

An electric market design based on the nodal model of power transmission service

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Abstract. Nodal model of network access can enhance flexibility, reliable use and development of the network, and market efficient integration, due to adequate treatment of commercial and operational aspects of power transmission.

Abbreviations

CM - Congestion Management

DP - „Driving – Point” or „Point-of-Connection” [power transfer capability]

G & L - „Generation” and „Load” [nodal] transmission rates

ITC - Inter – TSO Compensation [mechanism]

PP - “Point - to - Point” [power transfer capability]

MC - Marginal Cost

MOF - Market Opportunities Fee

TCI - Transfer Capability of [relevant and/or critical inter-area] Interconnection

PS – Power System

TC - Transmission Capacity

TSO - Transmission System Operator

Keywords – Electricity; transmission capacity; rate; market design; nodal model; network capability; opportunity fee; marginal cost.

1. Introduction

Lessons learnt from the last two major incidents in Europe, in 2003 in Italy and in 2006 in Germany, have shown that inconsistent market and transmission system operation rules, and lack of coordination of several TSOs, appeared as main difficulties associated with regional trade. Increasing uncertainty on the electric transmission system operation is induced by the variable intensity and direction of power flows and load evolution, and the wind power intermittency. In this context, TSOs are often solving internal bottlenecks by moving congestion to the country border exacerbating unpredictability of interconnectors' capacity limits. Defining and determining the limits of power transmission become more and more difficult under current electric market design.

2. Transmission capacity and congestion in electric market design - the "nodal" model

Transmission Capacity (TC) for electricity trade is a capping threshold for the volume of energy transactions meant to protect integrity of PS operation and individual network elements [5].

In our interpretation [6,8], TC is essentially a „Driving-Point“ (DP) or „Point-of-Connection“ power transfer capability of the network. A transmission transaction would rent a share of TC and any further limitation of contractual capacity for compliance to the PS operational standards may be referred as congestion. Thus, the DP (commercial) congestion is limitation of energy transaction at access point to transmission system reflecting cumulative effect of PS constraints.

However, for the cross – border trade particularly, the current European regulation [1] defines the TC as “Point-to-Point” (PP) power transfer capability from a source network area to a sink network area. The PP congestion is managed prior to conclusion of transmission deal while it do not occur at the place of energy (and transmission) transaction, but at certain interconnections (cross – border, critical), somewhere across the transmission network.

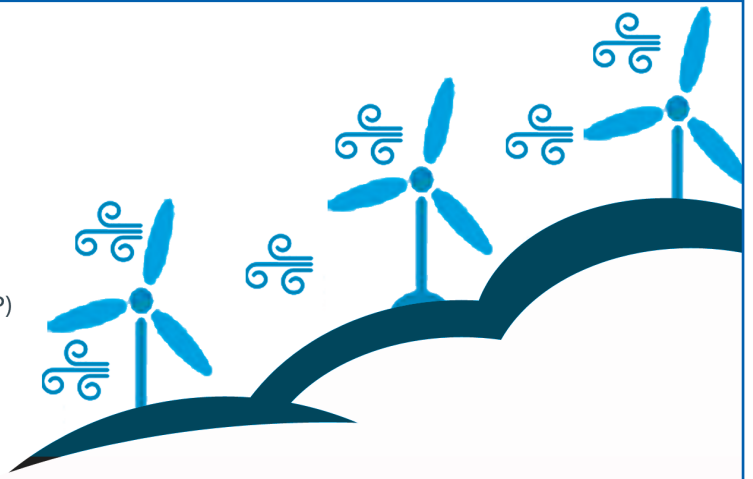
DP and PP transmission capacity models deal differently in respect to the key requirements of grid access and market design, namely:

a) Consistency of network planning and usage

Transmission system is primarily enhanced in order to connect new power facilities, and the TSO shall guarantee the requested capacity under rather indeterminate operational and commercial conditions. Hence, DP and not PP transmission capacity is relevant information in transmission grid planning. Greater and less predictable power market transactions could jeopardize the system integrity if standards of planning and operation were not the same.

b) Meaningfulness of transmission capacity

TC should be assessed and posted so as to be understandable for market players. While the DP –TC information is fairly easy to understand, a market player being able to optimize its market portfolio, this cannot be said of PP –TC capacity that does not appeal to the average grid user. Power flow limits for “critical” network elements are meaningful for the TSOs only. Transparency and meaningfulness in capacity calculation process is also very important for the market players in order to manage their risks more effectively



c) Predictability of transmission capacity

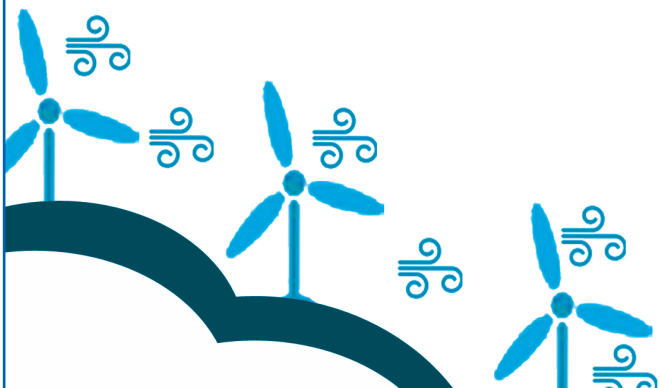
For a certain time horizon, transmission capacities should be as predictable as possible, and almost without exception this is accomplished by the limits on node power injections only.

d) Increase in the network efficiency and market integration.

DP capacity is naturally associated to implicit allocation of grid capacity. Implicit allocation is ensured within the very energy auctions. Allocation of TC on market players in explicit auctions does not create incentives for the TSOs to allow greater transmission system utilization. Market fragmentation and network inefficiency can be introduced when electricity deals and capacity allocation result from separate auctions.

In the national context, normally, the TSO reimburses the market players for any degraded transaction as a result of Congestion Management (CM). Transmission rate – based income should cover the extra cost of generation redispatch on the assumption that generators’ gaming is properly prevented. Transmission rates can be established as marginal / incremental costs at the generation (delivery, entry) node ($G = MCG$) and at the load (receipt, exit) node ($L = MCL$).

In a multi-TSO harmonized environment, the G s and L s are supposed to be established on a common grid model following the same rules of grid service and cost definition. G in the entry point and L in the exit one can be collected by the TSOs in the exporting and importing countries, respectively. Their sum is meant to recover all service cost of the multi-TSO interconnection. Each TSO may reimburse his own customers for the relief of congestions either for feed in or take off powers. With the regional balancing mechanism in place, the TSOs can minimize the volume of these reimbursements while the ITC mechanism redistributes the cost effects of transits among the TSOs involved. The current ‘competitive’ mechanisms of market operators for allocation of PP congestion costs and rents, either explicitly or implicitly, give TSOs’ a questionable reason to move congestion to the borders while failing to model the optimal congestion relief process in respect to different PS constraints as well. They would no more be necessary if the rate - based reimbursement mechanism was in place.



3. Transfer capability of network corridors and management of constraints

in power system operational security - the „source to sink“ model

The TSO has to prevent operational inadequacy due to PS constraints by verifying if the observed level of security complies with the security 'N-1' criterion as well as with the additional criterion of taking into account certain 'N-2' situations in operational planning studies. According to operational rules, the TSO manages the PS constraints in two step decision making process, as follows:

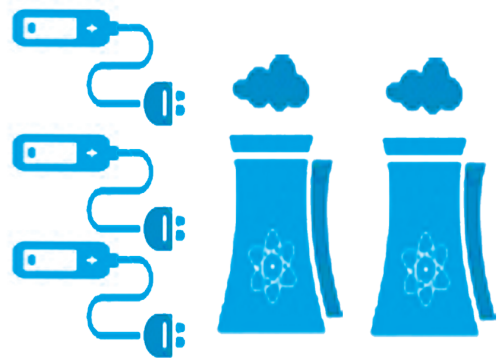
- Scheduling electricity flows for reliable PS operation after completion of transaction day and receive transactions notifications (maintenance rescheduling, if the case). Predictive security assessment must be performed for each candidate dispatch scheme, under normal and contingencies conditions. Constraint relief can lead to generation rescheduling or to transactions curtailment in certain cases.

- Dispatching the PS, which includes transmission monitoring and application of corrective / remedial actions when PS constraints are detected such as redispatching, generation commitment or transaction curtailment.

PS operating states are generally checked up as against specific steady - state and transient stability criteria and equipment thermal ratings.

For control reasons, power Transfer Capabilities can be established for relevant and/or critical inter-area Interconnections (TCI). Romanian system operator has been controlling the aggregate line – flows over relevant TCIs including cross – border tie lines since the mid of 70s, and the author developed the specific methodology, which is based on PS steady – state stability margin. TCI results as a flow limit when the system's operational state is „worsen“ following a PP approach. Being dependent on the PS particular states, the TCIs are understood by the TSOs only while certain inter-area interconnections can overlap each other. Noticeably, the TSO's scheduling and real-time operations are much more complex than „marked – based“ CM solutions of market operators addressing power transfer issue. TSO's management of constraints must also be optimal in respect to total congestion cost. To this aim, the TSO purchases necessary resources on the ancillary system services and balancing markets, and apply least - cost procedures for constraint clearing. These procedures are either based on simulation of the system operation (preference may be given to the conservative models) or on expert systems that store and use the knowledge gathered from specialists and ex-ante PS simulations [3].

Uncertainties for individual TSOs can be decreased by coordination of constraint management including calculation of transfer capabilities. Coordination of the pan-European PS can be improved by making available to all TSOs a frequently updated snapshot of the whole 400 kV interconnection network in both time frames: day – ahead and near real-time. A Congestion Management and Monitoring Office (CMMO) may assist TSOs to coordinate PS scheduling and to take remedial actions when constraints involving several TSOs are detected. The CMMO could also administrate a regional scheduling system providing correlation of network scheduling with optimal measures for congestion relief in order to maximise use of the network.



4. Nodal transmission pricing and its impact on the market design

Gs and Ls may represent relevant allocations of the TSO's Revenue Requirement (RR) on grid customers while sending "locational" price signals with significant influence on electricity transactions. However, the marginal costs, when applied to transactions at every node for generation or load and every trading/time interval, give rise to less income than the regulated RR [4].

Paper [7] describes the method to recover all cost of serving users by charging Market Opportunity Fee (MOF), as a pro-rata with the benefit grid user get from full network access. Sellers and buyers on electricity market take advantage of the differences between their offered prices and the market price. As a supplier of the service of access to the market, the TSO ought to be able to request a MOF based on opportunity cost, for every electricity transaction, in each trading interval. The MOFs are added to Gs and Ls rates in the corresponding nodes, so as to have the TSO's income adjusted to the value of RR. Normally, the benefit is significantly greater than the associated fee paid for transmission service. The market benefits are evident in the centralized marketplaces. They could also be established at standard values for negotiated bilateral contracts.

Balancing rate components of the MOF model may be derived from the net benefits of market participants, considering the Gs and Ls included within electricity price-offers (Figure 1).

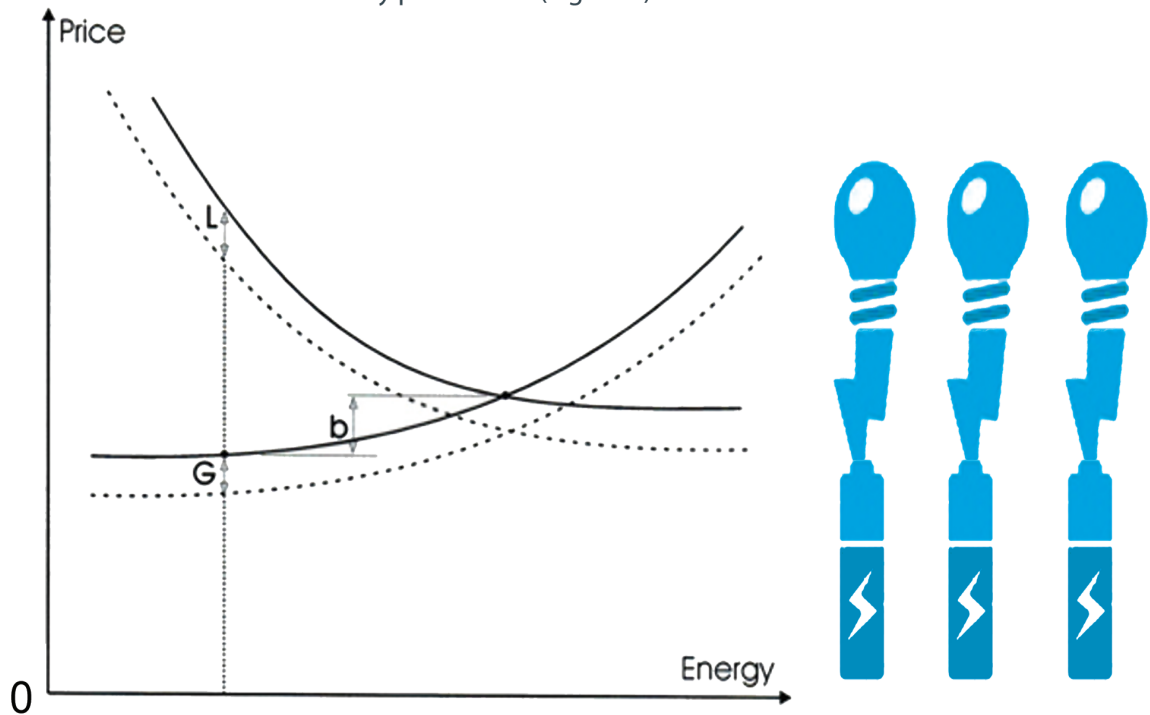


Figure 1. Aggregation of energy and transmission transactions in the nodal model, and the net benefit of a market participant (seller)

Transmission customers would pay the posted Gs and Ls directly to the TSO, while allocation and payment of opportunity fees would be ensured by the trading mechanism of the electricity market itself. The TSO shares the net benefits of market participants as ex-post opportunity fees arising from the market access service the network is providing.

The node-discriminated DP transmission capacity and cost of access to the grid can discover actual merit order of sell and buy offers, market clearing price and total volume of energy transactions. The fictitious clearing price of the current marketplace would be replaced by a real market price of energy. This price aggregation would help increase market efficiency and develop a rational market infrastructure.

5. Conclusions

Transactions, prices, and infrastructure capacity of an electric market are essentially of “nodal” nature. In the MOF method of nodal transmission pricing, costs and revenues for transmission service are balanced in each trading interval with a proportion of the differences between offered prices and the market price for each sell and buy energy transaction. The method can substantiate a new market mechanism, in which the energy price - offers are aggregated with the nodal transmission rates. With resources provided by the (nodal) transmission rates, the TSO may reimburse its customers for the effects of congestion i.e. limitation of transmission contractual capacity. Transmission capacity and transmission congestion are assessed at the point of access to transmission system.

Nodal approach to network access and electric market design can ensure (i) transparency of deals, because transmission capacity offered to trade would mirror capacity of users’ facilities, (ii) limitation of capacity panching with congestions artificially moved to the borders, because only TSOs would be involved in clearing of interconnectors’ constraints, and (iii) consistency of congestion management with the PS operating rules.



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