefits, but can also create new problems.

A wide array of restructuring proposals have been advanced by parties in various jurisdictions. Despite the diversity of details, the approaches fall in one of the following four categories:

- *Incremental wholesale competition:* This is the model of competition envisioned in the Energy Policy Act of 1992. All generators would have equal access to the transmission network. Each distribution company, when faced with the need for new generation, would have the choice of building it, buying from any other utility, or buying from a non-utility generator located in its own territory or a remote location. Integrated utilities would remain integrated, and ratepayers would generally continue paying for, and receiving power from, the plants that have served them in the past. Existing retail load would remain captive to the generation of the integrated utility, although load served through wholesale contracts would become subject to competition when existing contracts end or notice provisions expire, or earlier if the purchaser elects to pay stranded-cost charges under the formula FERC has selected.
- *Total wholesale competition:* Each distribution company would purchase its entire power requirement from one or more generation companies, affiliated or otherwise, at spot prices or under short- or long-term contracts (or a mix), as determined by an IRP process, competitive

solicitations, and Commission oversight. Purchases would generally be at market-based bid prices, rather than cost-of-service. No load would be captive to generation. Costs may be stranded.

- *Pool-mediated competition:* Each distribution company would purchase its entire power requirement from the regional power pool, at spot-market clearing prices. Customers who wish to moderate price risks could enter into futures contracts—usually assumed to be contracts for differences (CFDs)—with generators or brokers.
- *Direct-access retail competition:* Each customer would select a power supplier, who could be a generation company or a marketer or reseller. Each power supplier would be responsible for meeting its entire subscribed load for energy and associated capacity needs.[1] Direct-access retail competition offers consumers the opportunity to choose the supply, energy services, and pricing options that best suit their particular needs.

Incremental wholesale competition is now the minimum level of competitive restructuring nationwide. The debate in Maryland concerns how far the state should go beyond incremental wholesale, and where.

Recommended Market Structure

The OPC recommends that the Commission adopt a system of total wholesale competition, modified to allow consumers the option to purchase power at the spot-market price or to petition for direct access to competitive suppliers. As discussed below, total wholesale competition is likely to significantly reduce costs relative to the incremental wholesale competition.[2] With the spot-pricing and direct-access options, total wholesale competition also offers the pricing and supply flexibility of pool-mediated or direct-access retail competition, while avoiding many of the problems and complications associated with these approaches. Most importantly, the recommended structure retains the reliability, consumer-protection,

[1]Capacity needs may include installed capacity, available capacity, operating reserves, frequency regulation, load following, reactive power, black-start capability, and transmission voltage support, with several of these requirements differentiated by location.

[2]Indeed, in its Order No. 72136 (Case No. 8678), the Commission found that "many of the benefits attributed to retail wheeling—particularly decreased costs and increased efficiency at the generation level—can be achieved through wholesale competition" (45).

efficiency, and environmental benefits that have been achieved under incremental wholesale competition.

Under the spot-pricing option, rather than purchasing the utility-supplied power-supply mix, each customer would be given the option to purchase power through the utility at the short-term pool price, either on an hourly basis (for customers with hourly meters) or at the load shape of the customer's class.[3] This option would allow customers to hedge against the pool price with any type of CFD offered by the market.

This option could be exercised when restructuring is first implemented—in which case customers would pay the same stranded-cost charge regardless of which option they chose—or at any later date deemed appropriate by the Commission. If market prices of power fall, customers who switch from utility power supply to pool prices after restructuring is first implemented would be required to pay a stranded-cost charge to cover new utility purchase commitments that are above market prices. If market prices of power rise, customers who switch from pool prices to utility power supply would similarly face some catch-up charge. Customers may also be limited as to the frequency of conversions from utility to pool supply pricing. These conditions should be made clear to customers who switch to pool pricing.

If the pricing options of the utility power-supply mix and the pool price are not sufficient, or if direct access is desirable for some other reason, the Commission should consider customer petitions for direct access. Such a petition should

- represent a significant amount of load;
- demonstrate that the proposed direct-access service would meet some significant need not satisfied by the utility offerings, and that could not be met by CFDs or other side contracts;
- demonstrate that the move to direct access would not shift costs to other customers; and
- certify that the supplier has procured adequate supply to meet the subscribed load, has established metering and billing arrangements with the local distribution utility, and has agreed to abide by all Commission

[3] This would be the same load shape used in allocating the utility's purchased-power supply mix to customers.

directives regarding information disclosure and consumer protections that currently apply to regulated utilities.

The direct-access option is most likely to be attractive to customers with special concerns about pricing and ability to interrupt service (such as Eastalco and Bethlehem Steel), those interested in multi-fuel and total-energy service, and those concerned with the location, fuel, or environmental impact of their energy supply. This option would allow, for example, a marketer offering consolidated supply, energy services, and billing for a national retail chain to petition to provide such services to outlets in Maryland. Similarly, the direct-access option would provide the opportunity for a local environmental group to offer its members' a combination of environmentally benign supply and energy-efficiency services.

The Commission need not adopt a particular structure for metering and billing in order to implement the direct-access option. Instead, petitioners should be required to provide for such arrangements with the local distribution utility, utilizing the approach that best suits their interests.[4] In addition, the Commission can continue to regulate and oversee customer protections under the direct-access option without substantially revising existing enforcement mechanisms. Instead, the Commission should premise its approval of a petition on the supplier's agreement to abide by all Commission directives regarding information disclosure and consumer protections that currently apply to regulated utilities. Failure to abide by such provisions would be grounds for revoking a supplier's right to provide retail services.

The experience gained under these two options should provide the Commission critical information for ongoing assessments of the performance and benefits of the recommended market structure. If either option is very popular, it would signal that the Commission should consider moving from wholesale competition to pool-based or direct-access competition. The Commission would then have the benefit of experience with these two options to guide the transition. If most customers are content with the utility's competitive supply acquisitions, wholesale competition can remain the standard, with other needs dealt with as exceptions.

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[4]If the Commission eventually decides to implement direct-access competition, the experience gained with regard to petitioners' approaches to metering and billing, including experience resolving disputes between petitioners and distribution utilities over these approaches, should prove invaluable in establishing protocols for metering and billing by competitive suppliers.

Benefits of the Recommended Market Structure

The recommended market structure offers a number of advantages compared to both the existing structure and the pool-mediated or direct-access alternatives. These include:

- significantly reduced costs compared to incremental wholesale competition, with perhaps equivalent costs compared to the direct-access alternative;
- the opportunity, but not the requirement as under pool-mediated competition, for customers to purchase power at spot-market prices and to hedge such prices with CFDs or other instruments;
- preservation of existing public protections and benefits, and continuing regulatory authority over such protections and benefits;
- the benefits of waiting to determine how other models of competition work in other states;
- the benefits of resolving structural changes in a gradual and incremental fashion, observing the effects of each change before implementing another round of changes.

Total wholesale competition can reduce electricity costs compared to incremental wholesale competition in several ways.

- Restructuring is likely to decrease the costs of new resources and increase the value of existing generation. Since total wholesale competition leaves to the owners of generation all the risks and rewards of building and operating power plants, it should improve incentives to build only cost-effective and required resources, minimize the costs of generation, and cancel or retire uneconomic plant.[5] The high bidder for divested generation is likely to be a party that believes it can reduce costs, increase output, and otherwise increase the value of the plant. That high bid would thus exceed the value of the plant to the existing owner.
- Restructuring of above-market resources eliminates a portion of the plant's cost from the utility's or NUG's books and converts the

[5]These improved incentives, and the fact that distribution companies would be signing contracts at fixed prices (or prices tied to specific indices), are also likely to reduce the regulatory burden on the Commission in overseeing construction decisions and determining prudence of construction and operation.

remainder to a regulatory asset that should have much lower risks and financing costs.

- Mutually beneficial contract renegotiation (giving sellers a higher degree of assurance of payment, earlier payment, or other features), in combination with refinancing, can further reduce total costs to ratepayers.
- The transition from cost-of-service to market-based pricing, with associated recovery of the above-market portion of generating assets, should also reduce costs, at least in the short-term. Under traditional ratemaking, charges for utility-owned generation are front-loaded and fall over time. Since market power prices start low and rise over time, repricing generating resources at market prices will result in immediate rate reductions.[6] These reductions will be offset by recovery of the generating assets' above-market stranded costs. However, there should still be a net reduction, since stranded-cost recovery effectively spreads the difference between existing resource costs and market prices evenly over the life of the resource.

These savings are driven by restructuring of the wholesale market and repricing of generation at market prices. None of these savings are dependent on retail access. In fact, restructuring of the wholesale market is likely to account for the vast majority of the generation-cost savings typically assumed to be achievable with retail access.

It is typically assumed that retail competition can reduce costs by providing customers direct access to wholesale power. Wholesale power is currently less expensive than power from the local utility's resource portfolio. However, market prices for power in PJM (and elsewhere) are currently depressed due to a combination of excess capacity and the absence of a truly competitive market for such excess power. In essence, wholesale marketers are engaged in a bidding war to attract buyers of excess capacity in a market where opportunities for wholesale transactions are severely constrained by utilities' unwillingness to provide open access to the transmission system.

These conditions are unlikely to persist in PJM for more than a few years. Market prices should rise dramatically in the next three years, since the

[6]Repricing of long-term utility or NUG purchases should also yield short-term reductions, whether contract payments are based on cost of service (typical of utility unit purchase) or levelized (as with many NUG contracts).

power market is expected to tighten by the year 2000. Moreover, opportunities for wholesale transactions should widen with restructuring of PJM and the adoption of open-access tariffs in 1998. At that point, most customers are unlikely to gain much of a price advantage with direct access to the wholesale market compared to prices attainable by the local distribution utility under total wholesale competition.

The recommended market structure offers several advantages over pool-mediated competition. Unlike with total wholesale competition, under pool-mediated competition the Commission would have no control over the effects of generation choices: price volatility, fuel-supply diversity, local development implications, or environmental effects. Nor would any other public agency, nor even the distribution utility, have any ability to protect the public interest with regard to bulk power supply. In addition, the requirement to pay spot-market prices could expose small customers to extreme price volatility, since such customers are unlikely to engage in any form of price hedging.

There are several disadvantages of direct access compared to total wholesale competition. These include the complications of cost-effective metering (including avoiding premature commitment to expensive or inflexible technologies); billing and attribution of load to suppliers; the need to regulate the new marketers in terms of financial qualifications, ability to perform, and customer protections; mechanisms for determining what party is responsible for what portion of a customer's power supply in a month in which the customer changes supplier; the need for a default power supplier; protection of customer-specific information; and regulation of relations between distribution companies, marketing affiliates, and generation affiliates.

Finally, the recommended market structure offers the Commission the opportunity to restructure Maryland's electric-utility industry in a gradual and incremental fashion. By starting with a modified version of total wholesale competition, the Commission will have the benefit of experience in Maryland with the spot- pricing and direct-access options and elsewhere with alternative competitive structures to inform its decisions regarding further modifications to the market structure.

There is no reason why the Commission cannot take such a measured approach to restructuring. Nothing in the national or regional situation requires Maryland to move beyond even incremental wholesale competition.

No Federal or state legislation, and no FERC regulation, requires any greater level of competition.[7]

In addition, there is no pressing problem in Maryland for retail access to solve. As indicated below, Maryland has relatively low electric rates compared to the states in which retail competition has been pursued most enthusiastically (California, New York, Massachusetts, New Hampshire, Rhode Island, New Jersey, and to a large extent, Pennsylvania.)[8]

Electric Rates by State
(Cents per kWh)

State	Average Price
New Hampshire	11.32
New York	10.92
Rhode Island	10.24
Connecticut	10.18
New Jersey	10.06
Massachusetts	10.00
California	9.78
Maine	9.63
Vermont	9.13
Pennsylvania	7.87
District of Columbia	7.12
Maryland	7.03

Nor is there any compelling reason for every state in PJM, ECAR, or even the APS system to have the same industry structure. For example, a restructured PJM power pool can support direct retail access in Pennsylvania, pool-mediated competition in New Jersey, and wholesale competition in Maryland.[9]

[7]Legislation mandating retail competition is currently under consideration by Congress that could constrain the Commission's authority to restructure in a gradual fashion.

[8]The data on average prices are from New Jersey Board of Public Utilities (1997, 23).

[9]Where a single utility operating company serves portions of two or more states (e.g., Potomac Edison, Delmarva), the company may need to be reorganized to reflect differences in power supply arrangements between the states. This should not pose any major problems.

Hence, Maryland can select the electric industry structure that meets its needs and maximizes benefits, without any particular urgency or constraints.

Industry Structure

Under most variants of wholesale or retail competition, industry restructuring entails breaking up vertically-integrated IOUs into the following parts:[10]

- an unregulated generation business,[11]
- a bulk transmission system operated by an independent system operator under FERC regulation,
- a distribution company under state regulation.

In the direct-access model, the energy-merchant function of the distribution company is replaced by

- unregulated retail power-marketing and energy-services businesses.

In any of the models, but especially under direct access, additional market participants are likely to arise: brokers, aggregators, traders of electric power and financial instruments based on power prices.

The following section discusses the OPC's recommendations with regard to the structure, relations, and regulation of these separate businesses. These recommendations are based in large part on its findings regarding the opportunities for abuse discussed in the sections on vertical and horizontal market power.

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[10]This model may not be wholly appropriate for cooperative or municipal utilities.

[11]In the general model, the Commission would no longer directly regulate retail prices charged by generators or marketers. However, the Commission should continue to exercise jurisdiction over supplier practices with regard to the provision of non-discriminatory retail pricing and other consumer protections.

Recommended Industry Structure

Generation

The generation market will consist of generation currently owned by IOUs, or under contract to them, imports from PJM and beyond, and newly-constructed plants. Existing non-utility generation may remain under contract to a utility affiliate or be transferred to another entity, or the contract may be bought out and the NUG allowed to operate in the competitive market. With retail competition, some new plants may be cogenerators, built by energy service companies providing total energy services to large customers. As discussed elsewhere in the report, the distribution company should also build (or at least plan and facilitate) some distributed generation.

To preclude the anti-competitive practices catalogued in the section on vertical market power, it is essential that the generation businesses of the four IOUs in Maryland be fully divested from the regulated transmission and distribution businesses.[12] Less comprehensive solutions to vertical market abuses, such as segmentation of the vertical structure into separate business units or creation of separate affiliates within a holding company, are unlikely to fully mitigate vertical market power without a significant increase in regulatory oversight.[13]

Divestiture is a feasible solution even if the Commission does not have the authority to require it. The Commission can encourage voluntary divestiture in at least two ways. Until the utility has committed to divestiture of all central generating capacity, the Commission can

- limit stranded cost recovery. Until the Commission sees how much the most enthusiastic bidder is willing to pay for each power plant, it cannot determine whether the utility has any net stranded cost, let alone how much.

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[12]As discussed in the section on horizontal market power, further diversification of generation ownership may be necessary to avoid monopoly power.

[13]Some opponents of divestiture claim that it would result in a significant loss of efficiency. Given the lack of overlap between the staffing and equipment required for operation and maintenance of generation, on the one hand, and T&D on the other, it is unlikely that this would be the case. The distribution companies may continue to own transmission, or may provide maintenance services under contract to a regional transmission owner. If the divestiture of generation results in companies too small to operate economically, due to lost contributions to central overhead costs (e.g., financial and personnel), the resulting small distribution companies can contract to share management services with one another, or merge.

- deny a retail supplier access to the retail or wholesale market in Maryland if (a) that supplier is affiliated with any distribution utility in Maryland, or (b) it or its affiliates purchase any power from any central generation plant affiliated with any distribution utility in Maryland.

Depending on the market structure selected, the generating companies would sell through some combination of a Power Exchange spot market and bilateral contracts. In pool-mediated competition, bilateral contracts would be replaced by CFDs, which could also exist in any market structure that included a publicly-available pool price.

Under any likely regulatory structure, the Commission would not directly regulate the rates of competitive generators. However, the Commission should require that all generators and resellers that wish to sell power in Maryland (to distribution companies or retail customers) meet financial and environmental requirements, and file financial and operating data necessary to review and evaluate the cost, reliability, environmental effects, financial condition, and future prospects of Maryland's power supply.

Role of the Power Exchange

The power exchange would establish an hourly spot energy market that would make price information by location available to all market participants in real time, and create the structure necessary to support longer-term physical or financial contracts for price hedging.

The power exchange should function at a regional level. It should be developed through a process that includes input from the full range of stakeholders, and established as a not-for-profit business entity, controlled by a combination of representatives of all stakeholders.

Additional power exchanges may arise as secondary markets, much like existing commodity markets. These secondary power exchanges need not be subject to close regulation, but the Commission should reserve the option of regulating any anti-competitive behavior by these exchanges, by restricting purchases from abusive exchanges by licensed retail resellers.

Control of the Transmission System

No aspect of restructuring offers greater opportunity for abuse and inefficiency than control of the transmission system. Without full and fair access to transmission, generators will be unable to compete. Inappropriate pricing of transmission services can seriously mis-allocate costs between groups of consumers (by load shape, region, or relationship to the transmission owner), and subsidize uneconomic decisions about the construction and operation of resources.

It is therefore vital that control of the transmission system reside in an independent system operator (ISO), a non-profit entity that is financially and operationally independent of generators, transmission owners and other market participants.[14] *Ownership* of the transmission assets can remain with the current utility companies, and even be affiliated with distribution and/or generation companies, so long as *control* resides with the ISO. Alternatively, some or all transmission facilities can be sold or leased to a separate transmission company.

Regulation of the ISO, power exchange, the transmission company or administrator, and other regional entities will tend to fall to FERC, due to the interstate and wholesale nature of their operations. The Commission's initial approval of the ISO and similar arrangements will be required, since the utilities will be entering into contracts, transferring assets. The Commission should be especially careful that it provide clear direction to its jurisdictional utilities, and use its one-time approval of transmission, to ensure that the interests of Maryland ratepayers are protected. To retain some continuing regional control, the governing boards of these entities can be composed of representatives or appointees of the state Commissions or Governors.[15] While FERC would still review contracts and rates, the initial filing would be prepared by a staff ultimately reporting to representatives of the states.

In order to be effective, the ISO will need wide-ranging authority to

- ensure reliable and least-cost operation of the generation and transmission system;
- exercise full operational control over the transmission and generation system, dispatching of all generation and transmission resources (including energy-limited resources such as storage hydro) to minimize total costs;

[14]The failure to ensure ISO independence appears to be the primary reason for FERC's recent rejection of the PJM utilities' ISO proposal.

[15]The models for increased regional action include variations on federal legislation such as the river basins commissions, the old regional commissions, the Nuclear Regulatory Commission agreement states programs and the Federal Communications Commission joint boards. The basic framework should provide for regional action at the initiative of a group of states or the FERC, with a provision for FERC to decide if the states cannot agree within a specified time.

- ensure economic expansion of transmission capacity;
- control bidding practices in the power exchange and require contractual diversification (such as by auctions of short-term capacity entitlements) of control of generation, if anti-competitive behavior arises;
- cooperate with state and regional authorities in monitoring the sources of power (particularly to support enforcement of disclosure and environmental policies.)

The ISO should also be able to identify needs for expansion of transmission capacity and transmission support, determine reasonable costs for expansion projects, and either require cost-effective investments by transmission owners, select a developer to expand capacity, or recommend expansion to another agency with the power to build (or require the building of) transmission projects. Each state Commission should retain its authority for granting eminent domain and certificates of convenience and necessity; this authority is especially important if some transmission is constructed by non-traditional developers.

In addition, the ISO should operate under a regulatory and institutional framework that provides strong incentives at all times to improve the performance of the transmission system and to attract and retain personnel with the skills necessary to assure reliable operation.

It will be essential for the activities of the power exchange and the ISO to be closely coordinated on a regular and frequent basis, since the system of generation and transmission is linked is such an intricate manner. For example, the set of generators that is running at any particular point in time will influence the amount of power that can be carried over various transmission lines. The necessary coordination can be done by having the power exchange and the ISO as a single entity, or by having two closely-related entities that exchange information rapidly, in order to iterate toward efficient system operating decisions.

It will also be essential to give the ISO authority to order upgrades to constrained transmission interfaces or control bidding practices in the power exchange when evidence of anti-competitive behavior arises. In particular, the ISO should have the authority to reject or restrict changes to hourly bid prices if such bids appear to have been manipulated to affect the market-clearing price.

Transmission Pricing

Region-wide transmission rates should be structured to facilitate new generation where it makes economic sense, thereby enhancing the chances of achieving both economic and environmental benefits. Also, mechanisms for allocating transmission (and distribution) revenues should be designed to encourage and reward economic and technological innovation, rather than to simply increase profitability by increasing throughput.

Some form of zonal pricing is likely to be most appropriate, with zones defined by major transmission constraints. Any transmission pricing (or out-of-order generation pricing) that varies with short-term market conditions may result in over- or under-collections of revenues, which should be retained by the ISO to even out variations in revenues over time. Over-collections can also be applied to the funding of transmission investments to relieve the constraints that caused the over-collections.

Charging out-of-order generation costs only in the locations that require generation support will provide appropriate price signals for energy efficiency, load shifting and construction of new generation and transmission. However, customers who do not have sufficient transmission facilities to serve them with economically-dispatched generation should not be paying for the transmission facilities that serve customers with more than sufficient capacity. Thus, the pricing of generation in transmission-constrained areas must be tied to appropriate pricing of all bulk transmission.

Ancillary Services

In addition to hourly energy, the provision of reliable electric power requires a number of ancillary services, which may include:

- reactive power, which may be provided by generation, capacitors on the transmission system, and capacitors on the distribution system;
- black-start capacity;[16]
- load following (also called frequency regulation);
- spinning and operating reserve, which may be required in several categories (e.g., 5-minute, 15-minute, and 30-minute reserves);
- transmission voltage support; and
- planning reserve margin.

[16]Black-start generators do not require an outside source of electricity to start up from cold shutdown. They are therefore relied on to restore the grid after system blackouts.

Transparent measurement and availability of ancillary services is important in ensuring reliable least-cost service, an equitable allocation of costs, and mitigation of market power.[17] The ISO will need to determine how much of each ancillary service will be required, how the service will be measured, and how that requirement will be allocated and priced.

For example, the ISO may charge for the service and compensate providers, or require each participant to provide or purchase the service in a secondary market. The service requirement may be allocated to participants on load or generation, and by the minute, day, month or year. Prices may be set by zones, or on a postage-stamp rate for the entire pool.

Some ancillary services, such as black-start capability, should be assigned to generators, while others (reactive power, load following or regulation, transmission support, operating reserves) should be assigned as a function of load.[18] The ISO should determine the amount of each service provided by each generating unit; the purchasers of capacity would normally also purchase the ancillary services of the unit, although rules could be developed for assigning and tracking these services differently. Pricing should be left to the market, with the ISO providing reconciliation services and perhaps providing a default pricing mechanism to ensure that the market clears and all participants can obtain the services they are required to provide.[19]

Regulation of Distribution

The restructured distribution utility should be required to provide least-cost distribution service, including the costs of the generation and transmission services paid for by its customers (whether those are charged through the utility or separately, as in direct access). The Commission can employ appropriate performance-based ratemaking (PBR) mechanisms to promote least-cost distribution system planning and investments.

Detailed consideration of PBR should be deferred until the pressing issues of restructuring are resolved. When it is implemented, PBR should be based on

[17]The market valuation of generation is an essential portion of divestiture of generation. In order to determine the value of capacity, purchasers will need to know how much they will be paying or will be paid for ancillary services.

[18]For wholesale and pool-mediated competition, the distribution utility would supply the load-related services. Under direct access, the load-related services can be assigned to the marketer or to the distribution utility. This greater range of choices in allocation, with the related problems of accounting and reconciliation, raise yet more complications for direct access.

[19]PJM currently provides such a default service for planning reserve.

total cost per customer, including other costs and benefits for customers imposed by the distribution company, such as power quality and (in direct access) power supply costs avoided by utility improvements in delivery and end-use efficiency. PBR should also reflect distribution-level reliability and customer service, either as constraints or as part of a reward-and-penalty formula.[20]

Establishing a PBR structure and efficiency-improvement targets raises many complicated issues. For example, if costs, losses, reliability, and other parameters are to be compared between companies, these values should be corrected or normalized to reflect such characteristics as customer mix, customers per line-mile, percentage of customers with dedicated transformers, percentage of customers served at primary and above, percentage of line-transformer capacity owned by customers, percentage of load served underground, load-growth history, and distribution equipment vintage. These issues deserve careful examination once the restructuring plans are complete and the process is well under way. In general, the Commission should ensure that it understands the implications of one set of major changes (such as the disaggregation of vertically-integrated utilities) before embarking on another set of major changes.

Competition within the Distribution Function

In the near term, the distribution companies should continue to provide metering, billing, and related customer services. Under wholesale competition, the distribution company would continue to offer metering alternatives (such as time-of-use rates) where the Commission finds them to be cost-effective.

At some point in the future, especially if the Commission chooses to implement direct access, power suppliers may want to utilize a range of metering and billing technologies, to facilitate real-time pricing, two-way communication, remote control of end-use equipment, and other services. At that point, the Commission will need to decide how to unbundle metering and billing services. The Commission could create either (1) a structure for the distribution utility to provide a range of non-discriminatory metering and billing options that meet the needs of the utility, its customers, and power suppliers; or (2) a regulatory structure that allows for competition in metering and billing, while preventing cheating and ensuring that customers,

[20]See the discussion in “Universal Service” (p. 31) regarding performance-based incentives for universal service.

the distribution utility, power suppliers, and the regional power market (including the ISO and power exchange) receive accurate and reliable billing data.[21] If the distribution companies are not divested from generation services, it is important that the integrated company not be permitted to use the provision of metering, billing and customer services to the advantage of affiliated suppliers.

The Commission could require each utility to post a price schedule for upgrading metering beyond the level currently required by the utility for the customer's rate class. Each utility would post prices for upgrades from single-register energy meters to either three-period TOU meters, hourly recording meters, or real-time meters with one-way and two-way communication.[22]

Vertical Market Power

Vertical integration provides opportunities for the following types of anti-competitive behavior:

- favoring affiliates in purchasing decisions;
- providing affiliates with preferential service;
- timing and siting of transmission upgrades to favor affiliated generators;
- cross-subsidizing unregulated affiliates, allowing for predatory pricing;
- providing affiliates with proprietary market data.

The Federal Energy Regulatory Commission has catalogued in detail the propensity of vertically integrated utilities to abuse their market power (70 FERC ¶ 61,357 [1995, 65–85]). FERC's observations include the following:

[21]The Commission should consider the effects of unbundling billing and collection on consumer rights. The authors discuss this issue further in "Consumer Protection," p. 41.

[22]Demand meters will not be useful to power suppliers, and should not be installed for any new customer classes, unless they are cost-effective in improving the distribution company's pricing of loads close to the customer's meter (service drops, and those secondary lines and transformers that serve only a few customers).

> In the past, transmission-owning utilities have discriminated against others seeking transmission access. Transmission-owning utilities have denied access by outright refusals to deal.... More often, however, discrimination is likely to be manifested more subtly and indirectly. One such way would be [delaying negotiations until]....the window for the customer's trade opportunity has closed. Another way of frustrating access is to substantially change the terms of negotiated agreements through protracted delay including filings with regulatory agencies.
>
> Another way...is to allow access but only on noncomparable or unsupportable terms and conditions that are inferior to the conditions [available to]...the transmission owners themselves [such as refusing network services, denying postage stamp rates, denying priority service, insisting on long scheduling lead times, denying flexibility in the use of firm transmission capacity, providing inferior ancillary services, requiring onerous deposits, and requiring double payments in lieu of reciprocity]....
>
> Finally, an additional way for transmission-owning utilities to frustrate access and competition is by granting each other superior rights and lower rates, in pools, interconnection agreements and other protocols. (71-78; citations omitted)
>
> In today's emerging competitive wholesale power markets, the practices of some transmission-owning utilities are unduly discriminatory and anticompetitive. These practices produce market distortions today.... (81)

FERC describes similar past vertical market power abuses in the gas industry, when pipelines discriminated in favor of their own gas, and concludes:

> Our experience in the gas area influences our decision that, at a minimum, functional unbundling of wholesale services is necessary in order to contain non-discriminatory open access and to avoid anticompetitive behavior in wholesale electricity markets. (85)

With direct-access competition, market power at retail may also be a problem. Incumbent utilities have considerable advantage in providing retail service as a result of their current relationships with customers, information about customers, and in some cases contracts with customers. Barriers to entry in the retail-services market may be particularly severe, given the working relationships that have built up over time between customers and their incumbent utilities.

Mitigating Vertical Market Power

The Commission's primary objective at the outset of the restructuring process should be the development of an effective and competitive electric-energy market; deregulation should proceed only as rapidly as that objective is achieved. Deregulation that leaves monopoly or ineffective competition in place would defeat the primary purpose of restructuring: cost reduction.

The OPC recommends a strategy for mitigating vertical market power that combines the following elements:

- divestiture of generation (and retail energy services under direct access) from regulated transmission and distribution services;
- limitations on merger activities to preclude future re-integration of vertical components; and
- creation of a truly independent ISO with authority to order transmission investments and with a management structure that precludes control by any one group of market participants.

There are four basic options for separating the competitive generation from the regulated transmission and distribution functions:

- Maintaining a completely integrated company, with costs allocated to specific functions.
- Functional unbundling into separate business units, with no change in corporate structure.
- Creation of separate affiliates within a holding company (corporate unbundling).
- Divestiture of generation from regulated businesses.

Of the four options, full divestiture is likely to offer the strongest safeguards against abusive practices. The firewalls erected between functions or business units within a vertically integrated utility or between holding-company affiliates are unlikely to fully protect against cross-subsidization, collusion, or other anti-competitive practices. The most important practical problem is that the employees of supposedly separate operations are ultimately working for the same top management and the same shareholders. This situation creates an irresolvable conflict.

Moreover, regulatory oversight of cost allocations and affiliate transactions may not be sufficient to identify and mitigate anti-competitive practices. Regulating cost allocation and affiliate transactions among functionally unbundled companies would be complex, requiring PUC, FERC, and SEC involvement, with potential for conflicts between agencies.

Horizontal Market Power

Even with mitigation of vertical market power, there may be opportunities for abuse of market power arising from horizontal concentration in generation. Dominant firms can raise market prices by withholding capacity from the market, thereby increasing profits over competitive-market levels.[23] Breaking up the larger owners, and limiting market share in generation ownership would resolve this problem.

Preliminary examination of market concentration in the PJM electricity market suggests that there may be opportunity for abuse of market power in generation if restructuring moves forward. These concerns arise mainly in situations where capacity is tight, for example in hours with high levels of demand or multiple large unit forced or scheduled outages.

While there are important mitigating factors, including market entrants (imports or new facilities), demand elasticity, and antitrust regulation, the OPC remains concerned that abuse of market power in generation may be common and significant, both in local load pockets and broadly in the regional market.[24] Detailed studies are needed, in which strategic behavior is analyzed in the context of real markets with generation ownership patterns, transmission constraints, and opportunities for new entrants. Until the necessary detailed analyses are performed, any group of affiliates controlling more than 10% of the regional capacity should be subject to special controls on pricing and, if necessary, profits.[25]

[23]Profits are larger even though sales are lower, since the price increase offsets the sales loss.

[24]Market concentration and abuse of market power are a concern to Maryland ratepayers even if Maryland IOUs are not the dominant firms in the regional market. The exercise of market power by any utility or generating company in the region will increase prices paid by all customers and profits to all generators in that market above competitive levels.

[25]Similar concerns apply with respect to ECAR, especially with regard to American Electric Power's dominance of the generation system. Maryland may have less influence over the course of developments in ECAR, but can encourage disaggregation of generation ownership by prohibiting sales from generation companies with market power to Potomac Edison, its customers, or into the Maryland portion of PJM.

Market Concentration and Oligopoly Pricing

An oligopoly is a market structure in which a few firms dominate the supply of a commodity. Its occurrence is quite common. Economic theory tells us that in oligopolistic markets prices can be expected to fall between the extremes of a perfectly competitive market at the low end and an unregulated monopoly market at the high end. It is impossible to say with confidence how a particular market will behave within the two tractable extremes.

The two most common measures of market concentration are the Herfindahl index, and the "concentration ratio." The Herfindahl is the sum of the squares of individual firm's market shares. For example, the Herfindahl index would be 1000, for an industry with ten equal size firms. "Concentration ratios" are specified for a particular number of firms. For example, the three firm concentration ratio (CR3) for that same industry would be 30 percent. No single metric can capture the complexities of the cost structures and relationships in a real market, but the Herfindahl and concentration ratio are both useful measures that can serve as starting points in analyses of market power.

Different oligopoly theories point to different measures of concentration as the most appropriate for explaining how significantly prices might deviate from marginal costs. Similarly, empirical explorations of concentration and price data in various industries are inconclusive in establishing a generally preferred measure of concentration for accurately predicting pricing behavior. At one theoretical extreme, oligopoly firms may act competitively, or "quasi-competitively," resulting in reasonable market prices. At the other extreme, the firms may collude perfectly, with results much like an unregulated monopoly.

Theoretical models may offer some insight as to the behavior of a market in electricity generation. However, even for markets that have existed for years and have been studied in detail, there are likely to be differences of opinion about how the market has behaved. It is simply impossible to say with confidence how a complex market will work before it exists, and with many aspects of its regulation and structure unresolved. The most we can do is to study the current market structure and cost functions, and to identify areas of concern and potential solutions.

Concentration and Price in Other Industries

Leonard Weiss (1989) has examined the relationship between market concentration and price in many markets and has found that higher levels of concentration do tend to correlate with higher prices. Weiss's summary of 121 data sets of concentration and price covering a wide range of industries (including airlines, banking, cement and many others) shows a convincing majority of studies in which concentration appears to result in higher market price:

	Number of Data Sets
Significant positive effects	76
Non-significant positive effects	30
Non-significant negative effects	11
Significant negative effects	4
TOTAL	121

Market Concentration and Market Power in PJM

There is relatively little actual experience with the functioning of deregulated generation markets, and therefore very little information regarding the relationship between market concentration and price or between concentration and market power. However, a preliminary examination of concentration in PJM does suggest that there is the potential for serious abuse of market power by the dominant generators in the region.

Based upon current ownership, the capacity shares of the five largest companies in PJM, including the NUG capacity they control by contract, are as follows:

PSE&G	20%
GPU	18%
PECo	16%
PP&L	15%
BG&E	12%
PEPCo	12%

Thus, the concentration ratio for the three largest companies (CR3) is about 54%, and the concentration ratio for the five largest companies is 81%. The merger of BG&E and PEPCo would increase the CR3 to about 62%.

The Herfindahl (or "HHI") index is about 1550. The pending BG&E-PEPCo merger would increase the HHI by roughly 300 points to about 1850. According to Department of Justice guidelines (1992), markets with an HHI index about 1000 are "moderately concentrated," and mergers that raise the HHI by more than 100 points "potentially raise significant competitive concerns." The guidelines also indicate that, at a Herfindahl above 1800, the market is "highly concentrated" and adverse effects are "presumed." In such concentrated markets, there are significant concerns of market power, although whether and to what extent there is a problem depends upon a variety of other factors, for example, barriers to market entry.

While useful indicators of the potential for market power in PJM, the HHI and concentration ratio cannot measure the full extent and economic impacts of horizontal market power in the PJM system. The extent to which market concentration will result in significant market power problems will depend upon many case-specific factors, including the opportunities for strategic pricing by dominant firms and coordinated action among market participants, the nature of the procurement process, the extent of product differentiation, and the magnitude of barriers to market entry.

Determining the annual cost of various levels of concentration will require detailed studies, in which strategic behavior is analyzed in the context of real markets with generation ownership patterns, operating constraints, outages, transmission constraints, and opportunities for new entrants. For example, an analysis of market power in the New York Power Pool found that the largest firm, with a market share of 30%, could "essentially dictate the market price." By following a simple strategy of bidding at double its variable costs, the largest firm could increase the pool's average clearing price from $29/MWh to $40/MWh, dramatically increasing its profits, as well as the profits of other smaller companies and significantly increasing electric bills to customers (Falkenberg 1995).

Such studies will need to consider situations where opportunities for abuse are enhanced, such as in transmission-constrained locations or during hours when capacity is constrained due to high levels of demand or multiple large unit forced or scheduled outages. Moreover, such studies should assess opportunities for cooperation among two or more firms in setting prices.

While there are important mitigating factors, including market entrants (imports—although these are limited by transmission constraints that are unlikely to disappear—or new facilities), demand elasticity, and antitrust regulation, the abuse of market power in generation may be common and significant in the PJM regional market. The current concentration of generation creates horizontal market power for some participants at some times. Analyses to date of market power in the PJM region have not adequately explored the specifics of strategic pricing behavior in constrained markets to fully understand the extent of the problem or the range of solutions. Until the necessary detailed analyses are performed, any group of affiliates controlling more than 10% of the regional capacity should be subject to special controls on pricing and, if necessary, profits.

Mitigating Horizontal Market Power

There are a number of mitigation measures available for market power, including: transmission system reinforcements, new generation, reconfiguration of loads, demand-side actions, contractual methods, continued regulation, prices caps, increasing the number of owners of generation through divestiture. Detailed studies will be required to determine what mix of measures is best for particular situations, and to determine what institutional arrangements best promote appropriate solutions.

Joskow (1995) observes, “If the market power problem arises from the presence of one or two dominant firms, price caps could be applied to the dominant firms” while other smaller firms could use market-based pricing. This approach has been used by the FCC in regulating AT&T, given its large share in the markets for some services.

Limits on ownership of generation can be established as a condition for certification to sell power into a particular pool, limiting a generator’s ownership interest to no more than a certain percent of the capacity active in that market. Policy measures to address barriers to entry might involve open access to transmission wires, power pool membership requirements, and auctioning plant sites (locations with fuel access, grid access and public acceptability are scarce). Stranded cost recovery may be the most effective policy tool for enlisting utility cooperation in setting up market structures to foster competition. It is, therefore, imperative that the problems and solutions be identified and put in place early in the transition to a more competitive electric generation market.

Shepherd (1996) finds that “premature deregulation, before those conditions [for effective competition] are reached, is a cardinal error and is usually irreversible.” Electricity deregulators should heed this warning—and restructure the industry at a pace and in a manner that will provide for truly competitive electricity markets.

Competition and Merger Strategies

In a competitive market, Maryland will need to develop additional oversight to protect against mergers or acquisitions that create vertical or horizontal market power.[26] Unfortunately, mergers of utilities outside Maryland—but in the same regional market, such as PJM—can create horizontal market power over Maryland's power supply. Ideally, regional, or regionally consistent, restrictions upon ownership concentration should be put in place. These requirements could include prohibition of either of the following:

- mergers of suppliers with distribution utilities;[27]
- the marketing of power generated by affiliates of the local distribution utility (except as permitted by the Commission, for distributed generation or prior to full divestiture during the transition);
- the marketing of power generated by power producers who, with their affiliates, own more than a maximum permissible percentage of regional generation.

These could be implemented and enforced at the level of state certification of suppliers of retail electricity service.

The Commission should review its authority to review and condition merger approvals, and to pursue and penalize anti-competitive behavior. If necessary, the Commission should request augmentation of that authority.

[26]The competitive importance of mergers depends, among other things, on the size of the participants. The Delmarva-Atlantic City Electric merger is likely to be too small to substantially increase market power problems. The Constellation merger, on the other hand, will create the largest generator in PJM, posing risks of significant horizontal market power.

[27]This vertical reintegration has occurred to a surprising degree in the UK.

Preservation and Advancement of Public Benefits

Maryland's ratepayers have benefited significantly from an industry structure and regulatory process that provides reliable, efficient, and relatively clean energy services while vigorously protecting consumers' rights. The restructuring process should not place these benefits at risk. In fact, restructuring should be an opportunity for further enhancement of such benefits.

With the possible exception of environmental quality, these public benefits are likely to be preserved if the Commission adopts a system of total wholesale competition. In addition, the Commission can exercise its regulatory authority over distribution utilities under total wholesale competition to establish and enforce the obligation to provide non-discriminatory service at reasonable rates to all consumers.

In contrast, there is a significant risk that retail competition could seriously degrade the reliability, efficiency, environmental, and consumer-protection benefits that have been achieved under the current industry structure. With the introduction of retail competition, retail providers may respond to economic pressures by reducing spending on services that benefit Maryland consumers, as well as its economy and environment, but that appear to diminish the providers' net profits.

This need not be the case. As we discuss below, the Commission can continue to protect and promote the public interest with regard to the provision of unregulated retail services through the exercise of its regulatory authority over local distribution utilities. If the Commission or the Legislature adopts retail access as the model for Maryland, the industry and the regulatory process must be restructured to preserve and perhaps enhance public benefits in a competitive retail market.

The OPC recognizes that the Commission may not now have jurisdiction, under the Public Service Commission Law, to protect the public interest with regard to the provision of unregulated retail service. Legislation may be required to extend Commission jurisdiction over consumer-protection issues related to competitive supplies as well as licensing of electric-service providers.

Universal Service

Regardless of the competitive structure adopted by the Commission, the OPC recommends that the Commission explicitly obligate regulated distribution utilities to provide non-discriminatory universal service to all customers.[28] We define *universal service* to mean the opportunity to take service on a non-discriminatory basis at reasonable rates and under reasonable terms by all customers desiring and willing to pay a reasonable price for such service. We define *opportunity to take service* to include an affirmative obligation to engage in specific efforts to make service available to all customers to the maximum extent practicable.

The obligation to support universal service can reasonably be viewed as a quid pro quo for the use by investor-owned utilities of public facilities and institutions in support of their business. These facilities and institutions include the use of the power of eminent domain, as well as the use of city streets and other public ways. So long as utilities enjoy the fruits of that exchange, they should be subject to the obligations as well.

This principle has long been upheld with regard to the granting of eminent domain:

[28]As in the restructuring of the telecommunications industry, the restructuring of the electric-utility industry presents an opportunity to institute universal service as an obligation of the entity that remains under Commission regulation.

> It is contemplated that all of the inhabitants in the territory shall be eligible to obtain the service by complying with reasonable conditions. Having endowed the cooperative with the power of eminent domain, the legislature has at the same time imposed upon it the responsibility to reasonably furnish nondiscriminatory service to its members, the members, of course, being the public in the area served.[29]

Other courts have reached similar conclusions.[30]

This principle of universal service as public compensation is now also being applied with regard to the use of public ways. Within the context of cable television:

> Local governments are realizing the unique value of public rights-of-way for which they act as trustee. Public rights-of-way are acquired and paid for through government action....Thus, the public rights of way are the most valuable property rights in the hands of government. Local governments must receive fair compensation for granting use of the rights-of-way. Otherwise, government is merely subsidizing the businesses of private rights-of-way users....Traditional users of the public rights-of-way were deemed to provide public compensation in the form of universal service and regulated rates....With traditional users of public rights-of-way, compensation for use of the public rights-of-way was passed onto the end consumer through rate regulation and other public benefits like universal service, rather than being paid directly by the governments, the actual owner of the public rights-of-way. (Miller and Nven 1996, 12–13)

The Commission should implement universal service by requiring distribution utilities to adopt a set of universal-service provisions that:[31]

- provides access on a non-discriminatory basis, and provide for basic supply service for all customers;
- provides funding for rate-affordability, energy-efficiency, and crisis-intervention initiatives, via a non-bypassable charge recovered from all distribution customers under the distribution-delivery rate;
- prevents the imposition of new service fees or reductions in services that disproportionately affect low-income customers;

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29 *Dairyland Power Cooperative v. Brennan*, 82 N.W. 2d 56, 63 (Minn. 1957).

30 *Capital Electric Power Association v. McGuffee*, 83 So. 2d 837 (Miss. 1955), cited by *Dairyland Power Cooperative*, 82 N.W. 2d (63).

31 In addition, if retail access is adopted, the Commission can promote universal service indirectly by enabling aggregation of low-income customers through appropriate agencies, such as LIHEAP, public housing, assisted housing, or first-time home buyer programs.

- establishes a performance-based or other measurement scheme specifically for measuring and rewarding universal-service performance;[32]
- establishes billing and metering procedures for small customers.

Obligation to Serve

The obligation to serve under current regulation encompasses both the obligation to provide distribution service and the obligation to provide energy service. These obligations should continue in a restructured market, albeit in modified form.

The obligation to provide non-discriminatory distribution services, including connection to the distribution system and billing, metering, and collection of distribution-related costs, can continue to be the responsibility of the regulated distribution utility.[33] The policies and regulations providing for such obligations may need to be revised to more-precisely define the right of access in a restructured market. For example, provisions for right of access may need to be expanded to prevent denial of access based on disputes over or non-payment of non-access-related bills.[34]

If the Commission decides to deregulate retail supply under retail competition, the obligation to provide energy services will need to be reformulated to provide for basic service through a supplier of last resort for customers that either do not choose a competitive supplier or are refused service by suppliers.[35]

There are likely to be a significant number of customers who do not or cannot choose a competitive supplier.[36] It is therefore critical that the process for selecting the supplier(s) of last resort be designed in a way that

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[32]The universal-service PBR could be incorporated as a component of a broader distribution-service PBR or as a PBR add-on to continuing cost-of-service ratemaking.

[33]Moreover, as discussed above, the distribution utility should continue to be obligated to provide least-cost distribution services.

[34]In its final order on restructuring, the Vermont Public Service Board (1996, 99) concluded that its disconnection policies should be expanded in just this fashion.

[35]More direct remedies may be required in instances where the refusal to provide service constitutes a discriminatory practice. See the discussion below.

[36]This is the experience in the telecommunications industry, where AT&T has retained a majority market share. Moreover, customer surveys indicate that significant percentages of residential customers would stay with their current utility if allowed the opportunity. A survey by the Maine Public Utilities Commission (1996, q7a) found that 22% of customers surveyed would prefer not to choose, even if rates decreased 10%.

does not distort the competitive market, but does provide full access for these last-resort customers to the prices and services available to other customers.

There are three basic options for selecting the provider of last resort:

- Obligate the distribution utility to provide this service.
- Put the right of providing last-resort service out to bid.
- Distribute the pool of last-resort customers among retail service providers.

Under the third option, the pool of last-resort customers is distributed among retail service providers in proportion to their market share in the local distribution utility's service territory. This may be the be best approach in the long run. This option will likely entail imposing the obligation on suppliers to accept such customers in exchange for the right to provide retail services in the local distribution utility's service territory. If so, the Commission will probably need to adopt explicit standards and protections to prevent suppliers from discriminating against their residual customers.

This approach offers several clear advantages over the other two options. Under the first option, distribution utilities are unlikely to offer competitive prices or services to last-resort customers, since they will not be under any competitive pressure to do so. Moreover, this option may raise a host of anti-competitive concerns when the distribution utility is affiliated with an unregulated generating company that sells power in the same service territory.[37]

Although less costly than if provided sole-source by the distribution utility, the option of putting last-resort service out to bid is likely to resort in a considerable premium relative to competitive-market prices being paid by the pool of last-resort customers served in this fashion. This has been the experience in other industries that make use of providers of last resort. For example, in the insurance industry, Austin (1983) finds, "The public markets provide less coverage at higher premiums and on worse terms than is generally provided by the private markets." Indeed, Austin observed,

[37]Alternatively, the distribution utility could be required to procure all supply on the spot market. However, this could expose customers to extreme price volatility or require the distribution utility to engage in complex, risky, and expensive hedging practices.

> In the case of residual market automobile insurance, almost all state plans limit coverage in both dollar amount and type of coverage, although less so now than in the past. Typically, the coverage was limited to the minimum requirements of compulsory insurance and financial responsibility laws. Residual market plans commonly charge higher rates than the voluntary markets. Indeed, at least one court has steadfastly ruled that residual market insureds are *supposed* to pay higher rates.

Property insurance coverage under such residual market mechanisms is also more limited and more expensive. The types of coverages provided, as well as the coverage limits, are restricted. FAIR-plan insureds also generally pay higher premiums than do voluntary market insureds.[38] Finally, FAIR-plan insureds also receive slower claims service and are usually denied a premium payment plan.

Funding Low-Income Programs

Financial support for low-income programs should be part of a restructuring plan, regardless of the competitive model adopted. While retail access may significantly increase the risk that service will be unaffordable, affordability will continue to be a concern with total wholesale competition.

Low-income programs supporting universal service in Maryland should be funded in part through a competitively neutral and non-bypassable wires charge on all distribution utilities.[39] A low-income wires charge should generate funds for the provision of each of the following:

- cash fuel assistance,
- crisis intervention assistance,
- energy efficiency improvements.

Although each of these services contribute to affordability, it is likely that no one service will be adequate in isolation, since

- the energy burden of low-income Maryland residents likely exceeds that proportion of income which should reasonably be expected to be paid;
- there are likely to be a substantial number of low-income Maryland residents with incomes so low that energy-efficiency improvements or

[38]For property insurance, the statutory residual market scheme is referred to as a “FAIR plan.” FAIR is an acronym for “Fair Access to Insurance Requirements.”

[39]We recommend that this charge be billed as part of the overall distribution delivery rate, not as a separate line item on customers’ bills.

cash fuel assistance will not avoid the need for assistance in helping to pay arrears when facing a service shutoff situation;

- there are likely to be a substantial number of low-income housing units in Maryland that are in need of energy-efficiency improvements, but which have not yet been treated.

The OPC recommends that the level of funding for low-income affordability programs be pegged to historical levels of LIHEAP funding.[40] Specifically, we recommend that the funding level be set at 150 percent of the Maryland LIHEAP allocation devoted to electricity in the year of the historically highest LIHEAP appropriation (1986), brought forward to current-year dollars. The funding level is set at 50% above the historic amount to account for the fact that the wires charge will address non-heating bills, as well as heating bills.

The 1986 Maryland LIHEAP allocation was roughly $35.5 million (U.S. Department of Health and Human Services 1986, 67 [Table C-4]). Inflating this amount to 1996 dollars produces a heating benefit of $44.0 million, of which $13.6 million was devoted to electricity. Increasing this amount by 50% produces a total 1996 estimate of $35.6 million, or approximately 0.7 mills/kWh based on 1993 energy consumption in Maryland.

We further recommend that the wires charge for universal-service programs be imposed on all customer classes. Viewed from the perspective of universal service as compensation for private use of public goods, the benefits of such uses have generally accrued to all utility customers, and therefore the costs of compensation should be allocated to all customers. Moreover, it would be counter-productive and perhaps politically unpalatable to allocate such costs directly to residential, and therefore low-income, customers.

Finally, wires charges should be collected through, and distributed by a private non-profit agency with an independent board of directors. This third-party trust can be modeled after such institutions as the Colorado Energy Assistance Foundation or UTAC, the trust responsible for administering the Illinois universal-service fund for telecommunications under the auspices of the Illinois Commerce Commission.

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[40]LIHEAP is the federal Low-Income Home Energy Assistance Program. In Maryland, it is know as the Maryland Energy Assistance Program. The OPC's proposal is not intended to supplant the existing LIHEAP program, but to support it.

Such trusts distribute wires funds within utility service territories (either to the utility, to weatherization agencies, or to providers of crisis assistance) based on a determination of need, rather than in proportion to their contributions to the fund. This approach targets the distribution of funds to those in greatest need, maximizing the resulting benefits.

As with other trusts, the Commission's regulatory oversight of a third-party trust should include review of the allocation of revenues between cash-assistance, crisis-intervention, and energy-efficiency programs; approval of annual workplans developed and submitted by the trust; and general oversight of revenues and expenditures.

Distribution-Service Cost and Quality

Without reasonable protections in force, the restructuring process could result in both a significant increase in costs and a degradation in the quality of distribution services that are disproportionately relied on by low-income customers. Such service costs could increase if these services are unbundled and explicitly assessed service fees that are not cost-justified or if existing fees are simply increased. At the same time, service levels could decline with cutbacks in services.[41]

Unbundled service fees can represent a significant increase in rates to customers even if base rates remain the same or decrease. Customers who are facing payment troubles, for example, can nonetheless still face significant increases in the moneys which they owe to a utility if the utility unbundles existing elements of service and institutes new fees for those individual elements, or institutes increases in existing fees for certain elements of service other than those paid for through base rates.

Examples of the unbundling of services and fees might include the addition of collection charges to the bills of customers who are already having trouble paying for service, or the implementation of a charge on the voluntary disconnection and reconnection of service. Examples of existing fees that may be increased include deposit requirements, late fees, and reconnect fees.

Service fees have increased in other industries that have deregulated. Weber (1995) notes:

[41]A poorly designed base-rate freeze or PBR mechanism could strengthen the incentive for instituting new service fees or cutting back services.

> Since bank deregulation in the 1980s, fees charged by banks have been skyrocketing. Recent headlines proclaim: "Banks Begin to See Gold in Bounced Checks." Reports state that non-sufficient-funds (NSF) fees have risen from an average of $15.11 in 1990 to an average fee of $19.35 per check by 1993. The large banks are charging fees averaging 971% more than the processing costs.

Researchers estimate that banks earned in excess of $1 billion in 1994 from NSF fees alone.[42]

As discussed below with regard to cost reallocation proposals in general, the restructuring process is not the appropriate context for considering proposals for existing-service fee increases or service unbundling. Instead, such proposals are appropriately evaluated in the context of a general rate proceeding, where the total effect of all reallocation proposals can be assessed. In the interim, the Commission should cap the levels of all fees imposed upon small user customers at their existing levels; and establish a moratorium on all new fees to which small user customers might be subject.[43]

Universal service could also be threatened by cutbacks in services that are disproportionately relied on by payment-troubled customers. Experience in other industries indicates that it is just such areas that might see cutbacks in service levels, with

- reduction of staff devoted to responding to telephone customer contacts, including situations where a customer initiates a telephone call to the company involving bill inquiries (including inquiries relating to deposits); requests for deferred payment plans; and responses to shutoff notices.
- reduction of staff devoted to responding to walk-in customer contacts, including situations where a customer personally visits a company office regarding bill inquiries; requests for deferred payment plans; and responses to shutoff notices.
- reduction of staff devoted to handling company-initiated collection contacts, which involve, in addition, negotiation of payment plans,

[42]Other fees include the deposit-item-returned fee, per check fees, stop payment fees, and automated teller machine fees. Many banks also have balance requirements, charging a fee when the balance goes below the minimum at any time during the month. A deposit-item-returned fee is a fee charged when an NSF check is deposited into the account.

[43]A cap is proposed rather than a freeze. Fees for such service components may well need to decrease.

provision of information regarding federal fuel assistance, and provision of information regarding other sources of bill payment assistance.

- delays in posting government assistance payments to customer accounts.
- reduction of immediate telephonic access to customer service personnel, without need for call-backs or without obtaining busy signals.
- lengthening of the time taken to answer telephone calls and to respond to customer inquiries.

The most effective mechanism for discouraging such reductions in service is likely to be a performance-based ratemaking system for universal service, as discussed below. Through that mechanism, the impacts of reduced levels of service on payment-troubled or other groups of customers can be measured and appropriate penalties applied.

In addition, the Commission could require utilities to show as part of their filings for corporate restructurings or mergers that any claimed cost savings are not the result of reductions in service to customers or any group of particularly vulnerable customers. Such reductions should only be considered to be in the public interest if the cost savings clearly outweigh the economic and social costs of service reductions (for example, see Colton 1996).

Performance-Based Ratemaking for Universal Service

Given the wide variety of customer services provided by utilities and the wide range in the uses and reliance on such services by different customer groups, it will likely be a daunting task to track changes to levels of customer service and the discrete effect of such changes on the overall level of affordability of electric service for low-income customers. Instead, the Commission should consider implementing a performance-based mechanism for measuring and evaluating overall universal-service performance based on one or more performance indicators.[44]

A performance-based mechanism not only provides a tool for assessing quality and levels of service, but also provides the means to directly reward or penalize a utility for its universal-service performance. In this way,

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[44] A universal-service performance indicator should take into account factors such as the number of shutoffs, the level of arrears, the rate of successful completion of deferred payment plans, and the levels of money owed and at risk. Taking each of these factors into account prevents the creation of unintended incentives. The various factors should be structured not only to measure positive impacts on their own, but to balance the potential negative impacts created by other performance measures.

utilities will have a direct financial stake in reducing both the utilities' and the social costs of unaffordability.[45]

Performance-based criteria based on the affordability of service has precedent in the telecommunications industry. A similar issue was addressed in the "Universal Service Questionnaire Results of the Universal Service Project of the Staff Subcommittee on Communications of NARUC," presented at the NARUC annual meeting in New York on November 14, 1993. Question 12(a) of that questionnaire asked, "In the future, should penalties be considered by regulators for companies who are remiss in the provision of universal service?" Regulators approved of penalties by an 88 percent margin.

Metering and Billing for Small Customers

If small customers are actually to benefit from direct access, the Commission will need to develop methods for competitive sales to customers without hourly meters. Pricing for small customers without hourly metering should be settled well before transition, or these customers will be left out of the competitive market.

One such approach would be the geographic aggregation of residential and small-commercial load. Municipalities or other public entities (municipal utility districts, neighborhood associations within cities) could function as regional aggregators, to allow for hourly metering at their borders. (Some allocation may be necessary, where a feeder serves areas both within and outside the aggregation.) Individual customers could opt out of the aggregation once they have hourly metering. This scheme resolves the small-customer billing problem and also gives small customers increased market clout.

Another approach would be to establish procedures for allocating the hourly costs of bulk power to individual non-aggregated customers without real-time meters. The marketer would allocate the costs of power on an hourly basis according an allocation formula based on monthly MWh by class, multiplied by hourly allocation factors (based on load-research data by hour, day-type and weather), reconciled to actual hourly loads at the distributor's delivery points, net of hourly-metered retail load.

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[45] Indeed, utilities have largely been able to downplay the financial impacts of low-income inability-to-pay since they are allowed to directly flow through all credit and collection expenses, as well other expenses associated with non-payment.

The final settlement of power supply bills between the marketer and the power exchange could not occur for at least a month, following billing of all customers. The process will be further complicated by the need to estimate losses, to determine how much more power the marketers need to supply above the level delivered to the customers.

Consumer Protection

As a general rule, the customer safeguards and protections that are in force under the current industry structure should be maintained and enhanced once vertically integrated utilities are unbundled and the power-supply function is deregulated. Moreover, we believe that current protections applicable to the provision of power supply can continue to be applied to deregulated supply without placing undue obligations on competitive suppliers.[46]

The full range of regulatory protections will remain in place under total wholesale competition. In order to maintain the current level of consumer protection in a under retail competition, existing consumer-protection policies will need to be revised and strengthened to accommodate the increased potential for customer-payment problems and additional opportunities for fraudulent activity by marketers. Specifically, consumer-protection policies should

- continue existing customer-service protections, including disclosure of terms and conditions of service, dispute-resolution procedures, billing requirements, and privacy protections;[47]
- provide for certification and licensing of electric-service providers, including financial-responsibility requirements and standards of conduct;

[46]Legislation may be required to extend Commission jurisdiction over consumer-protection issues relating to competitive suppliers.

[47]For example, requirements would need to be established for written contracts between the suppliers and customers; the specification of contract terms, including adoption of a uniform method for pricing and environmental disclosures, availability of a dispute-resolution procedure, and protection of the customers' privacy interests; the prohibition of the distribution companies from denying or disconnecting service based upon a customers payment problems with a third-party supplier; and the prohibition on the billing for distribution-company services by the energy supplier.

- provide for specific Commission oversight mechanisms and disclosure requirements for preventing discriminatory practices, including enforcement mechanisms.

Some of the above could be accomplished by the Commission under its existing statutory authority. As discussed below, the Commission could exercise control by requiring the use of a system of billing-and-collection service contracts, similar to those between interexchange and local-exchange carriers in the telecommunications industry, and by imposing certain requirements on the energy suppliers as a condition of entering into agreements with the distribution companies, by means of the distribution companies' tariffs. While these mechanisms may be sufficient to deal with certain consumer-protection requirements, they may not be sufficient to address the certification and licensing requirements and Commission oversight over deceptive and discriminatory practices. These may require legislative action.

Customer-Service Protections

As with the issue of obligation to serve, existing customer-service protections applicable to the provision of distribution services should continue in force with the distribution services provided by distribution utilities in a restructured market. With regard to those protections associated with the provision of supply, the OPC recommends that the Commission establish the means for retaining such protections, and for retaining such protections under Commission purview, as the supply market is deregulated.

Specifically, we recommend that distribution utilities continue to be responsible for billing and collection for both distribution and energy services.[48] Customer services associated with energy-services billing, collections, and bill inquiries would continue to be provided by the local distribution utility and, therefore, continue under Commission jurisdiction.[49]

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[48]Most utility restructuring proposal assume that distribution utilities continue to be responsible for energy-service metering, data collection, and perhaps billing and collection, at least during the transition. In addition, the Pennsylvania legislation regarding restructuring explicitly authorizes the distribution utility to continue providing customer services, including metering and collections.

[49]This responsibility is often assigned to one party for residual markets in the insurance industry. In the automobile, property, and casualty insurance fields, responsibility for administration is often assigned to one or a limited number of firms, with the costs allocated to all market participants in proportion to their market share. See, for instance, Lee and Formisano (1975).

Distribution utilities could provide such services to suppliers through a system of billing-and-collection-service (BCS) contracts, similar to those between interexchange and local exchange carriers in the telecommunications industry. These BCS systems typically consist of three services: (1) providing billings to consumers; (2) providing an inquiry service to consumers (through which consumers may seek information about their bills); and (3) providing collection services (which involves not only collecting unpaid bills, but receiving payments and posting those payments to accounts). Consumer contacts regarding billings, collection efforts, and bill inquiries would thus all be undertaken through the established processes.

Continuing the billing and collection function through distribution utilities offers several benefits. First, all customers, regardless of supplier, will be afforded equal levels and quality of customer-service protection as established by Commission order. Under the BCS system, suppliers will not have the option to reduce costs by scaling back customer services, since such services will be uniformly provided through the BCS, with costs associated with such services recovered through contract charges to the suppliers.

Second, the BCS system can provide suppliers with explicit financial incentives to target energy-efficiency improvements to its payment-troubled customers. Studies have found that energy-efficiency improvements targeted to payment-troubled customers will help lower credit and collection costs, bad debt, working capital expenses, and other costs associated with non-payment and delinquent payment.[50] The BCS process would require quantification of these credit and collection expenses, as the basis for BCS charges to suppliers. In turn, the magnitude of such expenses, as reflected in contract charges, would be revealed to suppliers as costs avoidable with efficiency investments for payment-troubled customers.

Finally, the BCS process should reduce consumer confusion about the appropriate contact for billing inquiries. With the locus of the billing at the distribution company, there is a single point of contact for the customer for either distribution or energy-service bill inquiries.

Licensing Requirements

To provide public oversight of the entry of retail service providers in the State of Maryland, the Commission's restructuring plan must provide for the

[50]For example, ICF Resources (1991); Harrigan (1992); Synergic Resources Corporation (1988); Energy Coordinating Agency of Philadelphia (1989); Monte de Ramos et al. (1993, 771).

licensing of electric-service providers.[51] This licensing is consistent with other industries that significantly affect the public interest. If an entity fails to meet the requirements imposed upon it by the Commission, the license can either be limited or revoked.

At a minimum, licensing requirements should include

- certification of membership in the PJM power pool or successor ISO/Power Exchange;
- agreement to abide by the Commission's standards of conduct;
- registration filing with the Commission, and agreement to abide by the Commission's regulations regarding information disclosure;[52]
- agreement to post standard prices and provide service at such rates to all takers;
- agreement to provide customer's with standardized supply-contract terms and conditions, as established by the Commission;[53]
- posting of performance bonds, securing irrevocable lines of credit, obtaining liability insurance, or other appropriate arrangements for demonstrating financial viability during normal operations and the ability to cover potential liabilities from lapses in service.

Anti-Discrimination Measures

The potential for competitive retail service providers to engage in discriminatory practices is a significant consumer concern. While racial and gender discrimination is not an issue historically associated with electric utilities, retail providers operating under competitive conditions could very well engage in the types of discriminatory practices that have been employed in other competitive industries. When choices arise for competitive electric service providers—be it choosing which areas to serve or choosing which service options to provide within each area—there is an opportunity for the provider to engage in discrimination.

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[51]Legislation may be required to extend Commission jurisdiction over licensing of electric-service providers.

[52]Including disclosure of such information as required to identify potentially discriminatory practices. See the discussion below.

[53]Variations on the standard terms and conditions could be allowed where not disruptive to the market and where all special features could be clearly identified to customers.

Indeed, such discriminatory practices, though inequitable and unlawful, may simply reflect economically rational decision-making in a competitive market. (See, generally, Trczinski 1993.) For example, redlining of minority neighborhoods by lending institutions may reflect the fact that the transaction costs for processing loans in these neighborhoods may be significantly higher than in areas where households readily satisfy traditional measures of creditworthiness. In these instances, profit-maximizing lending institutions with limited capital are likely to target those neighborhoods that provide the greatest profit margin.

Discrimination is often an extension of market research and test marketing practices of the involved industry. In the telecommunications industry, for example, the regional bell operating companies have come to believe that households with the greatest disposable income are the most receptive and reliable customers for advanced communication services. Despite evidence to the contrary, this belief significantly affects marketing strategy. Even in those instances where the telecommunications industry has expressed a willingness to eventually extend services such as video dial tone to low-income and minority communities, the industry has failed to respond to the concern that minorities and low-income people will be the last to receive the social and economic benefits of the Information Superhighway.

The same concerns are directly applicable to a competitive retail electric industry, as income and electric usage are directly correlated. Offering advanced new services only to affluent communities or, conversely, disproportionately providing limited services (such as prepayment meters or service-limiter adapters) in less affluent communities, would constitute discrimination in the provision of electric service.

The Commission can employ an “effects test” to prevent business practices that have a discriminatory impact upon a class of people even though the intent of the company is neutral on its face. The “effects test” has been employed in federal statutes covering such areas as employment, housing, consumer credit, and home loan mortgages. It involves proven models for preventing discrimination.

In addition, the Commission can adopt disclosure requirements for electric retail competitors in order to prevent discrimination against communities with high concentrations of racial minorities and/or low-income people.

Such disclosure requirements can be closely modeled upon the federal Home Mortgage Disclosure Act.[54]

DSM in Competitive Markets

Objectives for DSM under Restructuring

Maryland law and regulation have required vertically-integrated electric monopolies to minimize customers' total costs of regulated energy services they provide. This responsibility has included the obligation to make markets operate more efficiently by intervening in the marketplace with programs designed to overcome market barriers to energy-efficiency investment. Since under current regulation, utilities choose energy supply to serve their customers, they have had the responsibility to pursue energy-efficiency savings available from their customers that cost less than supply alternatives.

The economic benefits of such market intervention have been substantial. In 1995 alone, PEPCo's and BG&E's combined DSM investments are expected to realize $86 million in net benefits to Maryland. These net energy service cost reductions provide real benefit to Maryland's economy. They result in increased employment and economic activity by increasing disposable income of consumers, and by lowering the costs of doing business. Laitner and Goldberg (1996, 3) estimate that continuing to expand Maryland's investment in energy efficiency and renewables would generate $13 billion in increased economic benefits to the state, including the creation of 15,300 net new jobs by the year 2010. Accordingly, utility DSM investment has been a critical component of state energy policy.

The overriding goal of the restructuring process should be to maximize economic benefits to consumers without depriving utility shareholders the opportunity to recover costs and earn a fair return on regulated investment. Maryland should seek to exploit both the economies of competitive supply and the continuing economic benefits of DSM market intervention.

[54]Disclosure policies would require electric service providers to submit service and technology-deployment plans and periodic reports demonstrating compliance with the anti-discrimination regulations as a condition of receiving authorization to provide electric service. The disclosure requirement would permit the Commission to specify the types of statistical data to be included in plans and periodic reports in order to evaluate compliance.

The Role of DSM in Utility Restructuring

Does retail competition conflict with or obviate the need for DSM investment? Several arguments could be made for concluding that this is not the case.

Under retail competition, DSM is still valid because cost minimization remains the responsibility of the distribution utility.

Distribution utilities will continue to be regulated by the Commission, and should therefore continue to be obligated to minimize costs to customers. At a minimum, such an obligation should extend to the provision of regulated distribution services. In addition, this obligation could be extended to cover the provision of supply so that the obligation continues as today to minimize customers' total energy-service costs, regardless of the source of such services.

DSM efforts will continue to be cost-effective investments for distribution utilities.

Although distribution utilities will no longer incur the costs of supply on behalf of their customers, avoiding energy and capacity costs will still represent a major benefit of energy-efficiency investment to the Maryland economy. Just because they are not avoided by the regulated distribution monopoly does not mean they should be ignored in calculating the cost-effectiveness of DSM programs sponsored by distribution utilities. This is merely an extension of the practice of counting avoided customer costs such as reduced customer-owned equipment in determining the cost-effectiveness of DSM measures and programs under current regulation.

Distribution costs are either directly or indirectly avoidable by load reductions generated by DSM investment. In the past, the Commission has recognized that distribution investment can be deferred because of DSM load reductions. The practice has been to reflect the average of avoidable distribution costs based on randomly distributed load reductions throughout the utility system. Such averages have reflected cost savings that vary over a wide range. At one end of the range, avoided distribution capacity costs are zero from small load reductions deposited on circuits that will have excess carrying capacity for the foreseeable future. At the other end of the range, large load reductions have an extremely high value—as much as an order of magnitude greater than the average reflected in system-level computations of avoided distribution costs.

Utility resource planning has so far failed to specifically target DSM load reductions where they would have the most value, or to integrate the higher value of such targeted savings in DSM resource planning and acquisition. Such opportunities will not only persist under restructuring, but loom larger as a source of cost reductions as transmission and generation resources are functionally unbundled from distribution planning and investment.

Market barriers to customer investment in DSM will remain after restructuring.

The array of market barriers that impede customer investment in energy-efficiency investment originate from the nature of energy-efficiency investment: capital must be substituted for energy use. The primary barriers that have been recognized as impeding customer commitment of additional capital required for energy-efficiency investment include

- Lack of ready access to capital
- Cost and/or lack of specialized information needed to make decisions to commit capital to energy-efficiency
- Split incentives between efficiency decision-makers and energy users
- Real and perceived risks associated with committing capital for energy-efficiency investment

Other recognized barriers include transaction costs, lack of market infrastructure for some efficiency options, pricing discrepancies, and institutional constraints.

Regulators recognize that allowing customers to choose their electricity supplier will not make these barriers disappear.[55] Indeed, the same barriers have prevented customers from investing in efficiency costing less than unregulated energy sources, such as fuel-oil and propane. It is even plausible to expect that introducing customer electric choice will make energy decision-making more complicated than it is now, aggravating current barriers to efficiency investment.

ESCos seek to profit by overcoming market barriers that prevent customers from making energy-efficiency investment on their own. They attempt to do so by providing capital, obtaining information, taking risks, and incurring the

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[55]For example, the Vermont Public Service Board (1996, 106) recently wrote, "[W]e are persuaded that there is a strong likelihood that market barriers will continue to impede consumer acquisition of all cost-effective energy-efficiency measures even *after* the establishment of competitive generation markets and the functional separation of traditional utility companies. Those market barriers will need to be addressed to ensure that Vermont consumers realize the benefits of improved efficiency in electrical use."

transaction costs associated with energy-efficiency investment. The ESCo industry has matured and expanded since utility energy-efficiency investment in Maryland increased in the early 1990s. Opening up the retail electricity market may increase the role of ESCos by allowing them to bundle more services and add more value to customers.

Experience in Maryland and other jurisdictions shows that ESCos overcome some of the market barriers to some efficiency investment potential in some markets. They have been most successful with retrofits for relatively large customers. Transaction costs and timing constraints have so far prevented ESCos from making substantial inroads among residential customers and small business customers generally, or in the lost opportunity, market-driven efficiency potential from new construction and equipment replacement among larger customers.

Competition may provide market incentives for some suppliers to provide some of the efficiency measures and services currently or previously offered by utility DSM programs. It is reasonable to conclude, however, that market barriers will persist for most efficiency investment opportunities by most customers. These markets will therefore continue to offer substantial economic benefits from market intervention by regulated utilities. Maryland consumers and the Maryland economy will suffer if these opportunities are abandoned under restructuring.

Significant opportunities remain for transforming the efficiency market through utility DSM programs.

The vast majority of residential, low-income, and small business customers have not been reached by comprehensive retrofit programs. Lost opportunity markets—new construction, equipment replacement, and remodeling—probably have been partially but by no means fully transformed. In order for these markets to have been transformed, the vast majority of customers would choose high-efficiency equipment in the absence of utility DSM programs. This is probably only the case for selected equipment at certain efficiency levels. For example, such partial market transformation has occurred in Maryland with residential HVAC replacement of SEER 12 and below, and electronic ballasts in non-residential new construction.

But sales figures and utility participation data clearly establish that there are efficiency measures and premium efficiency equipment available and applicable to these and other markets that customers still do not choose due to market barriers. Further market transformation efforts through utility DSM programs are therefore still warranted where cost-effective.

Separating the generation from distribution functions will significantly reduce the lost-revenues disincentive for DSM investment by distribution utilities.

With the generation function and associated costs removed to a separate entity, only distribution revenue is lost when sales are reduced. The same remedies that work to overcome this disincentive for vertically-integrated monopolies will work for distribution utilities. The important difference is that the amount of lost revenue that must be recovered through rates will be considerably less.

As for competitive electricity suppliers, the sales revenue losses caused by distribution-utility-sponsored DSM are irrelevant. The Commission should not be concerned about the effect on retail suppliers' profitability from sales reductions caused by DSM programs sponsored by the distribution utility.

Proposed Actions

Based on the conclusions on restructuring and DSM reached here, and also on emerging policy in other jurisdictions, we recommend the following:

THE COMMISSION SHOULD REQUIRE DISTRIBUTION UTILITIES to continue to invest in cost-effective DSM. Distribution utility DSM should concentrate on three areas:

- Low-income DSM,
- market transformation, and
- DSM investment targeted to minimize total costs, particularly distribution costs using distributed integrated resource planning.

DEMAND-SIDE-MANAGEMENT MARKET TRANSFORMATION should be planned and implemented to achieve maximum effect and minimum cost. Accordingly,

- It should focus on market-driven events, such as in equipment purchases and building construction and remodeling
- It should be targeted at market actors most likely to have long-lasting effect, including manufacturers, vendors, and architect-engineers
- To have maximum effect in the Maryland market, strategies should be coordinated across distribution-utility service areas and even with other jurisdictions as part of ongoing or developing regional or national efforts

- Individual utilities should eliminate duplication of effort by planning and implementing market transformation efforts jointly in order to minimize costs to ratepayers

LOW-INCOME AND MARKET-TRANSFORMATION DSM PROGRAMS should be funded through a non-discriminatory, non-bypassable wires charge levied on all distribution utilities.[56]

THE LEVEL OF THE WIRES CHARGE should be set at minimum at 3 mills/kWh.[57] This is roughly midway between the amount of DSM spending undertaken by PEPCo and BG&E in 1995 (1.5 mills for BG&E, 4.2 mills for PEPCo).

THE COMMISSION SHOULD DIRECT UTILITIES to enter into a single collaborative with the Staff and other interested parties to develop a statewide strategy of jointly-delivered core low-income and market transformation programs.

THE COMMISSION SHOULD DIRECT ALL DISTRIBUTION UTILITIES to initiate pilot efforts to design and implement targeted DSM investments and distributed integrated resource planning (DIRP). These pilots should

- Develop and apply a methodology for consistently estimating the value of deferral of specific planned distribution investments based on specified load reductions on specific components
- Design strategies and develop the capability to produce load reductions in amounts necessary to defer specific projects
- Plan monitoring and evaluation activities to assess the effectiveness and feasibility of applying the strategies and approaches tested in the pilot efforts.
- Targeted DSM investments should employ program designs that have proved effective in securing maximum cost-effective savings from participants.

ANY SERVICES AND FINANCIAL INCENTIVES offered by distribution utilities in pursuit of market transformation and DIRP objectives should be available to unaffiliated energy service providers to incorporate in their retail offerings to

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[56]We recommend that this charge be billed as part of the overall distribution delivery rate, not as a separate line item on customers' bills.

[57]This is separate from and in addition to the wires charge for universal-service programs.

distribution customers, as long as such competitive providers comply with the information and planning needs of the distribution-utility-funded programs.

ALL DSM EXPENDITURES INCURRED IN PURSUIT OF DIRP OBJECTIVES should be in addition to the costs recovered through wires charges for low-income and market transformation programs.

TO FURTHER THE TRANSFORMATION OF THE ESCO MARKET, the Commission should explicitly encourage the formation of energy-service-buyers' cooperatives.

- The Commission should encourage ESCo-ops to offer re-bundled energy services, including electricity, natural gas and other fossil fuels, energy-efficiency, and renewable supply. Such comprehensive service would allow customers greater opportunity to realize economically optimal choice of energy sources and comprehensive energy-efficiency investment.
- Formation and market entry of such cooperatives would serve the public interest by offering comprehensive energy service at competitive energy prices, thereby offering a new opportunity for small customers to minimize their total energy service costs from a provider owned and controlled by member consumers.
- To encourage such market transformation in the energy services market, the Commission should lower any regulatory requirements that might otherwise be imposed on privately-owned or for-profit energy-service providers.
- The Commission should take notice that regional partnerships are being formed to establish a network of energy-service cooperatives in jurisdictions where electricity deregulation is imminent. For example, a regional co-operative agreement has been reached to serve several New England states.

Environmental Quality

Air Quality

Air pollution remains an important concern for Maryland, in terms of health, quality of life, and economic development. Maintaining and improving air quality will be expensive if the regulatory mechanisms are excessively circumscribed by source or geographical region.

Mechanisms already exist for control of air emissions in the state, particularly from new sources. However, in the near future, most electricity-related emissions in Maryland will be from older, higher-emission plants. Existing generating facilities have been "grandfathered," allowed to operate at higher emission rates than would apply to new units. In addition, a large share of the air pollution experienced in the state (the NOx that contributes to ozone and smog, fine particulates, mercury, and other heavy metals) blows in from up-wind states.

Increased competition in the electric industry should be implemented in a manner that supports and furthers the goals of environmental improvement. Over time, there should be more equitable treatment of old and new generation sources with regard to air pollution controls and costs. The older plants should be required to move toward meeting the regulations that apply to new facilities in the State, in order to provide for clean air and fair competition. The Commission should also avoid degrading air quality in Maryland (or imposing additional control costs in-state) due to increased power imports from high-emission upstate generators. To minimize the costs of environmental improvements, the Commission should emphasize market-based approaches.

To achieve these ends, the Commission should require that each supplier (the utilities in wholesale competition, each marketer in direct access) certify and demonstrate that its power supply is no more polluting than the average of generation in the regional pool, or presently owned by Maryland utilities.[58] This standard would be stated in pounds/MWh for NOx, SO_2, fine particulates, mercury, and (to lessen future vulnerability to carbon taxes and caps) carbon dioxide, and would allow trading of emission credits from suppliers whose plants are cleaner than average. The emissions standard would also reinforce Maryland's continuing support for broad regional air emissions cap-and-trade systems that would reduce the emissions from older, high-emitting generators in upwind states.[59]

Environmental Disclosure

If the Commission implements direct access, suppliers can be expected to use environmental claims in their marketing to customers. These claims have

[58]To avoid Commerce Clause issues, the standard should not favor in-state generation.

[59]EPA's pending revisions to State Implementation Plan requirements to reflect the results of the OTAG process may provide additional tools for reducing up-wind emissions. As those rules develop, the Commission should attempt to coordinate its policies with them.

been prominent in pilot direct-access programs in New Hampshire and Massachusetts, and have sometimes been very misleading.[60] If the competitive market is to be effective in reflecting consumer preferences, customers must be provided with accurate and useful information about the sources of their electricity. "Green" consumers (and businesses seeking an environmentally friendly image or ISO 14000 certification) should have meaningful opportunities to buy a "green" electricity product.

Protocols for environmental disclosure thus need to be developed, addressing the complexity of the electric power grid, bulk power transactions, and the variety of generating sources. To this end, suppliers must be required to disclose their full resource mix, and provisions must be developed for certification of generation mix and emission rates. As for the emissions portfolio standard discussed above, environmental disclosure will require that protocols for tracking transactions be put in place, ideally at the scale of PJM or larger. In addition, the rules must address knotty issues of attributing emissions to purchases that simply shift pool dispatch upward in the loading order.

Regulators in Vermont (VPSB Docket No. 5854, December 30, 1996) and Massachusetts (DPU 96-100, December 30, 1996) adopted environmental disclosure as part of restructuring. In addition, at the National Association of Regulatory Utilities Commissioners recent meeting in San Francisco it adopted a "Resolution in Support of Customer 'Right-to-Know' and Product Labeling Standards for the Retail Marketing of Electricity." In the resolution, NARUC "urges states adopting retail direct access programs to include enforceable standards of disclosure and labeling that would allow retail customers easily to compare the price, price variability, resource mix, and environmental characteristics of their electricity purchases."

Renewables

Renewable power sources offer a number of benefits to utility consumers, including reduction in environmental effects of energy production, reduced risk of fuel-cost volatility, diversification of supply mix, and (especially for solar photovoltaics) distributed support for the T&D system. Renewable resources provide immediate benefits in terms of pollution reduction and

[60]For example, Northeast Utilities claimed that it was selling entirely clean renewable hydro-electric power from its pumped-storage facility, which operates only about 20% of the time, and then requires about 1.3 kWh of fossil generation for every kWh of power delivered from the storage plant.

system diversity. They provide long-term benefits as our electricity system makes a transition to sustainability.

Maryland and PJM have been very dependent upon nuclear and coal generation. As nuclear plants are retired (which may occur sooner than currently scheduled), the replacement generation should be selected to minimize increases in air emissions or dependence on fossil fuels. Indeed, if carbon dioxide regulations are imposed in this same time frame, renewable resources may be required to play a major role in the generation mix.

Development of renewable resources faces significant market barriers. These include capital-intensity, lack of mechanisms to recognize pollution-reduction benefits, difficulty in financing, lack of familiarity, and limited market infrastructure. Examples of policies to address these barriers include: funding via a system benefits charge, a renewables portfolio standard with tradable renewable energy credits, studies to identify and overcome siting barriers, policies to address financing barriers, such as aggregation of projects, direct loans and project loan guarantees, net metering and billing for on-site projects, standardization of contracts for small renewable projects, education and information resources on renewables, tax policies, and integrated resource planning by the distribution companies. Broader policies, such as air emissions regulations, can be designed such that renewable resources receive appropriate credit contributing to compliance (e.g., for air-emissions caps and trading programs).[61]

Maryland can prepare for the future by encouraging the commercialization of certain renewable technologies, including wind, solar and biomass gasification. A renewables portfolio standard or a systems benefits charge for renewables can be designed and used in a manner that will provide for the development of infrastructure, and the commercialization of these technologies without undue impact on near-term electricity prices.

Commercialization of new renewable generating resources should be part of an electric industry restructuring package. In wholesale competition, the Commission can set a renewable portfolio standard for each utility. In direct retail competition, the renewable portfolio standard would apply for each supplier, although that standard could allow for trading of renewable energy credits, allowing market mechanisms to add renewable energy to Maryland's

[61] Under direct access, renewables will also be aided by green disclosure protocols, discussed above.

energy mix at minimum cost.[62] This portfolio standard should be designed to produce new renewable generating capacity, and to exclude hydro-electric generation (an established resource that needs no development push and has significant site-specific environmental costs) and municipal-waste combustion (a major source of air toxics). In any structure, a mandate for distributed utility integrated resource planning will tend to encourage the adoption of photovoltaics.[63]

As an alternative or supplement to the portfolio standard, funds could be collected through the system benefits charge and allocated to projects that will promote the commercialization of particularly desirable renewable technologies, thereby ensuring the development of a diverse mix of renewables and the local supporting infrastructure.

[62]With pool-based competition, encouraging renewables, local generation, fuel diversity, or other desired supplies would be more difficult. If pool-based pricing is offered as an option in wholesale competition, as we recommend above, any excess cost of renewables, over an equivalent portfolio of conventional resources, should be recovered from all customers on an equal cents-per-kWh basis.

[63]The Vermont Public Service Board (1996) recently adopted this approach. The Arizona Corporation Commission (1996) recently adopted a “solar portfolio standard” in its December 26 “Opinion and Order” in Docket No. U-0000-94-165. This standard requires electric service providers, starting on January 1, 1999, to derive at least one half of 1% of the total retail energy sold to be from new photovoltaic or new solar thermal resources. The requirement increases to 1% in the year 2002.

Stranded Costs

Policy Issues

Many utilities claim that regulators are obligated to compensate utility shareholders for all stranded investment, due to a "regulatory compact" between shareholders and regulators. This claim has no merit. The Commission has broad discretion in setting cost recovery for two basic reasons. First, there is no regulatory compact or other general binding constraint on the Commission when determining how to treat stranded costs, since

- the regulatory compact never existed;
- investors have long been aware that serious losses, even bankruptcy, were possible in the electric industry, and that retail competition was among the risks that they faced;
- electric-utility investors have for many years been compensated at levels sufficient to cover the risk of some loss of their strandable investment;
- some strandable investment may not have been prudently incurred.

Second, stranded-cost disallowance is supported by Maryland regulatory policy and precedents. Investors in Maryland utilities have always known that they have a reasonable expectation of a fair return only on the used-and-useful portion of plant.

A decision to allow stranded-cost recovery is a social-policy decision, akin to decisions regarding lifeline programs or economic development rates. Such decisions often link shareholder well-being to the achievement of larger societal ends. Similarly, the appropriate level of stranded cost recovery is the level that best achieves the overall objectives of the state in the restructuring process. Since the most-sensible compact proponents do not insist on full recovery of all strandable investment,[64] this issue seems amenable to a resolution in which the opportunity for substantial recovery is expressly conditioned on full utility cooperation in achieving the best result for customers and the environment in the years ahead.

No Compact Ever Existed

Many utilities across the country claim that regulators are bound by a clear and long-standing compact, understood by regulators, investors, customers and utilities. However, one searches in vain for any discussion of such a compact before the early 1980s.[65] One finds only general arrangements that varied from state to state and from time to time, arrangements that might give rise to investor hopes but not to the rights now claimed by utilities.[66]

In fact, we have not been able to find the phrases “regulatory compact” and “regulatory bargain” in any book or article written before 1985. Neither Bonbright, Phillips, or Kahn discuss a compact or bargain in the editions of their leading treatises on utility regulation published in the 1970s.

Dr. Kahn’s first use of the phrase apparently came in an August, 1985 op-ed piece in the Wall Street Journal. Because this is an early, clear and typical articulation of the “bargain,” it is worth examining closely.

Dr. Kahn warns that commissions that “define prudency on the basis of hindsight, and only for failures...play a regulatory game of heads-the-consumer-wins, tails-the-investor-loses,” thereby violating

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[64]For example, Baumol, Joskow, and Kahn (1994, 24), writing on behalf of the Edison Electric Institute, state, “A failure now of policy makers to ensure the companies *at least some reasonable level of recovery* of their regulatorily approved costs in any transition to competition would leave investors, in effect, with part—a very large part—of the value of their property expropriated by the change in the rules of the game” (emphasis added). Dr. Kahn (1994, 80) restates this point: “I have systematically refrained from making recommendations about the extent of the entitlement of utility companies to recover their sunk costs....It has been my consistent explicit policy to leave such determinations to regulators on the basis of considerations of equity, the likely effect of disallowances on the future cost of capital and assessments in the particular circumstances of the extent to which investors might properly be held to have had foreknowledge of the possibility of the change in the rules to their disadvantage or to have been compensated for such risks.”

[65]Even during the early 1980s, the discussions contained warnings to investors and others that the compact was broken, not affirmations of an ongoing agreement.

[66]“Actually, there never was a compact—only a wishful delusion by utilities” (Studness 1991, 34).

> the essential basis of public utility regulation...an implicit bargain between consumers and investors that, in exchange for a monopoly franchise, the company accepts the strict legal obligation to serve all customers on reasonable terms. This means that shareholders accept a return on investment equivalent only to something like the market cost of capital...along with the duty conscientiously to anticipate the future needs of the public and to make whatever investments may be necessary in order to meet them efficiently. This means that if the company makes a particularly successful investment,...the lion's share of the benefit goes to the consumer....The other side of the bargain is, and has to be, that investors are permitted to earn that same minimum return on the dollars that they put into investments that turn out sour.[67]

Dr. Kahn is not, and does not claim to be, articulating a contract. He is stating a way that regulation ought to work. To transmute Dr. Kahn's approach into a compelling claim for stranded-cost recovery, one would have to establish that utility investors has so absolute an assurance that regulation would work in Dr. Kahn's recommended fashion that any risk to the contrary cannot be assigned to them or at least that they have not been compensated for the risk of substantial loss.

Investors Were Warned

Investors have long been aware that serious losses were possible and that no compact protected them from regulatory change or competitive risk. Regulatory practice has varied widely among the 50 states. No one arrangement ever fit them all. Several deviations from Dr. Kahn's "regulatory bargain" were so pervasive that investors must have been aware of them.

The first was the doctrine in many states that customers should not pay for property that is not used and useful. The second was the proposition that regulators should not be expected to compensate investors for values undermined by competition. The third was the notion that regulators would not allow rate increases adequate to support traditional returns, and that bankruptcy for some utilities was a real possibility, especially in light of the fact that the recently discovered compact was badly broken. Finally, franchise agreements differ substantially. In New Hampshire, for example,

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[67]Similar formulations appear regularly after 1985, invariably in the context of assertions that the bargain has been broken. See, for example, Phillips (1993, 21) quoting Stelzer (1987, 20). The lament for the lost bargain was often accompanied by prophecies of blackouts and brownouts in the early 1990s if the bargain was not restored. See, for example, Butler (1985), Navarro (1985, 5–7), Pierce (1991).

franchises have never been exclusive, and state agencies are under a constitutional duty to further competition instead of monopoly.

In many states and at FERC, the-used-and useful doctrine has provided for the disallowance from rates of prudent investment. In 1981 the DC Circuit Court of Appeals restated its affirmation of this result as follows:

> NEP says that capital prudently invested in a generating facility is taken for public use and therefore must be included in the rate base....The general rule recognized by this court is that expenditure for an item may be included in a public utility's rate base only when the item is 'used and useful' in providing service: that is, current rate payers should bear only legitimate costs of providing service to them.[68]

The DC Circuit reaffirmed this view in an en banc opinion by Justice Bork:

> Absent that sort of deep financial hardship described in Hope, there is no taking and hence no obligation to compensate, just because a prudent investment has failed and produced no return.[69]

The U.S. Supreme Court reached the same result in *Duquesne Light and Power v. Barasch,* noting that a "rigid requirement for the prudent investment standard" would

> foreclose a return to some form of the fair value rule just as its practical problems may be diminishing....The emergent market for wholesale electric energy could provide a readily objective basis for determining the value of utility assets.[70]

As noted earlier, investors have for many years been aware that no compact or other claim assures them of protection in the case of assets whose value is undermined by competition. As long ago as 1932, the Supreme Court warned that the Constitution

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[68]NEPCo Municipal Rate Commission v. FERC 668 F. 2d 1327, 1333 (1981).

[69]*Jersey Central Power & Light Co. v. FERC*, 810 F. 2d 1168, 1181 (1987, n.3). Judge Starr concurring (1190) wrote "The prudence rule looks to the time of investment whereas the 'used and useful' rule looks toward a later time. The two principles are designed to assure that the ratepayers whose property might otherwise be 'taken' by regulatory authorities, will not necessarily be saddled with the results of management's defalcations or mistakes, or as a matter of simple justice, be required to pay for that which provides ratepayers with no discernible benefit....The 'used and useful' rule operates as a restraining principle, reminding utility managers of economic forces working against an investment which is prudent at the time it is made."

[70]488 U.S. 299 (1989, 316).

> does not assure to public utilities the right under all circumstances to have a return upon the value of the property so used. The loss of, or the failure to obtain patronage, due to competition, does not justify the imposition of charges that are exorbitant and unjust to the public. The clause of the Constitution here invoked does not protect public utilities against such business hazards.[71]

Twelve years later, the Supreme Court sustained a decision of the California Commission to set rate base for the Market Street Railway not at prudent investment but instead at the price that the utility had asked of the city for its properties. In an opinion devoid of any discussion of stranded investment, exit fees or compacts, the Court wrote as follows about state-franchised utility assets whose value had diminished as a result of state-encouraged competition from state-built highways and streets, and state-certified taxis and trucks:

> The Due Process Clause has never been held by this Court to require a commission to fix rates on....an investment after it has vanished, even if once prudently made, or to maintain the credit of a concern whose securities already are impaired. The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.[72]

The compact proponents apparently claim that despite this history, investors are entitled to full cost-recovery because the particular traumas of retail competition could not have been foreseen. As a factual matter, this claim is dubious. Utility cost-of-capital witnesses frequently argued for higher returns on equity because of the increased risk of competition throughout the utility industry. Retail competition came to both long-distance telecommunications and gas pipelines well in advance of the changes rocking the electric industry today. Utility investors have never been entitled to complete protection from the risk that customers would find ways to benefit from lower costs (including through change in the regulatory structure).

Finally, electric-utility investors have known for many years of the possibility of substantial losses, including bankruptcy. Investors from the late 1970s on were alerted that regulators were not allowing rate increases adequate to support traditional returns. Burdened by power plant

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[71] *Public Service Commission of Montana et al. v. Great Northern Utilities Co.,* 289 U.S. 130, 135 (1932).

[72] *Market Street Railway Co. v. Railroad Commission of California et al.*, 324 U.S. 548, 567 (1944). This and the Montana case are discussed in Phillips (1993, 381).

construction costs, Consolidated Edison Company of New York omitted its dividend payment in April, 1974. Leonard Hyman, former head of the utility research group at Merrill, Lynch, describes investor reaction:

> Con Edison's dividend omission hit the industry with the impact of a wrecking ball. It smashed the keystone of faith for investment in utilities: that the dividend is safe and will be paid. Wall Street firms, at the behest of panic stricken clients, prepared lists that showed which utilities were in bad shape....Investors had to accept the possibility of financial risk in utility securities. (Hyman 1988, 109)

It also became clear that bankruptcy for some utilities was a real possibility. After Cincinnati Gas and Electric announced in October, 1983, that it could not afford to complete the Zimmer nuclear plant, according to Hyman (1988, 110–111),

> utilities tottered on the brink of bankruptcy....Within twelve months, six utilities cut or omitted dividends, almost $6 billion of construction effort was consigned to oblivion, and the stock prices of the affected utilities fell 60–80% from their 1983 highs. The message was clear. Utilities with serious problems caused by construction failures and extreme cost overruns would not be made whole by regulatory agencies. Investors could not depend on regulators for guaranteed returns or for bailouts.

A municipal corporation, the Washington Public Power Supply System defaulted on some $2.5 billion worth of revenue bonds and established that even investors with seemingly real contracts were not fully protected (Phillips 1993, 681–682)

Investors Have Been Compensated for Risk

The National Association of Regulatory Utility Commissioners publishes an analysis of utility shareholder returns. Some of the key findings from a recent edition are as follows:

> The common stockholders of 72% of all major electric and telecommunications utility companies earned a higher internal rate of return than did the average stockholder of the major non-regulated U.S. industrial corporations over the 21 year period 1972-1992....
>
> A second technique for determining the returns...documents that 45% of electric- and telecommunications-utility companies earned a higher rate of return than did the average stockholder of the major non-regulated U.S. industrial corporations over the same 21-year period.
>
> A third method...shows that 73% of electric and telecommunications utility companies earned a higher rate of return than did the stockholders of the major non-regulated U.S. industrial corporations over the same 21-year period. (Foley and Thompson 1993, i)

In a reporting on an earlier edition of the same study, the study's authors conclude "that individual investors have earned returns from electric utility common stock which exceeded those of non-regulated industrial corporations over the 17 year period 1972–1988" (Foley and Thompson 1989, 34).[73]

If electric utilities have really outperformed industrial companies, whose investors clearly accept the risk of bankruptcy and adverse governmental action, then surely utility investors also have been compensated for the risk that some of their investment will be lost, by stranding or by some other means. This conclusion is reinforced by the fact that most utility stocks have traded significantly above book value for all or most of this era. This condition can only occur if shareholders are earning more than the required return on book, i.e. in excess of the constraint to which they have ostensibly agreed as part of their obligation under the "compact."

This seems to be the view of some utility executives. Wisconsin Electric CEO Richard Abdoo told the House Energy and Power subcommittee in July, 1994, "Our company has written off its uneconomic assets, so allowing others to recover stranded costs would penalize us" (quoted by Penn 1994, 2). A year later he was blunter still: "Stranded cost is a utility term. In economics it's called uneconomic assets. And in Economics 101 those sunk costs get written off. There's no rocket science involved" (*Energy Daily* [December 4, 1995]:4)

Some Strandable Investment May Be Imprudent

Utilities assert that their right to recovery extends to every dollar not disallowed as imprudent. However, regulators know how small a percentage of the total utility revenue stream is ever actually reviewed for prudence. The discrepancies between the resources available to regulatory agencies and the construction budgets of most utilities is so great that millions of dollars make their way into rates without serious scrutiny. That is one reason why most commissions put the burden of justifying even existing rate levels on utilities in rate proceedings.

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[73]Foley and Thompson (1989, 29) quote John V. Cleary, then CEO of Green Mountain Power, who states, "If you had invested $100 in utilities in 1955 and another $100 in a composite of industrials and reinvested all the dividends paid on both portfolios, the total pretax return in nominal dollars on your utility investment at year end 1986 would have been, you guessed it, greater than the return on industrials." Forbes Magazine is quoted as concluding, "Utility stocks have soundly beaten the market since 1975—catching much of the street napping."

Maryland Regulatory Precedent

Investors in Maryland utilities have always known that they have a reasonable expectation of a fair return only on the used-and-useful portion of plant. This proposition has long been a basic tenet of ratemaking in Maryland, and has been reaffirmed in a number of decisions. For example, in Order No. 73011, Case No. 8715 (In the Matter of the Inquiry into Alternative Forms of Regulating Telephone Companies), the Commission stated that "utility rates are set so as to recover all prudently incurred operating expenses as well as a return on prudent, used and useful investments...." (61–62) Similarly, in BG&E's latest gas rate case, the hearing examiner stated that "a basic tenet of ratemaking for utilities is that a return on investment is allowed on plant which is used and useful...." (*Re: BGE*, 86 Md. PSC 378 [1995, 407])

Investors should also have been aware that the Commission was willing to apply this principle in practice. For example, in *Re: BGE*, 75 Md. PSC 171 (1984), the Commission excluded from rate base as not used and useful the common costs allocated to Unit 2 of the Brandon Shores plant, since Unit 2 had not entered service.

Determination of Stranded Cost

The restructuring process will separate the utility's generation operations from cost-of-service recovery. This may result in the stranding of generation-related regulatory assets, nuclear decommissioning costs, and above-market costs of power plants and power purchases.

Ratepayers are unlikely to benefit significantly from restructuring if stranded costs are not accurately determined and equitably recovered from ratepayers. If stranded costs are overstated, restructuring will result in windfall profits for utility shareholders and higher rates for customers.[74] If stranded costs are not reasonably allocated to customer classes, restructuring could entail an inequitable shifting of embedded costs among customers.

While this discussion is phrased in terms of positive stranded costs, it should be noted that stranded costs can also be negative. For the Maryland utilities,

[74]Shareholders profit, and ratepayers suffer, because the combination of stranded cost recovered through rates and revenues gained from sale of plant output on the market exceeds the cost of service that would have been recovered under traditional ratemaking. This excess recovery could also give the utilities the financial resources to increase their market power.

restructuring of generation is more likely to produce a gain than a loss. The only major generation resources likely to be priced significantly above market price are a few NUG contracts (such as Warrior Run), some nuclear entitlements (particularly Salem), and potentially PEPCo's purchase from Ohio Edison.

The bulk of nuclear decommissioning liabilities should probably remain with the current distribution utility's ratepayers, to ensure that nuclear plants can be safely retired. Some portion of the costs should be borne by the owners of the plant, to provide cost-control incentives and reflect the increased decommissioning costs due to continued operation.

Regulatory assets, such as the generation-related portion of under-funded post-retirement benefits and previously deferred costs, should be offset by regulatory liabilities (over-funded pensions, deferred taxes).[75] The differential is apt to be small and not very controversial.

Final Determination

Stranded generation costs should be determined on a net basis, as the difference between the utility's net investment and the market value of the utility's generation resources. The estimate of stranded investment should reflect both restructuring gain from assets with market value in excess of net book cost, and stranded costs for investments in excess of market value.

Future operating costs should not be counted in the calculation of stranded cost for uneconomic generating assets. A plant whose operating costs exceed the market price of its output has no market value and should be retired. The stranded cost for such a plant is simply the net book cost.

The calculation of stranded investment should include only those costs that cannot be reasonably mitigated through prudent reductions to operating costs, through renegotiation or buyout of power-purchase contracts, or through refinancing or securitization of stranded costs. Stranded-cost recovery should be contingent on the showing of a good-faith effort to mitigate excess costs.

Stranded-cost determination should be based on a verifiable market valuation of generating assets; the allowed level of recovery should be pegged to divestiture or equivalent market-derived value. Divestiture, if done properly, should provide a direct market valuation of assets for

[75]Demand-side-management deferrals are not strandable costs, since they have nothing to do with generation and will continue to be collected through the distribution utility.

determination of the net effect of the transition to competition. Specifically, if generation assets are sold through a properly-structured auction, the market value of the assets will be maximized and total electricity bills can be minimized.[76]

Strandable investment will be affected by market power. If the market structure is not fully competitive, market prices for energy and capacity will tend to be higher, thereby lowering strandable investment. Concerns about market power (including utility reluctance to divest generation) would justify reductions in stranded-cost recovery.

Interim Stranded-Cost Determination

The final determination of stranded costs will take some time, as utility assets are auctioned off or otherwise revalued. Some power-purchase contracts may simply continue, with the stranded portion or gain determined by future market value. In the meantime, restructuring can proceed with interim stranded-cost charges, based on an administrative determination and subject to true-up.

The Commission should set interim stranded-cost rates at the low end of the plausible range, to encourage utilities to move forward in the restructuring process.

Interim stranded costs for each power plant would be determined as the difference between net book value and estimated market value, where the latter is the present value of the annual operating profit:

market value of power – future operating costs

over the remaining expected life of the plant (the license life for nuclear units, at least 20 years for most fossil units, and 40 years for hydro units). If a unit's annual operating profits are projected to be consistently negative, the plant should be treated as retired, and the net book value split between shareholders and ratepayers as it would be for any other retired plant. In no case should any future operating costs, including capital additions, increase stranded costs. Indeed, the Commission should establish a cut-off date for recognizing capital additions in net plant.[77]

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[76]Divestiture also provides a solution to the problems of vertical integration, by separating generation from distribution.

[77]This is particularly important for plants that are more expensive than their market value.

The market value of power should reflect both energy and capacity, and the energy values should reflect plant operating schedules: the average kWh from a peaking or intermediate plant is more valuable than the average kWh from a baseload plant. Since PJM is rapidly approaching the date at which it will need new power supplies (roughly 2000), the market price of power can be expected to rapidly rise to reflect the capacity costs of CTs and the baseload energy cost of combined-cycle plants.

The interim stranded costs should also reflect improvements in annual energy output and in future operating costs, driven by competitive-market incentives and possibly new ownership.

Mitigation of Stranded Cost

If any stranded-cost recovery is allowed, it should only be allowed for utility plants that have been (or are to be) sold at a properly structured auction, and for purchased-power contracts that have been restructured to minimize costs. Major plants that are not performing to the standards set by the utility and the industry should be valued as if they were up to standards, rather than at the lower price created by poor management. The burden should always be on the utility to demonstrate that these conditions have been met.

Stranded costs can be mitigated by recognizing such assets as over-funded pension accounts, excess tax collections including those being repaid pursuant to the Tax Reform Act of 1986, and the value as generation or industrial sites of land divested with the generation assets, including retired plants and land held for future use.

Maximizing Market Value of Utility Plant

The maximum value for power plants is likely to be achieved through sale of ownership shares at auction. No utility can be said to have fully mitigated strandable costs of its generation assets unless it has sold off each such asset to the highest bidder, through a properly-structured auction.

The value of a power plant is not determined by its operating costs, capital requirements, technical capabilities, fuel costs, or useful life under the current utility's ownership. Nor is it determined by the expectations of those values, or market prices (which depend on assessments of the prospects for other power suppliers, existing and new), held by the utility, the Commission, or any particular party to the restructuring process. Even future actual conditions at the plant and in the market do not determine the market value of the plant today. All that matters is what each bidder believes about the potential for the plant if it were under the bidder's control, given its technical expertise, access to fuels, and projections of future costs. Some bidders will pay too much, and find that their acquisitions are not very profitable, while others will reap windfalls for good choices and good management.

The structure of those auctions should be subject to Commission review and approval. The auctions should allow for

- full disclosure of operating and technical data, and detailed inspection of the plants by potential buyers;
- multiple rounds of bids;
- flexibility in bidding, to allow buyers to bid by unit, plant, or group of plants (e.g., the steam and combustion-turbine plants at Chalk Point, or all PEPCo coal plants with supporting services);[78]
- bidding by the utility or an affiliate (which might allow retention of deferred taxes and allow for a higher bid for the plant), but only under the supervision of an independent agent, selected by the Commission.

The timetable for divestiture will vary by utility and plant, taking into account the following considerations:

- The current uncertainties in operation of the regional power market and the valuation of ancillary services would probably suppress the market valuation of generation assets. The ISO and power exchange should be structured, and at least draft pricing rules should be in place, prior to the first auctions.
- The Commission should seek to avoid a flood of simultaneous sales of generation (in Maryland, regionally, and nationally), which may overwhelm the market. A more gradual approach is more likely to maximize value.
- Fossil plants can be sold more easily than nuclear plants (only BG&E's Calvert Cliffs and Delmarva's small shares of Salem and Peach Bottom are relevant to Maryland). Experience should be accumulated in auctioning off fossil capacity (and the small amount of jurisdictional hydro capacity), prior to attempting nuclear sales. Recent experience—

[78]The size of the packages should be constrained by considerations of horizontal market power.

equity issues by Great Bay Power, the privatization of British Energy, and the sale of Soyland's share of Clinton to Illinois power—indicates that viable nuclear plants can be sold. If sales are not possible, nuclear capacity can be spun off into separate corporations through initial public offerings (IPOs).

- All, or a controlling majority ownership, of each jointly-owned plant should be sold to a single buyer. In most cases, buyers will want to be able to control the plant's costs and operation. This will require coordination between state regulatory Commissions in PJM, to maximize the value of such plants as Conemaugh, Keystone, Safe Harbor, Salem, and Peach Bottom.[79]

Ratepayers should not bear the costs stranded due to the utility's failure to maintain plants in good condition.[80] The Commission should require utilities to explain any reduction in value attributable to the failure to maintain the performance levels (O&M, availability, heat rate) typical of industry practice, or those promised at the time the Commission approved acquisition or additional investment in the site. The burden should be on the utility to demonstrate that the diminution in value was prudent or unavoidable.

If any significant portion of utility plant cost is stranded, it should be securitized and refinanced to reduce annual and present value carrying charges.

Minimizing the Costs of Purchase Contracts

By national standards, Maryland's exposure to power-purchase contracts is limited. Nonetheless, above-market power purchases from utilities or NUGs can be mitigated in the following ways.

- Where power-purchase arrangements do not reflect the seller's cost structure, total costs can be reduced and value increased by renegotiation of contract terms. NUG contracts for fixed quantities of energy at high prices may be split into variable and fixed costs, to facilitate economic dispatch and load following. These renegotiated agreements may provide lower revenue to power producers, in exchange for reduced generation

[79]Similar coordination will be necessary with the other regulators of Potomac Edison (Virginia and West Virginia) and the other APS subsidiaries (Pennsylvania). Virginia and West Virginia have shown much less interest in restructuring than has Pennsylvania.

[80]Salem is an example of a plant that has performed very poorly, and will probably have a low market value as a result.

and reduced costs. Utility contracts for baseload power may be revised to follow the incremental cost of power from the seller's plant or pool.[81]

- If a plant is uneconomic to operate, the utility should be able to negotiate a temporary or permanent shut-down of the facility that leaves both the utility and the seller better off than continued operation.
- Securitization (and more generally refinancing) of the above-market portion of a contract as a regulatory asset should generally reduce the costs of the purchase. The financing can pay for a one-time buyout or buydown payment to reduce rates to market levels, or it can spread the short-term above-market annual costs over a longer period.
- Contract renegotiation in combination with refinancing can further reduce total costs to ratepayers.

Securitization

Securitization is being promoted by utilities and the financial community as a vehicle which can substantially reduce the expense of stranded-cost recovery by replacing the high-cost equity component of stranded costs with low-cost debt. Because equity is riskier and, unlike interest, dividend payments are not deductible for income tax purposes, equity capital is generally two to three times more expensive than investment-grade debt.

Securitization involves creating a stand-alone financial asset which yields a fixed and certain stream of income, and is legally and economically separate from the owner's other property in a manner that protects lenders from any possible bankruptcy risk. The secure income from the asset can then be used to collateralize high investment grade bonds which will be sold on the asset-backed securities market. See, generally, Blankton and Mamdani (1990).

Securitization is presently used primarily with respect to large portfolios of credit card, auto, and home equity loans. Under electric utility restructuring, the securitization asset consists of the irrevocable obligation of ratepayers to pay "transition charges," i.e. the utility's recoverable stranded transition costs, through non-bypassable surcharges

In many respects, securitization is not fundamentally different from traditional non-recourse project financing, or traditional accounts receivable financing. What primarily distinguishes securitization from these more

[81]Restructuring of the selling utility (PECo, Ohio Edison) may require renegotiation of the contract in any case, since the utility system on which cost-of-service rates were set may no longer exist.

traditional devices is the amount of money at issue, and how the securitization packaging gives the borrower direct access to low-cost ABS financing.

The objective of stranded-cost securitization is straightforward: to put the proceeds of low-interest securitization bonds into the hands of the restructured utility so that it may use these funds to immediately repay expensive debt and preferred stock, reduce the amount of high-cost common stock capitalization, and pay off transition charges associated with restructuring.

Opportunities to reduce the costs of corporate debt with securitization may be limited, since securitized financing may be more expensive than high-grade corporate bond financing, and only marginally cheaper than intermediate level investment grade bond financing. According to a filing for approval of securitization for Philadelphia Electric Company, "in spite of their pristine credit ratings, ABSs do not typically trade at spreads over U.S. Treasury Securities as narrow as AAA-rated corporate bonds," and, in fact, generally trade at about 20 basis points above these corporate bonds (Hiller 1997, 12–13).

Once issuance and credit-enhancement fees are taken into account, the effective interest costs of securitization financing will probably be more than that of most of the outstanding bond indebtedness of large utilities. The PECo securitization filing, for example, anticipates accruing up-front securitization financing costs of $277 million in order to generate $3.6 billion in net securitization proceeds (Cohn 1997, Exh. ABC-10). Taking these up-front transaction costs into account, the effective interest rate connected with PECo's securitization is about 9%. By contrast, the blended interest rate of PECo's callable-bond indebtedness is only about 7.7% (Mitchell 1997, Exh. JBM-2).

As a result, the primary benefit of securitization may not be in replacing corporate bond debt with securitization debt, but in replacing equity capital with debt of any grade. Even with debt interest at 9% or higher, securitization can significantly reduce cost of capital if used to replace equity capital, because the comparable effective before tax cost of equity will generally be in the 20-to-22% range.

The potential for reducing the overall utility cost of capital by replacing equity with debt has always existed. There have, however, always been financial and legal impediments. Thus, for example, the existing first-mortgage indentures of most utilities require that they maintain certain minimum debt coverage and earnings-to-interest ratios (Parish, Green, and Kinney 1997). Even without the indentures, excessive leverage has been viewed as inherently dangerous, particularly for utilities experiencing financial stress, because it magnifies the financial risks of cash flow uncertainties and increases the prospects of bankruptcy.

In contrast, stranded-cost securitization gives a utility access to low-cost non-recourse financing, and reduces the inherent financial risks of, and impediments against, a more highly leveraged capital structure. It does so by

- creating a stream of fixed and certain revenues through the imposition of irrevocable transition charges on ratepayers,
- creating a distinct and assignable financial asset secured by these revenues,
- legally separating this financial asset from the utility by selling or otherwise transferring it to a legally distinct special purpose entity.

These attributes make the transition bonds secured by this asset more marketable in the ABS market and better suited for substituting for equity capital. The assignment of the transition-charge asset and its receivables as bond security is bankruptcy proof, meaning that these assets are absolutely immune to the bankruptcy trustee should the utility petition for bankruptcy relief. Moreover, the transition-charge asset and its associated debt liability are off-balance-sheet for the utility, which has transferred away legal title to the asset, and is not itself liable on the bond debt.[82]

By removing the financial asset and the non-recourse bond debt from its balance sheet, the utility is effectively able to replace equity capital with debt capital without altering debt to equity ratio of its residual balance sheet.[83]

The mechanics of this model of securitizing stranded costs and its balance-sheet effects are set forth in Schedules 1 and 2 with respect to a hypothetical utility called XYZ. Schedule 1 shows the flow of funds and assets at the time

[82]See, generally, the January 22, 1997 "Application of PECo Energy Company for Issuance of Qualified Rate Order Under Sections 2808 and 2812 of the Public Utility Code, before Pennsylvania Public Utility Commission."

[83]A recent decision by the staff of the Security and Exchange Commission's Office of Chief Accountant calls into question the ability of utilities to give off-balance-sheet treatment to the anticipated transition-charge receivables and the bond liabilities they secure.

of XYZ's original bond issuance, and over the course of the repayment of the bond indebtedness.

Schedule 2 shows how, through the mechanics of securitization, XYZ is able to retain a 50-50 debt to equity ratio even while the absolute amount of its associated debt increases from $4 billion to $6 billion, and absolute amount of its equity capital contracts decreases from $4 billion to $2 billion.

For all the potential benefits of securitization, there are a number of reasons why the Commission should exercise caution in approving securitization proposals and issuing the requisite irrevocable rate orders.

First, the ability to sell securitization bonds at low interest rates is contingent on the market's perception as to the absolute certainty that the transition charges securing the securitization bonds will, in fact, be paid. This requires an enforceable government pledge that ratepayers' obligation to pay these transition charges is irrevocable. The notion of imposing irrevocable obligations on ratepayers is somewhat unprecedented and should therefore be employed with caution, particularly given the magnitudes of the stranded-cost obligations to be imposed.

Second, the concept of the irrevocable rate order raises a complicated legal issue of whether one legislature may, by statute, impose prospective obligations on one class of citizens (ratepayers) with respect to another class of citizens (utilities and their successors in interest) and bar future legislatures from repealing or modifying these obligations. In this regard, the general rule is that "one legislature is competent to repeal any act which a former legislature was competent to pass; and that one legislature cannot abridge the powers of a succeeding legislature."[84] There are exceptions to this rule, however, when the government's sovereign act to repeal or modify prior legislation conflicts with its own obligations as party to a contract, or when the subsequent legislation abrogates a vested right.[85] It is uncertain whether the irrevocable transition-charge obligations imposed on ratepayers under securitization legislation are within these exceptions.

Finally, the securitization mechanism will need to be carefully designed to insure that the issuance proceeds are targeted so as to maximize the public benefit, while minimizing transaction costs.

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[84]*Fletcher v. Peck,* 10 U.S. 87, 6 Cranch 87, 3 L. Ed. 162 (1810).

[85]See, generally, *United States v. Winstar Corporation,* __ U.S. __, 116 S. Ct. 2432, 135 L. Ed. 2nd 964 (1996).

As discussed above, securitized debt rates could be as high or higher than the utility's embedded debt cost. If so, virtually all the cost savings from securitization will come from replacing equity with debt. In this regard, the largest source of transaction costs may not be legal, brokerage, and investment banking fees, but the payment of stock repurchase premiums above book value to induce shareholders to resell their stock back to the utility. Assuming such premiums are paid, it would be inappropriate to include their costs among the stranded and transition costs reimbursable through the irrevocable transition charge. This charge is intended to indemnify shareholders for prudent costs incurred with respect to third parties, not for premiums they elect to pay to themselves.

Moreover, payment of such premiums is not necessary in order to achieve the objective of reducing the amount of outstanding common equity capitalization. Utilities can achieve the same objective by using the proceeds from the transition bonds to fund a special one-time dividend or distribution. This device will reduce the amount of equity capitalization on the utility's balance sheet without any need for large premiums.

Schedule 3 illustrates how a one-time dividend or distribution can accomplish the same equity capitalization shrinkage as a stock repurchase, without the need for a large repurchase premium. Ultimately, whether the utility chooses to reduce its equity capitalization through stock repurchases or with dividends should be a matter of indifference to ratepayers, provided ratepayers are not called upon to fund the repurchase premium.

Stranded-Cost Recovery

Stranded costs that are approved for recovery should be recovered through a non-bypassable distribution wires charge.[86] Determining this wires charge requires rules for the allocation of stranded costs among and within rate classes and over time. Allocation of stranded costs should meet the following criteria:

- The cost-recovery mechanism should be a usage-based, not a customer-based, charge. In general, if the utility is to recover some above-market

[86]For customers that leave the distribution system (e.g., through on-site generation without backup service), stranded costs could be recovered through some form of an exit fee. However, to the extent that restructuring reduces prices, the likelihood of distribution-system bypass should decline.

costs on the grounds that those costs would have been recovered under regulation, those costs should be recovered as they would have been under regulation. Hence, usage-based surcharges collected by the distribution utility are generally appropriate.

- To the extent that stranded costs are recovered from ratepayers, they should be recovered from the classes that would have paid the costs under regulation, or on a simplified dollars-per-MWh basis.
- Consistent with standard cost-allocation principles, stranded costs should be allocated to customer or rate classes on the basis of the benefits claimed to justify the initial investment. Restructuring gains should be allocated based on the classes' share of the costs of the investment.
- Rates should be designed to equitably recover from customers within the rate class the stranded costs allocated to that class.
- The cost recovery mechanism should be structured so that it does not provide incentives for a company to keep an uneconomical generating unit in operation. Stranded-cost recovery mechanisms in which recovery over time is predicated upon continued operation of generators could lead to inefficient decisions not to retire plants that should be retired, thereby slowing market entry by other producers and technologies.

In order to allocate costs equitably among and within rate classes, the OPC recommends that restructuring gains be allocated on demand and restructuring losses be allocated on energy. Customer or rate classes have been paying for plant investment based essentially on contribution to peak. They should therefore receive the benefits from that investment in proportion to their peak demand. Restructuring losses, on the other hand, are primarily associated with uneconomic investment in fuel-saving, baseload plant. These energy-related stranded costs are most appropriately allocated on energy.

The setting of the distribution wires charge also requires the selection of a reasonable cost-recovery period. The acceleration of stranded-cost recovery involves tradeoffs between short term and long term concerns and must be determined on a case-by-case basis. The appropriate recovery period depends upon such factors as

- whether there is a restructuring loss or restructuring gain,
- the magnitude of the loss or gain,

- the short- and long-term effects on consumer bills, reflecting anticipated trends in market prices of power,
- the effect of timing on the length of the transition period.

The timing of cost recovery also depends upon the type of stranded cost or restructuring gain. There are categories of stranded costs that should not be included in accelerated recovery, including regulatory assets and nuclear decommissioning. Unlike generation resources, which under restructuring will be valued according to market price, these costs will still be cost-based. In addition, utilities should stretch out the recovery of the above-market NUG contract payments, since NUG contracts are continuing costs. In addition, distribution-related costs, including DSM expenditures and distribution-related regulatory assets, are not part of the restructuring and should be recovered according to existing practice.

Rate Unbundling

Following restructuring, consumer rates will consist of the following charges:

- A cost-of-service-based distribution charge, with customer, energy (time-differentiated where feasible), and (where feasible) demand components varying by class, covering metering, billing, and customer services, distribution equipment, and transmission costs (net of charges and revenues from the ISO).
- A systems-benefits charge, probably as energy charges varying by class, covering low-income services, energy efficiency programs, and R&D expenditures (other than those related to the distribution function). There is no particular reason to state this charge separately on the bill; it can be part of a total delivery charge.
- A stranded-cost charge.
- A power-supply charge, with energy (time-differentiated where feasible) and (where feasible) demand components reflecting the current market price of power for each class's load shape. Customers who select direct access would not pay this charge to the distribution company.[87]

While the first two categories can be combined, the stranded-cost charge may change repeatedly over time as projections are reconciled and

[87]There are also a number of ancillary services, which will have to be priced separately at some point. In direct access, these services may be charged to power suppliers. Hence, they might best be included in the power supply charge. If distribution utilities pay for ancillary services, the costs can be recovered in the distribution charge.

continuing costs change, and should probably be stated separately. The power supply costs should also be stated separately.

Rate discounts in special contracts should be applied to the generation cost component. If recovery is allowed for any stranded generation costs, the discount can be applied first to the stranded cost component.

As we have seen in other jurisdictions, the process of unbundling rates provides utilities the opportunity to inequitably reallocate costs to its most vulnerable customers. To restrain such opportunistic behavior, the OPC recommends that utilities be required to include the following in their unbundled tariff filings of August 1, 1997:

- the cost-of-service data, embedded-cost-allocation study, and marginal-cost study relied on to develop unbundled rates, along with a comprehensive description of the changes to currently-approved data or methods incorporated in these studies;
- a complete description of, and all supporting workpapers for, the calculations of unbundled rates from the underlying cost-of-service data, embedded cost allocation study, and marginal-cost study;
- the quantitative effects over time on class allocation of costs from accelerated depreciation of plant, shifting of depreciation reserves, or other measures for collecting or offsetting stranded costs;
- a description of the procedures used to calculate the effects on class cost allocations of adopting the seven indicators of local distribution proposed by FERC in Order 888, and all results of such calculations.

These filing requirements would be in addition to those established by the Commission in Order No. 72938.

Cost allocations should be reexamined to, among other things, remove biases toward large energy users, more realistically reflect contributions to distribution equipment peak loads, and allocate power-quality investments to the large customers who demand them. To minimize confusion, this review of cost allocation methodologies and issues should be procedurally and temporally separate from the restructuring process.

Tax Implications of Restructuring

Consumers generally have a common interest with shareholders in ensuring that restructuring is favorably treated for federal and state tax purposes (e.g. in exempting interest payments on competitive transition bonds, or in preventing accelerated recognition of gain with respect to items designated as intangible transition property) in order to minimize the transition costs of restructuring. Accordingly, both ratepayers and shareholders have common interest in utilizing those tax-planning vehicles that will permit the ownership and control of utility assets and operations to be restructured without immediate recognition of capital gain.

Such tax-related interests diverge when considering the allocation between shareholders and ratepayers of the tax costs and benefits associated with restructuring. Ratepayers have a strong interest in ensuring that all the tax costs and benefits arising from restructuring are clearly and accurately accounted for, and that timing and character differences between rate and tax treatment of items of income, expense, and loss generated by restructuring do not result in an inequitable shifting of burdens and benefits.

Treatment of Accumulated Deferred Income Taxes

This is particularly true with respect to ratepayer advances for Accumulated Deferred Income Tax Liabilities (ADITs) under IRS and other normalization requirements. These advances have resulted in ratepayers acquiring a quasi-ownership stake in plant, as reflected in the dollar-for-dollar reductions in rate base and consequent reduction in shareholder return. With the large stakes involved, Maryland ratepayers have a significant interest in preventing

ADIT reserves and Accumulated Deferred Investment Tax Credit (ADITC) reserves from generating "stranded benefits" to shareholders.[88]

ADIT reserves arise because taxable income as reported on utility tax returns is usually less than before-tax income reported for book purposes, largely because of temporary differences which will ostensibly reverse over time. Thus, the tax deductions associated with an individual plant asset are disproportionately concentrated in the early years of the asset's life, when the asset's tax basis depletes much more rapidly than the plant's net book value for financial accounting purposes. As a result, the early tax benefits yielded by the asset will eventually reverse, and the asset will yield taxable income above actual book income in the latter years of its service life.[89]

The Internal Revenue Code, and most federal and state regulatory commissions, have made ratepayers normalize the income tax deferrals and other tax benefits through rules which require that ratepayers reimburse utilities for current tax expenses as if these tax benefits did not exist.[90] The utilities book the difference between the current tax liability actually payable and the imputed tax liability actually charged to and recovered from ratepayers to an Accumulated Deferred Income Tax reserve.[91]

Although most of the moneys accumulated in the ratepayer funded ADIT reserves will eventually have to be remitted over to the IRS, the interim right to use this money interest free is extremely valuable and belongs to ratepayers.[92] To insure that the use value of these reserves inure to the benefit of ratepayers rather than shareholders, Commissions require that the balance booked to the ADIT reserves reduce, dollar for dollar, the rate base upon which utilities are permitted to earn. As a result, utilities must make the undivided portion of utility plant allocable to ADIT reserves available for the

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[88]As of 12/31/95, Baltimore Gas and Electric's total ADIT liabilities exceeded $1.3 billion.

[89]To reflect the eventual reversal tax deferrals on balance sheets, the Generally Accepted Accounting Principles require an entry for Accumulated Deferred Income Tax liabilities. See, generally, Financial Accounting Standards Board (1992).

[90]See 26 U.S.C. Secs. 167(l) (accelerated depreciation), 168(i)(9) (accelerated cost recovery), and 46(f) (investment tax credit.)

[91]Before the Investment Tax Credit was eliminated in 1986, the Internal Revenue Code also required normalization of the credit, which at the time of its repeal was equal to 10% of qualifying capital investment.

[92]Pre-1987 ADIT reserves attributable to the portion of the 46% tax rate above 34% will not have to be repaid and are referred to as *excess* ADITs.

benefit of ratepayers, as it were, rent free. The resulting cost savings to ratepayers are significant, and should be protected and appropriately accounted for in the transition to competition.

Citing dubiously reasoned IRS private letter rulings as support, however, investor-owned utilities have been taking the position that the benefits of all accumulated ADIT reserves (including excess ADITs, resulting from the pre-1987 accumulation of ADIT reserves before the applicable tax rate was reduced from 46% to 34%) and ADITCs associated with costs of the transferred assets are irrevocably lost to ratepayers with the removal of utility assets from rate base (e.g., DeLoitte & Touche 1996; Hrisko 1996). Private Letter Ruling 8920025 held, for example, that on a regulated telecommunication company's transfer of customer-premises equipment out of rate regulation, all associated ratepayer funded ADIT reserves, even excess ADITs which clearly would never need to be remitted to the IRS, had to move with the assets, with ratepayers deprived of all present and future benefits associated with these ADIT reserves.

These private letter rulings have no precedential value (26 U.S.C. Section 6110[j][3]), and no binding IRS or court ruling has actually held that ratepayers cannot or should not be compensated for the full value of their beneficial interest in ADIT reserves upon the removal of associated assets and operations from rate regulation. Moreover, absent a binding ruling, IRS normalization rules do not prevent regulatory commissions from taking into account the transfer to shareholders of valuable ratepayer interests in ADIT reserves or other deferred tax related interests in sorting through claims for recovery of transition costs and other competing equities.

Absent a binding ruling from the IRS, the Commission can ensure that the existing ADIT-related benefits continue to accrue to ratepayers under restructuring. To do so, the Commission should ensure that utility restructuring proposals do not call for any taxable disposition of generation plant, and are structured to defer recognition of gain from stranded-asset recovery over extended periods. In this way, removal of plant from rate base will not result in an immediate tax liability in the full amount of the deferred reserves, and ratepayers can continue to benefit from deferral of ADIT liabilities over an extended period.

Schedules 4 and 5 illustrate the magnitude of the potential ratepayer benefit from deferred ADIT liabilities, or the windfall to shareholders from extinguishing these ADIT reserves when removing an asset from rate base.

The hypothetical generation plant in Schedule 4 went into service in 1984 at a cost of $300 million, and is scheduled to be removed from rate regulation in 1998. The plant has a 30 year service life and was depreciated for tax purposes over ten years. Schedule 4 shows how the difference between current taxes actually payable (col. 7) and the tax expense chargeable to ratepayers under normalization (col. 8) results in a growing reserve balance (col. 9), which then begins to decline after the reversal. Most noteworthy is the difference between the plant's net book value (col. 1) and the rate base upon which it actually generates a return for shareholders (col. 5.) The cost savings which this reduction to rate base generate for ratepayers in the form of reduced earnings is set forth in column 11, and the present value of this cumulative stream of rate reductions is set forth in column 12.

As of the date of its removal from rate base in 1998, the asset will have a net book value of $160 million, but a rate base value of only $96 million. As of 1998, the present value of the plant's deferred income tax liabilities are $31 million.(assuming a 10% discount rate.) The present value of the ADIT benefits which would have been conferred upon ratepayers from reductions to rate base had the plant remained in rate base are $33 million.

Under the utility industry's model, on movement of this plant out of rate base, this $33 million interest is extinguished, without quid pro quo, and the associated benefits transferred to shareholders.[93] If the plant is worth its full net book value upon transition to competition, the entire $33 million benefit is pure gain to the utility. Schedule 5, Scenario 2.

Tax Implications of Stranded-Cost Disallowances

There are other deferred tax issues associated with restructuring. In particular, to the extent that stranded generation costs are disallowed, shareholders and ratepayers may have adverse interests in designating the deemed origin of the disallowed costs. Shareholders, for example, have an interest in allocating these disallowances to sunk costs which have been fully depreciated for tax purposes, because they will then be able to reduce the ADIT reserve balances associated with this accelerated depreciation. Ratepayers, by contrast, have an interest in allocating the disallowances to

[93]This example disregards the effect of accumulated deferred investment tax credits, which would increase the potential loss to ratepayers.

the equity portion of unamortized AFUDC, as opposed to hard sunk costs. For tax purposes, this disallowed AFUDC represents foregone income which was never in fact recognized. The utility would therefore not be entitled to a tax deduction with respect to this disallowance; nor will the utility be able to make any charge against ADIT reserves, because no ADIT reserves were ever provided with respect to this AFUDC.

Recommendations

As discussed above, ratepayers have a large stake in ADITs and a significant interest in insuring that their ADIT-related interests are appropriately protected in restructuring. In order to protect these interests, the Commission should require utilities to file proposals for stranded-cost recovery that

- identify and quantify ratepayer rights and interests associated with ADITs;
- leave shareholders no better off with respect to ADITs after restructuring than they would have been but for restructuring;
- offset recoverable stranded costs by the present value of ratepayer ADIT benefits “stranded” by restructuring.

Conclusions and Recommendations

The restructuring process should be guided by two overarching principles. First, a restructured industry must provide Maryland consumers access to adequate, safe, reliable, and efficient energy services at fair and reasonable prices and at the lowest long-term cost to society. Second, the electric industry should be restructured only to the extent that it improves economic efficiency, provides tangible benefits to all consumers, and serves the broader public interest.

Experience with existing wholesale electricity markets indicates that there are likely to be significant benefits from enhancing competition in these markets. However, there is little experience to rely on in assessing whether opening up retail markets to competition will provide tangible benefits beyond those achievable with wholesale restructuring, or whether such benefits will outweigh the costs of restructuring the regulatory process to preserve public benefits in a competitive retail market.

Accordingly, the OPC recommends restructuring the wholesale market to create a fully competitive and efficient market for wholesale power supply. In addition, we recommend that consumers be afforded the opportunity to petition for direct access to competitive supply on a case-by-case basis. This approach will provide immediate benefits to ratepayers from wholesale restructuring, while providing time for the Commission to learn from experience with the retail-access option and from experience with retail competition in other states.

Wholesale markets will not be truly competitive if utilities can exercise vertical or horizontal market power in the regional market. The OPC therefore recommends complete divestiture of the unregulated generation from the regulated distribution business. Moreover, we recommend that control of the bulk transmission system be transferred to an independent system operator that is financially and operationally independent of generators, transmission owners, and other market participants.

Maryland's ratepayers have benefited significantly from an industry structure and regulatory process that provides reliable, efficient, and relatively clean energy services while vigorously protecting consumers' rights. These benefits are likely to be preserved under total wholesale competition. In contrast, retail competition may seriously degrade such benefits. If the Commission or the legislature adopts retail access as the model for Maryland, the industry and the regulatory process must be restructured to preserve and perhaps enhance public benefits in a competitive retail market.

Restructuring may result in stranded investment. If so, the Commission has broad discrimination in setting the appropriate level of recovery. Recovery of stranded costs should be conditioned on utility cooperation in promoting the public interest in the restructuring process.

Based on the findings and conclusions in this report, we offer the following recommendations for restructuring electricity markets and the vertically-integrated utility industry.

Recommendations

Market Structure

1. The Commission should restructure jurisdictional utilities to create a system of wholesale competition in generation services, with distribution companies remaining as monopolies under cost-of-service regulation.
2. Customers or suppliers who can demonstrate a special advantage to direct access, not available through utility offer, should be able petition the Commission to establish direct-access pilot programs for them.

Industry Structure

1. The Commission should support the establishment of an independent system operator for PJM (and another including the APS system), closely coupled to a power exchange, with the ability to
   - ensure least-cost dispatch of generation and transmission,
   - provide for fair and efficient pricing of transmission services,
   - allocate and price ancillary services, while assuring all participants access to those services,

- mitigate market power through the control of bidding practices or other means, and
- ensure construction of economic transmission.

2. The Commission should encourage the full corporate divestiture of generation from transmission and distribution functions.
3. Horizontal market power should be reduced by limiting each participant's ownership share of generation at the regional level. The Commission should condition access to the Maryland load on compliance with the ownership guidelines. Mergers of generation owners should not be allowed to create or increase market power.

Universal Service

1. Regardless of the competitive structure, the Commission should explicitly obligate regulated distribution utilities to provide non-discriminatory universal service to all customers.
2. Distribution utilities should provide a market-based default supply service for any customer not otherwise served.
3. Distribution utilities should provide funding for rate-affordability, energy-efficiency, and crisis-intervention initiatives, via a non-bypassable charge on all customers, initially set at about 0.7 mills/kWh.
4. Distribution utilities should not impose new service fees or reduce service quality in a manner that would disproportionately affect low-income customers.

Consumer Protection

1. Customer safeguards and protections that currently exist should be maintained under any future industry structure.
2. The Commission should adopt and enforce consumer-protection policies that
   - continue existing customer-service protections, including dispute resolution and privacy protections, under Commission purview as part of the provision of billing and collection services by regulated distribution utilities;
   - provide for certification and licensing of electric-service providers, including financial responsibility requirements, standards of conduct, pricing and environmental disclosure requirements, and provision for standardized supply-contract terms and conditions;

- provide for oversight mechanisms and disclosure requirements for preventing discriminatory practices.

DSM in Competitive Markets

1. Regardless of the form of competition, distribution utilities should continue to bear the obligation to minimize costs to customers, and hence to invest in cost-effective DSM, concentrating on three areas:
   - low-income DSM,
   - market transformation,
   - distributed integrated resource planning.
2. Low-income and market-transformation DSM programs should be funded through a non-discriminatory, non-bypassable wires charge levied on all utilities, set at a minimum at 3 mills/kWh.
3. The Commission should direct utilities to enter into a single collaborative with Staff and other interested parties to develop a statewide strategy of jointly-delivered core low-income and market transformation programs.
4. The Commission should explicitly encourage the formation of energy-service buyers' cooperatives.

Environmental Quality

1. The Commission should impose an air-emissions portfolio requirement on all suppliers to distribution utilities and to ultimate consumers, limiting emission rates (in pounds/MWh) to the regional average for NOx, SO_2, fine particulates, mercury, and carbon dioxide. Suppliers who over-comply on one pollutant should be allowed to sell their excess credits to other suppliers.
2. The Commission should develop requirements and protocols for meaningful environmental disclosure, reflecting generation mix and incremental emission rates.
3. Development of infrastructure and the commercialization of renewable energy sources should be encouraged through a portfolio standard or a systems benefits charge.

Stranded Costs

1. The Commission should not presume that utilities have any net stranded costs, or any right to recover such costs if they exist. Recovery of any stranded costs should be contingent on utility cooperation with efforts to mitigate such costs.

2. If generation resources have market values greater than their net book cost, the restructuring gain should be credited to ratepayers.
3. The bulk of nuclear decommissioning liabilities should remain with ratepayers, to ensure safe retirement. Some the costs should be borne by the owners of the plant, to provide cost-control incentives and reflect the increased decommissioning costs due to continued operation.
4. Interim stranded-cost charges should be based on an administrative determination and subject to true-up.
5. The Commission should set interim stranded-cost rates at the low end of the plausible range, to encourage utilities to complete the restructuring process.
6. Final stranded-cost determination should be based on a verifiable market valuation of generating assets, through divestiture or the equivalent.
7. The calculation of stranded investment should include only those costs that cannot be reasonably mitigated through prudent reductions to operating costs, through renegotiation or buyout of power-purchase contracts, or through refinancing or securitization of stranded costs.
8. Ratepayers should not bear any costs stranded due to the utility's failure to maintain plants in good condition.
9. Any approved stranded costs should be recovered through a usage-based non-bypassable access charge.
10. The Commission should allocate restructuring gains on demand (using the utility's traditional generation demand allocator) and restructuring losses on energy.

Rate Unbundling

1. Restructured consumer rates should consist of the following charges:
   - A cost-of-service-based distribution charge;
   - A systems-benefits charge, bundled with the distribution charge into a single set of delivery rates;
   - A stranded-cost charge;
   - A power-supply charge. Customers who select direct access would not pay this charge to the distribution company.
2. To prevent inequitable reallocation of costs to the most vulnerable customers, the Commission should review the cost basis and projected

rate effects of unbundled tariff proposals, with at least the level of care that it would exercise in any other rate proceeding.

3. Rate discounts in special contracts should be applied to the generation cost component, and should be borne by stockholders, not by ratepayers.

Tax Issues

1. The Commission should require utilities to file proposals for stranded-cost recovery that
   - identify and quantify ratepayer rights and interests associated with ADITs;
   - leave shareholders no better off with respect to ADITs after restructuring than they would have been but for restructuring;
   - offset recoverable stranded costs by the present value of ratepayer ADIT benefits "stranded" by restructuring.

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