

THE ECONOMICS OF PARTICIPANT-FUNDED ELECTRICAL TRANSMISSION

Robert J. Michaels *

ABSTRACT

The costs of new transmission investments under Regional Transmission Operators (RTOs) have generally been recovered on a rolled-in basis, i.e. prorated among all utilities in the region. Under recent proposals for “participant funded” additions, a new generator will be responsible for the cost of new lines and upgrades needed to access the grid and maintain the grid’s integrity. Plans to implement participant funding propose two classes of lines – those with a small number of beneficiaries will be participant funded, while the costs of lines needed for reliability will be shared by all parties. Unfortunately, a participant-funded line that has been deferred long enough becomes necessary for reliability and its costs will be socialized, leading to free-rider problems that cast doubt on the value of participant funding. This paper investigates how a demand-revealing process originally proposed in the 1970s (and since largely neglected) could be used to elicit truthful valuations of alternative transmission investments whose reliability benefits are public goods. The original demand-revealing process was justifiably rejected as an alternative to mass elections. It appears, however, to be quite suitable for the choice of transmission investments in a regional grid, in effect complementing a competitive generation industry with competitive transmission investments.

* Professor of Economics, California State University, Fullerton 92834 rmichaels@fullerton.edu and Affiliate Consultant, Tabors Caramanis & Associates, Cambridge MA rmichaels@tca-us.com The author has been a consultant to independent power producers, power marketers, and other entities in the electricity and gas industries. Views expressed below are only coincidentally those of his affiliations or clients.

I. Introduction

Once the model of a regulated industry, electricity is undergoing the last of the great deregulations. Unlike others that have been opened to competition, electricity's record is decidedly mixed. The Federal Energy Regulatory Commission (FERC) faces growing political opposition in its efforts to increase the role markets play in the industry. Some opposition reflects anxiety that California's experience will repeat itself elsewhere, while other opponents include incumbent utilities and other interests that fear the consequences of competition. As non-utility power production has increased, a consensus on the potential competitiveness of many generation markets has arisen. During the same period, a belief has persisted that transmission is so inherently monopolistic and externality-prone that markets should do little more than set short-term nodal prices.

This view of transmission is now being reexamined. Inefficiency is a likely outcome if energy sells at marginal cost while transmission is priced by allocating average cost among users, with or without congestion adjustments. Over the longer term, this inefficiency will affect the capacity and location of new transmission and the locational choices of generators.¹ Under rolled-in transmission pricing (proration among the region's utilities unrelated to use), a collectively-funded line might allow a generator to profit by exporting power from the region, while the line itself has few reliability benefits that might justify the sharing of its costs

A second realization also calls the conventional wisdom on cost sharing into question. Most existing transmission in the U.S. was built during the first two-thirds of the twentieth century, prior to the rise of power markets. Self-sufficient utilities with territorial monopolies built lines to link anticipated customer growth with generators that they owned. The locations of these lines and plants may have been efficient for insular systems, but changes in technology, customer location, fuel prices, and markets have virtually ensured that the choices utilities made

¹ Efficient locational choice is further complicated by the fact that natural gas transportation charges are also regulated at average cost, but with some sensitivity to distance. See Frame and Quinn (2002).

forty years ago will only by accident be those they would make today. Most regional transmission grids can accommodate a large variety of potential additions and upgrades, while investors in competitive generation have differing projects and expectations which will impact their views on the best new transmission investments. If the existing grid is robust and less than optimally designed for today's markets, the case for central planning of most transmission becomes weak. One utility executive recently went so far as to say that "[w]e cannot optimally plan the transmission grid any longer, and we should not try and pretend that we can."²

This changed view of transmission is reflected in applications to FERC by Regional Transmission Operators (RTOs) that propose "participant funding" of some lines. The next section of this paper describes the proposals, and the support and opposition they have engendered. Common to all proposals has been an attempted distinction between lines built for "economic" reasons and those needed for "reliability." Since power flows through all lines in a grid in accordance with physical laws, every line jointly produces market-related and reliability benefits. The externality greatly complicates any standard for participant funding. Section III discusses the free rider aspects of the problem in more detail. If the RTO classifies a proposed line as "economic," its beneficiaries may choose to delay construction until its absence raises reliability issues. If it is reclassified as necessary for reliability, the costs will be shared by a larger group while the benefits continue to be concentrated on a few market participants. As in other cases of public goods production, all parties will often have incentives to understate the line's value to them. Without accurate estimates of value, neither central planning nor the market will produce efficient choices.

Section IV proposes an alternative method to elicit valuations that starts by rejecting proposals to classify lines as privately or collectively funded. Instead of producing only market benefits or only reliability benefits, any line will provide a mix of the two that must be consumed jointly. To induce truthful statement of a line's benefits, I reexamine a protocol known as the

² Bruce Edelston, Director of Policy and Planning, Southern Company, quoted in Radford (2003).

Demand Revelation Process (DRP). That process elicits truthful statements about valuation of public goods by introducing a tax that in effect charges each decision-maker the marginal cost of changing the group's decision to that decision-maker's most preferred one (Tideman and Tullock 1976). This section outlines the demand revelation (DR) tax and its optimality properties, which turn out to be analogous to those of second-price auctions.

A DR tax has never (to my knowledge) been used to determine electoral choices, and beyond legal obstacles there are practical reasons to reject it as an alternative to voting. It may well, however, have useful application to choices over transmission alternatives in the context of RTOs. Unlike voting populations, RTOs contain manageable numbers of participants who will probably have adequate incentives to inform themselves about the issues. The dollar values of benefits can be estimated with relative ease, and the scheme is potentially consistent with existing regulation. Market power and collusion are unlikely to constitute substantial problems. Most economists justifiably question claims that are made for novel decision-making methods, but in this case some experiments may be in order.

II. Participant Funding Arrives

Over the past decade FERC has intensified its efforts to induce transmission-owning utilities to cede operating control over their lines to regional authorities, originally called Independent System Operators [ISO] and now known as Regional Transmission Organizations [RTO]. Issued in 1999, Order No. 2000 specified in varying detail the attributes and operating practices that it would require from utilities applying to organize RTOs.³ In particular, it specified that RTOs would have ultimate responsibility for planning and expansion of grids in

³ Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (1999).
<http://www.ferc.gov/legal/ferc-regs/land-docs/RM99-2A.pdf>

their regions. The responsibilities would include allocation (also subject to other regulations) of the costs and benefits of these additions. The Commission stated a clear preference for market-determined congestion management and investment over central planning of these functions.⁴ It went on to address the problem of lagging transmission investment under existing rules by proposing that some new lines be participant funded, i.e. that “those who benefit from a particular project (such as a generator building to export power or a load building to reduce congestion) pay for it.”⁵

A. SeTrans

On June 27, 2002 a group of southeastern utilities petitioned FERC for a declaratory order approving the structure of their proposed RTO, known as SeTrans.⁶ They proposed participant funding of some transmission for reasons of efficiency and equity. Their area’s gas resources had attracted independent power projects and proposals whose aggregate capacity if built would far exceed local load growth. Rolled-in transmission pricing for generators exporting from the region would give inaccurate locational signals and shift costs to locals who benefitted little from the plants.⁷ SeTrans’ planning process would ensure that participant-funded lines not degrade reliability. Alongside those facilities the RTO would assess all of its members for the

⁴ *Id.* Slip Op. at 486, 488.

⁵ SMD, Slip Op. at 110. The complex provisions for allocating the cost of interconnecting new generators to the grid are the subject of yet another proceeding. Standardization of Generator Interconnection Agreements and Procedures, Notice of Proposed Rulemaking, Docket No. 02-1-000 (April 24, 2002). http://www.ferc.gov/electric/gen_inter/rm02-1-04-24-02.pdf

⁶ Cleco Power LLC *et al.*, Petition for Declaratory Order Concerning the Proposed SeTrans RTO, Docket No. RT01-100-000 (June 27, 2002). Two very large utility holding companies that dominate the region, Southern Company and Entergy Corporation, were the major forces behind the request. <http://www.setransgrid.com/docs/Final%20Petition.pdf>

⁷ *Id.* at 55.

costs of “Base Plan” additions required for reliability.⁸ Participants funding their own lines were also liable for mitigation of their projects’ detrimental effects (e.g. greater congestion) on others. SeTrans would have Locational Marginal Pricing (LMP, also called nodal pricing), and would allocate newly-created congestion revenue rights (CRRs) to the builder for the economic life of the line.⁹

Criticizing the proposal at FERC, independent power producers (IPPs) and industrial users asked that participant funding be restricted to projects that benefitted only the builder.¹⁰ State regulatory commissions favored the practice on grounds that it was a more accurate allocator of costs incurred in their jurisdictions.¹¹ IPPs and municipal utilities argued with some justification that transmission-owning utilities would use their dominance of SeTrans’ governance to protect their own generation and increase the costs of potential competitors. IPPs favored collective funding of some lines to their plants because economies of scale dictated larger capacities than IPPs required at the outset. Participants have little reason to fund excess capacity because it renders the associated CRRs valueless. Finally, IPPs claimed that the joint products of reliability and market benefits were either incommensurable or difficult to reduce to dollar terms, leaving unasked the question of how anyone could perform a cost-benefit analysis.¹²

With little regard for such arguments, FERC largely approved SeTrans on October 10, 2002. It also prohibited Entergy (a major sponsor) from requiring participant funding prior to

⁸ *Id.* at 56. Both participant-funded and base plan lines may be owned or financed by almost any responsible entity.

⁹ The holder of a CRR on transmission between two points is entitled to receive the difference between their nodal prices. RTOs usually either auction them or allocate them to existing transmission users. A new line can relieve congestion elsewhere in the system, and thereby create additional CRRs for its builder.

¹⁰ Joint Protest of Calpine Corporation, Mirant Americas Inc., *et al*, Docket No. EL02-101, Aug. 5, 2002.

¹¹ Protest of the Louisiana Public Service Commission, Docket No. EL02-101, Aug. 5, 2002.

¹² *Id.* This left unasked the question of how a cost-benefit analysis could ever be performed.

SeTrans' opening.¹³ SeTrans, however, never opened. State regulators commissioned studies showing few benefits from an RTO, while the region's Congressional delegation put provisions into the 2002 and 2003 draft energy bills (neither of which passed) that would slow all RTO activity. SeTrans withdrew its application on December 2, 2003, with a statement that conflicting regulatory demands made it futile to continue. Participant funding played no role in the decision to disband.¹⁴

B. 2003

While SeTrans was in process, FERC proposed to simplify its regulatory duties and eliminate interregional trade barriers. In August 2002 it instituted a rulemaking on Standard Market Design (SMD) that would impose uniform trading protocols in all regions.¹⁵ Congress reacted with hostility to SMD's proposal to put some state-regulated transmission under FERC jurisdiction, and in April 2003 the Commission replaced SMD with a more modest "Wholesale Power Market Platform."¹⁶ Participant funding was an option in both proposals, but events of 2003 (including the August blackout) rendered market design a dormant issue. The comprehensive energy legislation of 2003 (not enacted) also specified that FERC offer participant funding as an option.

In a related area, FERC issued its final rule on interconnection of large (over 20 MW) generators in July 2003.¹⁷ In keeping with FERC's goal of RTO membership for all, the rule

¹³ Cleco Power LLC *et al*, Order Granting Petition for Declaratory Order, Docket No. EL02-101-000 (Oct. 10, 2002). <http://www.ferc.gov/Electric/RTO/el02-101-10-10-02.pdf>

¹⁴ Statement of the SeTrans Sponsors, PR Newswire, Dec. 2, 2003.

¹⁵ Remedying Undue Discrimination Through Open Access Transmission Service and Standard Market Design, Notice of Proposed Rulemaking, Docket No. RM01-012, Aug 12, 2002. <http://www.ferc.gov/industries/electric/indus-act/smd/nopr/08-12-03-nopr.pdf>

¹⁶ White Paper, Wholesale Power Market Platform, April 28, 2003. http://www.ferc.gov/press-room/pr-archives/2003/2003-2/White_paper.pdf

¹⁷ Standardization of Generator Interconnections and Procedures, Order No. 2003-A, 106 FERC ¶ 61,220 (Mar. 5, 2004). <http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen/order2003-a.pdf>

allows utilities in RTOs (and not others) to apply for an option to allow (but not require) participant funding. Newly-formed state committees (representing regulators) in each region will determine conditions that allow participant funding.¹⁸ Absent RTO membership by its utility, the generator pays for facilities on both sides of the interconnection, but on the grid side the transmission provider must provide it with transmission credits and interest over the next five years.¹⁹

C. The PJM Proposal

In March 2003 transmission owners in the Pennsylvania-New Jersey-Maryland (PJM) RTO petitioned FERC for approval of new rules to determine the need for transmission and who will pay for it.²⁰ In effect the plan institutes involuntary funding by participants. PJM will determine all “economic” upgrades to its system, which include both those necessary for reliability and those which relieve chronic congestion. It will continue to socialize the costs of the former, while the latter will be funded by “transmission enhancement charges” imposed on utilities serving narrowly defined zones that benefit from reduced congestion. PJM’s proposed decision process starts by comparing “monthly cumulative unhedgeable congestion” along a constraint with “an applicable Market Threshold.”²¹ (At a high enough price any congestion is

¹⁸ *Id.*, Slip. Op. at 157.

¹⁹ *Id.* at 37. Smaller generators pose fewer issues of participant funding since they are likely to be closer to loads and in many cases will not connect to FERC-jurisdictional lines. FERC’s July 2003 Proposed Rulemaking on Small Generator Interconnections has met with resistance from state regulators, who see it encroaching on their powers to regulate access to lines used for both wholesale and retail transactions. Standardization of Small Generator Interconnections and Procedures, 104 FERC ¶ 61,104, (July 24, 2003) <http://www.ferc.gov/whats-new/comm-meet/072303/E-2.pdf> Also see Bruce W. Radford, “Close to Load, Far from Consensus,” *Public Utilities Fortnightly*, Nov. 15, 2003, 16.

²⁰ PJM Interconnection LLC, Order on Rehearing and Compliance Filing and on Tariff Filing, 104 FERC ¶61,124 (July 24, 2003). Order on Rehearing and Compliance Filing Regarding Transmission Expansion Projects Needed to Promote Competition, 105 FERC ¶ 61,123 (Oct. 23, 2003).

²¹ *Id.* Slip Op. at 4.

hedgeable, e.g. by installing generation near load.) PJM then opens a one-year window for proposals to loosen each constraint. Forms of relief might include merchant transmission projects, new generation, or load management. After approving some proposed solutions, PJM will estimate the benefits of additional relief, discuss the matter with stakeholders, and file its upgrading plans at FERC.²²

PJM faced some resistance from the same interests that opposed SeTrans. IPPs complained that the proposal's alleged bias toward transmission solutions would dampen opportunities for new generators "precisely where they are needed most."²³ Intervenors also felt that transmission owners benefitted because PJM's plan only imposed solutions after congestion had become a problem, rather than proactively spotting bottlenecks before they became serious. Further, PJM's cost-benefit test imposed too high a barrier to new construction.²⁴ PJM will continue to allow pure merchant projects independently of these procedures, but some intervenors believed that the certification proposal gives it excessive power over grid additions that are necessary if new generators are to enter the market. In October 2003 FERC approved parts of the proposal, while remanding others to the petitioners. It found PJM's criteria for acceptable hedges overly vague, and claimed that the RTO's method of estimating unhedged costs was economically illogical.²⁵

III. The Slippery Slope and the Public Goods Dilemma

²² What happens to a utility that chooses not to build a line desired by PJM has yet to be determined. *Id.*

²³ Quoted in Radford (June 15, 2003) at 14. IPPs opposed SeTrans' proposal on the opposite grounds, arguing that utilities would resist plans for transmission in order to insulate their generators and loads from market forces.

²⁴ Motion to Intervene and Protest of Continental Cooperative Services, Docket No. 01-2-007 (April 21, 2003), 5-11.

²⁵ Order on Rehearing (Oct. 24, 2003), Slip Op. at 13.

A. The Slope

In its October decision FERC acknowledged intervenor concerns about gaming by transmission owners and others. In particular, FERC did not accept PJM's plan to define cost shares for a project only after its one-year market window had closed, on grounds that uncertainty about who bears the cost will adversely affect incentives to invest in constraint relief.²⁶ "Those parties who could best bring about a market solution that would eliminate the necessity of requiring an upgrade have been unwilling to step forward and do so."²⁷ Further, with advance information on cost shares there might be strong incentives to reach agreement, since the alternative is an imposed solution..²⁸ FERC also noted the proposal did not foreclose other games that took advantage of PJM and FERC rules.²⁹

These observations lead to more general free-rider concerns. The U.S. has seen a 30-year decline in transmission investment, surely due in part to attempts by states (which have siting authority) to capture some benefits for themselves while avoiding the costs.³⁰ FERC is clearly interested in increasing those investments, but William Hogan (2003 at 22-23) questions whether the Commission is actually attempting to implement its vision of optimal investment rather than the market's. In particular, the PJM plan centralizes decisions that he believes should be decentralized, requiring that participants pay for investments that they would not necessarily

²⁶ "Region" is subject to numerous definitions. For example, do only occupants of an affected load pocket pay, or is the burden shared with adjacent areas?

²⁷ Order on Rehearing (Oct. 24, 2003), Slip Op. at 19.

²⁸ *Id.*, Slip Op. at 20.

²⁹ As examples, Delaware municipal utilities noted that a participant wishing to maintain its market power could offer a solution during the one-year window, wait until PJM reached its spot in the queue, and then cancel the project. National Grid discussed a generator that proposes to operate in a load pocket and then suspends its activities during the period while it waits in FERC's interconnection queue prior to construction Order on Rehearing (Oct. 24, 2003), Slip Op. at 18.

³⁰ Re the reduction in transmission investments, see Hirst and Kirby (2001) at 5-8.

favor if left to choose. PJM's identification of bottlenecks and calculation of economical congestion hedges can be the beginning of a return to integrated resource planning, which in the end would compare transmission investments with generation and demand management. Hogan's "slippery slope" ends with the abandonment of markets in the name of competition. To avoid it, he proposes a line between collectivized and entrepreneurial investments:

"Regulated transmission investment would be limited to those cases where the investment is inherently large relative to the size of the relevant market and inherently lumpy in the sense that the only reasonable implementation would be as a single project like a tunnel under a river. Everything else would be left to the market. This would be a principled hybrid system. (2003 at 22-23.)

The operational significance of the distinction is unclear. First, in antitrust the "relevant market" is a set of products and a geographic area in which competition is affected by the actions at issue. Difficulties in defining substitutes for buyers and predicting entry of competing sellers often make its definition the central question in such litigation. As the industry changes FERC has substantially revised its market definitions and criteria for competition, but the usual focus in such dockets has been generator market power over short-term energy and capacity under open access to transmission.³¹ Those commodities are probably not at the nexus of competition that an addition to transmission will affect, and the regional characteristics of power flows further complicate market geography. Limited transmission capacity is a fundamental barrier to transactions, but neither FERC nor the courts have ever relied on structural measures to determine the relevance of a proposed transmission market.

Second, there no obvious threshold that makes a line large relative to the market. Elements of "size" might simultaneously include capacity, location, and length, and larger lines are often more economical to construct and operate per megawatt-mile transmitted.³² Hogan

³¹ Order No. 642, Revised Filing Requirements Under Part 33 of the Commission's Regulations, F.E.R.C. Stats & Regs. ¶ 31,111 (2000), 65 Fed. Reg. 70,983 (2000) (codified at 18 C.F.R. pt. 33).

³² National Regulatory Research Institute (1987) at 115. Hogan (2004 at 7) refers to a line characterized by downward-sloping marginal costs as a "possible transmission market failure" because it has "no sustainable

(2003 at 23) defines an investment as large if it so affects the value of FTRs that it cannot be justified on private cost-benefit grounds. By this standard, it is possible that most such lines would be collectively funded by members of RTOs, or at least constructed by regulated utilities able to fold their costs into a rate base. “Reasonable” implementations are also likely to be quite limited in a grid where finding a transmission path, getting the line permitted, and constructing it can take over ten years.

Beyond scale and location lie the complications of path dependence. Regardless of how an RTO determines the sizes and locations of “reliability” projects, the characteristics of earlier upgrades can affect a new generator’s interconnection costs. A generator in the interconnection queue will incur charges that depend on its position, and there is no obvious rule for allocating the charges among those in the queue. If some positions are more advantageous than others, gaming could ensue. There may also be times when waiting is the best strategy. An RTO may require a generator intending to use 5 percent of a facility that is 95 percent filled to pay the entire cost of an upgrade. In the normal course of business, however, pre-existing users may choose to loosen a potential constraint such as this one, allowing the new generator’s share of costs to be rolled-in. (Fox-Penner 2003)

B. Transaction Costs and Public Goods

Any bright-line distinction between participant- and RTO-funded transmission will be less a matter of economics than one of regulatory convenience. If negotiation is costless and initial rights are well-defined, the Coase (1960) Theorem ensures that any number of parties can contract their way to an efficient outcome, regardless of the situation’s underlying complexity. If so, the line between participant and collectively funded transmission is set where the transaction costs of implementing an efficient solution become prohibitively high. At one extreme, a radial

market price In reality, a two-part price will allow cost recovery, but the nodal system only allows one-part prices.

line that links a single generator to the grid will be efficiently constructed by the generator itself. Transaction costs rise with the number of affected parties and with the complexity of the network that links them.

If transaction costs are high, the individual assignment of rights may matter (Demsetz 1972). If those costs are low enough, the parties may also voluntarily reallocate rights to reach an efficient outcome. Assume, for example, that regulators require all transmission owners in a grid to approve any proposed addition to the system. The power that such a rule grants to holdouts may lead to the breakdown of negotiations over investments that increase efficiency. Alternatively, let regulators confine the necessary approvals to those whose own lines will actually be connected to the proposed line. The cost of negotiating will be lower, and more lines of all types will be sited. If most new lines that are approved by the smaller number of transmission owners are in reality efficient, the rule is superior than one that grants veto power to holdouts. Alongside the efficient investments, a small number of inefficient lines will also be built. Baseline and participant funded transmission correspond to a rough split between lines with high and low negotiation costs. High transaction costs may also result from inadequate information: PJM's refusal to inform interested parties about their cost shares until after its window for alternatives closes needlessly raises transaction costs and with them the likelihood that the Interconnection will treat the lines in question as collective investments.

Participant funding occupies an odd niche in electrical restructuring. Over the course of reform the design of such institutions as power exchanges and ISOs has been informed by a strong concerns about economic efficiency, as constrained by law, regulation, and politics. This concern has been far less evident in transmission. Proposals for LMP, augmented by CRRs, originally appeared to provide efficient solutions for transmission investment and generator location. Now, however, there is growing recognition that nodal prices by themselves cannot

resolve free rider and related gaming problems, and that they can induce inefficient investments when scale economies are present. The next section proposes an alternative institution.

IV. The Demand Revealing Process

A. Externalities and Joint Production

Free-rider problems may so permeate some public goods that their production is best turned over to a government that can impose taxes on beneficiaries who would otherwise misstate their valuations and refuse to pay taxes based on them. In the extreme example of defense, increasing the nation's population still allows each original citizen to continue enjoying the same amount of services from the armed forces. More commonplace private security investments nevertheless take place because their private benefits outweigh the costs to the investor, while non-payers also benefit.³³ Institutions can matter. Folding the costs of lighthouses into the fees ships pay to use British harbors solves a free-rider problem that otherwise appears intractable (Coase 1974). In the 18th century they were privately provided and financed by port fees on ships. The lighthouse exemplifies the more general principle that an organization can sustain the production of a public good if it is capable of tying that good's supply to the supply of an excludable private good (Olson 1971)

A transmission line produces two services: it facilitates efficient power market transactions, a private good to those with the rights to undertake them, and it improves reliability, a public good that benefits everyone on the grid to differing degrees. Since the market services are jointly produced as functions of the line's capacity, their value for a given capacity is the sum

³³ Ayres and Levitt (1998), for example, found that auto theft in a cross-section of cities fell significantly as the percentage of cars with Lojack locator devices increased. By their calculation, the installer of a Lojack reaped only ten percent of the total benefits to society that arose from his investment. Hence the free rider problem is solved here, but investment in Lojacks is short of the amount that maximizes their net social benefits.

of the values of those with rights to use the line. (These may include non-investing parties who at times can obtain interruptible service.) Because capacity is excludable, market participants have incentives to truthfully reveal their willingness to pay for it, as for any other private good. With joint production, however, their demands as functions of capacity are added vertically rather than horizontally.

A new line also raises the network's carrying capacity and may increase the threshold at which a disturbance will trigger a widespread outage. That protection has attributes of a public good, since all utilities (and their customers) on the grid benefit from it without affecting the benefits of others. Different utilities, however, will value the reliability effects differently. Smaller systems will receive fewer dollar benefits than large ones, and ones near the line may enjoy greater outage protection at the margin than those at a distance from it. Assume that the line's marginal contribution to reliability is positive but diminishes with its capacity. A distant utility may enjoy few or no reliability benefits because a failure in the neighborhood of the line can be stopped before it cascades.³⁴ Because the construction of the line itself produces reliability benefits for payers and nonpayers alike, reliability is subject to a free rider problem that induces beneficiaries to misstate their true valuations. For such a pure public good, individuals' demand curves for reliability are summed vertically. The total value of the line's market and reliability services is then the vertical sum of the market demands for each of them.

B. The Demand Revealing Process

In a cryptic 1973 article, Edward Clarke proposed a process that would induce individuals to reveal their true valuations of a public good. His work went unnoticed until

³⁴ Thus in Figure 1(b) B's marginal valuation of reliability could fall to zero past a certain line capacity. If systems are to pay for the line in accordance with their marginal reliability benefits, B should not be assessed, even though it receives inframarginal benefits. The externality that a large-capacity line produces is not "Pareto relevant." See Buchanan and Stubblebine (1962).

Tideman and Tullock (1976) rediscovered it a few years later. After that publication, it enjoyed a short notoriety among public choice economists, after which it returned to obscurity.³⁵ The idea may never have taken hold because the only proposed applications were for legislative budget negotiations and mass decisions on departmental budgets, both highly unlikely as institutional changes. Participant-funded transmission, however, appears surprisingly amenable to the demand revelation process (DRP), which may provide a way out of the free-rider problems encountered in participant funding proposals.

Assume that the true valuations of three stakeholders (X, Y, and Z) for three mutually exclusive public goods (A, B, and C) are given in Table 1, taken from Tideman and Tullock. The voters' cost shares are exogenously determined.³⁶ Since A is valued most highly (for this allocation of costs), it should be chosen.³⁷ The procedure involves tallying the values of the alternatives for each N-1 member subset of the population, and allowing the excluded person to change the outcome if he is willing to pay an odd tax, sometimes called a Clarke tax. The winner is the option for which voters are willing to pay the largest total Clarke tax.

First consider Voter X. Voters Y and Z state their valuations of the alternatives, and C is the choice with the highest value (\$70) summed over them. X's benefits, however, are maximized if A is the outcome, and in fact he values C at zero. His choice is between accepting C and paying no tax (since that choice would not change the outcome), or claiming to prefer A and paying a tax. That tax equals the difference between [1] the total value that voters 2 and 3 place on their winner C, i.e. \$70, and [2] the total value that those two voters place on A, i.e. \$40. X gets his most desirable option in return for paying a \$30 tax. The payment of \$30 to change

³⁵ A collection of articles on the process fills a supplement to *Public Choice* 29 (Spring 1977). At roughly the same time Groves and Ledyard (1977) invented a more general method of preference elicitation than Clarke's, but it too has remained a theoretical curiosity.

³⁶ Thus this is not a full Lindahl equilibrium. Renegotiation to determine cost shares is discussed below.

³⁷ In this example a pairwise majority choice followed by a runoff against the excluded choice produces cycles, i.e. the winner depends on the sequence in which votes are taken.

from C to A leaves him with \$20 in net benefits. This is more than from staying with C (\$0), and also more than from misrepresenting his preferences by choosing B. He can pay \$10 to change the outcome to B, but this leaves him with only \$10 (= \$20 - \$10) in net benefits.

Next, exclude voter Y from the first part of the process. X and Z choose A, worth \$90 to them. Y values A at zero and if unconstrained would choose B, which the others value at \$20. To get B, Y must pay $\$90 - \$20 = \$70$, which exceeds his \$60 valuation of A. Thus he settles for A, gets no benefit and pays no tax. Finally, with Z excluded from the first round, X and Y choose B, worth \$80 to them. Z can change the outcome to A by paying \$30, and doing so leaves him \$10 better off than settling for B. A wins because it collects the highest total tax (\$60), while B and C each produce no payments. The money must either be thrown away or put to a use that does not induce voters to lie about their valuations.

This process produces the optimal selection by giving voters incentives to truthfully state their preferences. Since given the choices of others no voter wants to alter his own choice, the outcome is a Nash equilibrium. X's bid changes the outcome of an election by Y and Z from C to A. If X tries to claim that A is not worth at least \$30 more than C to him, he runs the risk that others will not pay enough to make A the winner, which would leave X worse off than if he had paid \$30. A voter who overstated his willingness to pay for some alternative would find himself paying more tax than it is worth to him to change the outcome. The tax puts a personalized price on the public good for each voter, determined by that voter. It is equal to the marginal cost of his changing the social decision to his most preferred one.

As in all known allocation processes (including private goods markets) inefficiencies can result if a coalition of voters misstates its members' valuations. The optimality of the Clarke procedure is analogous to that of a second-price auction for a private good. If individuals' valuations are private and heterogeneous, bidding one's actual valuation is a dominant strategy in a second-price auction. Bidding more may leave the winner to pay a second-high bid that is also

above his valuation, while bidding less entails a risk that someone who values it less highly but is truthful will obtain the good that our bidder was willing to pay more for (Dutta 1999, Ch. 14)

C. The Continuous Case

Figure 2 depicts a proposed transmission line whose capacity can be continuously varied. D_T is the vertical sum of all participants' willingness to pay, here assumed to be two persons with demand curves D_X and D_Y . Their shares of its constant marginal cost are C_X and C_Y , which sum to C_T . Q_Y is the capacity that maximizes Y's net benefits, but X wants more because at Q_Y its value exceeds his marginal cost. Under the DRP, X must pay a tax that equals the loss to Y, who will be forced to consume an amount that is excessive relative to his optimum. Like a conventional deadweight loss, it is the triangle below C_Y and above D_Y , between Q_Y and Q^* . By construction, X pays the lower shaded triangle in tax and is left with benefits equal to the remainder of the trapezoid below D_A and above C_A . Q^* is the quantity at which market demand equals marginal cost summed over the participants.

Q^* will be the choice regardless of whose decision is first. Let X start by choosing Q_X , a capacity that Y finds excessive. Reducing capacity to Q^* leaves X with a loss equal to the difference between C_X and D_X from Q^* to Q_X . After Y pays that amount as tax, his net benefits from the change remain positive. As in the numerical example, the DRP encourages truthful revelation. Overstatement of the benefits of a change leads to payment of an excessive tax, and understatement runs the risk that the change will not take place. Also as before, the proceeds cannot go to the party whose consumption is being moved away from his own optimum. The purpose of the tax is to induce a change that maximizes welfare defined as the sum of

(producer and) consumer gains, and not to compensate someone whose well-being decreases in the process of that maximization.³⁸

D. Properties of the DRP

The DRP produces a Samuelson (1955) equilibrium where the public good's aggregate marginal valuation equals its marginal cost. The cost-sharing rule, however, creates welfare losses that are unavoidable due to the consumption uniformity inherent in public goods. At their exogenously determined cost shares, individuals are left over- and under-consuming. In Figure 2 we can adjust X's cost share upward and Y's downward by equal amounts so that each pays exactly his marginal valuation of Q^* . Doing so, however, requires an intervention that leaves X worse off than originally. Since the tax cannot be returned as compensation, this Lindahl equilibrium can only be reached by coercion.

The likelihood that an individual's vote will alter the outcome of an election decreases disproportionately with the number of voters. The members of a large electorate will thus have few incentives to inform themselves and to vote in the absence of mitigating circumstances.³⁹ On the other side, the more parties that take part in a DRP, the smaller the proportion of them that will pay a tax, so the waste from throwing away the proceeds or spending them suboptimally becomes relatively smaller. The tax is also less feasible where the policy to be chosen has a more than one or two dimensions. Properly, voting would have to take over all possible combinations of those dimensions. Dimensionality also diminishes the tax's feasibility in situations where goods have multidimensional attributes or are traded in bundles that cannot be decomposed.

³⁸ The usual argument that compensation need not be paid does not strictly hold, since here it must not be paid because the promise of payment would alter a person's incentives to accurately state his valuation.

³⁹ For example, they may feel a duty to vote, or may acquire political information because it is enjoyable to discuss with others.

V. The DRP and Transmission

The DRP eliminates problems of distinguishing market-related and reliability transmission by using a single decision process that allows the parties to value both the private and public good aspects of a line. There are both legal and practical obstacles that stand in the way of using the DRP in popular elections, but most of them do not carry over to transmission decisions made under RTOs.

Small numbers and substantial stakes. In most regions the number of utilities who are materially affected by a new line will be manageably small. Unlike members of a mass electorate, utilities will usually have large enough stakes to warrant careful evaluation of alternatives. To perform those evaluations, utilities have technically competent employees and consultants whose costs they can recover in rates. Those whose interests are only marginal or who are certain they will not alter the outcome can easily identify themselves and justifiably put less effort into their calculations.

Small numbers of choices and elections. Utilities voting on transmission additions or upgrades will generally face few alternatives. There are a limited number of standard voltages rather than a continuum, and environmental factors will often leave them with only minimal choices about routes. Since most transmission is already in the ground, the number of major projects over a year will often be small.⁴⁰ Lines that degrade the grid or confer undue market power on their builders can be eliminated prior to initiating a DRP.

Measurable costs and benefits. Momentary flows along a line are unpredictable, but utilities have data on patterns of generator operation and demand behavior over longer periods that can help them evaluate benefits. The line's marginal contribution to reliability will be harder

⁴⁰ Low-voltage distribution lines will be state jurisdictional and probably continue to be built by single utilities

to estimate, because it depends on largely speculative estimates of the value of lost load.⁴¹ This problem, however, must be coped with regardless of the decision process that determines system additions and upgrades.

Consistency with regulation. The DRP is compatible differing regulatory regimes that range from cost-of-service to price caps and other incentive schemes. It is consistent with an RTO's choice of nodal, flowgate, or zonal pricing, and alternative schemes (including auctions) for the allocation of congestion revenue rights. There is no reason to expect that a decision made using the DRP will have adverse market power consequences that are not also present in other choice processes. If regulators allow vertically integrated utilities to exercise market power, the DRP does not stand in the way of utilities' continuing to do so.

Economies of scale. The DRP, unlike most other incremental choice processes, does not fail if scale economies are present. The DRP will reach a solution regardless of how costs vary with capacity. Cost recovery will continue to require nonlinear pricing, whatever the method the parties use to decide on capacity and determine its construction schedule.

Cost shares. The DRP starts with exogenously determined cost shares. Unlike some other goods, it is often feasible to estimate the benefits of a transmission line to market participants prior to building it. Utilities already use system simulations for many purposes, and regulatory rules can lower the transaction costs of allocating the line's costs among the parties. Supporters of the DRP have yet to analyze the renegotiation of cost shares, e.g. as prior rounds of bargaining affect the expectations and strategic behavior of the parties.

Throwing away the tax proceeds. If the tax payments by participants are not thrown away, inefficiency can result because the DRP then in effect rewards them for misstating their

⁴¹ The political implications of blackouts may make regulated utilities place higher values on reliability than would be justified on strictly economic terms. Any decision system that allows utilities to recover their capital costs can produce this outcome.

preferences. Some form of incentive-based regulation may be necessary because under cost-of-service schemes any such payments become part of the utility's revenue requirement.

Price cap regulation offers the possibility of recovering some or all of the payments (with the likelihood determined by regulators) as a reward for efficient operation. As a practical matter, the proceeds from DRP taxes are likely to be small and could be disposed of as funding for other public goods, e.g. renewable resources or research on them that benefits the entire system some time in the future.

Intertemporal dependence. Under fairly general conditions, a second-price ("Vickrey") sealed-bid auction will induce truthful revelation of bidder preferences, be economically efficient, and produce the same expected revenue as an ascending oral auction. Vickrey auctions, however, may be rare because they convey information about a bidder's costs or preferences that can be useful to competitors in future auctions or help others to extort rents from the winner in post-auction negotiations (Rothkopf *et al* 1990).⁴² The DRP has analogies to a Vickrey auction, but its intemporal consequences when investments are part of a network warrant further analysis.

VI. Conclusions

The DRP resolves free rider and demand revelation problems when several parties benefit from and pay for a public good. In electricity, it potentially ameliorates an important weakness inherent in the structure of RTOs as groups of stakeholders whose decisions are made collectively. The free rider problems addressed by the DRP cease to exist (save for interregional effects) if all lines in an area are owned by a single regulated firm ("transco") whose investment decisions internalize regional externalities.

Any new industry institution proposed by an outsider carries a heavy burden of proof. Electrical restructuring, however, has centered on the creation of new exchange and governance

institutions that are responses to issues that transcend the territories of individual utilities. Regulators have been particularly concerned with short-term exchanges and coordinated operation, but their expectation that short-term nodal transmission pricing will induce efficient investments is coming into question. FERC's policy of support for participant funding when lines have small numbers of beneficiaries is running up against free-rider problems in important applications. The DRP is a possible tool the commission can use to untangle market-based from reliability investments by putting them under the same process.

As electricity moves toward competition, participant funding can be a foundation for greater decentralization. Today's grids were not centrally planned, but arose from the interconnection of self-sufficient utilities. Most are robust enough to allow considerable flexibility in the siting of new generation and construction of additional links, leaving reliability unaffected or improved. Existing transmission owners have no obvious superiority in foreseeing how loads and supply conditions will evolve. Beyond RTOs, electricity's transformation will largely be one of decentralization and organizational innovations to bring about changes never contemplated in models of regulation. Economists have been the creators of many such innovations. Some, such as California's consideration of a second-price auction for cogenerator contracts with utilities (Rothkopf *et al* 1990), were overtaken by events before they could be implemented. Others, such as price-cap regulation and locational marginal pricing of transmission, are widely acknowledged improvements. The DRP for transmission investments is one more such attempt at institutional innovation, with the potential to be useful in other collective decisions beyond transmission investment.

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TABLE 1

AGGREGATION OF PREFERENCES

VALUE OF OPTIONS

| VOTER | A | B | C | TAX |
|--------------|----------|----------|----------|------------|
| X | \$50 | \$20 | \$0 | \$30 |
| Y | 0 | 60 | 20 | 0 |
| Z | 40 | 0 | 50 | 30 |

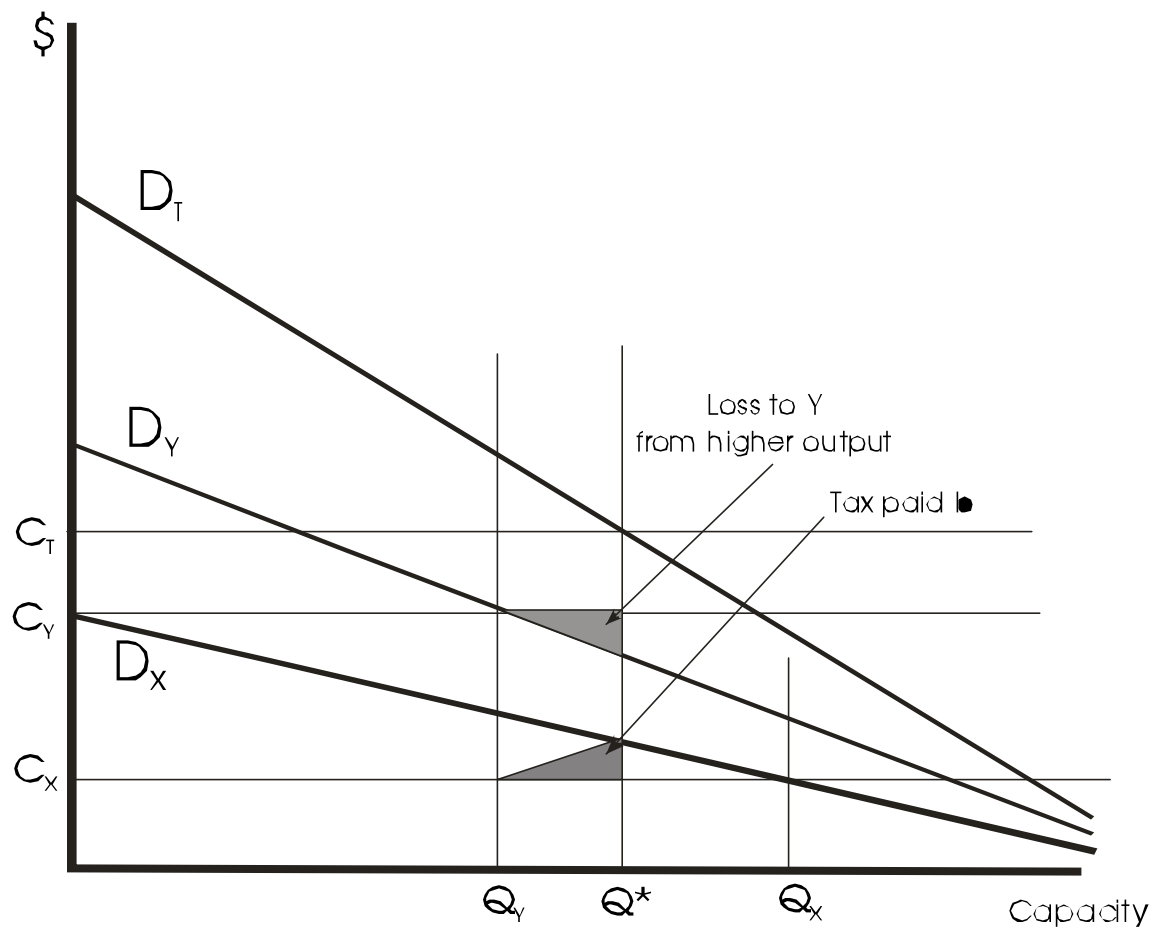


Figure 1
The Demand Revelation Tax