Important Practical Considerations in Designing an FTR Market

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ABSTRACT: This paper presents the fundamental elements of a well functioning Financial Transmission Rights (FTR) market that is necessary for supporting wholesale competitive electricity markets. Emphasis is placed on the practical considerations that need to be carefully evaluated in implementing an FTR market. The paper presents an analysis of the FTR procurement alternatives market participants can deploy for procuring financial instruments as part of their hedging strategy. The paper focuses on the FTR allocation approach as a key methodology for procuring FTRs. Two main considerations are presented; the eligibility rules and the validation rules. The paper finally presents various allocation methodologies and an analysis of the incentives of the associated objective formulations. A numerical example is presented to illustrate the market benefits of the Simulated Auction Single Round approach over the Least Squares Approach with Sequential Rounds.

KEY WORDS: Wholesale electricity markets, transmission rights, hedging, locational marginal pricing, optimization, point-to-point FTRs, FTR Allocation.

1 Introduction

A critical component of any market based congestion management system is the definition of transmission rights [1-2]. A generally accepted type of transmission rights are the Financial Transmission Rights (FTRs), or passive rights, that provide market traders an instrument for constructing financial hedges as part of long-term energy contracts. The specification of FTRs is complicated by externalities due to network loop flows. A market-based solution to this externality problem is to issue a set of well-defined FTRs that internalize these effects. A market for these rights enables the external effects associated with a transaction to be incorporated into private purchasing and sales decisions [3].

In most of the Regional Transmission Organizations (RTOs) that are currently in operation today, FTRs are source-to-sink congestion hedging financial instruments, or Point-to-Point (PTP) FTRs. In general, the sinks and sources for FTRs may be single network nodes, or sets of nodes, such as Trading Hubs or Load Aggregation Points (LAPs). The definition of the size of the LAPs and the surrogate load aggregation points is a very important consideration for optimal market efficiency but it is outside the scope of this paper. The types of allowable FTR Sources and Sinks are usually defined to be compatible with the Sources and Sinks specified in Existing Entitlements for Transmission Service or Existing Transmission Contracts (ETCs), in order to facilitate conversion of ETCs to FTRs.

An alternative way for defining FTRs is to use the capacity in each link or flow-gate of the network. In general the capacity of each link is determined by physical factors associated with the link (e.g. thermal limit, voltage stability, and dynamic stability) and is insensitive to the power flow pattern. Each power transfer requires approximately a constant fraction (known as the Power Transfer Distribution Factor, or PTDF) of the capacity of each link in the network. Market Participants (MPs) can acquire Flow-Gate (FGRs) and PTP FTRs to hedge the congestion costs associated with their use of the transmission system. Ownership of FTRs may or may not be required for the scheduling or use of the transmission system.

In some markets, MPs are able to acquire both PTP FTRs and FGRs in the form of either options or obligations. FTR holders are paid the difference between the congestion component of the Locational Marginal Price (LMP) at the sink and source of the FTR in the Day-Ahead market. Usually, FTRs are defined primarily as "obligations," so that the FTR holder will be obligated to make a payment when the congestion price difference is in the opposite direction of the FTR [4]. FGRs, on the other hand, are entitlements to the shadow price on one or more flow constraints imposed on the economic dispatch. In either case the rights can be defined as financial rights that are settled on the basis of locational prices (nodal or shadow prices) without direct impact on actual operation. In classical formulations the constraint shadow prices take non-negative values. In that case, one way to interpret the FGRs as obligations, even though they are inherently one sided instruments, is to assume that the seller undertakes an obligation while the buyer owns an option which he/she may not exercise [5]. Obviously, in hours, when a flow-gate is not a binding constraint, the shadow price will be zero and the FGR will have zero value. A comprehensive comparison of the benefits of PTP FTRs and FGRs is provided in [6].

Usually RTOs offer FTRs of multiple term lengths. The most typical case is two term lengths, one annual and one monthly. Sometimes distinct FTRs are also issued for the on-peak and off-peak periods. Annual FTRs may be available on a rolling multi-year basis, say two-year basis.

In this case, each annual release of FTRs makes specified quantities of FTRs available for each of the following two years; these quantities may differ for year 1 versus year 2. RTOs usually release a fixed percentage of the transmission capacity as annual FTRs for a particular operating year, after accounting for the impact of ETCs on the available capacity of the grid. For example, the California ISO has proposed to use 75 percent of transmission system capacity to support annual FTRs, and 25 percent of capacity to support monthly FTRs. Thus, the Cal ISO will use 75 percent of the transmission capacity to support annual FTRs for the first year and, separately, a half (37.5 percent) of the capacity to support FTRs for the second year. In the beginning of the second year the difference between 75 percent of transmission capacity at the time and the amount of capacity released in the first year will become available to support additional annual FTRs.

In this paper we analyze some key practical considerations that need to be carefully evaluated in implementing an FTR market. The paper is organized as follows. Section 2 describes an analysis of the FTR procurement alternatives MPs may deploy to procure these financial instruments as part of their hedging strategy. Section 3 focuses on the FTR allocation approach as a key methodology for procuring FTRs. Two main considerations are presented; the eligibility rules and the validation rules. Section 4 presents various allocation methodologies and an analysis of the associated objective function formulations. Section 5 presents a numerical example that compares the two main allocation methodologies. Section 6 presents the conclusions.

2 FTR Procurement Alternatives

There are several methods MPs can use to procure FTRs, such as a market auction, an allocation, a combination of both, a purchase in the secondary FTR market, or through transmission expansion or upgrade. In this paper we focus on the first three options, i.e., the market auction, allocation and a combination of these two methods.

Auction: An FTR auction is a process where MPs submit bids for the FTRs they wish to procure. These bids clear the FTR market the RTO is administering through an optimization process that uses an exact transmission model (e.g., a full AC model) or a close approximation (e.g., a DC model) of the power system to determine the resulting flows on all transmission system branches. The objective function of the optimization process is the maximization of the bid-based value for the total amount of cleared FTRs. The constraints enforced in the optimization process should be as close as possible to the operating constraints enforced in the forward energy markets, including contingencies. Enforcement of all constraints to ensure that all resulting flows on the network model are within their limits, is called the Simultaneous Feasibility Test (SFT).

Allocation: An FTR allocation is a process where MPs submit nominations (not bids) for the FTRs they wish to procure. Unlike the FTR bid, the FTR nomination does not have an associated bid price. Similar to the auction process, these nominations are input into an optimization process that also ensures simultaneous feasibility.

The key distinction between an auction and allocation process is the formulation of the objective function. In an auction, the formulation is based on the submitted bids. The bids that value the FTRs the most will be awarded the FTRs. However, in an allocation there are no submitted bids, thus other pertinent information is needed to distinguish which nominations should be awarded the FTRs. The possible distinctions that can be made in an allocation approach are provided in the next section.

Allocation/auction: A third method to provide FTRs combines both features of an auction and an allocation. This method is based on an Auction of Revenue Rights (ARRs) and has two steps. The first step is to allocate ARRs to eligible MPs. An ARR is identical to an FTR, but is solely a financial instrument whose price is dependent upon a subsequent FTR auction, which is the second step in the process. The second step is to hold an FTR auction, where all MPs may submit bids to buy FTRs. The holders of the ARRs receive a revenue stream based on the difference in the market clearing prices at the corresponding sink and source of the ARR.

Under open access each Transmission Owner (TO) must create a transmission tariff whose rates are based on an annualized Transmission Revenue Requirement (TRR). Typically, each TO places its transmission assets under the control of an RTO that charges all users of the transmission grid a Transmission Access Charge (TAC). This charge is applied on an hourly basis to all load and exports. The TAC is generally determined by dividing the annual TRR by the forecasted annual amount of usage by the TO’s native load, i.e., load that is served by the Load Serving Entity function (LSE) of the utility under which the TO is a subsidiary.

Others users that use the transmission for wheeling transactions must also pay a TAC, or in some cases a Wheeling Access Charge (WAC). Any revenue from WAC is used to offset the TRR. Congestion payments to the RTO can be seen as premiums for grid usage on top of paying the TAC or WAC. Therefore, the proceeds for auctioning FTRs should also offset the TO’s TRR. In the following, a brief analysis of the incentives of the three FTR procurement options is presented.

FTRs via auction: When all FTRs are provided to MPs via an auction, the native load has an incentive to outbid other users (e.g., wheeling transactions) of the grid. The reason is that the proceeds of the auction flows back to the TO to offset the TR, thus reducing the TAC. The reduction in the TAC mainly benefits the native load rather than the wheeling transactions, since in general the native load is much larger and pays the TAC every hour, where as the wheeling transaction may only take place during certain hours of the day. Therefore, the FTR proceeds cannot be an unbiased predictor of congestion charges, since LSEs in essence receive FTRs for free and can afford to outbid other FTR market players.

FTRs via allocation/auction: The ARR methodology has certain advantages in mature forward markets in which MPs can accurately forecast congestion charges and estimate the value of FTRs. Those MPs that were allocated ARRs can bid on them in an FTR auction, even at extremely high prices. If the bid is exactly conforming to the ARR, the revenue stream that pays for the FTR is provided back to them in terms of the ARR payment. Therefore, they are held financially neutral and yet they acquire the corresponding FTRs.

One advantage of the ARR method is price discovery. I.e., through the FTR auction a price is placed on the FTR that can make the process of load switching easier to handle. In most placed that use the ARR method, the ARR itself and thus the value of the corresponding FTR, is owned by the load and not the entity that is responsible to serve the load, i.e., the LSE. Thus, if the load switches LSEs, the new LSE has entitlement to a pro-rated share of the monetary value earned by the first LSE's ARR.

FTRs via direct allocation: The use of a direct FTR allocation also has its advantages. The main advantage over the ARR methodology is that the FTRs themselves are directly allocated to the MPs. In a market that does not have predictable congestion patterns, MPs may be much more comfortable with the FTR allocation option than risking putting a bid in an FTR auction. The procedure for the direct allocation of FTRs is very similar, if not the same, as the allocation of ARRs.

Many policy makers prefer the direct FTR allocation option for equity reasons. Specifically, before the commencement of competitive energy markets and under the traditional regulatory paradigm, individual TOs performed the congestion management function for both the native load and the wheeling transactions. Furthermore, the high cost of generation that was built in generation deficient pockets of the grid was spread across to all users of the grid.

Transmission, under the traditional cost-based regulation, was not built to support the usage of the grid under a competitive structure. With the onset of competitive energy/congestion markets, certain users of the transmission grid may be directly discriminated against due to their grid location and may suddenly be exposed to potentially high and unpredictable congestion prices. Therefore, in transitioning to competitive energy markets, direct allocation of FTRs may be appropriate as a way to address equity concerns and to avoid any mis-estimation of congestion costs and FTR valuations.

3 Allocation of FTRs

In this section we focus on the key considerations that need to be taken into account in designing an FTR allocation methodology, which has emerged as the main avenue of procuring FTRs in most operating competitive markets. There are three key issues that need to be taken into consideration when developing an overall allocation methodology. The first consideration is the development of the rules that will determine who is eligible to be allocated FTRs. These will be the entities that will submit FTR nominations to the RTO. The second consideration concerns the development of validation rules that will be applied to the FTR nomination process. The third consideration is the development of the allocation methodology via an appropriate Simultaneous Feasibility Analysis (SFA) that will further limit the FTR levels to ensure revenue adequacy. This section addresses the first two issues, namely the eligibility and the validation methodology. The next section addresses the development of the FTR allocation methodology.

3.1 Eligibility Issues

The question of whom to allocate FTRs to is crucial in the overall design of an FTR market. There are many different possible eligibility rules to set forth, however this paper does not necessarily support any particular set, but rather attempts to briefly analyze the issues related to the eligibility process. The eligibility rules can be contentious and are usually decided via a stakeholder process. In the following we present some basic rules and the problems associated with each rule.

The eligibility rules are basically the following: a) allocate FTRs to all users that will be charged congestion in the future or have been charged congestion in the past, b) allocate FTRs to all entities that pay for the embedded costs of the transmission system and c) allocate FTRs only to the native load.

Suppose FTRs are allocated to all entities that pay for the embedded costs. The key problem with this eligibility rule is the issue of equitable distribution of FTRs between the native load and those entities that wheel. Suppose a MP that wheels energy uses the transmission grid just one hour out of the year and thus pays some amount of the embedded costs. Should this entity be allocated FTRs? If so, should the allocation to all contributors of the embedded cost be based on the amount they contribute over the term of the FTR (e.g., a year). Note, that no matter what the allocation methodology is, it should never result be in a MW amount of FTRs per MP that is greater than its peak load (or export schedule). If the allocation of the FTRs is based on the amount paid for the embedded cost of the transmission, the wheeling transaction would get virtually zero MW since the FTR MW each user is entitled to is limited to their peak load.

Suppose that the eligibility for receiving an FTR allocation is based on the load within the control area and not on exports. Assume further that some portion of this load is not native load and that the allocation of FTRs is limited to each entity's non-simultaneous peak load over the term of the FTR. In this case, there can be large discrepancies between the amount of FTRs being allocated to an entity and the amount of embedded cost of the transmission system that they pay. For example, one entity can have a load distribution curve that is extremely peaky, but has very little energy under the curve. This implies that this entity has paid relatively little to the embedded of the transmission system as compared to another entity, whose load distribution curve is not as peaky, but has much more energy under the curve. In this case, the first entity will receive many more FTRs than the second, although it paid much less in embedded transmission costs.

3.2 Validation Rules

The proposed validation rules are designed to restrict the MPs to use only certain resources at specific locations as their sources and sinks in the FTR nomination process. They are not exhaustive and need to be modified to address the specific system conditions for each market. In general, they fall into three categories: a) FTR nomination restrictions based on an upper MW bound for each MP based on historical usage, b) restrictions on the source/sink locations that are allowed to be used in the allocation, and c) restrictions on the MW amount offered for certain type of sources.

It seems logical that no matter what methodology is selected to determine the eligible participants, a MW upper bound must be established. The MW upper bound would limit the total MW amount allocated to each MP, summed over the MW from each PTP FTR nomination. The restriction on certain source and sink location points is linked to the MP's actual historical use of the transmission grid. These restrictions will ensure that the FTRs are hedging against the congestion that will be result from the normal use of the grid. More importantly they are intended to prevent MPs from nominating source/sink pairs that maximize their FTR revenue.

The validation rules do not imply that MPs must submit FTR nominations. To the contrary, some MPs may not wish to submit FTR nominations depending on their specific location in the network. This is especially true, if the cleared FTRs result in a liability for the MP. For example, if the forward payment for the generation is larger than the charge for the load for a particular MP and the hedge type for the FTR is an obligation, then this FTR would be a liability for the MP, i.e., rather than receiving a positive revenue from the FTR, it would pay for having the FTR.

Finally, additional validation rules may need to be established to mandate the allocation of counter-flow FTRs. Without counter-flow FTRs, obviously, certain FTRs in the direction of congestion cannot be feasibly allocated. MPs have an incentive in this case not to request these counter-flow FTRs and gain windfall profits from providing counter-flow in the forward market. This is a clear case where the absence of FTRs provides certain MPs a windfall profit. The resulting cost shifting between MPs violates the basic principle of the FTR allocation process, which is to provide FTRs to eligible MPs that effectively hedges them over a long period of time and does not provide them with a windfall profit.

4 FTR Allocation Methodologies

After the issues of eligibility and validation have been addressed, the next key consideration is the allocation methodology. This process attempts to ensure revenue adequacy for the RTO, i.e., the net congestion rent collection by the RTO is not less than the net FTR payment to the FTR holders. This section addresses in detail all important considerations that need to be taken into account in developing a technically sound FTR allocation methodology.

4.1 Simultaneous Feasibility Analysis

The foundation of the FTR allocation process is the Simultaneous Feasibility Analysis (SFA). This analysis is conducted on a Full Network Model (FNM) similar to FNM used in the forward market that includes all relevant transmission constraints. The constraints originate from the explicit application of contingency analysis or may be in the form of nomogram limits (including simultaneous interface limits) that are applied directly to the base case topology. SFA is used to ensure revenue adequacy for the RTO. The theory of revenue adequacy is well understood and can be proven to be true under certain market and power system conditions [7].

xA key consideration of the SFA methodology is the treatment of losses and the use of a DC model. Typically, FTRs hedge solely against the price differences due to transmission congestion component of the LMPs. This means that losses may not need to be considered in the SFA. This immediately gives rise to the option of using a DC network model in the FNM and all of its convenient linear features. The DC model assumes that voltages are at their base voltage levels, i.e., at 1.0 per-unit and this removes from the SFA any impact that the reactive load consumption may cause. To compensate for this simplification, both thermal limits and other nomogram limits may be scaled downward by a system-wide scalar, or on an individual basis. The use of the DC model also implies that for each PTP FTR, the injection MW is equal to the withdrawal MW, making the FTR commensurate with transmission capacity.

The SFA can be decomposed into two sub-components: a) a Simultaneous Feasibility Test (SFT), and b) an optimization methodology that attempts to restore feasibility if the SFT fails. The SFT simply overlays all FTR nominations, that have passed the validation process, onto the FNM (FTR sources as injections and FTR sinks as withdrawals) and then compares the resulting system flows against constraint limits (including contingencies). Note that in the SFT, FTRs that are have a hedge type of ***option***, should not provide any counter-flow. The SFT part of the SFA is a straightforward process; however, there are different methodologies that can be used in the optimization process that restores feasibility if the SFT fails. Two key alternatives are discussed in the remaining of this section. However, before they are presented, a key consideration on the need for FTR priorities is discussed next. The modeling of FTR priorities is a key distinction between the two alternative allocation schemes that are presented in this section.

4.2 FTR Priorities: The ETC Case

In many jurisdictions, the provision of Existing Transmission Contracts (ETCs) complicates the developments of FTR markets in a substantial way. In general, ETC holders must be kept harmless under a competitive market structure. This means that ETCs must be honored to the maximum extent possible. As a result, procedural modifications need to be made in the SFA process to properly account for FTRs that need to be given priority (because of their association with ETCs) over other FTRs in the allocation process. This in practice means that higher priority FTRs should be allocated transmission capacity before lower priority FTRs. In this section we present two methods that can achieve this objective, a) the Capacity Reservation Method (CR), and b) the Scheduling Priority method (SP). An analysis of the incentives that each one creates is also presented in this section.

4.2.1 Capacity Reservation (CR) Method

ETCs typically take the form of a list of valid points-of-delivery (source points), point-of-receipt (sink points) and maximum individual and simultaneous MW limits [8]. In a competitive market structure the ETC benefits of the previous regulatory regime amount to a scheduling priority in the forward markets along with a procedure that would hold the ETC holder harmless from any congestion charges (assuming the ETC holder operates its resources within the provisions of its transmission contract).

The CR method reserves capacity in the forward market for the exclusive use by the ETC holders up to and including real-time. Under this option, all other MPs would not be allowed access to this capacity for scheduling in the forward market and since it is reserved up to real time, the RTO needs not to re-dispatch other users if in fact, the holder were to make additional dispatch changes in the real-time market. If the ETC holders scheduled within their rights and their capacity was correctly reserved, there would be no congestion on that portion of the capacity. However, this will certainly lead to a tremendous impact on congestion costs for other MPs since this reservation approach may severely limit the amount of transmission capacity others can use to schedule their transactions and increase the likelihood of congestion.

Another complexity of the CR method is that it is possible that the provision of the capacity in certain paths under the ETC contract with a TO may have been based on counter-flows created by the TO's generation and native load resources. The counter-flow is usually based on the assumption that certain TO resources are committed at a certain level. The created virtual capacity almost certainly is higher than the physical transfer capability of the path. Transitioning such an ETC with a virtual transmission capacity component into an FTR creates substantial technical problems for the RTO. Most, if not all, RTOs operate under strict reliability/security criteria that disallow the use of counter-flow in determining the transfer capability of paths that can be part of ETC contracts. These two fundamental problems make the CR method complicated and non-conducive to a competitive market structure.

4.2.2 Scheduling Priority (SP) Method

The SP method does not reserve any capacity in the forward market, but it provides the ETC holder a scheduling priority in the forward and in the real-time markets. Other users of the grid must be aware that although they may be granted transmission in the forward market, some of their resources may need to be re-dispatched in real-time due to the increase or even a decrease in the transmission usage by an ETC holder. The SP method has clear advantages over the CR method in terms of market benefits, but a process needs to be developed to ensure that ETC holders under this option are not subject to congestion charges. This paper proposes two alternatives to achieve this objective.

The first alternative is to provide the TO, or the ETC holder, with FTRs that would be used to hedge against congestion charges. (The authors have a slight preference to provide the FTRs to the TO, instead of the ETC holder, because the TO is the entity that provided the transmission capacity to the ETC holder, and is ultimately the underlying responsible party.) These FTRs can be allocated at a MW level on a one-to-one basis (and be subject to a SFT). As a result, over time, both forward market and real-time congestion charges would be recovered through the revenues received by the FTRs. If the FTRs are allocated to the TO, and over time, the net costs, considering congestion cost and FTR revenues, are positive, the TO may be able to pass these saving to consumers by reducing its TRR.

A second alternative would be to reverse any congestion charges associated with the ETC holder's transactions as long as these transactions are within the applicable bounds stated in the contract. Under this alternative, the ETC holder is perfectly hedged at all times. This reversal process, however, may create revenue adequacy problems for the RTO. To address this problem, the RTO must ensure that it does not allocate, through the FTR allocation process, to other MPs the transmission capacity that is associated with the ETC contract. A natural solution to this problem is to have the RTO hold the FTRs that would be allocated to the TO or the ETC holder. These FTRs would not generate revenue for any MP, but would rather be a placeholder that would prevent other MPs from obtaining the capacity under the ETC contracts.

It is clear from this discussion that if the FTRs associated with ETCs are issued by the RTO, they would need to be allocated before any other FTRs. These placeholder FTRs can have a hedge type of obligation or option or a combination of both. If, in the forward market the ETC transactions provide counter flow, it may be prudent to model the corresponding FTRs are obligations. If not, then it would be justifiable to model the FTRs as options so potentially other allocation eligible MPs cannot take advantage of the virtual capacity that their counter-flow may create. The next two sections outline two different optimization approaches and their effect on modeling FTR priorities. As mentioned earlier, the optimization process is the second step of the SFA and is used to restore feasibility if the SFT fails.

4.3 Least Squares Approach with Sequential Rounds

The first optimization process is based on the least squares (or minimum shift) objective formulation. If there are n FTRs and for FTR_i, X_i is the nominated value and Y_i the cleared value, the least squares approach is to minimize the shift from the nominated value, while still maintaining feasibility.

The formulation of the least squares approach is as follows:

$$\text{Objective function:} \quad \min\left(\sum_{i=1}^{n}\left(X_i - Y_i\right)\right) \qquad (1)$$

$$\text{s.t. } F_j(Y_1,\ldots,Y_n) \le \overline{F}_j,\; j = 1,\ldots,J$$

$$Y_i \le X_i,\; i = 1, \ldots, n$$

where F_j is the flow on constraint j (assuming J number of constraints) and is dependent on all of the cleared FTRs. The flow limit of constraint j is equal to $\overline{F}_j$.

The formulation in (1) can be used to allocate FTRs and model FTR priorities. The following presents a methodology for handling FTR priorities. To simplify the exposition we assume only two sets of FTR nominations, with one set having a higher priority (for example, associated with ETCs) than the other. Each step below utilizes the same FNM and the same set of transmission constraints and contingencies:

1. Apply by itself only the set of higher priority FTRs on the FNM and perform the SFA;
2. Identify those FTRs or portion of those FTRs that cleared the SFA and identify for each FTR the portion that was reduced to restore feasibility;
3. Model the cleared FTRs or the portion of those FTRs that cleared from step 2 as fixed injections in the FNM;
4. Apply the lower priority set of FTRs, along with the higher priority FTRs that did not clear in step 1, to the system (with the fixed injections as in step 3) and then perform the SFA once again.

The process described above is sequential in nature. If there were additional FTR priorities, steps 2, 3 and 4 would need to be repeated for each additional priority. In step 1 only the highest priority FTRs are included to guarantee that they will be fully allocated to the maximum extent possible. However, in step 4, there is no guarantee that the higher priority FTRs that did not clear in step 1 will clear. This is due to the fact that in this step the optimization cannot distinguish between the higher and lower priority FTRs.

Note that a reason that certain higher priority FTRs did not clear in the first step is that needed counter-flow from the lower priority FTRs are not present in this step. Going into step 4, the optimization again does not distinguish between the higher and lower priority FTRs and chooses to reduce (i.e., restore feasibility) those FTRs that have the least impact on the objective function. Thus at the end of this process, there could still be higher priority FTRs that could not allocated due to infeasibility conditions.

4.4 Simulated Auction Single Round Approach

An alternative method to the least squares formulation for restoring feasibility is a simulated auction approach. In this process, each nominated FTR by the MPs is assigned by the RTO a proxy-bid ($/MW), which has, for all practical purposes, the same properties as a bid in an actual auction. This methodology is similar to the auction approach in that the bid-based proxy value of the FTRs, in aggregate, is maximized. The proxy bid is a single step price starting at 0 MW and ending at the FTR nomination MW value. If X_i is the nominated value, Y_i is the cleared MW value and P_i is the proxy-bid for FTR_i, the formulation of this optimization problem is as follows:

$$\text{Objective function:} \quad \max\left(\sum_{i=1}^{n}\left(P_i \cdot Y_i\right)\right) \qquad (2)$$

$$\text{s.t. } F_j(Y_1,\ldots,Y_n) \le \overline{F}_j,\; j = 1,\ldots,J$$

$$Y_i \le X_i,\; i = 1, \ldots, n$$

The steps in this optimization process are as follows:

1. For each nominated FTR by the MPs, determine its priority and associated applicable proxy-bid (a

section below discusses this issue in more detail); and

2. Apply all FTRs to the FNM and perform the SFA.

This methodology is simultaneous in nature and all FTRs, regardless of their priority, are included simultaneously into the optimization problem. The advantages that this method has over the least squares method are two: a) the number of SFA rounds that need to be processed is reduced, and b) higher priority FTRs will be fully allocated over lower priority FTRs. So, application of this formulation in the example of section 4.3, would eliminate the problem of having lower priority FTRs cleared while having higher priority FTRs being reduced, due to the relative setting of the proxy-bids.

The selection of the proxy bids for different priority sets of FTRs is the key consideration in this procedure, i.e., if an FTR's proxy-bid is higher than another FTR's proxy-bid, then the FTR with the higher bid should be cleared first. This statement may be true in general, but under certain conditions it may be invalid. We believe that for a small set of FTR priorities (say smaller than 5), a FNM and a set of constraints and contingencies, a set of proxy-bids can be determined to guarantee that higher priority FTRs are in fact cleared first over lower priority FTRs. This paper does not attempt to prove this claim, in general, nor does it assume such a proof exists. Rather, this paper claims, based on extensive empirical evidence, that under limited conditions and assumptions (number of FTR priorities less than 5, etc.) this methodology will indeed provide the expected results.

The contribution of an FTR to a constraint is determined through the PTDFs. In practice, a relative flow tolerance factor, α, ($0 \leq \alpha \leq 1$) is established (say, α =3%), where FTRs that have a positive contributing PTDF greater than α are used as controls in the optimization. We claim that higher priority FTRs are awarded transmission capacity (i.e., cleared) before any lower priority FTR if the proxy bids associated with the higher priority set are at least ($1/\alpha$) times the proxy-bid of each FTR in the lower priority set.

To give credence to this claim we offer the following proof. Assume two FTRs, one with a high priority and one with a low priority. By assumption, each FTR's PTDF is greater than α. Assume that the lower priority FTR's proxy-bid is P_L and its PTDF in the direction of the enforced constraint is S_L. The higher priority proxy bid is P_H and its PTDF in the direction of the enforced constraint is S_H. To reduce the constraint flow by, say $x > 0$, the lower priority FTR must be reduced by x/S_L. This will impact the objective function (this impact will be negative and will reduce the value of the objective function which is to maximize the bid-based proxy value of all FTRs,) by the amount $x \times (P_L/S_L)$.

Similarly, to reduce the constraint flow by, say x, the higher priority FTR must be reduced by x/SH. This will impact the objective function by the amount, $x \times (P_H/S_H)$. The optimization process will reduce the lower priority FTR to reduce any violation on the enforced constraint as long as the impact on reducing the value of the objective function is smaller than it would be if the higher priority FTR were reduced.

In other words, the lower priority FTR would be used if, $x \times (P_L/S_L) < x \times (P_H/S_H)$, and since $x > 0$, this reduces to $(P_L/S_L) < (P_H/S_H)$. Note that $(P_L/S_L) < (P_L/\alpha)$ by assumption, i.e., in order to consider the FTR as a control its PTDF is larger than α. The smallest value the (P_H/S_H), can achieve is P_H, when $S_H = 1$, thus $(P_H/S_H) \geq P_H$. Since, by definition, the proxy bid associated with the higher priority set is at least ($1/\alpha$) times the proxy-bid of each FTR in the lower priority set, i.e., $(P_L/\alpha) < P_H$.; the inequality is proven: $(P_L/S_L) < (P_L/\alpha) < P_H \leq (P_H/S_H)$.

5 A Numerical Example

The section provides a simple numerical example where both the least squares approach with sequential rounds and the simulated auction approach are evaluated to illustrate which of the two is preferable from market efficiency perspective.

Assume there are three (3) eligible entities each nominating a single FTR. These FTRs are FTR1, FTR2 and FTR3 and all have a hedge type of obligation. Assume a FNM with only one enforced directional constraint, which is a transmission line with a limit of 50 MW. This constraint is applied to the base case. The following table provides the relevant nomination information for the three FTRs.

Table 1. FTN nomination information

FTR	Source	Sink	Nomination (MW)	PTDF for A to B	Priority
FTR1	Source1	Sink1	100	0.8	High
FTR2	Source2	Sink2	60	0.5	Low
FTR3	Source3	Sink3	100	-0.3	Low

Least squares sequential round approach

Based on the exposition of section 4.3, the first step is to apply first only the high priority FTRs. The nomination of 100 MW for FTR1 would create an overload on the constraint. This FTR would be reduced from 100 MW to 62.5 MW (62.5 MW × 0.8 = 50 MW). If FTR3 were included in this simulation, it would provide the needed counter-flow for FTR1 to be fully accommodated. The second step would be to identify those FTRs that were reduced in step 1. In this case it is FTR1 with 37.5 MW of reduction. The third step is to fix the FTRs that cleared from step 1. The fourth step is to apply the lower priority FTRs and the reduced FTR portions from step 1. In this step, FTR3 provides 30 MW of counter-flow on the constraint. The least squares methodology would reduce FTR1 from 37.5 MW to 10.53 MW and would reduce FTR2 from 60 MW to 43.15 MW. Thus, the higher priority FTR cannot be fully accommodated. The cleared MW for each FTR is shown in Table 2.

Simulated auction single round approach

Based on the exposition of section 4.4, assume a relative flow tolerance factor to be 5%. The first step is to set the proxy-bids of the FTRs. Set the proxy-bids of the lower priority FTRs (FTR2 and FTR3) to be $1/MW. Set the proxy-bid of the higher priority FTR (FTR1) to be at least (1/0.05) = 20 times the price of the lower priority-bid. Set this price to $25/MW. The second step is to perform the optimization. The final results are provided in Table 2. The higher priority FTR (FTR1) is fully accommodated where as the lower priority FTR (FTR2) is fully reduced.

Table 2. Final results based on the two methodologies

FTR	Least squares sequential round approach		Simulated auction single round approach	
	Cleared MW	Flow on Constraint (MW)	Cleared MW	Flow on Constraint (MW)
FTR1	62.5 + 10.53 = 73.03	58.424	100	80
FTR2	43.15	21.575	0	0
FTR3	100	-30	100	-30

6 Conclusions

This paper presents the fundamental elements of a well functioning Financial Transmission Rights (FTR) market that is desirable for supporting wholesale competitive electricity markets. Emphasis is placed on the practical considerations that need to be carefully evaluated in implementing an FTR market. The paper presents an analysis of the FTR procurement alternatives market participants have at their disposal for procuring financial instruments as part of their hedging strategy. The paper focuses on the FTR allocation approach as a key methodology for procuring FTRs. Two main considerations are presented; the eligibility rules and the validation rules. The paper finally presents various allocation methodologies and an analysis of the incentives of the associated objective formulations. A simple numerical example is presented to illustrate the market benefits of the two FTR allocation mechanisms. It is shown that the Simulated Auction Single Round approach has substantial market benefits over the Least Squares Approach with Sequential Rounds.

7 References

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8 Biographies

Dr. Roger Treinen received his Ph.D. in Electrical Engineering from Iowa State University in 1993. From 1994 to 1998 he worked as a consultant for Pacific Gas and Electric Company in various areas including voltage stability. In 1997 he helped PG&E in the transition to California's new deregulated electrical market. Since 1999 he has been working for ECCO International providing consulting services to many clients in the electric restructuring area. Currently he is the lead technical architect in developing the California ISO's Congestion Revenue Rights allocation and auction system and technical lead in working with California stakeholders in developing CRR feasibility studies.

Dr. Alex D. Papalexopoulos is president and founder of ECCO International, an Energy Consulting Company that provides consulting services on electricity market design and software issues within and outside the U.S. to a wide range of clients such as Regulators, Governments, Utilities, Independent System Operators, Power Exchanges, Marketers, Brokers and Software vendors. ECCO International is currently involved in various energy deregulation projects around the world including North America, Europe and Asia. Dr. Papalexopoulos received the Electrical and Mechanical Engineering Diploma from the National Technical University of Athens, Greece in 1980, and the M.S. and Ph.D. degrees in Electrical Engineering from the Georgia Institute of Technology, Atlanta, Georgia in 1982 and 1985, respectively. He worked at the Pacific Gas and Electric Company from 1985 till 1998. He has made substantial contributions in the areas of network grid optimization and pricing, market design, ancillary services, congestion management, competitive bidding, and implementation of EMS applications and real time control functions and forecasting in a utility environment. He has published numerous scientific papers in IEEE and other Journals. He is the 1992 recipient of PG&E's Wall of Fame Award, and the 1996 recipient of IEEE's PES Prize Paper Award. Dr. Papalexopoulos is a fellow of IEEE.