Self-Management of ATC by the Marketplace

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Abstract

The commercial model for providing transmission service is rapidly evolving. In the future, rights to use scarce transmission resources will be self-allocated using economic information provided by market participants. Prerequisites for efficient self-management of ATC by the marketplace are a well-defined, simplified commercial model of the transmission grid and freely-tradable firm transmission rights. This paper describes modeling approximations which can reconcile commercial and operational needs, defines a model of firm transmission rights, and outlines a process for maximizing the commercial value of the transmission grid through decentralized self-management of transmission access.

Keywords: ATC, firm transmission rights, zonal model

1. Overview

The purpose of this paper is to lay out a framework for addressing the Available Transfer Capability (ATC) calculation problem in the restructured electric power industry. The commercial model and requirements for providing transmission service are rapidly evolving; consequently, both the market needs and regulatory requirements for ATC are changing as well. R&D efforts which focus on addressing the problems of today’s vertically-integrated world of centralized control - such as those geared towards real-time calculation of ATC to facilitate posting and updating of OASIS sites, or those designed to enable the current generation of transmission loading relief processes - may not produce results of substantive value.

The ATC calculation problem should be viewed from the proper perspective. The fundamental reason for defining and calculating ATC should be to maximize the commercial value of the transmission grid, subject to system reliability and security constraints. Thus, efforts to develop methods which improve the precision of calculations at the cost of increased complexity or reduced flexibility for market participants may be misdirected.

This paper reviews the objectives of industry restructuring and the marketplace’s requirements for electricity “transportation” service, describes modeling approximations which can reconcile commercial and operational needs, defines a model of firm transmission rights, and outlines an overall process for maximizing the commercial value of the transmission grid through decentralized self-management of transmission access by market participants.

A more-detailed version of this paper will be made available at the HICSS-32 conference in January 1999. That version will subsequently be available for downloading from the author’s web site at http://www.tca-us.com.

2. Solving the Right Problem

There are many industry efforts aimed at calculating ATC. But are they attacking the right problem? Some efforts focus on yesterday’s problems: for example, calculating and posting ATC under the transmission access regime created by the Federal Energy Regulatory Commission’s April 1996 Order No. 888 - a regime which has at most a few years of remaining life. Other efforts are founded on premises which will never survive in an efficient competitive energy marketplace - such as “first-in-line is first-in-right,” ex post pricing of transmission service, or the belief that long-term transmission rights are not necessary and need not be made available to the marketplace. It is important to begin by considering the requirements of the customers in the electricity transport marketplace.

The determination of ATC and TTC (total transfer capability) is important to the participants in the electricity marketplace for two reasons. First, it
enables the determination of the amount of “long-term” (one year or longer) transmission system capability that can be defined, allocated, sold and traded on a firm basis. Second, it supports the near real-time (day-ahead to week-ahead) determination of the transmission system’s capabilities, to enable the secure operation of the system and to permit the short-term sale of additional transmission rights.

3. Decentralization of Decision-Making

There are two fundamental drivers behind virtually every aspect of electric industry restructuring, including wholesale access, retail access, mergers and consolidations, and the creation of Independent Scheduling Administrators (ISAs), Independent System Operators (ISOs) and regional transmission companies (Transcos): the elimination of economic inefficiencies associated with institutional barriers and regulatory constraints, and the unshackling of market participants from the chains of centralized “optimization.”

There is growing recognition that centralized approaches which purport to optimize markets are inherently inefficient. They impose “averaging” and ignore the multi-dimensional value functions and flexibilities of individual suppliers and consumers, they create inefficiencies associated with commoditization, they cannot optimize over the relevant mid-to-long-term time frames, they cannot readily manage risk, and they cannot make sound tradeoffs between the many different complex variables germane to truly efficient decision-making. Many would argue that the fundamental objective of electricity industry restructuring is to create value by enabling decentralized decision-making and control.

4. Requirements of the Marketplace

As in every other industry, market participants must be allowed to manage and make tradeoffs between the fundamental elements of production, transportation and consumption. To do this, market participants must be able to acquire and self-manage standardized long-term transportation rights. Such rights must:

(i) Provide commercial certainty: both certainty of price and certainty of delivery

(ii) Be available at ex-ante prices, rather than priced on an ex-post basis

(iii) Be sufficiently “firm” - i.e., not subject to excessive curtailments, particularly where such curtailments are the result of interactions with other rights rather than “force majeure” events such as very improbable physical contingencies

(iv) Be available to the marketplace well in advance of the energy trading period

(v) Have durations that are consistent with the duration of typical energy commodity contracts

(vi) Provide liquidity: the rights should be fungible and freely-tradable through bilateral exchanges and secondary markets.

Liquidity of transportation rights is an extremely important requirement. Because transportation rights are defined on the basis of underlying commercial models, this requirement implies that commercial models which rely on simplifying approximations may often provide much greater commercial value than precise but complex commercial models.

5. A Model to Support the Marketplace

Can the electric transmission grid, with all of its complicated interactions and real-time requirements, support such a transportation rights model? Yes. There are no technical reasons why the commercial model for the acquisition and use of firm transmission rights needs to be significantly more complex than the models for transportation rights in other industries, including natural gas transportation, telecommunications or air freight.

The commercial model of the grid must be designed to permit the creation of transmission rights which meet two key criteria:

(i) The rights must be definable and well-defined

(ii) The rights must be independently exercisable. This means that a rights-holder must be capable of exercising its rights without infringing on the rights held by other rights-holders. However, it does not imply a need for complete lack of interaction between rights: as long as the rules for interactions between rights are well-defined and create only minimal commercial burdens - as may be the case when rights are related through infrequently invoked nomograms - some interdependence of rights may be acceptable.

5.1 The Zonal Model
In many transmission networks, it is possible to directly rely on grid topology to define a “zonal” model of the grid. In such a model:

(i) The boundaries between zones are defined by major transmission interfaces which experience predictable, commercially-significant amounts of congestion (i.e., significant scarcity costs); and

(ii) Within the zones, the differences in the marginal prices of energy are commercially insignificant, or there may be administrative or equity-based reasons for deeming such prices to be identical.

In the zonal model, a user of the transmission grid must obtain explicit rights in order to schedule energy from one zone to another zone (with all nodes within a zone deemed to be coincident) but does not need to acquire rights for intra-zonal energy schedules. Potential security constraint violations within a zone are managed by the grid administrator through the voluntary redispatch of resources, and the costs associated with such redispatch are “socialized” by allocating them to all grid users through a general uplift.

In the zonal model, the primary technical challenge is the determination of long-term inter-zonal transfer capabilities. These capabilities place upper bounds on the numbers of inter-zonal transportation rights that can be made available to the marketplace.

5.2 The Generalized Model

Even for those transmission networks where topology does not seem to readily favor the creation of zones, it is still generally possible to define zones of commercial significance (ZCS) which are interconnected to one another through multiple paths or sub-networks. The primary criterion for creation of a ZCS is that within each ZCS, the differences between the nodal marginal prices of energy are commercially insignificant, after adjusting for the effects of transmission losses (which may be taken into account in a number of ways - for example, through location-specific loss factors applied to generator outputs) and ignoring the effects of random phenomena. An arbitrary hub is selected for each ZCS and a simplified “commercial equivalent” network can be defined, linking such hubs.

In the generalized model, the fundamental technical challenge is to determine long-term TTCs between selected pairs of ZCS, in light of the fact that these TTCs may exhibit strong interdependencies. Although a certain amount of arbitrariness and judgment may be necessary, it is nonetheless possible to calculate:

(i) A set of simultaneously feasible transfer capabilities; and

(ii) The functional relationships between those inter-ZCS transfer capabilities which are strongly coupled.

Practical considerations, such as geography, and consistency of generation and fuel types within geographic regions, often minimize both inter-ZCS dependencies and intra-ZCS price differences, permitting substantial amounts of decoupling.

The most-significant technical challenge is quite similar to that of defining a multi-dimensional transfer capability nomogram. The fundamental non-technical challenge is to select a set of TTCs which roughly maximizes the commercial value of the transmission network (although precision is not necessary because the market participants can make tradeoffs between the inter-ZCS schedules based on the published functional relationships) in an environment of Balkanized transmission ownership. However, institutional restructuring - e.g., through the creation of Transcos, ISAs or ISOs - may address this problem.

Under both the zonal (“canals and lakes”) approximation or the more generalized (“turnpikes and streets”) approximation, a complete security analysis of the system - including steady-state, dynamic stability, transient stability, voltage stability and contingency analyses - can be used to determine the quantities of inter-ZCS TTC that can be simultaneously accommodated by the transmission grid. There is no need to compromise power system reliability or security. And in either case, the end result is similar: a commercial equivalent which provides grid users with a simplified model for understanding, acquiring and self-managing the use of transmission service.

[A final note on both of these models: a key underlying commercial assumption is that the embedded (sunk) costs of the transmission grid plus the non-transaction-specific variable costs of operating the transmission grid are recovered through “access fees” charged to connected loads and/or generation using billing determinants such as]
maximum demand or total energy consumption/delivery. Because the transaction-independent costs of the transmission grid are recovered through such access fees, the charges for the sale of inter-ZCS rights need not be encumbered by the need to recover transmission revenue requirements and can be permitted to reflect the economic (scarcity) value of the inter-ZCS interfaces. As to the disposition of the revenues from the sale of inter-ZCS rights: an approach that has received widespread support is to use such revenues as credits against the total transmission revenue requirement, reducing the size of the access fee.]

6. Firm Transmission Rights (FTRs)

Once the transmission grid’s long-term (e.g., one year or longer) inter-ZCS transfer capabilities have been defined, the grid administrator can easily determine - after it overcomes the commercial challenges of ascertaining already-committed uses of the grid under pre-existing contracts - the quantities of independently-exercisable rights that can be offered between various areas of the transmission grid. These rights can be released for sale as marketable property rights, known as Firm Transmission Rights (FTRs).

There are many details that must be addressed to clearly define the rights and obligations associated with such property rights. The most salient features of FTRs are as follows:

(i) The possession of FTR$_{ij}$ entitles its holder to schedule a fixed quantity (typically 1 MW) of energy from any node in ZCS$_i$ to any node in ZCS$_j$.

(ii) An FTR provides both scheduling certainty and financial certainty: the holder of the FTR is assured of scheduling rights from one ZCS to another ZCS at no charge beyond that which the holder has paid for the FTR - as long as the inter-ZCS transfer capability has not been derated.

(iii) However, if an inter-ZCS interface’s operating limit is reduced after an FTR has been sold to the marketplace and/or curtailments are required, the coverage of the FTRs on the affected interface(s) may be reduced pro rata.

(iv) Anti-competitive “hoarding” of inter-ZCS transfer capability is addressed through a mandatory capacity release mechanism: if an FTR is not scheduled by the start of the day-ahead scheduling process, it reverts to the grid administrator for resale as a firm (non-recallable) right which can be acquired by other entities for use in that day’s energy scheduling process.

7. Interfacing Commerce with Operations

For the purposes of commerce – i.e., for purchasing long-term (up to one year-ahead) energy transport rights and for scheduling daily uses of the transmission grid – grid users can think of the transmission grid on a zonal basis.

However, for the purpose of secure operations, the grid administrator can still model and operate the grid on a nodal basis. After accepting the valid energy schedules submitted by the grid users, the grid administrator can use its detailed security analysis tools to determine whether any security constraints would be violated. If so, the grid administrator may call upon generation resources which have submitted voluntary offers to redispatch their output to address such security problems in return for financial compensation. The associated costs incurred by the grid administrator are recovered through a transmission uplift charge.

The grid administrator may also determine, using near-real-time TTC analysis tools, that additional inter-ZCS rights can be made available. Depending on system conditions, submitted schedules and the tools’ capabilities, such rights could be made available day-ahead, week-ahead, or longer-term.

If real-time redispatch or curtailments are necessary, the grid administrator would in the first instance attempt to rely on the operating reserves and redispatch bids that have been made available to it. Should these prove to be insufficient to address the problem, the grid administrator may, under such emergency conditions, call for production changes from any generators and dispatchable loads connected to the grid.

The simplifications and approximations that are made to create and permit the use of a reasonably-defined commercial equivalent model should have no adverse effects on the secure and efficient operation of the transmission grid. Rather, they simply reflect the decision to socialize commercially-insignificant costs in the interest of implementing a commercial model which should enable market participants to create greater economic efficiencies by empowering them to self-manage their portfolios of production resources,
transportation and consumption.

Thus, any gaps between the commercial and operational models of the transmission grid are cost allocation issues, and not reliability problems. Such gaps simply indicate “smearing” (socializing) of minor costs, and/or absorption of risk or price volatility by the transmission service provider. To the extent that the transportation commitments made by the grid administrator through its release of FTRs require the grid administrator to incur redispatch costs (in effect creating additional ATC through such redispatch), this is no different than a service provider in any other industry incurring such costs to guarantee the performance of its products and services.

Successfully interfacing the commercial model and operations model of the transmission grid without imposing undue cross-subsidies on other grid users or burdens on the grid administrator requires: defining a set of FTRs that does not overstate the simultaneous capabilities of the grid; mapping the scheduled FTRs to the detailed grid model on a daily basis; using redispatch rather than curtailment as the primary tool for addressing real-time congestion; and insulating FTR-holders from additional charges (other than any general uplift charges) incurred as a part of real-time grid operation.

8. Additional Considerations

In general, both TTC and ATC are functions of price. TTC can be increased by capacitor switching, changing the settings of phase shifters, network topology changes, implementing remedial action schemes, and other mechanisms - all of which have cost impacts. Additional ATC can also be created by grid users through commitments to redispatch resources or schedule counterflows, and through buy-sell arrangements. The more that grid users are willing to pay, the more ATC can be made available. The static values of ATC that are posted on the Open Access Same-Time Information System (OASIS) nodes mandated by the FERC Orders 888/889 model are simply misleading, incorrect, and insufficient to support efficient commercial decision-making.

A more-sophisticated implementation of the model outlined earlier would accommodate at least three types of rights, each of which requires slightly different treatment:

(i) Salable, tradable, independently-exercisable inter-ZCS rights for which use of such rights is only marginally-affected by flows on other inter-ZCS interfaces

(ii) Additional rights that must be characterized by relatively strong interdependencies with rights on different inter-ZCS interfaces (and for which the grid administrator should make available to the marketplace the technical information which will enable grid users to make efficient tradeoffs)

(iii) Additional counter-flow based rights which can be created through redispatch and buy-sell commitments by market participants.

9. Self-Management of ATC by the Market

The process for efficiently allocating the use of the transmission grid has four phases:

(i) Long-term allocation of transmission rights

(ii) Mid-term reallocation of transmission rights

(iii) Short-term allocation of additional rights made available by scheduled uses of the transmission grid (including counter-flow commitments), by the release of unscheduled FTRs, and by updated short-term calculations of grid transfer capabilities

(iv) “Real-time” adjustments due to changing system conditions.

The first three phases can be handled entirely by market mechanisms, with minimal central coordination. Only the last phase requires active central coordination by a grid administrator.

9.1 Long-Term Allocation

The role of the central administrator of the grid is simply to oversee the definition of FTRs and their release to the marketplace through annual auctions conducted by its agent. Market participants efficiently self-allocate long-term transmission capability through their bids in these auctions.

There are many ways in which a “primary market” auction can be structured. One that is receiving serious consideration is the simultaneous, independent, multi-round, market clearing price auction. In this type of auction, the FTRs for each inter-ZCS interface are sold in a separate auction; the separate auctions are conducted simultaneously; and the auction for each interface uses a multi-round process designed to
facilitate price discovery. In such a process, the auctioneer announces the quantity of available FTRs for the inter-ZCS interface and sets a tentative price for such FTRs. If demand exceeds supply at that price, the price is ratcheted upward. If demand is less than supply, the price is ratcheted downward. This continues until supply and demand closely balance. The price at which this equilibrium occurs is the “market clearing price.” All winning bidders pay this price, multiplied by the number of FTRs they win for that inter-ZCS interface. Activity rules are used to minimize gaming behavior during the auction process and to deal with other auction details, such as convergence of the auction process and round-off problems.

9.2 Mid-Term Reallocation

After the release of FTRs to the marketplace through the primary market auction, the purchasers of the FTRs are entitled to divide them into hourly increments for resale at unregulated prices. Various types of secondary markets are expected to emerge to enable holders of FTRs to sell, trade or otherwise transfer their FTRs to other market participants.

“Transmission exchanges,” automated trading mechanisms that are similar to commodity exchanges, are already emerging to facilitate secondary market trading of FTRs. Such exchanges can also be used to facilitate the creation of additional ATC by bringing together parties that are willing to make counter-flow commitments and parties who are willing to pay for such commitments.

9.3 Short-Term Allocation of Additional Rights

As described earlier, the grid administrator will release additional rights to the marketplace on a daily basis as inter-ZCS TTC is updated and as unscheduled FTRs revert to the grid administrator for resale. The most straightforward mechanism for offering such rights to the marketplace is to release them through transmission exchanges.

9.4 Real-Time Redispatch

As discussed earlier, the use of voluntary redispatch rather than curtailments is the preferred mechanism for addressing real-time security problems. Although central coordination by the grid administrator is clearly required in this timeframe, even here the market plays a major role in determining efficient real-time management of the transmission grid through the market participants’ generation redispatch bids.

Administrative mechanisms such as the North American Electric Reliability Council’s (NERC) Transmission Loading Relief procedures (i.e., curtailments) should only be used as a last resort. The reliance on redispatch rather than curtailment as the primary mechanism for managing real-time congestion will provide grid administrators with additional tools to efficiently manage the secure operation of the grid, while at the same time providing the holders of FTRs with transportation rights of higher quality.

10. The Roles of ATC, the Grid Administrator and OASIS in the Decentralized Environment

In the decentralized environment, transmission usage is self-allocated based on economics; and the underlying premise that ATC is a fixed, calculable number is largely irrelevant since market participants will dynamically create additional ATC through tradeoffs between their production, consumption and transportation. At most, the calculation of TTC will remain as an important technical challenge.

As described above, the grid administrator’s roles in transmission rights allocation and reallocation are minimal, albeit crucial to the success of the process. First, the grid administrator presides over the long-term determinations of TTC, facilitates the annual release of FTRs, and provides important technical information to the marketplace. Second, in the day-ahead timeframe, the grid administrator updates TTC calculations and releases additional capacity to the marketplace. In neither case, however, does the grid administrator make economic decisions. The market participants do this. Finally, in real-time, the grid administrator is the coordinator of redispatch and curtailments.

OASIS will largely be replaced by markets. Because all long-term transmission rights will be brought to market as FTRs through an annual auction and such rights will be traded in secondary markets, the OASIS is not the mechanism for transmission reservations, for releasing FTRs to the marketplace, or for discounting of transmission charges. Once FTRs have been defined and made available to the marketplace, there will remain no rationale for making transmission reservations through an OASIS. The OASIS’ transmission reservation, acquisition and posting functions will be obsolete.
In the future, the primary role for OASIS sites will be to disseminate greatly expanded amounts of information to enable the efficient operation of the marketplace. This will include information regarding market conditions and any transmission grid conditions which might affect the market value of energy, ancillary services, or transmission capacity. This includes the functional relationships between interacting FTRs, projected transmission uses, scheduled line outages, load forecasts, potentially congested transmission facilities, flow distribution factors associated with the use of inter-ZCS interfaces, and factors which indicate the relative effectiveness of generation shifts in alleviating potential congestion.

11. Conclusion

The primary benefits of electric utility restructuring will stem from unbundling and from decentralization of decision-making. The rights to use scarce transmission resources will be self-allocated using economic information provided by market participants. The role of the central grid administrator will be limited to defining the TTC capabilities of the grid, defining FTRs and releasing them to the marketplace.

Prerequisites for efficient self-management of ATC by the marketplace are a well-defined, simplified commercial model of the transmission grid based on Zones of Commercial Significance and freely-tradeable Firm Transmission Rights. Any differences between the simplified commercial model of the transmission grid and the detailed operations model of the grid can be addressed without compromising reliability.

The primary institutional challenges are to define the Zones of Commercial Significance when there are strong interactions between inter-ZCS transfer capabilities, and to select an appropriate set of simultaneously feasible FTRs. The primary technical challenges are to develop a meaningful commercial equivalent model of the grid and to derive the relationships between interacting FTRs, so that markets can be empowered to make tradeoffs. In attacking these problems, model developers should strive to take advantage of the physical characteristics of the transmission grid - including grid topology and economics - with the objective of creating a sparse, decoupled, reduced commercial model.

12. Biography

Carl Imparato is a Senior Associate with Tabors, Caramanis & Associates, a Cambridge, Massachusetts-based consulting firm. He is currently involved in the restructuring of the electricity marketplace in the western United States, including the development of Independent System Operators in the Desert Southwest, Pacific Northwest and California, and Independent Scheduling Administrators in Arizona, Nevada and the Pacific Northwest. From 1978 until 1998, he worked for the Pacific Gas & Electric Company, where he played major roles in the development of transmission and ancillary services policies and protocols for the new California ISO; the development of the decentralized market model that underlies many of the industry restructuring efforts across the country; the creation of the Western Regional Transmission Association, the nation’s first Regional Transmission Group; the development of the Western Systems Coordinating Council’s regional planning policies; and the development of analytical tools for power system planning and operations, and their implementation in PG&E’s energy control center. He holds B.S. and M.S. degrees in Electrical Engineering from the California Institute of Technology and the University of California at Berkeley.