

Reliability Differentiation of Electricity Transmission

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## **Abstract**

In many jurisdictions, electric utility restructuring has included the creation of an independent system operator (ISO) to dispatch generation, establish the market-clearing price, and allocate limited transmission capacity among users. This paper differentiates reliability through rate unbundling. We propose a capacity reservation tariff (CRT) to induce the users to self-select their preferred levels of reliability. Based on these self-selected reliability levels, the ISO can efficiently allocate limited transmission capacity. Our proposed CRT can be a practical solution to the transmission congestion problem faced by the California ISO in the implementation of retail access.

## 1. Introduction

Beginning with the Public Utilities Holding Company Act in 1935, state and federal regulation has shaped the structure of the electric power industry. The current emphasis on deregulation at both the state and federal levels is leading to a profound restructuring of the industry (Joskow 1997).

The Federal Energy Regulatory Commission's (FERC) recent deregulation of electric-power markets was preceded by almost a decade of regulatory reform. The passage in 1978 of the Public Utility Regulatory Act sparked the early development of a competitive power-generation industry. FERC's action was also predated by deregulatory actions at both the state and federal levels in the United States, as well as overseas and Canada (Maloney 1996). Chief among these actions were the deregulation of electric industries in Europe (Thomas 1996), Australia (Schuler 1996), and New Zealand (Pleatsikas and Turner 1996), the passage of the Energy Policy Act of 1992, and several state-level initiatives to encourage market pricing of electricity.

Concerned with the potential abuse of market power by integrated utilities that owned the majority of the extant generation and transmission assets, FERC issued the Mega-Notice of Proposed Rulemaking (NOPR) that proposed *pro forma* tariffs

under which all transmission users (both generators and end users) would have open and non-discriminatory access (FERC 1995). These tariffs govern three types of transmission service: firm network; firm point-to-point; and non-firm point-to-point. While maintaining a level playing field and differentiating transmission service by location and reliability, the *pro forma* tariffs are largely driven by embedded cost, with an ensuing outcome of being economically inefficient (Massey 1997). FERC (1996a) later issued Order 888. The *pro forma* tariffs in Order 888 contain provisions that specify the priorities for use of reserved transmission capacity. While the priorities are determined by the duration of reservation, they also reflect the reservation fees paid by the transmission users. FERC's recognition that transmission rates should be commensurate with service priorities motivates our writing of this paper.

Parallel to the trend of federal deregulation, many states initiated their own deregulatory efforts. For instance, in 1994 the California Public Utilities Commission (CPUC) issued the restructuring proposal that recommended phased-in access by retail consumers (CPUC 1994). Two years later, the CPUC issued Decisions D.95-12-063 and D.96-01-009 (CPUC 1996) mandating the development of a power exchange and an independent system operator (ISO). And on September 23, 1996, California Governor Pete Wilson signed into law Assembly Bill AB 1890 that requires

the CPUC to implement a power exchange and Independent System Operation. Starting in 1998, all electricity consumers served by the three investor-owned utilities (i.e., Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company) and some municipal utilities (e.g., Sacramento Municipal Utilities District) will have direct retail access to electricity suppliers of their choice. Transmission service, however, will continue to be regulated with the rates set according to embedded cost. Other states can be expected to soon follow California's path (Regulatory Focus 1996).

Two important observations may be made from the preceding narrative. First, the regulatory drive towards a competitive energy market leads to an industry structure that revolves around a power pool into which generators bid to supply energy and from which end users seek to satisfy their demands. Second, transmission tariffs will be implemented as reliability-differentiated capacity reservation fees. Indeed, FERC has considered replacing its Order No. 888 tariffs with a capacity reservation tariff (CRT) for all wholesale transmission transactions under its jurisdiction (FERC 1996b). Little is known, however, as to the efficient design of a CRT.

These two observations underlie this paper's primary goal: to propose a CRT that will enable an ISO to efficiently ration

limited transmission capacity. This fills a major gap in the literature of transmission pricing.

This paper is also driven by practical considerations related to the nodal pricing of transmission service within a competitive energy market. Hogan (1992) proves that the nodal price for transmission between two nodes in a network is the difference between the spot energy prices at the two nodes. Absent active trading at widely dispersed nodes, the spot energy prices are approximated by node-specific short-run marginal energy costs computed in real time. The resulting transmission nodal prices are continuously disseminated to transmission users. Therefore, implementation of nodal pricing entails high transaction costs and information requirements.

We propose capacity rationing using forward contracts as a feasible alternative to nodal pricing. Our proposal bridges the gap between the current regulated market environment and the competitive transmission market envisioned by Chao and Peck (1996; 1997). As such, our proposal complements the work of Chao and Peck (1996; 1997), and can be implemented via a CRT with priority fees for varying levels of reliability. This proposal can be a practical solution to the congestion problem faced by the California ISO in the implementation of retail access.

Reliability differentiation unbundles the transmission service charge into four components: (a) a location-specific capacity reservation fee that reflects a user's required level of reliability; (b) a congestion surcharge to mitigate anticipated shortages; (c) a usage fee to collect operation costs due to line losses; and (d) a customer charge that collects the network's embedded cost. Our research focus is on (a) and (b). There is a general consensus on the role of (c), although how (d) should be set can be controversial (Joskow 1995).

We propose a customer charge based on the connected capacity of generators and the connected load of end users. Hence, the charge does not depend on capacity reservation. It is unlikely that the charge will distort the transmission users' connection decisions, because end users benefit substantially from being able to consume electricity instantaneously.<sup>1</sup> Thus, the remainder of the paper will assume that embedded-cost recovery can be adequately dealt with using a customer charge.

Similar to the papers by Chao and Wilson (1987) and Wilson (1989) for rationing generation capacity, our proposal establishes a set of rules that enables the ISO to efficiently allocate limited transmission capacity. These rules permit the users to self-select any one of as many levels of reliability

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<sup>1</sup> Outage costs of electricity consumers are more than ten times their average electricity rates (Woo and Pupp 1992).

that the ISO elects to offer. They tell the ISO exactly how to define and price the various levels of reliability that it should offer. Hence, these rules will improve a network's efficiency in the market environment which is likely to prevail over the next few years.

## **2. The Pricing of Transmission Services**

Based on Hogan (1992), the ISO recognizes that the demand for transmission service between any two locations is a derived demand, driven by the difference between the location-specific spot energy prices. The maximum transmission charge that a generator in location *A* is willing to pay for transmission service from the point of receipt (POR) *A* to the point of delivery (POD) *B* is the difference between the spot prices at *A* and *B*. As defined by FERC's *pro forma* tariffs, the POR and POD refer to the points of power injection and withdrawal, respectively.

Woo et al. (1997) empirically show that competitive spot prices prevail in major wholesale energy markets with active trading (e.g., Mid-Columbia and California-Oregon-Border in the Western Systems Coordinating Council). However, there are relatively few buyers and sellers at any one location within a network. Thus, the location-specific energy markets required to

determine competitive location-specific spot prices do not exist.

In the absence of such spot prices, nodal pricing of transmission will likely be based on the marginal (imputed) value of transmission, the economic gain from additional transmission capacity. This value is the difference between the short-run marginal costs of delivered energy at two locations. The short-run marginal cost of delivered energy is the sum of the marginal generation costs at the swing bus, marginal line losses, and marginal congestion costs (Bohn et al. 1984). Since the marginal generation costs at the swing bus are identical for all locations, the spot transmission price at any given time is the sum of the differences in (1) marginal line losses between two locations and (2) marginal congestion costs between those locations (Hogan 1992). Consequently, nodal pricing of transmission entails pervasive transaction costs and exposes the network to supply-and-demand imbalance due to miscalculated marginal energy costs (Spulber 1992). Transmission capacity rationing via reliability differentiation therefore becomes an alternative to nodal pricing.

Reliability differentiation achieves economic gains by allowing the ISO to allocate scarce transmission resources efficiently. In the simplest case of a radial system with one transmission line connecting two nodes, reliability

differentiation for transmission resembles that for generation, as previously established by Chao and Wilson (1987), Wilson (1989), Woo (1990), and Spulber (1992).

For a more complicated network, the available transmission capacity between any two nodes depends on the pattern of power flows throughout the entire network. Priority pricing of transmission may therefore follow the multi-product pricing approach in Wilson (1993). Here, however, we develop a reliability-pricing scheme that builds on the well-known "news vendor problem" (see, e.g., Hadley and Whitin 1963, 297-299), which seeks to determine the optimal purchase of a non-storable good under uncertain demand.

The latter problem can be framed as a Bayesian test of the null hypothesis that the "next" unit purchased can be sold (Hays and Winkler 1970, 496-499). In our variation on the theme, generators and end users in effect test the hypothesis that there will be a capacity shortage. The resultant pricing scheme is a CRT, spanning the gap between theory and practice.

### **3. Forward Contracts**

#### **3.1 Curtailable Energy Service**

Reliability differentiation utilizes forward contracts which govern service curtailment. An example of a forward contract is the curtailable service tariff commonly offered by electric utilities to their industrial customers. Before receiving service, a customer reserves the firm service level (FSL) that is not curtailable. When a shortage occurs, the customer's demand will be limited to its chosen FSL. The overall service reliability received by the customer varies directly with the FSL chosen. A customer willing to risk the loss of its entire load chooses  $FSL = 0$ . A highly risk-averse customer may choose an FSL above its anticipated maximum demand.

In return for the *right*, but not the *obligation*, to curtail demand, the utility offers an industrial customer an upfront payment. The curtailment service contract is in effect a call option sold to the utility by a customer. When the marginal cost of service to the customer exceeds the per kilowatt hour (kWh) retail rate (the strike price), the utility exercises the option to curtail service. The call option's price is a per kW payment from the utility to the customer. Since the difference between the marginal cost of service and the retail rate measures the marginal congestion cost, the per kW payment is the expected marginal congestion cost (Woo 1990; Spulber 1992).

### **3.2 Curtailable Transmission Service**

Reliability differentiation of transmission service using forward contracts may be structured in a manner similar to curtailable energy service. We assume that the ISO leases the network from transmission owners at rates based on the embedded costs of these owners. Then the ISO sells forward contracts to transmission users.

The principal attributes of a transmission service contract are: (a) the service priority and priority fee; (b) the congestion surcharge; (c) the usage fee; and (d) the fixed customer charge. Each contract specifies how an ISO would dispatch a generator's power and deliver the output to an end user. The contract specifies the POR for power injection and the POD for power withdrawal. It does not specify a contract path, thus avoiding the mistake of posting transmission rates based on the geographical concept of megawatt-miles (Koch 1997). The POR-POD representation follows FERC's *pro forma* tariffs. It permits a user to subscribe to both high-priority and low-priority services. When there is a transmission capacity shortage, low-priority service is interrupted before the high-priority service.

#### **4. Proposal**

We consider an ISO which gathers at the beginning of day  $t-1$

supply bids from generators for the amount of energy that they are willing to supply on day  $t$  at any given net price. Thus, the  $j^{\text{th}}$  generator provides the ISO with the supply schedule  $(q_j^s, p_j^s)$ , where  $q_j^s$  denotes the quantity that the generator is willing to supply to the power pool at a net price of  $p_j^s$ . The ISO simultaneously gathers demand bids from all end users, with the  $i^{\text{th}}$  end user providing the comparably-defined demand schedule  $(q_i^d, p_i^d)$ .

If transmission capacity was not a concern, the ISO could sum all the supply and demand bids and determine the market-clearing competitive equilibrium pool price,  $p^*$ , and output,  $q^*$ . There is no markup on  $p^*$ , since the ISO can earn a "fair" rate of return for its trouble and for the use of its facilities through the customer and priority fees.

In the real world, however, generators and end users may scatter over a wide geographic area spanned by the network. Furthermore, on any given day  $t$ , any one of a number of random factors (e.g., transmission line failure) may result in a shortage of transmission capacity. The ISO may therefore have to deny access to some generators and end users. We will now develop a proposal for transmission capacity rationing.

#### **4.1 The Basic Approach**

#### 4.1.1. Model

Our basic model makes the following assumptions:

- *Network Configuration.* The transmission system is radial, with  $N$  price-taking generators at one end of the line and  $M$  price-taking end users at the other end of the line. We initially suppose that each generator will supply either 0 or 1 units of energy, and each end user will demand either 0 or 1 units of energy, on any given day. It costs the  $j^{\text{th}}$  generator  $c_j$  to supply the unit, where  $c_j < c_{j-1}$ .
- *Energy Price Determination.* On the morning of day  $t-1$ , both the generators and end users inform the ISO of their bids to supply and acquire energy. These bids are made under the assumption that the network is uncongested. In so doing, they inform the ISO of the reservation price at which they are willing to supply and purchase energy on day  $t$ . The ISO then determines an equilibrium energy price and system quantity,  $p^*$  and  $q^*$ , for day  $t$  and immediately announces  $(p^*, q^*)$ .
- *Curtailment Probabilities.* For any given  $(p^*, q^*)$  the ISO's management assigns probabilities  $P(S = R)$  and  $P(S = 0)$ , which reflect its best judgments that unanticipated events will cause transmission congestion and effect shortages of  $S = R > 0$  ( $S = 1, \dots, q^*$ ), or no shortage,  $S = 0$ . The initial

probability assignments will combine management's prior information with any sample information. Where management has very little prior information, the prior distribution will be *diffuse*, in the sense that the prior information "is 'overwhelmed' by the sample information" (Hays and Winkler 1970, 482). In the course of its day-to-day activities, the ISO receives additional sample information, and the prior distribution will be revised in typical Bayesian fashion (see, e.g., Hays and Winkler 1970, 446-448). The probabilities that we refer to here are those that are current on day  $t-1$ .

- *Probability Calibration.* We assume that *ex ante* the assigned probabilities reflect the ISO's "true" beliefs and that *ex post* they prove to be well calibrated with the actual outcomes. In the former regard, there are scoring rules that penalize dishonesty; in the latter regard, the scoring rules penalize poor judgment (Winkler 1996). By way of illustration, we consider a logarithmic scoring rule, which is one of an infinite number of possible scoring rules.
- *Penalty on ISO's Failures.* Suppose that  $P(S)$  is in fact management's honest assessment of the situation, and let  $\Pi(S)$  denote the probability assignments that the ISO reports to its customers. The simplest logarithmic scoring rule is  $\sigma_R(\Pi) = \log \Pi(R)$ , where a shortage of  $S = R$  actually occurs. *Ex ante*, the ISO's *expected* score is therefore given by  $E_p[\sigma_\Pi] =$

$\sum_s P(S) \sigma_r(\Pi)$ . In an *ex post* analysis, which can only take place over an extended period of time, relative frequencies of  $P'(S)$  replace the  $P(S)$  in these formulae. One can then incorporate penalty functions,  $C(\sigma, P, \Pi)$  and  $C(\sigma, P', \Pi)$ , that are minimized when  $P = \Pi$  and  $P' = \Pi$ , ensuring the ISO's truthful revelation (Winkler 1996).

- *Fines*. The penalty functions could be used as the basis to "fine" the ISO for both its *ex ante* and its *ex post* failures on day  $t$  and over some more extensive time period. The fines collected might then be distributed among the successful day  $t-1$  bidders, or over the ISO's customers during the more extensive time period.
- *Probability Announcement and Capacity Reservation*. The ISO announces the probabilities immediately after it makes its probability determination. The generators and end users are given an option to reserve capacity at the priority levels offered by the ISO. The users can make this decision with the assurance that the probabilities provided to them are accurate representations of the ISO's assessment of the situation.
- *Congestion Cost*. For ease of exposition, it will be suppressed for the time being. This issue will be addressed in Section 4.3.
- *Line losses*. The usage fees recover the network's operation costs due to line losses. The fees may be set according to

marginal line losses. Over- or under-collection of the operation costs is resolved by adjusting the customer charge.

Using these assumptions, we derive an efficient CRT from the perspective of generators. The end-user's side of the problem may be dealt with in an analogous and symmetric manner (see Section 4.3).

Each generator is given the option to gain a priority on the existing capacity in the event of a shortage. To establish this priority when there is a shortage of  $S \leq R$ , each generator must agree to pay a priority fee of  $T_R$ .

Consider then the  $j^{\text{th}}$  generator which, along with the other generators and end users, has caused the ISO to establish  $(p^* = c_1, q^*)$ . That is, at the equilibrium price, the price equals the marginal cost of the least-efficient generator that the ISO permits to provide energy to this market. The generator must ask and answer the following question: Should I subscribe at the  $S = R^{\text{th}}$  priority level? Ignoring the usage fee for the time being, the generator is looking at the profit payoff relationships shown in table 1. Section 4.3 will show how to incorporate the usage fees into the priority fee calculation.

Table 1: Profit payoff matrix

	<b>Capacity condition</b>		
<b>Priority</b>	<b><math>S &gt; R</math></b>	<b><math>S = R</math></b>	<b><math>S &lt; R</math></b>
<b>R</b>	$-T_R$	$p^* - c_j - T_R$	$p^* - c_j - T_R$
<b>R-1</b>	$-T_{R-1}$	$-T_{R-1}$	$p^* - c_j - T_{R-1}$

For example, if the generator stops at the  $R-1$  priority level and if there is a shortage of  $S \geq R$ , then the generator suffers a loss of the subscription fee that it had paid for priority at the  $R-1$  level. Similarly, as long as  $S \leq R$ , then by subscribing at level  $R$  the generator earns a profit of  $p^* - c_j - T_R$ .

The above payoff table leads to table 2 showing the opportunity losses.

Table 2: Opportunity losses

	Capacity condition		
Priority	$S > R$	$S = R$	$S < R$
$R$	$T_R - T_{R-1}$	0	$T_R - T_{R-1}$
$R-1$	0	$p^* - c_j - T_R + T_{R-1}$	0

It is optimal for the risk-neutral generator to subscribe at priority level  $R$ , if and only if

$$P(S > R) [T_R - T_{R-1}] + P(S < R) [T_R - T_{R-1}] \leq P(S = R) [p^* - c_j - T_R + T_{R-1}].$$

The latter implies the following condition:

$$T_R - T_{R-1} \leq P(S = R) [p^* - c_j].$$

The generator will be indifferent between subscribing or not when the strict equality holds. For simplicity, we assume that indifference always results in subscription to level  $R$ .

Consider, then,  $R = 1$ . By definition  $T_0 = 0$ . Let the ISO fix  $T_1 = P(S = 1)\Delta_1 \leq P(S = 1)[p^* - c_2]$ . The ISO knows  $c_2$  because of that generator's reservation-price supply bid. Since  $c_2 < c_1$  and  $p^* = c_1$ , the high-cost generator elects not to subscribe to the level  $R = 1$  service. All other generators, however, do subscribe to the service. Hence, if the ISO is short one unit of

transmission on day  $t$ , the high-cost generator, and only that generator, is cut off.

Were no other options offered, the ISO's total subscription revenue from the  $q^* - 1$  subscribing generators at this stage would therefore be  $T_1(q^* - 1)$ . A revenue-maximizing ISO would set  $\Delta_1 = p^* - c_2$ , which would not necessarily maximize social welfare. But any  $0 < \Delta_1 \leq p^* - c_2$  achieves the self-selection objective of eliminating the high-cost generator, and *only* the high-cost generator, from subscribing at the  $R = 1$  level. Insofar as achieving other objectives is concerned, it is only necessary to place upper-limit constraints on the fee that the ISO is permitted to charge.

In similar fashion, the  $q^* - 1$  generators who will have elected to subscribe at the lowest priority level  $R = 1$  must now determine whether *instead* to subscribe at the higher priority level  $R = 2$ . Based on the rule established above, the ISO will set  $T_2 = P(S = 2)\Delta_2 + P(S = 1)\Delta_1 \leq P(S = 2)[p^* - c_3] + P(S = 1)\Delta_1$ . Once again, the ISO knows  $c_3 < c_2$ , because of the third-highest reservation-price supply bid made by the third-most-inefficient generator. And, once again, only one generator, notably the second-most-inefficient, will be unwilling to pay the subscription price. The process continues through the  $q^*$  possible

levels of shortage, with the revenue-maximizing ISO having established the priority- $R$  subscription fee as follows:

$$T_R = \sum_r P(S = r) \Delta_r,$$

where  $r = 1, \dots, R$ , and  $\Delta_r = p^* - c_{r+1}$ . In the process, one generator at a time removes itself from the priority-subscription roster.

#### 4.1.2. Numerical Example

Solely for expository purposes, we solve a simple numerical example described by the following assumptions:

- *End Users.* Demand is perfectly elastic at a price of  $p = 50.0$ .
- *Generation Costs and Supply.* The lowest-cost generator has  $c_{100} = 30.2$ , the next-lowest-cost generator has  $c_{99} = 30.4$ ,  $c_{98} = 30.6$ , and so forth until  $c_1 = 50.0$ . Thus, there are  $q^* = 100$  generators that will supply energy to 100 randomly-chosen end users at a price of  $p^* = 50$ .
- *Curtailment Probabilities.*  $P(S = 0) = .01$ ,  $P(S = 1) = .01$ ,  $P(S = s, s = 2, \dots, 100) = .01$ .

The ISO sets  $T_1 = .01(.20) = .002$ . That price eliminates

the high-cost generator, because, even if there is no shortage, the generator would suffer a loss by paying it. All other generators, however, would be willing to pay the price. As a result,  $p^*$  remains at 50. If, however, the ISO is short exactly one unit of capacity, the supply of the 99 generators that paid at least .002 for priority transmission service, will be randomly distributed among 99 lucky end users.

In similar fashion, the ISO sets  $T_2 = .01(.40) + .002 = .006$ . At this point, the generator with  $c_2 = 49.8$  will drop out. That generator drops out, because the probability that it will pay the .006 and still not gain access to the network is  $P(S > 2) = .97$ . Yet, there is only a  $P(S \leq 2) = .03$  probability that it will earn a profit of  $(50.0 - 49.8 - .006) = .194$ . Thus the positive side of the ledger records an expected gain of  $.03(.194) = .00582$ , the negative side of the ledger records an equivalent expected loss of  $.97(.006) = .00582$ , and the generator nets a zero expected profit. By stopping its subscription at level  $R = 1$ , the generator earns an expected profit of  $.02(.20 - .002) - .98(.002) = .002 > 0$ .

For the generator with  $c_3 = 49.6$ , the expected gain from being assured network access when  $S \leq 2$  is  $.03(50.0 - 49.6 - .006) = .01182$ , which more than balances off the expected loss of

.00582 in giving an expected profit of .006. Had *this* generator stopped subscribing at the  $R = 1$  level, it would have had an equivalent expected profit of  $.02(.40 - .002) - .98(.002) = .006$ . The equivalency results because generators follow the decision rule of subscribing when indifferent between subscribing or not doing so. The ISO knows this and exploits that decision rule by following the revenue-maximizing policy of setting the highest subscription fee consistent with that rule. At the next level,  $T_3 = .01(.60) + .006 = .12$ , etc.

## 4.2 The Basic Approach Extended

To better reflect reality, we extend the basic approach by relaxing the assumption of unit demand by each end user and unit supply by each generator.

### 4.2.1. Extension

Suppose that  $n$  generators have the same marginal cost of  $c_j$ . Suppose, too, that in accordance with the previously-established algorithm, each generator elects to subscribe at priority level  $R - 1$  at a fee of  $T_{R-1}$ . Let the generator with  $c_{j-1} > c_j > c_{j+1}$  be the marginal generator for which subscribing at  $T_{R-1}$  was not optimal.

The ISO will now want to set its next-level subscription fee such that it will be optimal for all  $n$  generators to pay the fee; even though not all  $n$  generators will gain access to the transmission service in the event of a shortage. For example, if two identical generators subscribe at level  $R = 5$ , implying that each is assured of transmission if  $S \leq 4$ . If  $S = 5$  the ISO will have to deny one of the generators transmission. The ISO will want to set the level  $R = 6$  subscription fee such that neither one of the  $c_j > c_{j+1}$  generators will be willing to pay that fee, but that the generator with  $c_{j+1}$  will be willing to pay it.

Suppose that the next level after  $R - 1$  at which the fee changes is level  $R + n - 1$ . When  $n$  generators are subscribing at level  $R + n - 1$ , and  $S = R$ , one randomly-selected generator will be denied access to the network. Hence, conditional upon  $S = R$ ,  $[p^* - c_j][n-1]/n$  is each generator's expected gross gain (which ignores the subscription fee). When  $S = R + 1$ , two randomly-selected generators will be denied access to the network. Thus, conditional upon  $S = R + 1$ , each generator's expected gross gain is  $[p^* - c_j][n-2]/n$ . Hence, conditional upon  $I = \{R \leq S \leq R + n - 1\}$ , each subscribing generator has an expected gain of

$$\begin{aligned}
E[\pi_{R+n-1}] &= P(R \setminus I) [p^* - c_j] [n-1]/n + P(R + 1 \setminus I) [p^* - c_j] [n-2]/n \\
&\quad + \dots + P(R + n - 1 \setminus I) [p^* - c_j] [1]/n \\
&= [\sum_{i=1}^n P(R + i - 1 \setminus I) ([n - i]/n)] [p^* - c_j] \\
&= \alpha [p^* - c_j],
\end{aligned}$$

where the upper limit on the sum is  $i = n$ .

We now use  $\alpha [p^* - c_j] - T_{R+n-1}$  to replace  $p^* - c_j - T_R$  in the second column of the basic payoff table, and re-label the first two column headings as  $S > R + n - 1$  and  $R \leq S \leq R + n - 1$ , respectively. This yields the following condition for subscription beyond level  $R - 1$ , for the case of  $n$  identical-cost generators:

$$T_{R+n-1} = P(R \leq S \leq R + n - 1)\alpha[p^* - c_j] + T_{R-1}.$$

That is, the ISO sets the priority fee at level  $R + n - 1$  based on the marginal cost,  $c_j$ , of the  $n$  identical-cost generators. It then sets the priority fee at level  $R + n$  based on  $c_{j+1}$ . This assures the ISO that each of the  $n$  generators with identical  $c_j$  will *not* subscribe at the next level, but that the generator(s) with lower cost *will* subscribe.

#### 4.2.2. Revised Numerical Example

We incorporate the extension in the numerical example presented in Section 4.1. Suppose that  $T_1 = .002$  has eliminated the high-cost generator and that  $n = 3$  generators have marginal costs of  $c_2 = 49.8$ . Given that  $I = \{R = 2 \leq S \leq R + n - 1 = 4\}$ , we determine  $P(2 \setminus I) = P(3 \setminus I) = P(4 \setminus I) = 1/3$ , and  $P(I) = .03$ ; hence,  $T_{1+3} = T_4 = (.03)(1/3)(50 - 49.8) + .002 = .004$ ; as opposed to the previous figure of  $T_2 = .006$ .

Ignoring the .004 subscription fee for the time being, consider the gross gains to generators in the following cases:

- $S = 0$  or  $1$  (i.e., no shortage). Each of these three generators makes a gain of  $50 - 49.8 = .2$ .

- $S = 2$ . One of the three generators will be denied access, so each makes an expected gain of  $.200(2/3) = .1333$ .
- $S = 3$ . Each has an expected gain of  $.200/3 = .0667$ .
- $S = 4$ . Each is denied network access and earns no income.

Since the last three cases are equally likely, the expected gain given the information  $I$  that there will be a shortage of between two and four units is  $(.1333 + .0667 + 0)/3 = .0667$ .

Subtracting  $T_4 = .004$ , which is incurred with certainty, reduces the net gain to  $.0627$ . The probability of making that net expected gain is  $P(I) = .03$ .

Now subtracting the  $.004$  fee from the  $.2$  gain that is earned with certainty when  $S < 2$ , each generator has an expected gain of  $.02(.196) + .03(.0627) = .0058$ . Since each generator's expected loss from  $S = 5$  is  $.95(.004) = .0038$ , each generator's net expected profit is  $.0058 - .0038 = .002$ .

If each generator had stopped subscribing at the  $R = 1$  level, paying  $T_1 = .002$ , each would have had an equivalent net expected profit of  $.02(50.0 - 49.8) - .002 = .002$ . Once again, then, in accordance with our decision rule, the three generators subscribe at the higher priority level.

This example shows that the extension enables us to deal with the single generator that wants to supply  $n$  units at a cost of  $c_j$ , by treating it as  $n$  individual generators, each having a marginal cost of  $c_j$ . When a second generator supplies  $m$  units at the same cost of  $c_j$ , the pair is treated as  $n + m$  individual generators, etc. For ease of exposition, then, our subsequent analysis will be carried out on the basis of generators and end users that supply or demand either one or zero unit(s).

### **4.3 Point-to-Point Transmission and Congestion Costs**

To this point we have focused on a radial network with generators on one end of the transmission line and end users on the other end. We have not considered the possibility of the ISO redispatching generation to resolve a transmission capacity shortage. This section modifies the basic model to accommodate point-to-point transmission in a multi-node network with congestion costs. The issue of interdependent transmission constraints is deferred to Section 4.4.

#### **4.3.1. Point-to-Point Transmission**

Suppose there are  $K$  location-specific nodes in the network, with multiple generators and end users at each node. All users must pay the customer charges for being connected to the network. A

point-to-point transmission with POR  $k$  and POD  $k'$  can be decomposed into two separate transactions: (a) transmission from the generator's POR  $k$  to the swing bus designated by  $k = 1$ ; and (b) transmission from the swing bus to the end user's POD  $k'$ . The total priority fee for point-to-point transmission is the sum of the priority fees for (a) and (b). The number of priority fees to be derived is  $2K$  because  $K$  nodes constitute  $K$  POR and  $K$  POD. Since the users already have paid the customer charges, the point-to-point charge has three components: the priority fee, the congestion surcharge, and the usage fee. The priority fee and the congestion surcharge are derived below.

#### **4.3.2. Congestion Cost**

Consider a generator  $G(j, k)$  with marginal generation cost  $c_j$  at POR  $k$ . The generator may face a transmission shortage that prevents it from injecting power into the network. Suppose the ISO, basing the data on the demand and supply bids on day  $t-1$ , can redispatch generation on day  $t$  to resolve the shortage at a projected incremental cost  $p_k$ . The ISO therefore announces a surcharge  $p_k$  before the end of day  $(t-1)$ . The surcharge applies to power actually injected on day  $t$ .

A generator when faced with the surcharge has two choices: (a) accept the surcharge and use the transmission service; and

(b) refuse the surcharge and do not use the transmission service. Consequently, if a generator chooses to pay  $p_k$  for injecting power at POR  $k$ , it incurs a variable cost of  $c_{jk} = c_j + p_k$ . As shown below, the presence of  $p_k$  alters the priority fees.

For notational clarity, we now let  $T_{Rk}$  denote the priority fee imposed at POR  $k$  when there is a shortage of  $S \leq R$ . Thus, generator  $G(j, k)$ 's profit payoff table now looks as follows:

Table 3: Revised profit payoff matrix

	<b>Capacity condition</b>			
<b>Priority</b>	<b><math>S &gt; R</math></b>	<b><math>S = R</math></b>	<b><math>S &lt; R</math></b>	<b><math>S = 0</math></b>
<b>R</b>	$-T_{Rk}$	$p^* - c_{jk} - T_{Rk}$	$p^* - c_{jk} - T_{Rk}$	$p^* - c_j - T_{Rk}$
<b>R-1</b>	$-T_{(R-1)k}$	$-T_{(R-1)k}$	$p^* - c_{jk} - T_{(R-1)k}$	$p^* - c_j - T_{(R-1)k}$

This payoff table results in the following opportunity loss table:

Table 4: Revised opportunity losses

	<b>Capacity condition</b>			
<b>Priority</b>	<b><math>S &gt; R</math></b>	<b><math>S = R</math></b>	<b><math>S &lt; R</math></b>	<b><math>S = 0</math></b>
<b>R</b>	$T_{Rk} - T_{(R-1)k}$	0	$T_{Rk} - T_{(R-1)k}$	$T_{Rk} - T_{(R-1)k}$
<b>R-1</b>	0	$p^* - c_{jk} - T_{Rk} + T_{(R-1)k}$	0	0

It immediately follows that the previously-developed condition for subscribing at level  $R$  is met, but with  $c_{jk}$  replacing  $c_j$ . That is, the revenue-maximizing ISO sets

$$T_{Rk} = P(S = R) [p^* - c_{jk}] + T_{(R-1)k}.$$

Thus  $T_{Rk}$  depends upon the generator's POR.

The fee  $T_{rk}$  induces a generator with low generation costs to subscribe high priority because the gross gain  $(p^* - c_{jk})$  decreases with  $p_k$ . When faced with a high surcharge, only the low-cost generators are willing to pay for high priorities to inject power at node  $k$ .

Since reducing power injection at a given node is identical to power withdrawal at the same node, a surcharge to a generator is a credit to an end user. Therefore if an end user decides to withdraw power at POD  $k$ , it will receive  $p_k$  from the ISO for so doing.

Because of the symmetry of the problem, we can perform the exact same analysis for the end users. In particular, expressed in monetary terms, end user  $U(m, k)$  at POD  $k$  obtains a benefit of  $u_{mk}$  from gaining access to a unit of energy.  $u_{mk}$  is end user's

gross benefit plus  $p_k$ , less the usage fee.<sup>2</sup>

When end user  $U(m, k)$  pays  $p^*$  for the unit of energy consumed, its gains  $(u_{mk} - p^*)$ . In order to be assured of  $(u_{mk} - p^*)$  during a shortage of  $S = R$ , the end user would have previously paid a fee of  $W_{Rk}$  for an  $R^{th}$ -level priority. Repeating the previous machinations, the revenue-maximizing ISO will charge this end user a fee of

$$W_{Rk} = P(S = R) [u_{mk} - p^*] + W_{(R-1)k}$$

for the  $R^{th}$ -level priority.

The fee  $W_{Rk}$  induces subscription that facilitates efficient rationing by the ISO on day  $t$  because  $u_{mk}$  increases with  $p_k$ . When faced with a large credit, all end users at node  $k$  are willing to pay more for high priorities to withdraw power. Conversely, if there is a high surcharge for power withdrawal at another node  $k'$  (e.g., a city with no local generation), only end users with relatively high  $u_{mk'}$  will be willing to pay for high priorities to withdraw power at that node.

As in the basic model, then, both generators and end users

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<sup>2</sup> The end user's gross benefit is its willingness to pay for capacity, which is private information unknown to the ISO. It can be estimated from data on priority subscription (Hartman et al. 1991).

self-select their optimal priority levels. This self-selection, however, takes place subject to the ISO's projected congestion costs and is therefore only *ex ante* efficient in the expectation sense. When the realized congestion cost is not equal to the projected cost, *ex post* efficiency may not obtain.

Finally, these priority fees can be modified to account for the usage fees for line losses. This modification entails (a) subtracting the usage fee from  $p^*$  received by a generator; and (b) adding the usage fee to  $p^*$  paid by an end-user.

#### **4.4 Network Interdependence**

A transmission network is comprised by a set of interlinked nodes. Power flows obey Kirchoff's laws, resulting in network interdependence, or the loop-flow problem. Chao and Peck (1996) solve the problem using a market mechanism and efficient dispatch to determine transfer payments between the generators and end users affected by transmission constraints. Their approach allows for the possible redispatch of generation to meet any unsatisfied end-user demand effected by the capacity shortage.

Our approach to the problem assumes that on day  $t-1$  all users must commit to the priority subscriptions that will enable them to access the network and use transmission during a shortage

on day  $t$ . These self-selected priorities determine to whom the ISO will deny transmission when a shortage develops. The priority-subscription decision, however, requires that the ISO provide potential subscribers with the information necessary for making that decision, before the end of day  $t-1$ . This information must take into account network interdependence. That accounting can be accomplished through the following procedure:

1. The ISO solicits supply bids from generators and demand bids from end users. The bids are made under the assumption that the transmission network is uncongested.
2. Using these bids, the ISO performs an optimal dispatch analysis to identify transmission congestion under mutually exclusive scenarios  $\omega$  for day  $t$  (e.g., hot weather with no network failure). This analysis follows the approaches in Luo et al. (1986), Li and David (1994) and Chao and Peck (1996). These approaches account for loop flow and costs due to generation redispatch.
3. The ISO applies the pricing formulae in Section 4.3 to compute the priority fees. The only modification required is to replace  $P(S)$  with  $P(S_k) = \sum_{\omega} P(S_k, \omega)$ , the probability of a shortage of  $S_k$  that affects power injection (withdrawal) by generators (end-users) at node  $k$ .

Because the priority fees are derived from an optimal dispatch analysis, they internalize the external costs caused by transmission constraints. The priority subscriptions that these fees induce from users become the basis for the ISO to resolve a transmission shortage.

## 5. Conclusion

Deregulation is presenting the electrical utility industry with some interesting challenges and opportunities, and it will continue to do so in the years to come. One of these challenges and opportunities that already looms large is the need to deal with transmission pricing for a network with limited capacity. As pointed out by a FERC Commissioner, William Massey (1997, 17), "Order 888 does a superb job in resolving the issues of discrimination, equity and fairness, but we will still fail to capture considerable economic efficiencies if we leave the old transmission pricing methods in place."

Our proposed CRT addresses Massey's (1997) five core issues in transmission pricing reform. First, our customer charge based on connected capacity (load) of a generator (end user) recovers fixed costs without distorting the market. Second, our priority fees, congestion surcharges and credits account for loop flows and congestion cost, thus sending the proper price signals to users. Third, our usage fees collect incremental costs for line losses. Fourth, our CRT manages transmission shortages by price, because transmission users self-select which will be denied access when a shortage develops. Lastly, our CRT defines transmission rights based on a user's capacity reservation and priority subscription. While we have no evidence on whether such

rights will be actively traded, we conjecture that reserved capacity with well-defined priorities will aid price discovery in a secondary market for transmission. Hence, our CRT bridges the gap between the existing market environment and the competitive transmission market that may emerge in the future.

Finally, our CRT can be used in the implementation of retail access. To illustrate this point, we consider how the California ISO resolves the transmission congestion problem (FERC 1997). The California ISO receives initial demand and supply bids made under the assumption of no congestion on day  $t-1$ . If the California ISO anticipates a transmission congestion on day  $t$ , it invites a second round of bidding that results in adjustment bids. The adjustment bids reflect the prices at which transmission users are willing to permit the California ISO to change their planned transmission use to relieve the constraints. Based on the adjustment bids, the California ISO redispatches generation in real time on day  $t$  to resolve the congestion and to set a congestion charge to be paid by all users of the constrained path. FERC (1997, 45) considers the resulting capacity allocation and congestion charge efficient.

We now consider how our proposed CRT works in a retail access scenario similar to California. After performing an optimal load flow analysis using the initial demand and supply

bids received on day  $t-1$ , the ISO estimates the redispatch costs required to resolve transmission constraints. The ISO then announces on day  $t-1$  the congestion surcharges and credits and the priority fees described in Section 4. Transmission users self-select to various reliability levels through priority subscription. The self-selected subscription establishes the *efficient* allocation of limited transmission capacity in the event of a shortage on day  $t$ . Priority subscription therefore replaces adjustment bids envisioned in California. Hence, our proposed CRT can be a practical solution to the transmission congestion problem in a retail access scenario.

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