ELECTRICITY TRANSMISSION AND EMERGING COMPETITION

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INTRODUCTION

Interesting times. Challenging times. Confusing times. The electricity industry and its regulators are now inextricably meshed in a tangle of interconnected reforms needed to support the emergent ideology of competition in electricity generation and supply. The EPAct[2] provided the authority, the Federal Energy Regulatory Commission (FERC) has demonstrated the will, and a critical mass of interested players has maintained the political pressure needed to open much of the electricity market to new entrants and new choices. With fifty states as laboratories, enough inquiries are moving forward to promise a demonstration effect and added momentum. The process is accelerating. There is no going back.

But which way is forward? The old model of a closed system of vertically integrated electric utilities offering bundled service has been discarded in theory and is being dismantled

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2 Public Law 102-486, 106 Stat. 2776 (1992).

in practice. However, consensus on a new model of the structure of the industry, the connection with technology, and the requirements for regulation has not yet emerged. The industry is in the throes of redefining itself in a process that is plagued by overlaps of jurisdiction, gaps between authority and responsibility, complex technical realities, a high noise to information ratio, and incentives created by a potential for huge transfers of wealth through control of the regulatory rules. The process is -- well -- interesting. The transformation underway requires nothing less than a complete reorientation of how we view this world -- a change of paradigm with new models, new definitions and new rules.[3]

The process has reached a critical stage that requires a clearer view of the structure of the new system. Parallel developments in FERC proceedings, state inquiries, and industry restructuring are lurching forward without recognizing fully how each part affects the others. There is a need for a greater sense of urgency here: fundamental connections among several pieces of the overall puzzle must be recognized soon and incorporated in the reforms if the promise of open competition is to be realized and the economic gains achieved.

The key is in understanding the role of transmission and the requirements for efficient competition. The principal challenge today falls to the industry, and especially to the existing utilities. The FERC has broken through many barriers in the recent Notice of Inquiry (NOI) on alternative pooling institutions[4] and the Notices of Proposed Rulemaking (NOPR) on stranded

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[3] T. Kuhn, The Structure of Scientific Revolutions, 2nd ed., enlarged, University of Chicago Press, 1970.

[4] Federal Energy Regulatory Commission, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000, October 26, 1994.

assets and transmission access.[5] The various notices ask many questions and even suggest a few default answers. The FERC goes far -- perhaps as far as FERC can go by itself -- but not far enough. The default proposals fall short of meeting the requirements for an open, efficient, competitive electricity market in a network. The FERC transmission analysis lays bare the many faults of the old model, but without a vision for an alternative to the old model, the old model endures. Now is the time for the industry to respond and offer FERC and the state regulators the means to see the new structure and go the next several steps forward without tripping over the wreckage of the past.

BREAKTHROUGH OR BREAKDOWN

The various FERC pronouncements have been well received by the industry, and with good reason. The decision to address transmission access and market structure problems early and in a generic way benefits from the experience in previous restructurings, such as with natural gas pipelines. The FERC has been explicit and forceful about the public's need and its desire for clarity and conviction in the commitment to support a competitive market through open access to the transmission grid and the "golden rule" of comparable service. The FERC has undertaken a serious inquiry into alternative institutions such as pooling mechanisms that go well beyond mere incrementalism to contemplate fundamental reforms. The FERC principles for treatment of potential stranded assets provide a firm backdrop for debate in the states where the major issues must be addressed.

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[5] Federal Energy Regulatory Commission, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket No. RM94-7-001, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, March 29, 1995.

Many utilities were so pleased with the FERC principles on stranded assets that they may have stopped reading the rest of the "mega-NOPR" on transmission access. This is not surprising given the appeal of the principles and the perseverance required to read the remaining three hundred plus pages of the document. However, the industry would be wise to read the treatise with some care. As with any large document written by a committee, there will not be complete agreement about everything that is said or implied in the mega-NOPR. Much that is said is thoughtful and constructive, consistent with the view that the mega-NOPR truly is a proposal with a request for comments, and not a foregone conclusion. However, there is a case to be made that the FERC process and the default proposals for transmission access have inadvertently headed the reform train down the wrong track, with the locomotive picking up steam. Having crafted an important breakthrough on the stranded asset principles, the FERC may have presented us with a work in progress on transmission access. If not stopped and redirected soon, this train may be headed towards a breakdown.

The key fault in the default transmission analysis reminds one of Sherlock Holmes' "curious incident" of the dog that did not bark in the night.[6] The most important component of the three hundred page transmission access analysis is not something that is there but something that is missing, something implicit that should be made explicit. The key implicit assumption underlying the proposal is that the non-price terms and conditions for transmission access and service can be defined <u>independently</u> of the institutional structure and market pricing provisions. In other words, the assumption is that transmission is like any other product or service. After all, we can define the characteristics of a bushel of wheat and its transport between locations without

[6] A. C. Doyle, <u>The Memoirs of Sherlock Holmes</u>, 1894.

needing to define simultaneously the organization of the wheat market. We know a bushel of wheat when we see it, and just how many bushels are in a carload; so too with electricity and transmission, or at least that is the assumption.

If true, this independence condition would simplify the reform process immeasurably. The regulators would need only define transmission services in an unambiguous way and make sure that everyone could buy or sell transmission services just like shipments of wheat. The complex and contentious issues of pricing and organization of market institutions could be deferred or avoided altogether as the market evolved under the principles of comparable open access. The problem would decompose into manageable pieces that could be addressed sequentially. The new regulatory structure could be built without any architectural drawings.

Evidence of this implicit assumption is found throughout the mega-NOPR. Most striking is the companion inquiry into Real Time Information Networks (RIN),[7] which has an accelerated schedule requiring comments to be filed 60 days before the corresponding deadline for the mega-NOPR. In this RIN proceeding, the FERC expects to focus on "determining exactly what information must be made available to transmission customers."[8] The FERC wants the RIN rules to be put in place early, "no later than the effective date of the open access rule."[9] The accelerated schedule and the accompanying discussion give no indication that the information needed might depend on how transmission is defined, how prices are set, or how the electricity market is organized.

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[7] Federal Energy Regulatory Commission, Real-Time Information Networks: Notice of Technical Conference and Request for Comments, Docket No. RM95-9-000, March 29, 1995.

[8] RIN, p. 6.

[9] RIN, p. 2.

The implicit assumption leads to the companion assumption that there is an obvious way to define transmission services. Without much discussion, the mega-NOPR launches into references to "firm" and "non-firm" transmission; "point-to-point" and "network" service; "wheeling through," "transmission capacity" and so on. These terms are not defined in the document in ways that relate to the technical requirements of transmission, but they come from an underlying model of transmission service that is based on the "contract path" with the assumption that transmission service refers to the actual movement of electricity along a specific contract path from source to destination.[10] The FERC recognizes the many deficiencies of the old contract-path model,[11] and sees this old model as one reason for moving to a generic, comprehensive approach to reform. However, after critiquing the many failings of this old model, the mega-NOPR proposal effectively reverts to familiar terms and definitions that make sense only in the context of a contract path implementation or a network without constraints. The tension is palpable as the FERC condemns on one page what it implicitly accepts on another!

The internal tension of the mega-NOPR appears again in the discussion of the need to open economic dispatch and pooling institutions to all participants on a comparable basis. The

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[10] The principal exception to complete reliance on a contract-path model is in so-called network service. But the FERC mega-NOPR recognizes that without the contract-path model it has no method for defining the essential details of what is used and how much there is: "Network service, as currently defined, is idiosyncratic because it is unique to the transmission user receiving the service. This service is purchased to integrate a set of resources into a set of loads given specific dispatch parameters and load profiles. The transmission provider has to plan and operate its system for this specific service. It is not clear that such service could be of any value to an entity other than the original buyer. It is also not clear precisely what would be resold because network customers do not have rights to a specific amount of transmission capacity, but have rights only to a varying amount of capacity needed to integrate load with their dispersed power resources. Such indeterminate rights may not be amenable to reassignment. We seek comments on reassigning network service. Can network service be structured such that capacity rights could be specified and reassigned?" p. 119.

[11] Federal Energy Regulatory Commission, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000, March 29, 1995, pp. 68-71.

mega-NOPR is laced with requests for comments on pools and dispatch services that complement or utilize transmission services. The apparent intent is to provide open access to these other essential services, presumably as discussed in the parallel proceeding that is dealing with alternative pooling arrangements. In the discussion, a reader could easily conclude that FERC assumes that transmission services can be defined and offered separate from or in addition to other services such as economic dispatch. The notion of the independence of transmission service terms and conditions follows through in the discussion of pools and related institutions.

If this underlying independence assumption were not correct, however, the entire strategy for approaching transmission access on the mega-NOPR would be called into question. Or at a minimum, the reform train engineer would need to apply the brakes quickly and switch to a different track before going much further. The farther we go down the path of defining the terms and conditions for transmission under the implicit, old, rejected model of the contract path -- all the while creating presumptive property rights -- the more difficult will be the repairs when the train breaks down because the parts don’t work together to make a whole.

Unfortunately, the underlying independence assumption is not true. The definition of terms and conditions for transmission access can depend in important and, unfortunately, complicated ways on the organization of the institutions and the markets. The problems are many, but a focus on the definition of the transmission service of moving megawatts provides enough by way of illustration to make the point.

Under the old model of the vertically integrated utility, the "contract path" provided a workable definition of transmission service. The theory was that service would be provided as though the power actually flowed, and actually flowed along a designated path in the network.

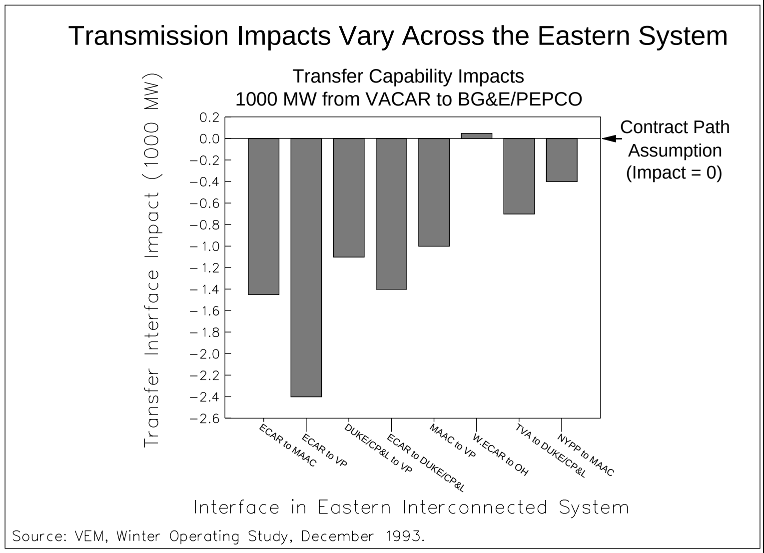
When the power could not flow, the service was interrupted. Higher priority power could flow, and this would be firm service, except when it too was interrupted. And so on.

Most of us never knew or cared anything about this contract path theory, and regulators could act as though the model was the reality. Of course, the utilities knew that this model had very little to do with what actually happened in the power grid. But as integrated monopolies it was easy for them to manage the few problems and handle the cost shifting that was often implicit rather than explicit. In the new world of the competitive electricity market, however, this happy accommodation will not survive. The contract-path model will not adapt well to the competitive world.

Under the contract path model, and the assumptions of the mega-NOPR, it would be possible to provide information in the RIN about the capacity of the various paths and the scheduled usage of the paths. The capacity would be defined in industry parlance as the "interface limit" for a set of lines, if not an individual line. Presumably, any user of the transmission system could look up the available capacity on an interface and make a decision and a commitment to use some of that capacity. The decision to use that interface could be made independently of any consideration of the limits on other interfaces elsewhere in the system. The new power flow could be identified and the change on that interface recorded. Similar decisions and commitments could be made by others for other interfaces in the network. Moving megawatts of electricity would be much like moving bushels of wheat.

How close is this stylized model to the real world? And how much would the differences matter? The answers are that the model is not at all close to the real world, and the differences matter a great deal. The interesting case is when the transmission system is congested. When the system is used only a little, anything can be done and the contract path fiction can be accommodated. However, when the system is constrained, there is a dramatic result totally at odds with the contract-path model.

Figure 1



The system operators in the eastern interconnected grid regularly conduct joint studies of the transmission transfer capabilities of various interfaces. One of these types of exercises was conducted by the VEM Study Committee which examined the impact of various power transfers under peak load operating conditions.[12] A central task undertaken in the VEM study was an evaluation of the impacts of a power transfer across one interface on the transfer capabilities across other interfaces. For example, what would be the impact of a 1000 MW transfer from the Virginia-Carolinas (VACAR) region to Baltimore Gas & Electric (BG&E) and Potomac Electric Power (PEPCO)? The assumption of the contract-path model is that there would be no impact on the transfer capability of other interfaces. Under the contract-path fiction, users could use the capacity on one interface without worrying about the limits on other interfaces. As Figure 1 summarizes, however, the actual effects elsewhere would be far from zero, and certainly not negligible. The impacts would range from a gain of 50 MW to a loss of 2400 MW, depending

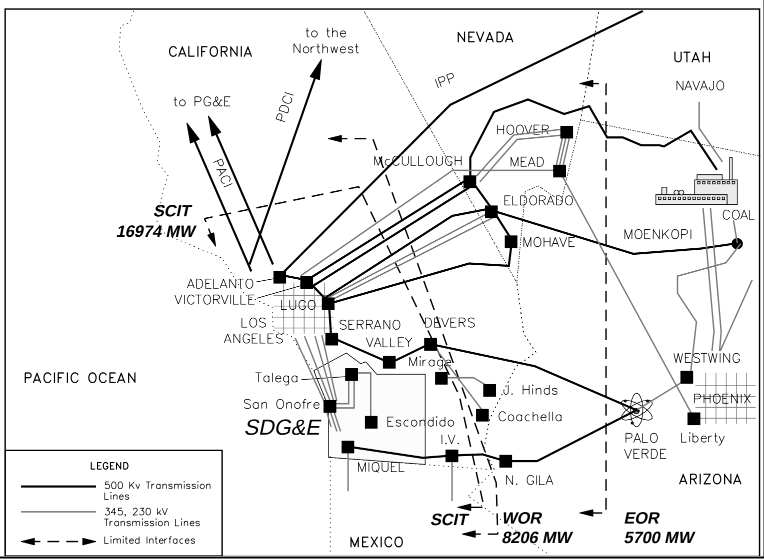
[12] Virginia-Carolinas (VACAR) (Subregion Electric Reliability Council), East Central Area Reliability Coordination (ECAR), Mid Atlantic Area Council (MAAC), Winter Operating Study, December 1993.

on the locations of the other interfaces. Clearly parties quite distant from the transaction would experience major effects, sometimes larger than the originating transaction, and have a keen interest in the decision to move 1000 MW from VACAR to BG&E/PEPCO.

The complex network interaction or "loop flow" effect is caused by the nature of the highly interconnected grid and the current state of technology governing power flows. There are many, interacting, nonlinear constraints that limit operations in power systems. The reduction to "interfaces" is a simplification that is used for network management in a highly coordinated system. The interface metaphor and contract-path fiction are not suitable for a decentralized market.

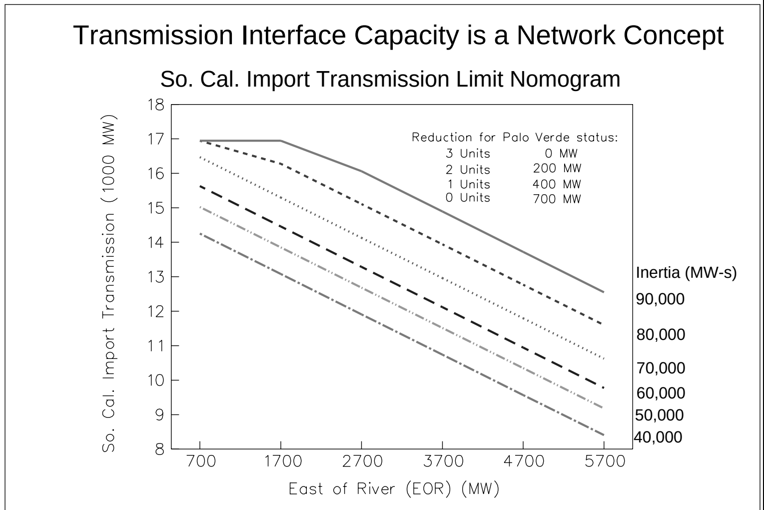
Furthermore, the problems arise in any interconnected grid, not as sometimes argued just in the highly networked system in the eastern part of the United States. Consider, for example, the simplified map of southern California as shown in Figure 2. The map provided by San Diego Gas & Electric (SDG&E) illustrates the location of major power plants, loads, and transmission lines. The schematic includes three interfaces with associated maximum transfer limits: The East of River (EOR) with a maximum of 5700 MW, West of River (WOR) with a maximum of 8206 MW, and the Southern California Import Transmission

Figure 2



(SCIT) with a maximum of 16974 MW.

Figure 3



Source: SDG&E. Inertia for Southern California on-line plants in MW-seconds.

Under the contract path model, presumably it would be possible to post these interface capacities and allow individual utilities or users to make decisions on how much capacity to use on each interface. In principle, the participants might assume that they could use both the 5700 MW on EOR and the 16974 MW on SCIT, simultaneously. Unfortunately, the indicated capacities are not all achievable simultaneously. In actual use of the system, there are further limits that are summarized in the "nomogram" of Figure 3. This figure reports on the net effect of limits on simultaneous flows on the EOR and SCIT interfaces. Because of the interaction of load patterns with a number of physical limits such as stability and voltage control, the allowable flow on one interface cannot be determined independently of knowing the flow on another. Furthermore, the limits on the flows depend on other factors such as the "inertia" of the available power plants operating in southern California and the status of the nuclear units at Palo Verde.

The interactions are complicated and large. In order to achieve the full SCIT limit, for instance, the EOR capability must be reduced from 5700 MW to 700 MW. Or in order to use the full EOR limit, the SCIT flows must be cut in half. And when we note that the flows over the EOR would be counted again in the SCIT flows, the reduction of the non-EOR imports across the SCIT could be by as much as a factor of seven! The model of the contract path and the assumed independence of interfaces is seriously misleading.

There are related dangers here, with ample worries for everyone. For the new entrants in the market, the fear should be that the incumbents would decide that the only way to guarantee a path-based right under a wide range of circumstances could be to define a very low transmission capacity, all of which is currently committed. Then new transmission capacity could be obtained only through expensive expansion, or not be available at all. For the incumbents the danger is that the larger non-simultaneous limits may be allocated by regulators, with the cost of meeting them under different conditions imposed on the incumbents. At a minimum the burden of proof would fall to the incumbents to demonstrate that capacity sometimes used would not always be available. For the regulator the concern should be that capacity rights might be allocated in ways that artificially constrain the available dispatch, increasing the cost due to congestion as the system operators stumble over keeping up with the information that for every 1 MW on the EOR interface someone may have to back off 2.13 MW on the remaining SCIT flows.

Clearly the contract path model is fatally flawed when viewed from the context of a competitive market in a constrained network. It is not possible to identify separately the capacities of individual paths and then allow third parties to make their own decisions on how to use those paths. The real system doesn't work that way. The real system is a network that requires careful coordination, and the real system may behave in ways that have nothing to do with moving power from one location to another along a designated path.

In practice today, of course, the utilities know this well and they take a network perspective in actual operations. For example, rather than having SDG&E, the Los Angeles Department of Water and Power (LADWP), Southern California Edison (SCE) and other users make independent decisions on power flows, they turn over management of the SCIT nomogram to SCE and work through SCE in scheduling their power. This is a workable network-based system, but it is far from the contract-path based model.

The same network approach could be adapted to the competitive market but this alternative approach would require a very different definition of transmission terms and conditions. These terms and conditions may depend critically on how we define and organize the market institutions. For example, if a system is to be built upon specific performance and decentralized decisions -- where the contracted power actually flows based on the choices of the participants -- then the transmission services may need to be <u>defined</u> in terms of the parameters of the SCIT nomogram, and the many other constraints that operate simultaneously. Or of a pool-based network approach is embraced -- where the power flows according to the preferences of the participants but through the choices of the dispatcher -- it would be possible to <u>define</u> transmission services in terms of financial contracts that convert the complicated interactions into locational price differences and simple financial settlements.

In each case, however, the unbundling of services and opening of access needs an explicit network model, not an implicit embrace of a contract-path fiction. Furthermore, the same problems extend beyond the ubiquitous effects of loop flow. The discussion of unbundling of ancillary services needs careful consideration. The mega-NOPR assumes implicitly that many or most ancillary services can be unbundled. However, there are at least two types of unbundling, and the mega-NOPR does not draw any distinction. The first, easiest type of unbundling is separating the cost of supplying a particular service to the network as a whole. Although never perfect, it is usually possible to separate the cost of reactive power support from the cost of spinning reserve, from the cost of frequency control, and so on. While this cost and supply unbundling is important, it is not the same as the second type which we might call "transaction unbundling" that would identify the amount of an ancillary service actually used by and attributable to a particular transaction.

For many services, such as providing spinning reserve, there is no mechanism available for identifying the transaction requirement. The services are "joint" or "network" services that cannot at present be separated by individual transaction. Hence, the responses to the mega-NOPR should take care to identify the terms under which transaction unbundling is possible. Otherwise, we run the real danger that in computing and presenting "unbundled" charges for ancillary services we will face the problem of users asking not to pay for those services which they wish not to use or which they prefer to provide for themselves. If the service cannot be truly unbundled for a transaction in a network, however, then it is impossible to stop the parties to a transaction from using the service (e.g., spinning reserve) or to know if they have provided the service (e.g., contingency based voltage support).

The approach in the mega-NOPR is understandable. With any policy revolution, with any change of paradigm, it is seldom easy to reorient the language and see or accept the vision of a new consensus.[13] It is doubly difficult to make the leap in the fog of the current process where "the extent of this underlying consensus is largely obscured by the divisive and often

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[13] Kuhn.

inaccurate rhetoric used in the debate."[14] With substantial but far from unlimited powers, the FERC is best able to provide the framework and the incentives, but in the end it is up to the industry to propose and the FERC to dispose. Without a well-developed alternative, the institution reverts to what is familiar rather than what is real.

The challenge, therefore, is for the industry to come forward with the new approach based on a contract network that can replace the contract path. It is not possible to avert our eyes forever from the reality that the old model is dead, and the real problems of the network interactions cannot be wished away.

The ball is in the industry's court. Until we breakthrough to the new network model of industry structure, the debate will be stilted, confused and disingenuous. It is time to acknowledge a few basic facts. First, the parallel proceedings on alternative pooling institutions and transmission access are not truly separable; they are talking about the same thing, or at least two things that are fully intertwined. The separate proceedings should be brought together as one conversation. Second, transmission service is inherently, unavoidably, irrevocably, and importantly a network phenomenon. The definition, measurement, management and pricing of transmission services must take a network perspective that integrates all these components. Third, this breakthrough is not beyond the ken of regulators or the industry. A workable consensus is near, and the pieces have been implemented and tested elsewhere, with the most advanced version perhaps in Norway, and proposed by a growing list of industry participants in the United States. The key to open, efficient transmission access in a network is in coordination through a pool-based market that can support emerging competition. This network-based

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[14] Reply Comments of the California Energy Commission in Response to FERC Inquiry Concerning Alternative Power Pooling Institutions, April 1995, p. 3.

approach is more different than difficult, and simplifies the most vexing problems that won’t go away.

COORDINATION FOR COMPETITION

Coordination through a well designed pool-based electricity market can be a large part of the solution to the problems of promoting open access and competition. There is a certain degree of flexibility in the particulars of implementation, but the core ideas enjoy a coherence that derives from a strong foundation in the basic physics and economics of electricity supply. The use of coordination in a network provides the foundation for the Poolco model which could serve as the new consensus.[15]

A concern with the role of coordination arises naturally from consideration of analogies with other markets where the invisible hand of competition is allowed to operate. In the typical market, explicit coordination of the actions of market participants is feared as a bar to the competitive forces seen as so essential for improved efficiency, both in short run operations and long run innovations. However, in the case of electricity, operational problems arise in the form of network interactions, sometimes referred to as "loop flow," that can greatly complicate the play of competitive forces. Even under the assumption of a workably competitive generation market there remains the challenge of allowing generators to compete through the interaction via the transmission network.

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[15] The remainder of the paper is a abridged version of W. Hogan "Coordination for Competition in an Electricity Market," Response to an Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000, Federal Energy Regulatory Commission, March 2, 1995. The issues are addressed in a series of discussions that go into progressively more detail. See the original for the appendices and quantitative examples.

Visible Hand

Contrary to the presumption underlying the extreme version of the invisible hand model for electricity dispatch, the electric system with current technology requires the very visible hand of the system operator to manage the short-term power flows and associated operation of generating plants. The basic coordination functions will always be there, somewhere. A system coordinator or pool is required in support of any electricity market. This insight is available from experience with the operation of competitive electricity markets in other countries. For example, Norway is often mentioned as having a system with a high utilization of bilateral contracts that execute the commercial activities of the market, where over 85% of the power is covered by long-term contracts. However, despite the acknowledged importance of the contract and negotiated business agreements, Norway relies on a pool operation to handle the short-term arrangements that provide the underpinning of the competitive market:

> "The importance of effective Pooling arrangements in a competitive [Electric Supply Industry] cannot be overstated. The Pool provides:
>
> - a source of firm back-up and top-up power to support either generators or suppliers offering long-term contracts to final customers; without access to a Pool firm power could only be offered by generators owning a portfolio of plant and to the extent that firm power is a necessary requirement of consumers the competitiveness of both the generation market and the final supply would be limited;
>
> - a ready market for generators unable to sell their power under contract or wanting a market for spill or excess production;
>
> - a reference price for long or short-term contracts struck outside the Pool which provide participants with price stability not immediately available inside the Pool;

- a reference price to be used in signalling the optimal development of generation and transmission capacity on the system.

> In addition, of course, the Pool provides the traditional means by which generation costs can be minimized through merit order operation and the aggregation of reserve requirements."[16]

Note that Moen, the Norwegian regulator, addresses the short-term efficiency of a better dispatch only as an afterthought. The real value of the pool and the bid-based least-cost dispatch is in providing the various elements that facilitate commercial bilateral contracts and that would be hard to obtain in any other way.

The basic summary of the pool-based system is found in the FERC's characterization of its understanding of the proposals developing in the California discussions. This general "Poolco" model has been advanced in California by two investor owned utilities in San Diego Gas & Electric and Southern California Edison[17]; in the recent proposal by the public power entities in the Southern California Public Power Authority in a variant described as the "Multiple Choice Pool" (McPool)[18]; in Wisconsin by Wisconsin Electric Power[19]; in Maryland by Allegheny

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[16] J. Moen, "Electric Utility Regulation, Structure and Competition. Experiences from the Norwegian Electric Supply Industry (ESI)," Norwegian Water Resources and Energy Administration, NVE, Oslo, April 1994, p. II-5.

[17] San Diego Gas & Electric and Southern California Edison described their proposal in a joint filing with the California Public Utilities Commission, Supplementary Comments of San Diego Gas & Electric Company (U-902-E) and Southern California Edison Company (U 338-E) On Competitive Markets and Appropriate Market Institutions in a Restructured Electric Industry, February 23, 1995.

[18] Southern California Public Power Authority, "The Multiple Choice Pool Model (McPOOL)," February 7, 1995.

[19] Wisconsin Electric Power Company, "Wisconsin Electric's View of a More Competitive Electric Industry," Investigation On The Commission's Own Motion Into The probable Costs and Benefits of Changing Electric Utility Company Structure and Regulation, PSCW Docket No. 05-EI-114, November 1, 1994.

Power System and The Potomac Edison Company[20]; and is under active consideration in many other areas of the nation. The FERC summary of the Poolco proposal includes:[21]

> ..., the poolco would be an independent entity that would not own any (or would own only a limited number of) facilities, but would control the operation of some or all generators, and all transmission facilities, in a region. The poolco would be open to all generators connected to the grid, who would automatically receive any transmission service needed to sell power into the regional pool. In effect, the poolco would be responsible for creating and maintaining a regional spot market for electricity. The spot price in each trading period (perhaps hour-by-hour) would be readily available and made known to all market participants.
>
> Generating resources would be centrally dispatched on an hourly basis by the poolco in much the same way as in current power pools. The principal difference appears to be that generators would be dispatched based on the bid price they submit to the poolco, rather than on their running costs. The poolco would operate a least-cost (in the sense of lowest bid) dispatch that accounts for any transmission constraints in the same manner as an existing power pool or a single utility dispatch center. Generators would be paid the market-clearing price[22] during each hour, as opposed to the bid price that each generator submitted to the poolco.[23] Likewise, distributors would pay the market-clearing price in each hour. Consequently, the poolco would break even in its basic dispatch function, since distributors would pay to the poolco what the generators receive from the poolco.
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> In effect, the poolco would become the market clearinghouse for the hourly energy market. Under the poolco concept, dispatch benefits are implicitly allocated among sellers and buyers by the spot trading at a

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[20] See, Putnam, Hayes and Bartlett Inc., "Electric Power Competition: A Proposal for Maryland," Prepared for Allegheny Power System Inc. and The Potomac Edison Company, January 17, 1995.

[21] Federal Energy Regulatory Commission, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000, October 26, 1994, p. 5-7.

[22] The market-clearing price is the highest bid price of any generator that is selected to provide service to the poolco in an hour. Each successful bidder would receive this price, regardless of whether its bid price was less than the market clearing price. (footnote in original)

[23] This method of pricing creates an incentive for each generator to bid near its marginal running cost, since it would risk losses if it bids less than its running costs and the poolco selected it to run, and it would risk losses if it bids more than its running costs and the poolco does not select it to run. (footnote in original)

> market-clearing price. The poolco would have no further role in dividing or allocating benefits. Also the proposed poolco would have no role in long-term energy or capacity markets. Generators and distributors could enter into contracts outside the poolco.
>
> Under San Diego's poolco concept as currently proposed,[24] spot prices would vary from one geographical location to another to reflect transmission constraints.[25] This would allow the spot trading to be conducted at a price that reflects the real ability and limitations of the grid to move power from low-cost to high cost areas. The proposal includes opportunity cost pricing for grid congestion, as well as tradable capacity rights.

The attraction of the Poolco proposal to public and private utilities, across the country and in other nations, stems in part from the gradual recognition that the Poolco is not a radical proposal. Rather, Poolco recognizes what exists today and what must happen under any system for a competitive electricity market. After some initial confusion, the continuing participants in the analysis of the electricity market recognize that the characteristics of the electricity system require the continued existence of a system operator. The only issue is the scope of the system operator's functions. At a minimum, the system operator must coordinate the actions of the market participants, to avoid violation of short-term system operating constraints, and provide balancing services that ensure both load following and backup for uncontracted demand. This coordination function exists today within the power pools or the utility control areas. Once it is clear that the coordination and balancing function must continue, three questions arise that define the role of the system operator and the connection to the Poolco proposal.

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[24] We understand that both San diego's and Edison's proposals continue to be revised, and that the two proposals may become more similar as details are worked out. (footnote in original)

[25] Under Edison's proposal, in contrast, spot prices would not reflect transmission constraints. (footnote in original. However, the author observes that the qualification is incorrect. The Edison proposal does include the effect of transmission constraints in spot prices))

The balancing functions require that the system operator have operational control over a minimum number of flexible generating plants and loads. The precise minimum number is difficult to define, with views ranging from many to few. However, it may not be necessary to define the number, depending on how we answer three remaining questions about the nature of the services provided by the system operator. For the flexible plants and loads, the balancing function is a dispatch function. The first issue is whether the system operator should dispatch the flexible plants to achieve the lowest possible cost under an economic dispatch:

Should the system operator be allowed to offer an economic dispatch service for some plants?

The alternative approach would be to define a set of administrative procedures and rules for system balancing that purposely ignore the information about the costs of running particular plants. There is no doubt that there are feasible options, such as minimizing the use of the transmission wires, that would preserve reliability and maintain system balance. However, the costs would be high. If we are to find an economic dispatch, then the argument is that the system operator should be able to do so better than anyone else. Although there are minor differences between textbooks in their respective definitions of natural monopoly, the common theme is that a single firm can provide the lowest total cost in serving a particular market. The economics -- the costs -- are essential, with the distinctive characteristic of a natural monopoly being not that there is no alternative to a monopoly, but rather that provision of supply through a monopoly is the lowest-cost solution. The arguments underlying the Poolco proposals stand squarely behind the proposition that economic dispatch is a natural monopoly. It seems that the natural answer is that the operator should be able to consider costs and provide an economic dispatch for some plants and loads, at least those that are part of the flexible components which must exist at some minimum level.

Once the economic dispatch service is available for some plants, access rules must be established to determine who can participate. Hence, the second question about the role of the system operator is:

> **Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?**

At one end of the policy debate stands the view that the minimum number of flexible plants is a very small fraction of the total. The prediction may be that only the minimum number will participate, or implicit in the argument may be a view that participation in the economic dispatch should be restricted to the smallest number of plants possible. However, the natural extension of open access and the principles of choice would suggest that participation should be voluntary. With only the caveat that a minimum number must be flexible, the principle should be that market participants can evaluate their own economic situation and make their own choice about participating in the operator's economic dispatch or finding similar services elsewhere in the market.

System control is a monopoly and therefore will be under regulation of some form. Its pricing rules are a matter for public oversight. If the operator does consider costs and choose an economic dispatch for the flexible plants, there is an issue in setting the prices that will apply to the associated power flows. And these same prices will play a central role in defining comparable transmission tariffs for those who do not participate in the economic dispatch. Hence, the third question about the role of the system operator is:

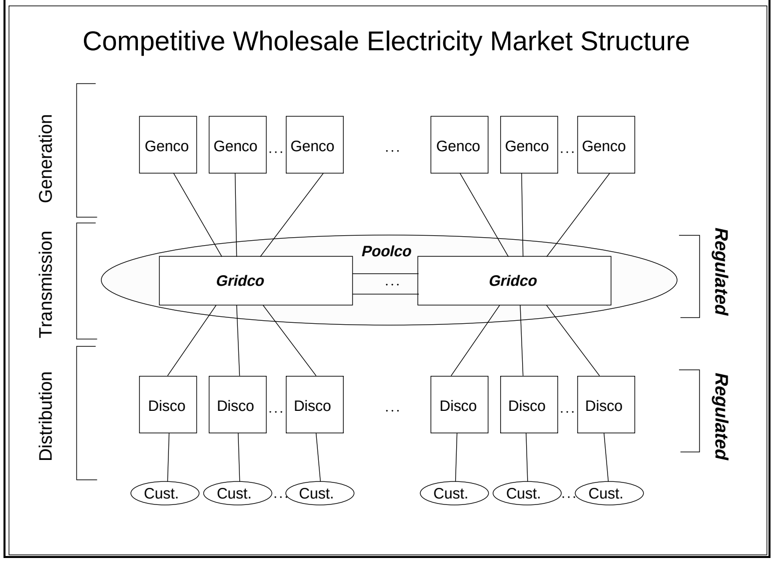
Should the system operator apply marginal cost prices for power provided through the dispatch?

The simplest conceptual approach would be to have an administrative price or penalty for the power obtained through the operator's economic dispatch. However, if set too low, there will be an incentive for participants to rely too much on the supply from the system operator, constituting a subsidy that the operator may not be able to support. Set too high, the administrative price becomes a penalty that provides incentives to avoid the economic dispatch and raise overall system costs. The alternative of marginal cost pricing based on participant bids has an obvious appeal. Under an economic dispatch for the flexible plants and loads, it is a straightforward matter to determine the locational marginal costs of additional power. These marginal costs are also the prices that would apply in the case of a perfect competitive market at equilibrium. In addition, these locational marginal cost prices provide the consistent foundation for the design of a comparable transmission tariff for all uses of the transmission system.

The three questions are posed to isolate what is reasonably left to be decided under the system variants that might be different than the Poolco model. And if the answers follow the recommendations here -- just say yes -- the system operator will provide an economic dispatch service that is open to anyone who wishes to participate. Pricing will apply marginal cost principles based on the voluntary bids of the participants. And these same prices would apply to all uses of the transmission grid under a comparable, open access transmission tariff. Bilateral contracts would be fully available to meet all other commercial requirements.

The structure of this market could follow many different forms. For the sake of the present discussion, it is useful to describe the various elements and functions in terms of the industry organization suggested in Figure 4. However, as discussed below, it is the division of the functions that matters, not any particular ownership structure. The important point in Figure 4 is to distinguish the Poolco dispatch function as an essential facility with open access requirements just as important as connection to the transmission wires.

Figure 4



This pool-based market provides many advantages that flow from the interaction of the various elements. In particular the pool-based system creates or builds on a few key ideas to exploit coordination for competition within a consistent structure that conforms to the particular operational and economic characteristics of the electricity system. These interconnected pieces include least-cost dispatch, separation of ownership and control, separation of physical and financial transactions, a framework for transmission pricing and a framework for long-term transmission contracts. The connections are outlined here, with each element discussed in greater detail in subsequent sections.

Least-Cost Dispatch

Any efficient system for organizing the electricity market should include least-cost dispatch as a centerpiece. To be sure, the least-cost dispatch concentrates only on the short-run, and although the short-run is important, the greater part of the value of a competitive system is to be found in the long-run decisions that will control location and investment. However as Moen suggested above, the Poolco model builds on least-cost dispatch because it provides a framework for addressing many of the otherwise vexing problems of coordination and balancing to preserve reliability, encompasses a wide variety of ancillary services and still connects with the competitive market.

The least-cost dispatch based on participant bids is the ideal short-run outcome that would appear in a competitive market if it were possible for all the many participants to define the appropriate property rights and conduct all the complex trades in the network. Because of the complexity of these trades and the lack of workable definitions of key physical property rights, the common judgment is that a system operator is needed to coordinate the dispatch, at least for some fraction of the flexible plants. Since the operator must function to provide coordination services, least-cost dispatch provides the natural framework that replicates as closely as possible the ideal outcome of the short-term competitive market. The Poolco model accepts and builds on this least-cost dispatch. And working from this starting point, the other features of the market can be derived within a consistent framework. The bidding process and least-cost dispatch provide naturally the level playing field for all market participants, both large and small. There is no special advantage to size in benefitting from dispatch diversity and acquiring backup supplies. These services are available to all on the same basis. This open access to the dispatch and related services will facilitate entry and the pursuit of the forces of competition.

Separation of Ownership and Control

The Poolco control of the transmission grid and open access to all buyers and sellers in the wholesale market exploits another key idea in the separation of ownership and control of the essential facilities. In most markets there is a natural, but by no means necessary, equation of ownership and control. The owner of the facility typically is able to control its use. In the case of an essential facility such as transmission wires, the concern has been that ownership could be utilized by those with both generation and transmission to control the market. Although this control of transmission use has never been completely true, as witnessed by the continuing loop flow problems in the industry, changing the ownership linkage between generation and transmission has been argued by many as essential for providing true open access to the transmission grid.

The Poolco model takes a different and simpler approach, simpler at least when we recognize the existence and continuing need for the visible hand of the system operator. The Poolco model envisions an independent system operator who controls the balancing functions and flexible dispatch. This independent system operator controls the use of the transmission grid. By taking the control of use of the grid out of the hands of the owners of the wires, Poolco provides a consistent and straightforward mechanism for implementing open access in a complicated network: all market participants can participate in the economic dispatch in the same way and on the same basis. This simple separation of ownership from control could sidestep the need for a formal change of ownership of the Gridco, even though such a change of ownership would also be compatible with the pool-based model. However, with or without a change in ownership, it is essential to remember that under the Poolco model individual owners cannot decide who gets to use which transmission lines. The power flows in the best way available, from sources to uses, to preserve operational reliability while meeting the least-cost test that is consistent with the competitive market.

Separation of Physical and Financial Transactions

Given the Poolco, it is a simple matter to separate physical and financial transactions. In most commodity markets, delivery of the commodity is simple to define and monitor and it is possible and necessary in the early stages of market development to link closely the physical and financial exchange. You pay the farmer for the wheat at the time the bushel is delivered. There is no ambiguity in the definition of the bushel of wheat or the payment. Later, as the market matures, separate financial contracts will arise for wheat futures with only a formalized connection to the cash market for delivery of bushels of wheat. Delivery may never occur, or the quantities delivered may be separate from the protection provided under the futures contract. Over time the market develops separate physical and financial transactions.

The same process would evolve with commodity electricity. However, the Poolco model allows us to anticipate and exploit this separation of physical and financial transactions to solve a difficult problem in the electricity market. In particular, the need for continual balance of a constantly changing load pattern presents great difficulties in defining physical delivery. A Genco may contract with a customer to deliver 100 MW, but over the course of the day both the generator and the customer may deviate from this contract, producing or taking more or less electricity. For these imbalances, or for any deliveries in the integrated network, it is impossible to say which electricity applied to a particular transaction. The easy direct link between delivery between participants and payment cannot be maintained. To solve this problem in an integrated network, Poolco conveniently skips the primitive step in the commodity market evolution by providing the foundation for separate physical and financial transactions.

The mechanism is through the pairing of simultaneous buys and sells with the Poolco and parallel bilateral contracts for a financial transaction between the parties. If, for example, the Genco delivers 102 MW to the Poolco and the customer takes 97 MW, the Poolco in effect buys the 5 MW imbalance at the spot price. As will be discussed below, the Genco and the customer might have a bilateral contract for differences for the original 100 MW at a long-term contract price. This separate contract can be arranged independently of the Poolco and has no bearing on the dispatch decisions. However, in this case, the effect would be for the Genco to deliver 100 MW to the customer at the contract price, *no matter what the spot price*. In addition, the Genco would sell 2 MW to the Poolco at the spot price and the customer would in effect sell 3 MW to the Poolco at the same spot price. The imbalances would be priced at the spot price, and the contracts quantities would be covered solely by the negotiated price of the contract. All this occurs automatically, and constantly, because the transactions with the Poolco are at the transparent Poolco price available to all, providing the cash market benchmark that allows separation of the physical and financial transactions.

A Framework for Transmission Pricing

With a least-cost dispatch, there is an immediate and straightforward analysis that identifies the competitive-market opportunity-cost-based prices that should apply for flows in the transmission system. Transmission pricing is one of the most complicated parts of the policy puzzle. The complex interactions in the electric transmission network, with loop flow and the many constraints that may limit transmission use, present significant challenges in the implementation of an open access system. For a pool-based competitive market framework, however, the solution is available from the work of Schweppe et al. in the natural application of market clearing prices.[26]

The ideal competitive market clearing price for power at any location is the marginal cost of meeting the next unit of demand. For a collection of generating plants and loads at a single location, this market clearing marginal cost price is simply the marginal cost of the most expensive plant running at that moment. In a transmission network connecting many locations, there is an analogous marginal cost of power for each location. With least-cost dispatch, this marginal cost is determined by the cheapest way to redispatch the system and meet an additional unit of demand at that location. In the absence of constraints in the transmission system, the marginal cost determined price differs across locations by the marginal cost of power losses in transmission. In the more interesting case when constraints limit the use of the transmission system, the marginal cost contains an additional component that captures the impact of congestion due to the constraint. In either case, however, the marginal cost is easy to define and compute as a byproduct of the least-cost dispatch, as illustrated through several examples in the appendix.

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[26] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, R. E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988.

With the marginal cost price of power available at each location, Schweppe identified the marginal cost of transmission between two points distant in the network as the difference in the prices at the two locations. In short, transmission of 1 MW from source to destination is equivalent to selling at the source and buying at the destination at the locational prices. Hence the true short-run opportunity cost of transmission between source and destination is the difference in the locational prices. This insight cuts through the maze of complexity of network interactions, loop flow, security constraints and all the other arcane details of transmission networks. It builds on the foundation of economic dispatch and reduces the problem of finding the economically efficient price of transmission use to the determination of the locational based prices that accompany the inputs and outputs of power in the network. And the prices apply no matter how complex the intervening network between destination and sources, with any number of users, and whatever the operating conditions. Just as the least-cost dispatch by the system operator handles all the network operating details, it also produces a solution to the problem of short-term pricing of transmission in a manner consistent with the overall framework of a competitive market.

A Framework for Long-Term Transmission Contracts

A solution for the economically efficient short-run pricing of transmission use based on the Poolco model of least-cost dispatch provides the foundation for a design of long-term transmission arrangements that can support efficient contracts between Gencos and distant customers. The first and most natural approach to long-term transmission access and rights would be to assume that it would be possible to define a physical right to use the transmission grid to move power from certain sources to other destinations. Once a market participant had obtained this physical right, the holder could move power as envisioned or trade the right to allow others to move power from the same sources to the same destinations. This property right would be the natural analogy to capacity rights in other markets, such as for interstate transport of natural gas, and seems necessary to provide the foundations for the essential long-run competition in the market.

Unfortunately, the natural presumption of the existence of such a well-defined physical transmission capacity right confronts three seemingly insurmountable problems. First, assignment of such rights implies control of the use of the physical transmission of power in a way that would reverse the separation of ownership from control that is an essential feature of open access to the transmission network. Second, restricting use of the grid to match the allocation of such rights would either place great demands for constant retrading in a short-run secondary market or would compromise the ability to achieve the least-cost dispatch. To obtain the economic dispatch, the system operator needs control over a sufficient range of flexible plants and control over the full transmission grid. Third, and more arcane, except in the case of a substantial under-allocation of what would seem to be the natural transmission rights, an under-allocation designed to avoid any possibility of confronting any transmission constraints, there is no well-defined physical capacity that can be allocated and assured. Due to the many interactions across locations, the "capacity" of the network is not amenable to any easy definition and the ability to move power between locations cannot be assured. The capacity of the network at any time depends on the configuration of the inputs and outputs.[27]

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[27] W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242.

Although physical transmission rights cannot be guaranteed, the Poolco least-cost dispatch would provide the foundation for a transmission contract that would serve essentially the same purpose as a physical right by defining a financial transaction that would not depend on matching physical flows in the actual dispatch. Transmission congestion contracts could be defined for a financial payment equal to the difference in congestion costs between locations. Such a transmission contract would allow a Genco to arrange a power contract with a distant customer and be assured of the delivered cost of the power. Through the Poolco dispatch, the system operator would collect congestion payments whenever the system was constrained, in turn disbursing the congestion payments to the holders of the transmission congestion contracts. The Poolco would keep none of the payments, and participants with long-term transmission contracts could fully protect the ability to deliver power at an agreed price, just as if there was the physical delivery from the source to the destination. However, unlike the physical transmission rights, the transmission congestion contracts are well defined, can use the full capacity of the network, and are consistent with actual flows moving according to the least-cost dispatch. Furthermore, the ability to honor the contracts does not depend on the configuration of the inputs and outputs. The transmission congestion contracts would provide a way to untangle the network and convert short-run opportunity cost prices into long-term transmission arrangements.

The Poolco model provides these several interconnected features of least-cost dispatch, separation of ownership and control, separation of physical and financial transactions, a framework for transmission pricing, and a framework for long-term transmission contracts to support a competitive market. The pieces fit together into a coherent whole. Each will be developed further below. This integrated framework under the Poolco model addresses many of the issues inherent in the creation of an open-access, competitive electricity market. To understand this framework, however, it helps to digress briefly and dispose of a few misunderstanding that have arisen about the Poolco model. A number of problems that have been attributed to the Poolco are seen on closer inspection to be either not applicable or, if applicable, independent of the Poolco model.

DISTRACTIONS

The national discussion of the Poolco model has produced a number of questions or concerns about possible failings of the approach that on closer inspection appear to be based on a misunderstanding or misinterpretation of the Poolco design. A brief summary of each suggests the possible source and a clarification of the misunderstanding. Describing what is not sharpens the description of what is included in the Poolco model.

Market Interference

For all whose transactions are organized through the economic dispatch of the system operator, the Poolco formally buys and sells the power. This buy-sell model looks close enough to the experience with natural gas and other industries to raise concerns that the Poolco will have its own commercial interests to consider in choosing which electricity to buy and at what price to sell. After all, it was just the concern with the system gas owned by the interstate pipelines that was at the source of many of the difficulties in developing comparable services and true level playing field in that market. If the system operator is buying and selling as a broker or trader -- taking positions in the market with an anticipation of profit or the risk of loss -- the

Poolco model would present similar problems of conflicting incentives and market interference.

Concern with this type market interference is not applicable to Poolco because of the special and limited nature of the formal buying and selling through the economic dispatch. In particular, all transactions with the Poolco are cleared at the same time and at the current market price. The Poolco takes no positions and makes no profit on the transactions through the economic dispatch.[28] The buying and selling may look like the Poolco operator is a trader in the market, but the buying and selling occurs only to simplify the transaction accounting. In principle, it would be possible to match all buyers and sellers, without the Poolco operator standing between as the formal intermediary, with the Poolco charging only market clearing prices for transmission and related services. But this would be an unnecessary recording keeping fiction, with the end result identical to the transaction of the net inputs sold to the Poolco and the net outputs purchased from the Poolco at the current market price. As described in the FERC summary, the Poolco is not another trader; "[i]n effect, the poolco would become the market clearinghouse for the hourly energy market." The Poolco as a clearinghouse simplifies the market accounting and transactions.

Market Limitation

Again because of the formal role of accounting for transactions through the Poolco, it might appear that contracts between buyers and sellers, generators and customers, brokers and aggregators, would be precluded or at least restricted. Only transactions through the Poolco would be allowed, and this would inhibit the intended innovation in the market through

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[28] For simplicity, this discussion ignores default and credit risk.

development of new products and services that would depend on direct customer access and contracting.

Again this concern is misplaced because of the limited role of the Poolco and the simple accounting process of tracking power in and out of the network. Of course, physical delivery of power through the network is not optional, and everyone in the market must follow the rules for power dispatch and payment for transmission services. However, within these rules, any contract between any parties in the market can be implemented under the generic Poolco model. For power transactions self-nominated and subject only to transmission charges, any contract can be arranged in a form that is virtually identical to the traditional conceptual model of direct delivery of power between the supplier and the customer. In the case of power bought and sold through the economic dispatch, any contract that supplier and customer could design could be implemented through the device of the contract for differences. The Poolco model provides a simple and efficient framework for implementing the full range of commercial contracts while simplifying the requirements for the necessary backup power, reference prices and other system services highlighted above by Moen as so essential to support a competitive electricity market.[29]

Market Dominance

The emergence of a Poolco that covers a large region raises the specter of market dominance. Market participants might control the pool or the bidding process in order to prevent competition and preserve their existing positions. The assertion and fear is that the Poolco would

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[29] W. Hogan, "To Pool or Not to Pool: A Distracting Debate," Public Utilities Fortnightly, January 1, 1995.

simplify the exercise of market power.

This is an important issue, but the concern is misplaced. At one level, the Poolco removes an important source of vertical market power by providing open access to the grid and the system dispatch. The independence of the system operator is a central feature of the Poolco model, and this independence removes the most obvious and most easily exploited element of vertical integration, thereby reducing market power. However, the Poolco model does not by itself change in any way the concentration of ownership of generators or control over final customers. To the extent that such high concentrations exist, there may be a potential for exercise of horizontal market power under the Poolco model.

Market power issues must be addressed in regional generation markets. No simple design can overcome a fundamental concentration of market power. The new market model for generation needs to recognize concentrations of ownership and provide mechanisms to prevent monopoly pricing through market dominance. However, as discussed below, the new Poolco institution of the competitive market will create alternatives for regulating generation that can prevent monopoly pricing while preserving competitive pricing, both of which will differ from cost-of-service pricing. Most importantly, the Poolco model does not create nor does it enhance the concentration of ownership of generation. The Poolco model removes barriers to entry, through open access, without erecting any new barriers. Where remaining concentrations of ownership exist, the Poolco provides a framework for dealing with the effects. Where market power exists, Poolco makes the situation better, not worse. The Poolco model by itself is not a complete solution to the problem of market power, but the attractions of the Poolco are not reduced by a concern over possible abuses of market concentration.

Bureaucratic Delay

The Poolco model sounds new and different and many fear that it will take too long to implement, thereby delaying the introduction of competitive market forces. This hypothetical concern was not reduced when just such a tactic of delay was the privately conceded and sometimes publicly announced policy of many in the utility industry.

There are three major reasons why this fear of delay may in the end be misplaced. First, the Poolco requires less innovation than appears on first inspection. For instance, the system operators, control functions and other services needed by the Poolco are already in place. They need not be created anew. These people and systems exist within the existing utilities and power pools; the Poolco innovation is to identify these people and functions and have them operate independent of the existing utilities. Surely this step of making the operators independent is necessary and unavoidable. Second, the major innovation of the Poolco is in the matters of pricing and transmission contracts. While new, these problems must be addressed under any system as part of the package of developing and implementing open access and comparable transmission pricing. The Poolco model provides a coherent and consistent approach for such access and pricing. The Poolco model may both simplify and accelerate a task that cannot be avoided, providing the fastest route to comparable transmission pricing that also conforms to the underlying economics of a competitive electricity market.

Third, when coupled with methods for recovery of stranded assets, as discussed further below, the incentives for existing utilities should change from an interest in delay to an interest in early adoption. Implementation of the Poolco model or its equivalent in customer access will likely be a necessary step for the existing utilities to be allowed to participate actively in the deregulated generation and supply markets. Without a Poolco, the regulated utilities may see their markets disappear to new entrants who will operate without the same regulatory constraints. To the extent that the utilities wish to participate in the market, it will be in their interest to implement the Poolco model. The utilities that have offered the Poolco proposals have made the explicit point that the Poolco is the fastest way to a competitive market that also conforms to the other regulatory and reliability obligations that should be met.

Bureaucratic Complexity

The collection of Poolco bidding, economic dispatch, locational-marginal-cost-based prices, transmission congestion contracts and so on appears just too complex. A simpler system would be preferred, and one requiring fewer changes in the status quo.

While the concern is understandable and legitimate, it is important to distinguish between what is truly complex, and what is simply different. The Poolco model is different, at least in its economic and institutional details. At an engineering level, it is much like the current system, designed purposely to capture the ideal design for best practice in the industry. However, the differences in pricing and institutions are not necessarily indications of an increase in complexity. As one industry observer noted, "the people who think the Poolco model is complex are people who think they understand the current system."[30] Yet few people do understand the details of the current system, where a great deal of complexity exists embedded in the operations that are internal to the monopoly utilities or existing power pools. In the open-access, competitive market, these hidden details cannot be hidden for long, as services and pricing rules

[30] Anonymous.

must be unbundled and made more transparent. For example, anyone who believes that the Poolco pricing rules are too complex should take up the task of explaining how current power pool split-savings pricing systems operate in the presence of system congestion, and then explain how this pricing regime could survive when faced with the pressures of arbitrage by those who can trade around the pool. Explaining how the present system works is at best difficult. An explanation of how to protect the split-savings pricing system from death through arbitrage in a competitive market would deserve a Nobel Prize.

The present industry access and pricing system is both complex and inconsistent with the incentives of the competitive market. By contrast, the Poolco model is built from a consistent model of an efficient competitive market and captures within the economic dispatch the principal and inescapable complexity of the network interactions. As Einstein admonished: "A theory should be a simple as possible, and no simpler." The Poolco model is simpler than the status quo, and may be the simplest model that is consistent with the economics of the industry and the Commission’s stated public policy objectives.

THE FUNCTIONS OF THE ELECTRICITY MARKET

The wholesale electricity market, like any well-functioning commodity market, will include diverse commercial and financial arrangements, including contracts of various types and duration, vertical integration where allowed, joint ventures, short-term trading and so forth. At the core of these commercial arrangements will be a spot market in which physical electricity is priced and traded. This electricity spot market will be technically complex but invisible to most consumers, just as the technically complex wholesale markets in petroleum and government securities are invisible to most buyers of petroleum and banking services.[31]

A spot market will develop for any commodity and it is not the usual focus of policy interest. However, the special characteristics of electricity increase the importance of the spot market in designing a framework to support competition. A spot market in electricity has two principal functions.

- **Maintain Efficient Short-Term Operations or Dispatch.** A spot market coordinates short-term operations of separately owned entities to assure that demand is met economically and reliably given the production facilities actually available on the day, largely independent of longer-term contract arrangements.

- **Facilitate Longer-Term Contracting and Competitive Entry.** A spot market reduces the risks of contracting by allowing contracting parties to buy and sell “overs and unders” to meet their obligations at least cost/highest profits, thereby facilitating entry by undiversified competitors, each of which can compete in the specific activity it does best without needing to be a self-contained, full-service producer.

Discussions of electricity spot markets usually focus on the first of these two objectives, maintaining efficient and reliable operations or dispatch. This focus is understandable, given the traditional central control of system operations and the difficulty or even impossibility of designing a spot market that will mimic the operations of a technically oriented dispatch process. But it is not the primary purpose of a spot market to improve or duplicate the dispatch of given plants with given cost characteristics meeting given demand *in the short run*; rather, it is to allow market forces to determine the amount, mix and costs characteristics of generating plants, and the level and shape of demand, *in the long run*. A well-designed spot market and

[31] D. Garber, W. Hogan, L. Ruff, "An Efficient Electricity Market: Using a Pool to Support *Real* Competition," The Electricity Journal, Vol. 7, No. 7, September 1994, pp. 48-60.

associated dispatch process will maintain or even improve short-run efficiency and reliability, albeit probably with more price-induced load management and less reserve capacity than is traditional. But even if a spot market appears to reduce short-run dispatch efficiency to some extent, this can be a small price to pay for the benefits of competition in the longer run, where the largest benefits are expected.

Contracts and the Spot Market

Most money flows in the industry will be determined by contracts rather than by spot market prices directly. One of the principal functions of a spot market is to facilitate contracting between producers and consumers, either directly or through middlemen of various kinds. A spot market allows contracting parties to buy and sell incremental amounts of physical product in the market, so that their bilateral contract does not have to try to perfectly match their individual physical operations. In a fully efficient market the parties to a contract may not even trade physical product with one another at all, but act independently in the spot market, with monetary payments between them based on the difference between the spot market price and a contractually defined price. Such "contracts for differences" can take many different forms, providing a flexible vehicle for allocating market and other risks any way contracting parties agree upon.

The commercial substance of the contracts that will prevail in a mature electricity market cannot and need not be predicted with certainty now, although it is certain that the allocation of risks and rewards will be different in a competitive electricity market than in centrally planned monopoly systems. It may be that, apart from the long-term contracts necessary to define the equity risks of long-term investments, most commercial contracts in a competitive electricity industry will be for relatively short terms of a few months to a few years. Such contracts will allow generators to manage their maintenance and cash flow, retailers to set their tariffs and negotiate contracts with customers, industrial customers to plan their operations and budgets and so forth, but will leave long-term energy market risk on generators -- where it probably belongs.

Because many parties will find contracts useful for managing their short- and medium-term operations and cash flows, on any given day much of the demand in the electricity market will be covered by contracts, so that spot market prices may determine only a small fraction of the money flows between consumers and generators. This does not make the spot market any less important or its price signals any weaker. Even with a high level of contracting, the spot market will determine the price expectations against which future contracts will be written, will facilitate contracting and entry and will maintain efficient operations by, among other things, providing strong incentives for incremental generation and load management when demand threatens to exceed supply. When spot prices increase to high levels, even a fully contracted generator has strong incentives to produce up to and beyond its contracted amount and even a fully contracted buyer has strong incentives to reduce its demand and sell its contracted but unused energy into the spot market.

A high level of contracting is important for spot market operations because it allows the spot price to fluctuate as widely as necessary to accomplish the critical coordination and market-clearing roles without exposing producers and consumers to large fluctuations in revenues and costs. Spot prices can and should vary widely and rapidly; they are high at some times, perhaps increasing by factors of several hundred during emergency conditions; and they are low at other times, perhaps even negative when inflexible generating plants are competing to avoid shut-down costs. These extreme price signals should be regarded largely as internal technical devices the industry uses to manage itself, much like a central bank's overnight interest rate, which can soar to annual rates of hundreds of percent -- for one day. Extreme fluctuations in spot market prices simply make explicit the equally extreme but mostly hidden measures a monopoly utility uses to deal with the same technical situations. Because spot prices may apply to little of the product that is actually traded at any time, these fluctuations may have little commercial significance to many customers, while providing opportunities for those who have the technical capability and commercial interest to operate in the wholesale spot market.

The Role of Dispatch in the Spot Market

An electricity spot market can work much like any other wholesale market in which buyers and sellers make offers, determine the prices at which supply equals demand and trade the product at those prices. Some special market arrangements are needed to deal with the special characteristics of electricity; but both the special characteristics of electricity and the market arrangements differ only in degree from those in other functioning commodity markets.

The most obvious special feature of electricity is the need for an integrated transmission grid. But centralized facilities for handling the physical product exist in many commodity markets. An electricity grid differs from port facilities, airports and stock exchanges only in the size of the capital investment and in the extreme degree of natural monopoly involved. Grid access and pricing must be regulated to assure nondiscriminatory treatment of all traders.

The more unusual and less appreciated aspect of electricity markets is the need for a centralized trading process. Because electrical energy cannot be economically stored, supply must equal demand virtually instantaneously everywhere on an interconnected system. Pricing energy to clear the market at all times means, strictly speaking, that a different price must be computed every minute or less and, when transmission losses or constraints are important, at different locations on the grid.

Least-cost dispatch is the competitive market equilibrium. The least-cost dispatch satisfies the "law of one price" and the "no arbitrage" condition of the competitive equilibrium. Convergence of a fully decentralized market to a competitive equilibrium depends on ease of trading and well-defined property rights. Neither condition holds in the electricity system. The characteristics of electricity coupled with poorly defined property rights create a natural monopoly in dispatch.

Natural monopoly is an economic concept. Although there are minor differences between textbooks in their respective definitions of natural monopoly, the common theme is that a single firm can provide the lowest total cost in serving a particular market. The economics -- the costs -- are essential, and without specifying the cost structure there would be no foundation for asserting a natural monopoly condition. There is no theory of "natural physical monopoly," and with appropriate restrictions virtually any market could be served in a number of ways that would involve more than one firm. The distinctive characteristic of a natural monopoly is not that there is no alternative to a monopoly, but rather that provision through a monopoly is the lowest-cost solution. The electricity system has special characteristics with important engineering and commercial implications that lead to a natural monopoly condition in dispatch:

- **Cost Diversity.** The short-term cost of operating existing power plants exhibits great heterogeneity across plant types and locations. There are always substantial gains from trade by using low-cost plants that are available to substitute for higher-cost plants.

- **Load Uncertainty.** Load conditions change substantially over the day and season. Variations in load are difficult to predict and change differently at different locations.

- **Complex Control Requirements.** Operating conditions require close monitoring and control on very short time horizons. For many important decisions, operating conditions must anticipate emergency contingencies. These constraints can and often do limit the flexibility to select the running levels of individual power plants.

- **Network Interactions.** The interconnected network under current technology creates strong interactions across locations. Every power plant and load affects all others. The interactions with system constraints can be large and differ substantially by location.

This combination of factors greatly complicates operation of a short-run bilateral market. It is difficult to specify and use decentralized information that would allow decentralized trades to approach the efficient short-run solution. These problems historically motivated the development of electricity power pools.

Operating such a system of decentralized, interacting, minute-by-minute markets without any central coordination is still and probably always will be impractical; hence it is necessary to continue relying on a monopoly dispatcher to provide the services necessary to match supply to demand instantaneously and across electrically separated locations. But it is practical to create a spot market that matches supply to demand and computes market-clearing prices for, say, each half-hour within a relatively unconstrained area on the grid, allowing the competitive market to deal with most of the problem and leaving the monopoly dispatcher to deal only with changes applying to a short period, say the hour or half-hour.[32]

Although a half-hour is a long time on an electricity system, it is still too short a period to expect a market to clear efficiently through decentralized information exchange and bilateral negotiation. Instead, it is necessary to do what is done in many other markets: establish a central process that collects buy and sell offers (including each offerer's reservation prices), determines market-clearing prices consistent with these offers and reservation prices, notifies the successful offerers, facilitates delivery of the physical product and settles payments among the traders.

Traditional dispatch is a form of market dispatch, with trading based on engineering estimates of incremental costs. By adding software to handle buy and sell offers from independent traders, determine a least-cost combination of trades and the associated market-clearing prices and settle payments among the traders, the dispatch process can be extended to support a commercially oriented marketplace. The resulting integrated dispatch and market process will then play two important roles:

- **Operate the Competitive Spot Market.** The dispatcher and market operator determines market-clearing quantities and prices for each half-hour, based on buy and sell offers from the market participants. This

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[32] The period to be covered by the central dispatcher depends on the strength and complexity of the dispatch interactions over time. The physics dictate a need for last minute control. A half-hour may be a convenient period. Unit commitment decisions might call for a sequence of market balances coordinated by the central dispatcher over the day and hour, as in the United Kingdom and Norway. There are significant differences in the lead times applied in the New York and New England Power Pools. However, choices beyond a month could be left to the decentralized decisions of the market. The selection of the best time frame for coverage under the central dispatch is an issue to be addressed.

process will determine most of the energy and some of the money flows in the spot market -- most of the money flows in the system will be determined by contracts.

- **Provide Monopoly System Services.** The dispatcher and market operator uses the market-determined supplies to meet the market-determined demands in each half-hour as far as possible, but then acts as a monopoly buyer of the incremental energy and ancillary services -- reactive power, spinning reserve and so forth -- needed to respond to changing conditions within the market period. The dispatcher covers its costs with charges no system user can escape, such as an uplift on the spot market price of energy.

Commercial transactions in the competitive electricity market develop principally through bilateral agreements between buyers and sellers. Contracts for long-term electricity supply, price protection and other competitive services contain any terms and conditions acceptable to the parties and feasible within the limitations inherent in the interconnected electric system. Under the Poolco model, the short-term electricity market addresses the few necessary constraints and technical issues by coordinating system operations and power plant dispatch. The system pricing and access rules permit the maximum degree of customer flexibility and choice. The same pool-based rules define a comparable, open-access transmission tariff. With rare exception, generators enjoy free choice to participate in the pool-based dispatch or manage their own generating plant operations under the transmission tariff. Customers, brokers and aggregators enjoy free choice to make long-term arrangements with any supplier or rely solely on access to the short-term market. The Poolco market supports any feasible bilateral transactions and provides everyone with additional options that resolve difficult problems such as obtaining backup supplies, transmission rights or other technical services.

Regulation of Essential Facilities

The electricity market will not be fully competitive. There will remain an important role for regulation to oversee the operation of monopoly activities and access to essential facilities. For instance, at the state level there will continue to be a responsibility for regulating access to and pricing of distribution wire services.

Wholesale market activities fall under the jurisdiction of the FERC. The Poolco system operator would presumably be subject to FERC oversight to monitor the application of the dispatch and pricing rules, administration of transmission contracts, and the other features of the Poolco model. Regulation would be light handed, with no need for the FERC to address any long-term investments or commitments in power sales.

Gridco expansion and pricing would continue to present a need for regulatory oversight, but the Poolco model would substantially simplify transmission investment decisions. Economies of scale and complex network interactions would continue to create incentives that would not be wholly compatible with decentralized decisions in a market. This need to address network expansion as an integrated problem leads to a continuation of the expected need for the Regional Transmission Groups (RTG). An RTG would be needed to review the operating reliability standards and evaluate the impacts of proposed transmission expansions. However, this evaluation need not extend to a central decision on the need or cost responsibility for transmission expansion. Under the Poolco model, the users of the system who are buying and selling electricity without a complete hedge through transmission congestion contracts will face the short-term market clearing price. In the face of transmission congestion, the locational prices provide the proper incentive for investment in transmission facilities. Investments should be made when justified by the savings in congestion costs. Those who are prepared to make the investment would obtain the associated transmission congestion contracts. The role of the states, the RTG and the FERC, therefore, would be to review requests for transmission expansion, examine the compatibility with the companion request for new transmission contracts, and ensure an open process for all to join in developing combined transmission investments recognizing the interactions in the network. The regulator would be responsible for enforcing a requirement for existing transmission facility owners to support expansions and reinforcements at a traditional regulated cost that recovered the incremental investment, and then to assign the corresponding transmission contracts.

The transmission congestion contracts, once created, would no longer need any special regulation. Although investments in the transmission grid would by lumpy and would require the cooperation of the owners of existing facilities, the transmission congestion contracts would be divisible and freely tradable in a secondary market. This secondary market would provide a ready source of transmission hedges that would serve as an alternative to system expansion. The price of the transmission contracts should never rise above the expected congestion opportunity costs or the cost of incremental expansion of the grid. In this way, the unregulated market for transmission congestion contracts would emulate the broad outlines of the FERC pricing policy. Transmission contracts would be obtained at the lesser of opportunity costs or incremental costs. Holders of existing transmission rights, converted into the appropriate transmission congestion contracts, would pay embedded costs but not opportunity costs. Those using the transmission grid without holding transmission congestion contracts would pay opportunity costs but not any embedded costs other than the costs of any stranded assets that would be collected from all users.

Most important of all, the long-term transmission market could be a market, relying as much as possible on the incentives and forces of competition, limiting the role of planning and regulation to address the unavoidable interactions in the transmission grid. Investment decisions would be made at the initiative and with the agreement of those required to bear the cost.

Market Power

To the extent that there is a high concentration of control of generation or load, there will continue to be a potential for an exercise of market power. This potential creates another demand for continued regulatory oversight. An advantage of the Poolco model is the ability to expand the range of options available to address potential problems of market power without compromising other goals in the development of a competitive electric market.

The two ends of the policy spectrum for dealing with market power are regulation and divestiture. At the regulatory end, firms with a high concentration of generation may be subject to a form of continued cost-based regulation designed to prevent any abuse of monopoly power. For the obvious reason, this is an unattractive approach that would be inconsistent with the competitive market. At the other end of the spectrum would be a policy of requiring divestiture of generation into a sufficient number of competing entities. In the U.K., where concentration of generation ownership has produced the expected behavior inconsistent with competitive pricing, the regulator has embraced this divestiture strategy as the principal tool for mitigating the effects of market power. However, the divestiture approach has its own limitations, including what might be the strong objections of the existing utilities who will dispute the existence of market power or argue the inability to exploit what potential power that may exist.

In the middle of the spectrum are many lesser options that could be implemented within the Poolco model and should be explored further. For instance, contracts adopted for a transition period can dramatically alter the incentives of generators with market power. In effect, a long-term power contract at a fixed price transfers the beneficial interest in the plant from the owner to the customer, leaving the generator with the incentives to control costs and maximize the economic use of the plant. This is easy to achieve in the Poolco model and is exactly what happened in the U.K. during the early days of its electricity restructuring. The generators were fully contracted and they behaved like competitors. Only when the generation contracts began to lapse did behavior turn strategic and pricing begin to deviate from the competitive norm.[33] Similar generation contracts could be fashioned in the United States and implemented as contracts for differences, perhaps as part of a larger strategy for recovery of past investment costs.

Absent contracts for the sale of the power, incentive contracts could be structured to insulate the operators of generating plants from the control and interests of the owners of the plants.[34] Generation owners could contract out plant management and bidding, with the incentive payments for the plant geared only to successful operation of the plant in a competitive framework, not to the profits created by strategic behavior that exploited market power. It would be an easy matter for regulators to monitor the terms of such contracts, with the result that the plant operators should perform in the same way as under a divestiture but without the difficulties of actually forcing the sale of the plants.

These examples illustrate the possibility of remedies that might avoid either extreme

[33] R. Green, "Britain's Unregulated Electricity Pool," in M. Einhorn (ed.) From Regulation to Competition: New Frontiers in Electricity Markets, Kluwer Academic Publishers, Boston, 1994, pp. 73-96.

[34] This idea was suggested by Michael Schnitzer.

end of the system. Before even these remedies may be needed, however, further consideration should be given to diagnostics that could reveal abuses of any market power. Again the Poolco model would simplify the regulator's use of such diagnostics to track the performance of the generators. Even if generators have market power, they may not use it, because it would be easy to detect. For instance, it may be possible to design data monitoring schemes that could effectively uncover abuses of market power along the following outline. Attention would concentrate on possible market abuses with existing power plants; entry provisions should be sufficient to assure competition with new facilities. For the existing plants, there is a great deal of data that could be used to provide reasonable estimates of the capacity and operating costs of the plants. With this information, and the transparent prices of the Poolco dispatch, exercise of market power to capture monopoly profit would be revealed by three simultaneous conditions:

> **Price Above Operating Costs.** The market price must be high enough to contribute to monopoly profits. If prices are at or below the operating costs of the plant in question, there is no profit, hence no monopoly profit. The plant may not be running, or if dispatched it would have no impact on the market price.
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> **Output Below Capacity.** The exercise of monopoly power in the Poolco market requires restricting output in order to support higher prices. If the plant is running at full capacity, high prices above operating costs may generate large profits, but these profits reflect scarcity and not use of market power. Scarcity prices should be paid and charged to provide the right incentives in the market; but scarcity prices apply only when the applicable plants are offered and running at full capacity.
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> **Significant Affiliated Output.** The profit from monopoly bidding and pricing is captured on the commonly owned output which enjoys the benefits of the higher prices created by the restriction. Hence the person restricting output must have other output sufficient to demonstrate a higher profit captured because of the use of market power.

These conditions should be easy to monitor with the information available from the Poolco dispatch. If any of these conditions fails to hold, then there is a natural explanation of the market outcome that differs from use of market power. Since the exercise of market power should the concern, not the simple fact of concentration of ownership, this outline of the elements of a possible diagnostic suggests a policy that could be followed before remedies need be applied. This would be a variant of light-handed regulation. The regulator would monitor the Poolco results for existing plants. As long as the three conditions did not exist simultaneously for a significant number of hours a year, bidding behavior would be accepted as consistent with market competition. Otherwise, the search for remedies would be on. Given the nature of the likely remedies, the result might well be that behavior would be competitive and no remedies would be required.

Providing Customer Choice Without Stranding Assets

More than the design of the wholesale market structure, interest in restructuring of the electricity industry centers on alternatives for providing customer choice and the treatment of stranded assets. Customer choice has value as a means to recognize greater diversity of customer needs and to reinforce the pressures of the competitive market. At the same time, offering customer options carries the risk of potentially stranding assets with the danger of subverting the intent of regulatory policy or subverting the intended transition to a more competitive market.

The means to recover any potential stranded assets exist under regulation to the extent that there are truly essential facilities. The simple principle is that otherwise above market costs can be recovered only through control of access to some essential facility. Although FERC will have an important role to play in the policy for dealing with stranded assets, most of the assets at interest fall under state jurisdiction, and the full stranded asset discussion is beyond the scope of this paper. Furthermore, most of the decisions regarding customer access rest in the first instance with jurisdictions other than FERC. As far as the design of the wholesale market is concerned, the principal concern here is to ensure that the system can be made compatible with local choices on customer access and the recovery of stranded assets. The Poolco model allows a great deal of flexibility, and it is possible to design methods for customer access and choice that strand no assets and are compatible with a workable mix of regulatory approaches at the local level.

The usual practice applies the label "retail wheeling" to expansion of competition to include sale of electricity to retail customers. This label appealed to a comfortable fiction that suggested power could be directed from one source to another destination by "wheeling" through the wires of intervening utilities. For a variety of reasons, the traditional retail wheeling approach is an exceptionally bad and misleading model of the actual operation of an electricity market. Ruff has provided an extensive critique under a charge to "Stop Wheeling and Start Dealing."[35] Major obstacles to retail wheeling are in the potential for jurisdictional conflict and uneconomic bypass leaving assets stranded. The traditional retail wheeling model envisions the delivery of power from a particular generating plant to a particular customer, paying a separate charge for the transmission service through the local utility. In the United States, however, this simple act of unbundling the transmission all the way to the customer raises the possibility that the entire transmission rate becomes FERC and not state jurisdictional. The reality of such a change would greatly complicate regulation at the state level, especially during the period of transition to a more competitive market. Even the fear of such a jurisdictional impact could foreclose the regulatory change.

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[35] L. Ruff, "Stop Wheeling and Start Dealing: Resolving the Transmission Dilemma," Electricity Journal, June 1994, pp. 24-43.

The traditional retail wheeling model carries with it the common, although false, notion that the customer somehow leaves the local utility. And the separation of the transmission charges from other costs creates the incentive and the opportunity for customers to bypass the local utility by "wheeling" power through the utilities wires for only the cost of transmission. To the extent that the local utility charges include significant recovery of sunk costs, the act of bypass threatens to strand the associated assets that gave rise to the costs. Given that many markets have a large potential for stranded assets, there is a real fear that traditional retail wheeling could lead to the financial collapse of many existing utilities. In principle, this bypass threat could be overcome through charges imposed on the wires. However, the retail wheeling model of the customer leaving the utility and the possible loss of state jurisdiction over the wire charges create substantial opposition to the retail wheeling approach and to customer choice. The active support of retail wheeling by others as the prerequisite for immediate lower prices only reinforces the concern. The only way to achieve immediate lower prices under retail wheeling is through bypass of the sunk costs and stranding of assets.

However, the traditional retail wheeling model is not the only way to provide customer choice. *Efficient Direct Access* to the wholesale price is a better and simpler concept that can support customer choice and a competitive market without stranding assets.

Customer choice through Efficient Direct Access builds on the reality of a competitive market with open access and comparability of service.[36] It provides real customer choice through access to the wholesale market consistent with jurisdictional boundaries and incentives for efficient decisions. One way to approach the concept is to start with a simple question: What

[36] W. Hogan, "Efficient Direct Access: Comments on the California Blue Book Proposal," The Electricity Journal, Vol. 7, No. 7, September 1994, pp. 30-41.

is required to provide customer access to the wholesale market? This question in turn carries with it the issues of physical access and price.

What is required to provide the customer physical access to the wholesale market? Answer: Nothing. Every customer, large and small, already has access to the physical wholesale market. When anyone flips the switch, the same power comes, retail as well as wholesale. There is no relevant distinction, and no technical method available to deny access to the power. Hence, all customers are already connected to the physical wholesale market.

Apparently the only issue remaining is to provide customers access to the wholesale market price. Viewed from this perspective, the problem of access is simplified. Only two new ingredients are required to complete direct access to the wholesale market and provide customer choice. The two ingredients are a spot price and a new customer tariff:

- **Arm's Length Spot Price.** The wholesale market will develop a transparent arm's length spot price. It may be through hubs--such as in natural gas--or a pool, or some mixture of a bilateral and a pool-based market. The more efficient the wholesale market, the better, but some price will appear against which buyers and sellers can trade.

- **Time-of-Use Tariff**. All customers remain with the distribution utility under traditional cost-of-service rate principles. However, customers have a time-of-use tariff with the energy component set to the observed arm's length spot price. This approach is related to "net back" pricing principles familiar from other regulatory settings and as advanced by many others (Moskovitz).

With the Poolco model, there is a clearly visible and transparent market clearing price available to all. With time-of-use rates at the distribution level, customers would have real access to the wholesale market. They could enter into contracts with generators, to provide whatever security or flexibility that they were prepared to pay for in the market. The technical step is to employ a contract for differences that keys on the spot-price.

With customer choice available, the obligation to invest in commodity energy should move from the regulated monopoly to a competitive market. Commodity energy investments could be left to the market. Regulated utilities could stop making investments in new long-term energy or generation capacity commitments under cost-of-service regulation. Hence the obligation to serve would be interpreted no more as the obligation to supply but only as the obligation to provide access to the market.

Efficient Direct Access requires only a competitive wholesale market such as that provided by the Poolco model and a modest rate design innovation. This approach to customer choice through direct access to the wholesale market is functionally equivalent to traditional retail wheeling but easier to implement and consistent with many constraints otherwise violated by traditional retail wheeling. Efficient Direct Access:

- **Changes No Jurisdiction.** Customers never leave the local utility. Formally the utility buys from the wholesale market and resells at the spot price. There are no changes in cost-of-service principles or formal entry into the FERC regulated wholesale market.

- **Requires No New Legislation**. State regulatory authorities have long set the time-of-use tariffs. The extension to using the arm's length spot price is important, but it is a difference only in a small detail that should raise no controversy.

- **Strands No Assets**. All customers remain under the cost-of-service tariff. Decisions on rates and cost recovery can proceed as before, independent of the existence of Efficient Direct Access and customer choice.

- **Abandons No Worthy Programs**. Whatever can be done under traditional cost-of-service regulation--limited by the inevitable pressures of a more open wholesale market--can be continued under Efficient Direct Access. Universal service support, investments in energy efficiency, and subsidies for renewable and other environmentally preferred alternatives could be made when justified, and included in the cost of service applied to all customers separate from the time-of-use energy charges.

Efficient Direct Access provides real benefits consistent with the many other goals of the partially competitive and partially regulated electricity market. Efficient Direct Access:

- **Provides Customer Choice.** Customers who wish to make long-term arrangements for contracts with generators have full freedom through the mechanism of contracts for differences, which conform to the reality of the electricity market.

- **Reduces Regulatory Demands**. Central planning for all commodity resource procurement can move to the decentralized decisions of the competitive market.

- **Supports Efficient Investment**. Since payment for sunk costs or other mandated programs is independent of the source of power or the arrangements under long-term contracts, the incentives support efficient investment in new facilities and services for commodity electricity.

- **Gives Utilities an Exit Strategy**. Since there is no need to delay Efficient Direct Access to allow for recovery of sunk costs, regulated utilities can immediately stop investment in new regulated generation commitments, redefining the obligation to serve as the obligation to deliver.

With the Poolco model available to provide open access in the wholesale market, and Efficient Direct Access as a means for providing customer choice, the basic elements would exist for consistent regulatory policies at the state and federal level that would promote the transition to a competitive market and allow for recovery of stranded assets. The remaining issues would be to deal with stranded assets that might be legitimately recovered from wholesale customers, which FERC could regulate through some variant of transmission access charges.

ILLUSTRATION OF MARKET OPERATIONS

In illustrating the operation of the market, it is natural to distinguish between the short-run operations managed by the Poolco and long-run decisions that include investment and contracting. The system is much simpler in the very short run when it is possible to give meaningful definition to concepts such as opportunity cost. Furthermore, the long run is just a succession of short runs. In ideal competitive markets, without economies of scale and other complications, there is a natural connection between long run and short run that, for example, equates short- and long-run marginal costs in equilibrium. This handy simplification from competitive market theory is assumed, often implicitly, in proposals for the electricity market much in the way it is implicit in proposals for incremental pricing of transmission. However, due to economies of scale in transmission, this handy condition of short- and long-run equilibrium at the margin is not valid in the case of electricity and it may be poor even as an approximation. Close attention to the connection between short- and long-run decisions, therefore, isolates unique features of the electricity market.

Short-Run Electricity Market

The short-run electricity market is relatively simple. In the short run, locational decisions have been made and power plants, the transmission grid, and distribution lines are all in place. Customers and generators are connected and the work of buyers, sellers, brokers and other service entities is complete. The only decisions that remain concern the delivery of power, which in the short-run is truly a commodity product.

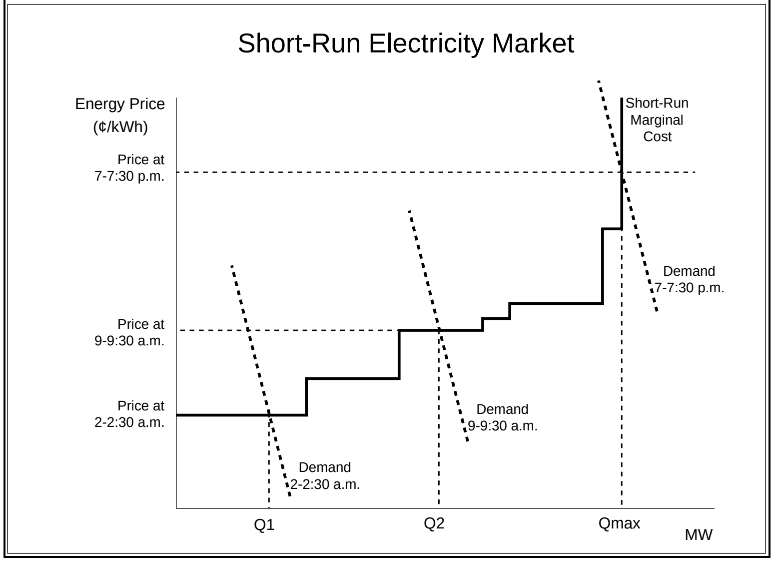
On the electrical scale, much can happen in a half-hour and the services provided by the system include many details of dynamic frequency control and emergency response to contingencies. Due to transaction costs, if nothing else, it would be inefficient to unbundle all of these services and many are covered as average costs in the overhead of the system. How far unbundling should go is an empirical question. For example, real power should be identified and its marginal cost recognized, but should this extend to reactive power and voltage control as well? Or to spinning reserve required for emergency supplies? For the sake of the present discussion, the focus is on real power -- reactive power may also be unbundled, but assume that further unbundling would go beyond the point of diminishing returns in the short-run market.[37]

On a human scale, over the half-hour the market operates competitively to move real power from generators to customers. Generators have a marginal cost of generating real power from each plant, and customers have different quantities of demand depending on the price at that half-hour. With these conditions in a fully decentralized market, with no information costs, customers and generators would search and trade until an equilibrium developed at the market price where supply and demand balance.

This short-term market result is illustrated in Figure 5. The collection of generator costs stack up to define the generation "merit order," from least to most expensive. This merit order defines the short-run marginal-cost curve that governs power supply. Similarly, customers have demands that are sensitive to price, and higher prices produce lower demands. As

[37] W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," Energy Journal, Vol. 14, No. 3, 1993, pp. 171-200. B. Ring, G. Read, G. Drayton, "Optimal Pricing for Reserve Electricity Generation Capacity," Proceedings of the 29th Annual Conference of the Operational Research Society of New Zealand, Auckland, New Zealand, August 1993.

Figure 5



illustrated simply in the figure, the same supply curve is assumed to apply throughout the day, but three different periods have been selected to show different levels of customer demand. In the early morning, there is little demand and the market equilibrium price settles at the marginal running cost of the cheapest generators. Later in the morning, demand increases and so does the equilibrium price. At this time, every customer actually consuming power pays the market-clearing price and every generator running is paid this same price. For the generators, the differences between the market price and their individual marginal costs are the short-run profits that make a contribution to recovery of capital.

At the peak period in the evening, the equilibrium price is very high, with all capacity in use. Here the dispatchable demand is setting the market price above the marginal cost of even the last, most-expensive generator, and all generators earn a short-run profit. The equilibrium price still measures the opportunity cost, but at the peak period the marginal opportunity is not to generate more power but rather to forgo that last increment of demand.

This description of the equilibrium economics of a decentralized short-run market could apply to any product with many producers and many consumers. The special complication in the case of electricity arises because the technology does not permit the many leisurely offers, acceptances and trades that are implicit in the search for an equilibrium in the decentralized market model. On the electrical time scale, all those within half-hour dynamics precludes sole-reliance unilateral or bilateral decisions by the participants in the market. Preserving electrical stability and achieving efficiency within the half-hour requires some form of centralized, or at least closely coordinated, dispatch of supply and demand.

This complication presents no insurmountable difficulties, but it does differentiate electricity from other products. This problem has always existed, and the traditional solution has been to operate the system with a close approximation of centralized control and least-cost dispatch. Generators and customers do not act unilaterally; they provide information to the dispatcher(s) to be used in a decision process that will determine which plants will run at any given half-hour. Power pools, especially tight power pools in the United States, provide the model for achieving the most efficient dispatch given the short-run marginal costs of power supply. Although dispatchable demand is not always included, there is nothing conceptually or technically difficult about this extension.[38] The central dispatcher controls operation of the system to achieve the efficient match of supply and demand.

In principle -- and now in practice in the United Kingdom, Norway and elsewhere -- this central dispatch can be made compatible with the market outcome. The fundamental principle to exploit here is that for the same load, the least-cost dispatch and the competitive-market dispatch are the same. The principal difference between the traditional power pool and the market solution is the price charged to the customer. In the traditional power pool model,

[38] Demand could be dispatched or, with appropriate technology, customers could respond to real-time pricing without explicit bids. Real-time pricing goes further than what is necessary for competition and efficient dispatch. For a discussion of real-time pricing, see F. C. Schweppe, M. C. Caramanis, R. D. Tabors, R. E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988.

customers pay and generators receive average cost, at least on average. Marginal cost implicitly determines the least-cost dispatch, but customers and generators pay do not include the marginal cost. Of course, this reliance on average-cost pricing is not necessary. This is apparent from the current practice in the U. K. where the power market operates in a manner that is essentially consistent with Figure 5, but transactions take place at marginal rather than average cost.[39]

An important distinction between the traditional central dispatch and the decentralized market view is found in the source of the marginal cost information for the generator supply curve. Traditionally the cost data come from engineering estimates of the energy cost of generating power from a given plant at a given time. However, relying on these engineering estimates is problematic in the market model since the true opportunity costs may include other features, such as the different levels of maintenance, that would not be captured in the fuel cost. Replacing of the generator's engineering estimates, which report only incremental fuel cost, with the generator's market bids is the natural alternative. Each bid defines the minimum acceptable price that the generator will accept to run the plant in the given half-hour. And these bids serve as the substitute to guide the dispatch.

As long as the generator receives the market-clearing price, and as long as there are enough competitors so that each generator assumes that it will not be providing the marginal plant, the optimal bid for each generator is the true marginal cost. To bid more would only lessen the chance of being dispatched, but not change the price received. To bid less would

[39] The United Kingdom market includes other features that cause the price to deviate from pure marginal cost, but the essential element is to determine the half-hourly equilibrium marginal cost, which is known as the system marginal price (SMP).

create the risk of running and being paid less than the cost of generation for that plant.[40] Hence, with enough competitors and no collusion, the short-run central dispatch market model can elicit bids from buyers and sellers. The dispatcher can treat these bids as the supply and demand curves of Figure 5, and determine the balance that maximizes benefits for producers and consumers at the market equilibrium price. Hence, in the short run electricity is a commodity, freely flowing into the transmission grid from selected generators and out of the grid to the willing customers. Every half-hour, customers pay and generators receive the short-run marginal-cost (SRMC) price for the total quantity of energy supplied in that half-hour. Everyone pays or receives the true opportunity cost in the short run. Payments follow in a settlements process with a single dispatch and single price that is simple by comparison with the settlements required under the multiple dispatches and multiple costs of traditional split-savings systems.

Transmission Congestion

This short-run market model is easy enough and workably approximated in the existing systems in the United Kingdom, New Zealand, Norway and so on. It could be readily adopted in tight power pools in the United States and elsewhere. However, this model implicitly relies on a critical assumption that all power is generated and consumed at the same location. In reality, generating plants and customers are connected through a free-flowing grid of transmission and distribution lines. The use of this transmission grid affects the short-run market model as summarized in Figure 5 on supply and demand.

In the short-run, transmission too is relatively simple. The grid has been built and

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[40] This "incentive compatibility" property of the dispatch auction is not strictly true for those bidders who have a significant chance of defining the marginal price, but if the margin is small the distortion will also be small.

everyone is connected with no more than certain engineering requirements to meet minimum technical standards. In this short-run world, transmission reduces to nothing more than putting power into one part of the grid and taking it out at another. Power flow is determined by physical laws, but a focus on the flows, whether on a fictional contract path or on more elaborate allocation methods, is a distraction. The simpler model of input somewhere and output somewhere else captures the necessary reality. In this simple model, transmission complicates the short-run market through the introduction of losses and possible congestion costs.

Transmission of power over wires encounters resistance, and resistance creates losses. Hence the marginal cost of delivering power to different locations differs at least by the marginal effect on losses in the system. However, with a few exceptions, the marginal losses on high-voltage transmission grids are relatively small, amounting to only a few percent of the cost of delivered power, and incorporating these losses does not require a major change in the theory or practice of competitive market implementation. Economic dispatch would take account of losses, and the market equilibrium price could be adjusted accordingly. Technically this would yield slightly different marginal costs and slightly different prices, depending on location, but the basic market model and its operation in the short-run would be preserved.[41]

Transmission congestion is another matter entirely. Limitations in the transmission grid in the short run may constrain long-distance movement of power and thereby impose a higher marginal cost in certain locations. In the simplest case, consider the generators in Figure 5 with the supply curve separated into low-cost and high-cost groups connected by a single transmission line. For sake of discussion, assume all the customers are located in the high-cost region. Hence

[41] In the United Kingdom, losses are ignored in setting prices and included in an average cost added to all consumption. In New Zealand and Norway, losses are determined and priced for each location.

power will flow over the transmission line from the low-cost to the high-cost region. If this line has a limit, then in periods of high demand not all the power that could be generated in the low-cost region can be used, and some of the cheap plants are "constrained off." In this case, the demand is met by higher-cost plants that, absent the constraint, would not run, but due to transmission congestion are now "constrained on." The marginal cost in the two regions differs because of transmission congestion. The marginal cost of power in the low-cost region is no greater than the cost of the cheapest constrained-off plant -- otherwise the plant would run. Similarly, the marginal cost in the high-cost region is no less than the cost of the most expensive constrained-on plant -- otherwise the plant would not be in use. The difference between these two costs, net of marginal losses, is the congestion rental.

This congested-induced marginal cost difference can be as large as the cost of the generation in the unconstrained case. If a cheap coal plant is constrained off and an oil plant that costs more than twice as much to run is constrained on, the difference in marginal costs by region is greater than the cost of energy at the coal plant. This result does not depend in any way on the use of a simple case with a single line and two regions. In a real network the interactions are more complicated -- with loop flow and multiple contingencies confronting thermal limits on lines or voltage limits on buses -- but the point is the same. It is easy to construct examples where congestion in the transmission grid leads to marginal costs that differ by more than 100 percent across different locations.[42]

If there is transmission congestion, therefore, the short-run market model and determination of marginal costs must include the effects of the constraints. This extension

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[42] W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," Energy Journal, Vol. 14, No. 3, 1993, pp. 171-200.

presents no difficulty, in principle. The only impact is that the market now consists of a set of prices, one for each location. Economic dispatch will still be the least-cost equilibrium. Generators will still bid as before, with the bid understood to be the minimum acceptable price at their location. Customers will bid also, with dispatchable demand and the bid setting the maximum price that will be paid at each customer's location. The economic dispatch process will produce the corresponding prices at each location, incorporating the combined effect of generation, losses and congestion.[43] In terms of their own supply and demand, everyone sees a single price, which is the SRMC price of power at their location. If a transmission price is necessary, the natural definition of transmission is supplying power at one location and using it at another, with the corresponding transmission price as the difference between the prices at the two locations.[44]

This short-run competitive market with bidding and centralized dispatch is consistent with least-cost dispatch. The locational prices define the true and full opportunity cost in the short run. Each generator and each customer sees a single price for the half-hour, and the prices vary over half-hours to reflect changing supply and demand conditions. All the complexities of the power supply grid and network interactions are subsumed under the economic dispatch and calculation of the locational SRMC prices. These are the only prices needed to provide efficient incentives, and payments for short-term energy are the only payments required to cover costs in

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[43] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, R.E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988. W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242.

[44] Locational prices reflecting short-run generation, losses and congestion are determined in the "regulation" spot market in Norway. See J. Moen, "Electric Utility Regulation, Structure and Competition. Experiences from the Norwegian Electric Supply Industry (ESI)," Norwegian Water Resources and Energy Administration, NVE, Oslo, April 1994. A similar approach is part of the proposed transmission pricing regime for New Zealand as described in Trans Power New Zealand "Transmission Pricing 1993," Wellington, New Zealand, February 1993.

the short run. The administrative overhead of the Poolco could be covered by rents on losses or, if necessary, a negligible markup applied to all power. The dispatch and settlements process are handled by Poolco, with regulatory oversight to guarantee comparable service through open access to the pool. Something like this system is necessary, and a pool operation is the natural mechanism:

> "The process of defining the comparability standard will dominate the electric transmission service debate just as it did in the case of natural gas. And for many reasons having to do with backup, balancing and so on, a natural resolution of this debate will be to give all eligible producers and customers equal access to a tight power pool, with the pool operating to provide economic dispatch."[45]

Long-Run Market Contracts

With changing supply and demand conditions, generators and customers will see fluctuations in short-run prices. When demand is high, more expensive generation will be employed, raising the equilibrium market prices. When transmission constraints bind, congestion costs will change prices at different locations.

Even without transmission congestion constraints, the spot market price can be volatile. In the United Kingdom, the "system marginal price" for generators, as shown in Figure 6, is calculated only in terms of the unconstrained dispatch. The figure shows the volatility in average monthly prices. The changes within a day or over the month have been greater, sometimes an order of magnitude greater. This volatility in prices presents its own risks for both generators and customers, and there will be a natural interest in long-term mechanisms to mitigate or share

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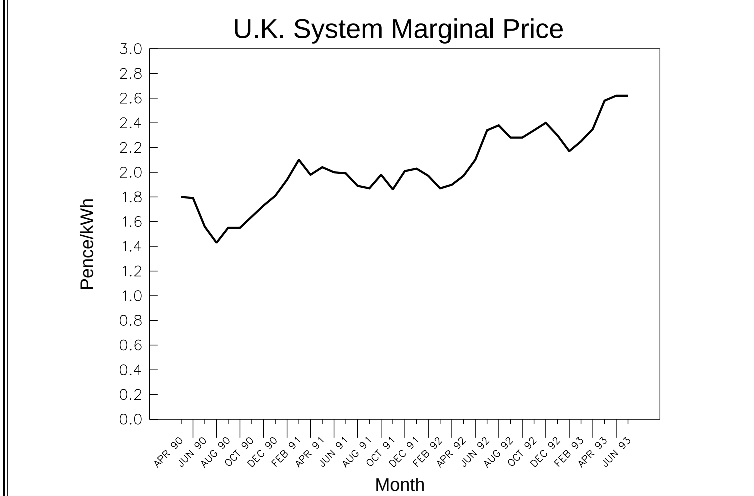
[45] L. E. Ruff, "Competitive Electricity Markets: Economic Logic and Practical Implementation," International Association for Energy Economics, 15th Annual International Conference, Tours, France, May 1992 (Revised June 1992).

this risk. The choice in the market is for long-term contracts.

Figure 6



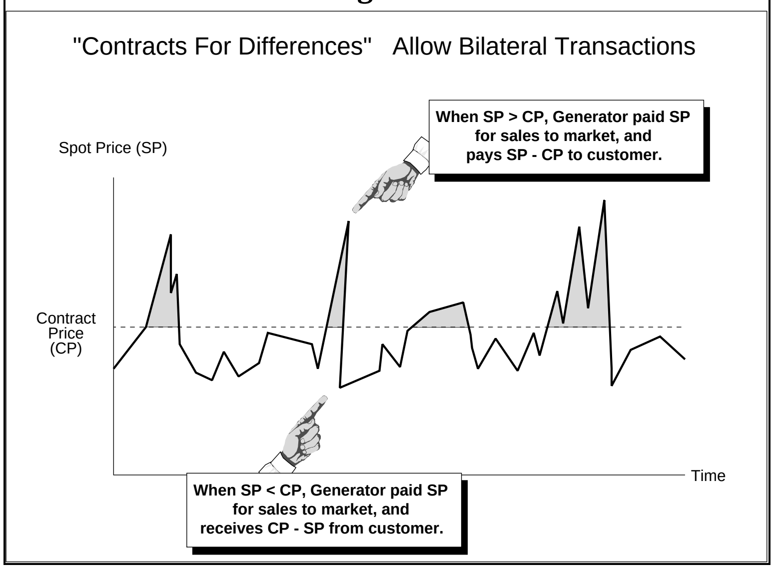
Source: U.K. Office of Electricity Regulation, Pool Price Statement, July 1993

Traditionally, and in many other markets, the notion of a long-term contract carries with it the assumption that customers and generators can make an agreement to trade a certain amount of power at a certain price. The implicit assumption is that a specific generator will run to satisfy the demand of a specific customer. To the extent that the customer's needs change, the customer might sell the contract in a secondary market and so, too, for the generator. Efficient operation of the secondary market would guarantee equilibrium and everyone would face the true opportunity cost at the margin.

However, this notion of specific performance stands at odds with the operation of the short-run market for electricity. To achieve an efficient economic dispatch in the short-run, the dispatcher must have freedom in responding to the bids to decide which plants run and which are idle, independent of the provisions of long-term contracts. And with the complex network interactions, it is impossible to identify which generator is serving which customer. All generation is providing power into the grid, and all customers are taking power out of the grid. There are no bilateral transactions and there is no way to operate a secondary market in the actual deliveries of power. It is not even in the interest of the generators or the customers to restrict the dispatch and forgo the benefits of the most economic use of the available generation. The short-term dispatch decisions are made independent of and without any recognition of any long-term contracts. In this way, electricity is not like other commodities.

This dictate of the physical laws governing power flow on the transmission grid does not preclude long-term contracts, but it does change the essential character of the contracts. Rather than controlling the dispatch and the short-run market, long-term contracts focus on the problem of price volatility and provide a price hedge, not by managing the flow of power but by managing the flow of money. The short-run prices provide the right incentives for generation and consumption, but create a need to hedge the price changes. Recognizing the operation of the short-run market, there is an economic equivalent of the long-run contract for power that does not require any specific plant to run for any specific customer.

Figure 7



Consider the case of no transmission congestion first. In this circumstance, except for the small effect of losses, it is possible to treat all production and consumption as occurring at the same location. Here the natural arrangement is to contract for differences against the equilibrium price in the market. As illustrated in Figure 7, a customer and a generator agree on an average contract price for a fixed quantity, say 100 MW at five cents. On the half-hour, if the pool price is six cents, the customer buys power from the pool at six cents and the generators sells power for six cents. Under the contract, the generator owes the customer one cent for each of the 100 MW over the half-hour. In the opposite case, with the pool price at three cents, the customer pays three cents to the Poolco, which in turn pays three cents to the generator, but now the customer owes the generator two cents for each of the 100 MW over the half-hour.

In effect, the generator and the customer have a long-term contract for 100 MW at five cents. The contract requires no direct interaction with the Poolco other than for the continuing short-run market transactions. But through the interaction with the Poolco, the situation is even better than with a long-run contract between a specific generator and a specific customer. For now if the customer demand is above or below 100 MW, there is a ready and an automatic secondary market, namely the pool, where extra power is purchased or sold at the pool price. Similarly for the generator, there is an automatic market for surplus power or backup supplies without the cost and problems of a large number of repeated short-run bilateral negotiations with other generators. And if the customer really consumes 100 MW, and the generator really produces the 100 MW, the economics guarantee that the average price is still five cents. Furthermore, with the contract fixed at 100 MW, rather than the amount actually produced or consumed, the long-run average price is guaranteed without disturbing any of the short-run incentives at the margin. Hence, the long-run contract is compatible with the short-run market.

The price of the generation contract would depend on the agreed upon reference price and other terms and conditions. Generators and customers might agree on dead zones, different up-side and down-side price commitments or anything else that could be negotiated in a free market to reflect the circumstances and risk preferences of the parties. Whether generators pay customers, or vice versa, depends on the terms. However, the Poolco does not need to take any notice of the contracts or have any knowledge of the terms. Just such contracts have emerged in the United Kingdom market to provide price hedges against fluctuations in the pool price.

In the presence of transmission congestion, the generation contract is necessary but not sufficient to provide the necessary long-term price hedge. A bilateral arrangement between a customer and a generator can capture the effect of aggregate movements in the market, when the single market price is up or the single market price is down. However, transmission congestion can produce significant movements in price that are different depending on location. If the customer is located far from the generator, transmission congestion might confront the customer with a high locational price and leave the generator with a low locational price. Now the generator alone cannot provide the natural back-to-back hedge on fluctuations of the short-run market price. Something more is needed.

Transmission congestion in the short-run market creates another related and significant problem for the Poolco. In the presence of congestion, revenues collected from customers will substantially exceed the payments to generators. The difference is the congestion rent that accrues because of constraints in the transmission grid. At a minimum, this congestion rent revenue itself will be a highly volatile source of payment to the Poolco. At worse, if the Poolco keeps the congestion revenue, incentives arise to manipulate dispatch and prevent grid expansion in order to generate even greater congestion rentals. The Poolco is a natural monopoly and could distort both dispatch and expansion. If the Poolco receives the benefits from congestion rentals, this incentive would work contrary to the goal of an efficient, competitive electricity market.

The convenient solution to both problems -- providing a price hedge against locational congestion differentials and removing the adverse incentive for Poolco -- is to redistribute the congestion revenue through a system of long-run transmission contracts operating in parallel with the long-run generation contracts. Just as with generation, it is not possible to operate an efficient short-run market that includes transmission of specific power to specific customers. However, just as with generation, it is possible to arrange a transmission contract that provides compensation for differences in prices, in this case for differences in the congestion costs between different locations across the network.

It is possible to define point-to-point transmission congestion contracts for compensation that make payments to the right holders in the event of constrained transmission in the grid. These point-to-point price protection transmission contracts can be defined in alternative equivalent ways, with various advantages for implementation and interpretation.[46] For example:

- **Difference in Congestion Costs**. Receive the difference in congestion costs between two buses for a fixed quantity of power.

- **Purchase at a Distant Location**. Purchase a fixed quantity of power at one location but pay the price applicable at a distant location.

- **Dispatch with No Congestion Payment**. Inject and remove a fixed quantity of power without any congestion payment.

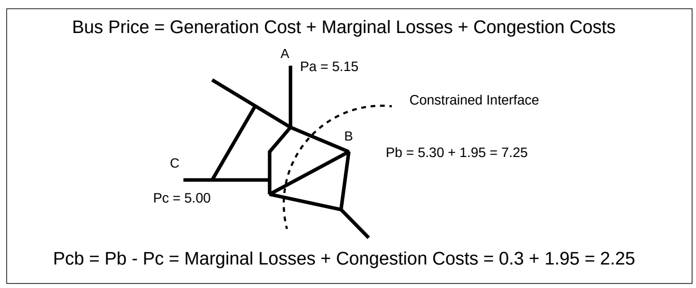
The total quantity of these contracts can be defined for a given configuration of the network. A particular pattern of flows in the network cannot be guaranteed, due to the effects

[46] Here losses are ignored for convenience.

of changing load patterns and the complex network interactions through loop flow. Hence, physical rights for moving power cannot be assured. However, the congestion rental or purchase rights, as defined here, in effect deal with assured compensation that produces the same economic effect as do assured flows. These transmission congestion contracts can be guaranteed for any pattern of loads in the network. In a real system, the associated flows under the transmission congestion contracts would respect all the constraints in the grid, including contingency constraints for thermal limits on lines and voltage limits at buses.

Figure 8

NETWORK TRANSMISSION CONGESTION CONTRACTS



- DEFINE TRANSMISSION CONGESTION CONTRACTS BETWEEN LOCATIONS.
- FOR SIMPLICITY, TREAT LOSSES AS OPERATING COSTS.
- RECEIVE CONGESTION PAYMENTS FROM ACTUAL USERS; MAKE CONGESTION PAYMENTS TO HOLDERS OF CONGESTION CONTRACTS.
- TRANSMISSION CONGESTION CONTRACTS PROVIDE PROTECTION AGAINST CHANGING LOCATIONAL DIFFERENCES.

The transmission right would exist for a particular quantity between two locations. For example, suppose that the generator in the example above operated at location C in Figure 8, and had a contract for 100 MW with a customer at location B. Without any constraints, the difference in prices might be a few percent, say 5 cents at C and 5.3 cents at B. The difference would be the marginal cost of losses, and the generator could promise the customer power at 5.3 cents per kilowatt-hour. When the system becomes congested, as it is in the figure, the efficient price might jump to 7.25 cents at location B, reflecting a congestion cost of 1.95 cents.

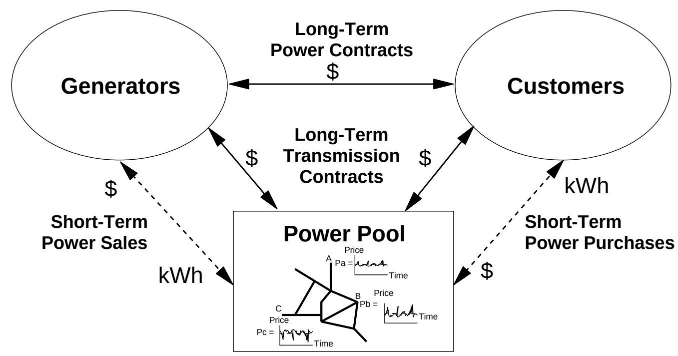
The generator in this case might have obtained a transmission contract for 100 MW between the generator's location at C and the customer's location at B. The right provided by the contract would not be for a specific movement of power, but rather for payment of the congestion rental. Hence, if a transmission constraint caused prices to rise to 7.25 cents at the customer's location, but remain at five cents at the generator's location, the 2.25 cent difference would be the cost of losses at 0.3 cents and the congestion rental of 1.95 cents. The customer would pay the Poolco 7.25 cents for the power. The Poolco would in turn pay the generator five cents for the power supplied in the short-run market. As the holder of the transmission contract, the generator would receive 1.95 cents for each of the 100 MW covered under the transmission contract. This revenue would allow the generator to pay the difference under the generation contract so that the net cost to the customer is 5.3 cents as agreed upon in the bilateral power contract. Without the transmission contract, the generator would have no revenue to compensate the customer for the difference in the prices at their two locations. The transmission contract completes the package.

The point-to-point congestion contracts can be provided by the pool and allow protection of new investment in generation and transmission. The pool takes no risk in offering these transmission congestion contracts because the revenue collected from users paying at short-run marginal cost is always great enough to honor the obligations under the congestion contracts.

When only the single generator and customer are involved, this sequence of exchanges under the two types of contracts may seem unnecessary. However, in a real network with many participants the process is far less obvious, but the net result is the same. Short-run incentives at the margin follow the incentives of short-run opportunity costs, and long-run contracts operate to provide price hedges against specific quantities. The structure of this market with contracts is illustrated in Figure 9. The Poolco operates in the short-run market to provide economic

Figure 9

Pool Operations Support Commercial Contracts



dispatch. It collects and pays according to the short-run marginal price at each location and distributes the congestion rentals to the holders of transmission congestion contracts. Generators and customers make separate bilateral arrangements for generation contracts. Unlike with the generation contracts, the Poolco's participation in the transmission contracts is necessary because of the network interactions that make it impossible to link specific customers paying congestion costs with specific customer receiving congestion compensation. In the aggregate the total congestion payments received by the Poolco will fund the congestion payment obligations under the transmission contracts, but the congestion prices paid and received will be highly variable and load dependent. Only the Poolco will have the necessary information, but the information will be readily available, embedded in all the pool's locational prices.[47]

If the pool transmission congestion contracts have been fully allocated, then the Poolco will be simply a conduit for the distribution of the congestion rentals. The Poolco will no longer

[47] W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242. These transmission congestion contracts define directional price differences that guarantee protection from changes in congestion rentals. Additional congestion payments from the grid to congestion contract holders may be necessary to pass through all the congestion rents inherent in short-run, locational, marginal-cost prices. For further examples, see the appendix in W. Hogan "Coordination for Competition in an Electricity Market," Response to an Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000, Federal Energy Regulatory Commission, March 2, 1995.

have an incentive to increase congestion rentals, because any increase would flow only to the holders of the transmission congestion contracts, not to the Poolco. The problem of supervising the Poolco and Gridco monopolies would be greatly reduced. And through a combination of generation and transmission contracts, participants in the electricity market can arrange price hedges that could provide the economic equivalent of a long-term contract for specific power delivered to a specific customer.

Poolco and Contract Flexibility

The pool-based market operation is fundamentally a technical device to facilitate bilateral contracts negotiated and administered totally independent of the Poolco. Because the pool provides and prices system services and incremental physical energy on an efficient, nondiscriminatory basis without even knowing about bilateral contracts, market participants can enter into any kind of bilateral commercial contracts they choose and can then meet their contract obligations flexibly and economically.

Gencos, customers and, perhaps, power merchants could enter into bilateral contracts specifying the prices and other conditions under which the seller would sell and the buyer would buy defined amounts of electricity at defined times and places. Such contracts would be used to guarantee prices for periods of, say, one year, to accommodate annual budget and weather cycles, planned maintenance schedules and so forth. Shorter-term (e.g., two-week) contracts would also be used to adjust contract positions to actual conditions as they develop. For example, a customer whose load evolved differently than expected earlier in the year, or a Genco whose generating capacity was temporarily less than it contracted to provide, could always satisfy its needs and obligations by buying and selling physical energy in the pool -- that is the great advantage of the pool -- but may want short-term contracts to protect against pool price risk.

The pool would allow last-minute adjustments by any entity who needs more (less) physical energy than it could produce or had contracted for. The ability to buy and sell such quantities at a common, efficient spot price at the time and location of the physical transaction is essential to maintain efficient short-run operations of the system, to reduce the risks involved in longer-term contracting and to facilitate contracting by exposing a common reference price.

A pool-based market allows great commercial flexibility in bilateral contracting and individual operations even though -- or, more accurately, because -- physical electricity is sold to and purchased from the spot market or pool. As a mechanical matter, however, the contracts must take the form of contracts for differences that specify payments between the parties based on pool prices.

The existence of a pool does nothing to limit the flexibility of any Genco or customer to operate as it chooses individually or as it has contracted to operate. The Poolco's dispatch and pricing rules would provide the flexibility for any Genco to operate whenever it wants to (subject to system-dependent technical limits) simply by providing a sufficiently low minimum-energy price bid or declaring itself "must run." In some variants the same outcome would be implemented through Genco self-nominations that would be treated as must-run dispatch. A Genco choosing to operate in this way will be passing up the opportunity to meet its contract obligations more cheaply by buying from the pool when the pool price is less than the Genco's incremental energy cost; but any Genco which wants to operate in such a manner would be able to do so. Hence, with the exception of some minimum number of flexible plants needed to manage the system at the margin, participation in the pool dispatch would be voluntary. For a Genco which would declare plants as being required to run, thereby forgoing the benefits to itself of pool participation, the pool purchase and sale arrangements would reduce to an accounting convenience to track deliveries and charge for imbalances.[48] The market participants would retain the maximum flexibility that would be possible, consistent with reliable operation of the system.

Long-Term Market Investment

Within the contract environment of the competitive electricity market, new investment occurs principally in generating plants, customer facilities and transmission expansions. In each case, corresponding contract-right opportunities appear that can be used to hedge the price uncertainty inherent in the operation of the competitive short-run market.

In the case of investment in new generating plants or consuming facilities, the process is straightforward. Under the competitive assumption, no single generator or customer is a large part of the market, there are no significant economies of scale and no barriers to entry. Generators or customers can connect to the transmission grid at any point subject only to technical requirements defining the physical standards for hookup. If they choose, new customers or new Gencos have the option of relying solely on the short-run market, buying and selling power at the locational price determined as part of the half-hourly dispatch. The Poolco itself makes no guarantees as to the price at the location. It only guarantees open access to the pool at a price consistent with the equilibrium market. The investor takes all the business risk of

[48] Under least-cost dispatch, running at a short-run loss would increase the total cost of operations in the system. With market-based pricing, there could be a redistribution of economic rents among the other market participants. However, the "must-run" Genco would bear the net increase in the total cost in the system.

generating or consuming power at an acceptable price.

If the generator or customer wants price certainty, then new generation contracts can be struck between a willing buyer and a willing seller, possibly through the intermediation of the aggregators and brokers. The complexity and reach of these contracts is limited only by the needs of the market. Typically, we expect a new generator to look for a customer who wants a price hedge, and the generator defers investing in new plant until sufficient long-term contracts with customers can be arranged. The generation contracts can be with one or more customers and may involve a mix of fixed charges coupled with the obligations to compensate for price differences relative to the pool price. But the customer and generator will ultimately buy and sell power at their location at the half-hourly price.

If either party expects significant transmission congestion, then a transmission congestion contract would be indicated. If transmission congestion contracts are for sale between the two points, then a contract can be obtained from the holder(s) of existing transmission congestion contracts. Or new investment by the Gridco can create new transmission congestion contracts. In the case of transmission investment, economies of scale and network interactions loom large, unlike the case assumed for generation. Hence, because of economies of scale it is expected that for any given transmission investment there will be a material change in the pool prices through reduced congestion rentals. In addition, the network interactions will create many potential beneficiaries.

These facts typically will require that any transmission expansion be organized by a consortium of transmission investors who negotiate a long-term contract that allocates the fixed cost of the investment and the corresponding allocation of new transmission congestion contracts.

The Gridco, as a regulated monopoly, builds the lines in exchange for a payment that covers the capital cost and a regulated return. The Gridco does not make transmission investments without long-run contracts signed by willing customers who will pay the fixed costs and recover any future congestion revenues. The Poolco participates in the process only to verify that the newly created transmission congestion contracts are feasible and consistent with the obligation to preserve the existing set of congestion contracts on the existing grid. Unlike in the traditional definition of transmission transfer capacity, which can be ambiguous, there is a direct test to determine the feasibility of any new transmission congestion contracts for compensation, while protecting the existing transmission congestion contracts, and the test is independent of the actual loads.[49] Hence, incremental investments in the grid are possible anywhere without requiring that everyone connected to the grid participate in the negotiations or agree to the allocation of the new transmission congestion contracts.

This structure and its key elements -- access to essential facilities including the wires and pool dispatch, use of short-run marginal-cost pricing and reliance on long-term contracts to provide economic hedges rather than specific performance -- are not far from actual operations or proposed reforms in other systems. This competitive market is the essence of the design of the current U. K. system, with the notable difference of the lack of locational short-run prices.[50] Locational prices are applied in Chile and New Zealand with an explicit treatment of losses and

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[49] The test is that the net loads implicit in the congestion contracts are feasible in the absence of any other loads on the system. See W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242.

[50] S. Littlechild, "Competition, Monopoly and Regulation in the Electricity Industry," U.K. Office of Electricity Regulation, June 1993. U.K. Office of Electricity Regulation, "Pool Price Statement," Birmingham, England, July 1993. The United Kingdom design is plagued by incentive problems created in unusual and unnecessary features of the calculation of market prices coupled with too few generators to ensure competition.

implicit use of congestion costs. Norway applies both losses and congestion costs. Transmission congestion contracts to hedge against locational cost differentials appear in several pooling proposals.

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