

*Milan Vukasovic<sup>1</sup>, Oliver John<sup>2</sup>, Nenad Stefanovic<sup>3</sup>*

## **LONG-TERM TRANSMISSION NETWORK EXPANSION PLANNING CONSIDERING THE ECONOMIC CRITERIA AND THE FLOW-BASED MARKET MODEL**

<sup>1</sup> VERBUND-Austrian Power Grid AG, Austria, + 43 (0)50313-56154, Milan.Vukasovic@verbund.at

<sup>2</sup> Amprion GmbH, Germany, +49 (0)231 / 438-3286, oliver.john@amprion.net

<sup>3</sup> Energy Agency of Republic of Serbia, Serbia, nenad.stefanovic@aers.rs

### **INTRODUCTION**

Transmission network expansion problems could be approached from the different directions. One of the relevant questions under the deregulated electricity market is who should undertake the investment: a regulated entity – in such a case TSO (Transmission System Operator) - or a third party who is not owner and operator of transmission system. In the second case investments are considered as merchant lines and the investor encounters the risk to which extent these lines will be utilized. The sale of transmission capacity to the market is the only source of income and hence only sufficient energy exchanges and the respective electricity flows over the lines lead to a positive return on investment (ROI). This, in turn, creates an incentive to invest. When TSOs are carrying out regulated transmission investment projects (e.g. reinforcements of their networks), they should aim to increase the overall system security and to integrate the relevant market. In this context, the relevant objective function under the liberalised market which has to be maximised is social welfare. In this paper, centralised planning concept undertaken by neighbouring (regional) TSOs is analysed taking into account a flow-based transmission capacity allocation method. It is shown that not only coordination among TSOs but also a consideration of relevant market players decisions is necessary in order to economically efficiently expand and use the transmission system.

### **EXISTENCE OF CONGESTIONS**

Congestions occur when the system is not able to facilitate all the requests placed on it by its users. In the special case of electrical transmission network, congestion occurs when either certain generators intend to inject energy or loads attempt to withdraw electricity from their connection points in excess of the technical limits of particular network components. The problems are usually recognised if load limitations of transmission network elements (lines, transformers) or critical voltage levels are reached. It is important to notice that congestion does not mean that a certain load is not be served (i.e. unable to consume desired energy), but rather that a certain engagement of generators would not be allowed due to the problems which this injection plan would cause in a particular part of the transmission network.

Congestions could be removed either before the operational phase (preventive) or during real-time operation with the implementation of the relieving measures [1] such as network reconfiguration and counter-trading/redispach (including the demand-side management). In the

long run congestions can be avoided by investments in particular network elements<sup>1</sup>. The existence of congestions should not per se be considered negative and completely removed by constructing an unconstrained transmission network. This would lead to excess transmission capacity and costs and hence constitute an inefficient allocation of resources. This means that the optimal level of network congestion is not zero and sometimes congestion management measures could be the most efficient way to solve network overloading. Therefore, existence of transmission network constraints is consistent with an efficient liberalised electricity market.

## **TRANSMISSION PLANNING UNDER THE MARKET ENVIRONMENT**

Planning of the transmission network upgrade and expansion has been strongly influenced by the opening of electricity market in Europe. Before the process of unbundling (deregulation), transmission planning departments were part of vertically integrated power generation/supply companies. The main aim of reinforcements was to ensure economical dispatch (minimisation of production costs) of existing and future power plants, taking into account security of supply, i.e. proper level of consumption increase. Therefore, network expansion planning was optimised in line with minimal expenses criteria and based on technical needs of a specific geographical area.

Under the present market conditions and unbundling provisions such an integrated planning approach is no longer possible. Consequently, several issues can have an influence on the transmission network planning process:

- lack of data needed for planning process (size and location of the new power plants);
- bidding behaviour of existing/new power plants owners;
- elasticity of consumption (i.e. consumers reaction on the high/low market prices);
- different view on transmission development from influential parties (e.g. regulators, producers, traders, suppliers, consumers.);
- changes in the electricity market design;
- disproportion between technical, economical, environmental and social requests.

Although transmission planners were faced to different uncertainties before, existing and new uncertainties make transmission planning more difficult.

Flow-based allocation procedures respect the physical impact of commercial activities by converting them into an (estimated) flow pattern for a particular region. Therefore, this method would also be appropriate for the assessment of critical (highly loaded) network elements (lines, transformers) on a regional level, based on their shadow prices (outcome of allocation process). Additionally, this allocation method could simultaneously ensure a higher system security level (identification of “loop flows”) in comparison with widely applied commercial allocation method (based on commercial constraints). With the flow-based allocation method it is possible to “trace back” original source-sink commercial transaction and, based on the proper network model, calculate its influence (estimated load-flow) on a certain network element.

---

<sup>1</sup> Capacitor banks and/or FACTS devices could be also considered as they could be less expensive and faster to implement.

## USAGE OF CONGESTION REVENUE FOR THE NETWORK INVESTMENT

As stated in Regulation (EC) No 1228/2003, Article 6 [2], any congestion revenue resulting from the allocation of interconnection shall be used for one or more of the following purposes:

- a) guaranteeing the actual availability of the allocated capacity;
- b) network investments maintaining or increasing interconnection capacities;
- c) as an income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified<sup>2</sup>.

Due to the congested transmission network, it is not possible to cover all demand request with the cheapest available electricity source in Europe. Therefore, congestions on a certain border will lead to a loss in social welfare (congestion costs) and congestion revenue collected by TSOs (Fig.1). For market participants both parameters are considered as costs. If option (c) is applied, costs for market participants could (theoretically) be reduced to congestion costs, as congestion revenues would be used to reduce network tariffs.

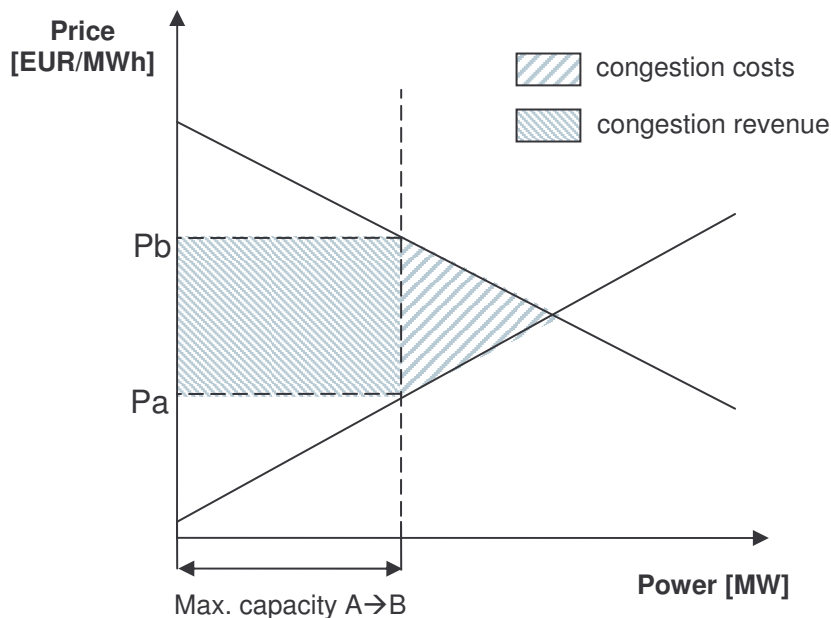


Fig. 1. Congestion costs and congestion revenue between market area A (low price zone) and market areas B (high price zone)

The only possibility to remove the congestion on a long-term level and to increase social welfare is to build a new economically efficient transmission line. Capital costs for such a project could be funded via congestion revenues, i.e. the above-mentioned option (b). From a regional point of view, an economically efficient investment would lead to an increase in the sum of net markets

<sup>2</sup> This possibility is also foreseen within “EC (No) 714/2009 of European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity” but only after the approval from the respective Regulatory Authority.

surpluses (demand and supply surpluses) plus the total regional congestion income in comparison to the market outcome in case without the proposed investment (base case).

This sum of surpluses is often the objective function that is maximized in some of the nowadays applied regional capacity allocations:

- a) it is the objective function of any regional market coupling;
- b) the outcome of explicit capacity auctions reflects the traders' anticipations of the price differences between energy markets on both sides of borders (day-ahead market). These anticipations do not necessarily correspond to the real market results. Nevertheless, explicit auctions should lead to market results which are at least similar to those under market coupling.

### **COST-BENEFIT ANALYSIS: TRANSMISSION NETWORK EXPANSION**

Based on a cost-benefit analyses, it is possible to estimate the regional value of a predefined transmission network enhancement project to the market. With such an approach, it would be necessary to rely on forecasts with regard to future changes in size and location of generation/consumption patterns, and to take into account externalities caused by policy measures (e.g. expansion of wind farms, nuclear policies etc.). Consequently, such forecasts inevitably contain external uncertainties.

The benefits of investments can be grouped into the following two categories:

- (a) social welfare increase on a regional level (could be defined as reduction in production costs and/or reduction in consumption costs on a regional level, or as a percentage mixture of both);
- (b) operational security increase for TSOs and decrease of network losses on a regional level;

All costs of predefined network reinforcement project could be grouped into the following categories:

- (a) capital costs of building a new line;
- (b) operational and maintenance costs (O&M) over the line lifetime;
- (c) environmental impact;

There are four methods commonly used to financially evaluate potential projects: payback time, Accounting Rate of Return, NPV (Net Present Value) and IRR (Internal Rate of Return). The first two methods are non-discounting. In other words money received in twenty years has the same worth as money received today. The second two methods are widely used throughout the world and are called DCF (discounted cash flow).

The indicator that is used for the investment decision in this paper is NPV [3, 4] for the defined period of time and a given discount rate  $s$ :

$$NPV = \sum_{k=0}^n \frac{P_k}{(1+s)^k} \quad (1)$$

where:  $p_k$  - calculated cash flow for the year k (calculates as the difference between benefits and costs),  $n$  – total number of years.

The minimum criterion for the transmission network investment is a positive NPV and an IRR that is above the discount rate requested by investors. The NPV method is used for the conversion of costs (capital costs and O&M costs) and benefits (social welfare) in the observed time horizon to the present values.

#### 4-ZONES TEST SYSTEM: LONG-TERM NETWORK EXPANSION PLANNING

For the analysis of long-term expansion planning decision small 4-zones test system has been used (Figure 2). Furthermore, a set of scenarios has been analyzed (Table 1). In all scenarios, an identical market participant bidding behaviour is assumed.

Investments in the internal transmission network have been investigated in scenarios R7 and R8. In both cases, network reinforcement inside the control zone of TSO C is considered. In the first scenario, building the new internal line C2\_C3 is considered, and in the second case reinforcement on corridor C1\_C2 with the new overhead-line (scenario R8).

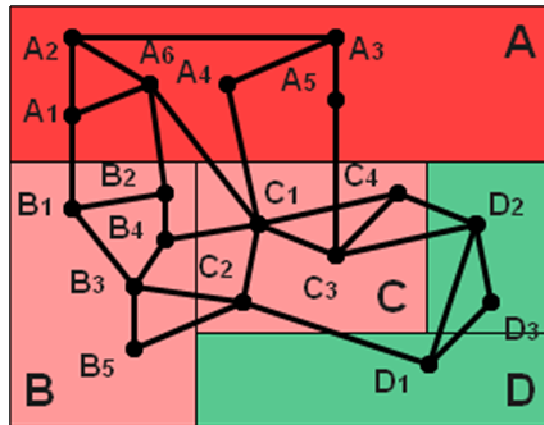


Fig. 2. Small 4-zones test system used for the long-term network expansion planning using the flow-based model

Table 1. Different network reinforcement scenarios (internal & cross-border investments)

Scenario symbol	Scenario description	Tie-line / internal line
STC	Starting case	-
R4	Starting case + reinforcement on corridor D2_C3	TL
R5	Starting case + reinforcement on corridor D1_C2	TL
R7	Starting case + building new internal line C2_C3	IL
R8	Starting case + reinforcement on internal line C1_C2 (double circuit)	IL

### a) Building of the new internal line C2\_C3 (scenario R7)

What can be noticed from Fig.3 is a significant decrease of the total accepted bid power in scenario R7 in both cases, with and without netting. Namely, bid C>B which has been partially accepted in STC is completely rejected and bid D>A is accepted to an amount which is lower than amount accepted in STC. This leads to lower total auction income as the auction clearing prices have not been significantly changed in comparison with the starting case. With the possible construction of the new internal line C2\_C3, binding constraints related to the insufficient transmission capacity of C1\_C2 internal line in scenario STC (n-1) case due to the critical contingency on tie-line C2\_D1 (available capacity from the node C1 to the node C2 is 61.29 MW) are relieved. In scenario R7, mentioned capacity of C1\_C2 internal line is increased to 172.87 MW. Nevertheless, with the construction of the new internal line C2\_C3, maximal “additional” transmission capacity on D2\_C3 tie-line in the (n-1) case caused by the critical contingency on tie-line C2\_D1 which is available for allocation in more critical direction D>C, would decrease to 38.57 MW (from the starting value of 48.52 MW in scenario STC). After the auction clearing process in scenario R7, load-flows between control areas B and C will change direction to B>C (case with the netting). This change will occur on all inter-TSO tie-lines: B4\_C1, B3\_C2 and B5\_C2. Bid with the source-sink pair C>B is completely rejected since with the building of the new internal line C2\_C3 power transfer distribution factor (PTDF) of this zonal source-sink pair will become positive (0.004) on congested D2\_C3 tie-line in (n-1) contingency case. In scenario STC, this PTDF counted to -0.0432, i.e. due to its negative value with the acceptance of this transaction additional capacity on critical network element has been produced (netting effect). In general, with the same bidding behaviour from market participants as in STC scenario, internal reinforcement proposed in this case is not in favour of the regional social welfare maximisation.

What is obvious from the analysed scenarios is the fact that for potential investments within internal network with the main aim to increase transfer capability of congested interconnector(s) (and at the same time to increase the regional social welfare) regional coordination is of crucial importance (regional approach) as well as the careful and in-depth analysis of all proposed scenarios. Namely, in the analysed scenarios, total accepted bid power and total auction income has decreased although the internal transmission network, controlled by TSO C, has been strengthened. With the same bidding behaviour considered during the analysis, commissioning of the new internal transmission line examined in scenario R7 would lead to decrease of “available commercial capacity” for allocation in export-import direction on D2\_C3 tie-line in the (n-1) case caused by the critical contingency on tie-line C2\_D1 in more critical direction D>C.

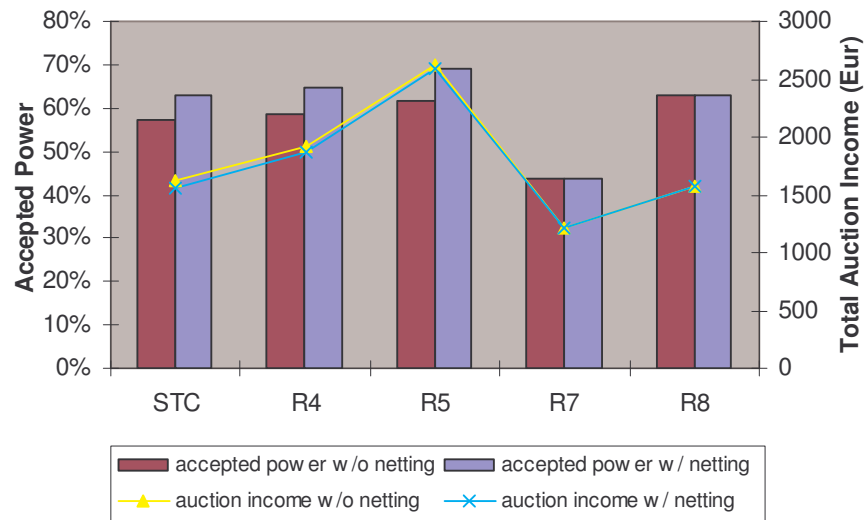


Fig. 3 Change of auction income and total accepted bid power after the proposed reinforcements in internal network (scenarios R7 and R8) and cross-border reinforcements (scenarios R4, R5).

**b) Tie-line investments (scenario R4 and R5)**

In scenarios R4 and R5 the investment analysis in congested cross-border tie-line has been analysed. With the reinforcement in congested tie-line D2\_C3 total accepted power of source-sink bids will be increased as well as the total auction income (in both cases, i.e. with and without netting). With the additional investment and reinforcement of the tie-line D1\_C2, total allocated power is meaningfully increased, especially in the case with netting. New interconnection between market areas D and C lead to the increase of accepted power for transaction D>A (which has the highest influence on the investment “hot spot”, as well as the highest bid price), and at the same time, a slight decrease of accepted bid power C>B. With those investments, the “virtual” capacity of internal line C1\_C2 has been just slightly increased (0.5 MW) in (n-1) case for commercially interesting direction with C2\_D1 critical contingency. Total import of area A as well as the total export of area D has been gradually increased (Table 2). At the same time, area C total has been decreased due to the decrease in accepted bid power of transaction C>B. What is important to notice is that the load-flows over the interconnection lines of the control area C (transit) are increased due to the export/import increase of control areas A and D.

Table.2 Totals of the different control area for the different analysed scenarios (in MW)

Scenario Symbol	TSO A	TSO B	TSO C	TSO D
STC	-357	98,7	201	56,8
R4	-373	103	197	72,6
R5	-409	114	186	109
R7	-350	200	100	50,2
R8	-353	50	250	53,1

## COST-BENEFIT ANALYSIS USING NPV METHOD

Cost/benefit investment analysis has been performed on a small 4-zones interconnected system, displayed in Figure 2. With the unchanged bidding behaviour from market participants (market input) it turned out that the critical network elements are tie-line D2\_C3 after the outage of tie-line C2\_D1 (n-1 case) and tie-line C1\_C2 after the outage of tie-line C2\_D1 (n-1 case). Therefore, the congestion is mostly present inside and on borders of area C for the export-import in direction from South to North. In order to reinforce the network, relieve congestion and increase regional social welfare, the following projects have been considered by TSOs:

- (a) Investment 1: 400 kV tie-line between areas D and C (D2\_C3): scenario R4 (investment costs of estimated 18.3 mil. EUR);
- (b) Investment 2: 400 kV tie-line between areas D and C (D1\_C2): scenario R5 (investment costs of estimated 26.3 mil. EUR);

The technical lifetime of transmission line is long and often exceeds the applied depreciation rate of 30 years. But as any forecast exceeding 15 years imply a significant share of uncertainty, the long-term net benefit of any proposed investment project should be taken with the higher level of reserve. On the other hand, shorter observation periods could underestimate the project and lead to the wrong conclusions. As transmission networks are considered public service good, the use of a social discount rate (in this paper of 4%) has been applied. Privately financed investments will require higher rates of return. However, the determination of an appropriate rate of return is out of the scope of the present analysis. The economic lifetime of transmission investment is assumed to be 40 years. Operational and maintenance costs are considered as 1.5% of the investment and updated with the yearly cumulated inflation factor.

For the auction income sharing among TSOs a key which takes into account both technical parameters (allocated load-flows) and commercial parameters (clearing prices) has been used. Tie-line clearing price (TLCP) key is based on the following formulations:

$$Income_{TSOA} = 0.5 \times \left( \sum_{k=A}^N \sum_{i=k}^N AAF_{k>i} \times CP_{k>i} \times \frac{\sum_{j=1}^M |PTDF_{j\_k>i}|}{\sum_{j=1}^{TL} |PTDF_{j\_k>i}|} \right) \quad (2)$$

$$TSO_A = \frac{Income_{TSOA}}{\sum_{i=A}^N Income_{TSO_i}} \times 100 \quad (3)$$

whereas:  $CP_{k>i}$  - auction Clearing Price between zones k and i in direction from k to i (in the case of market coupling: price difference between areas k and i), N - total number of TSOs in the



region,  $AAF_{k>i}$  - an additional flow over contract path between two TSOs that is caused by accepted transactions (for the case without netting  $|AAF_{k>i}^+|$  and  $|AAF_{k>i}^-|$  are separately taken into account),  $PTDF_{j\_k>i}$  - PTDF of transaction between areas k and i on line j,  $TL$  - total number of tie-lines in the region,  $M$  - total number of tie-lines on the respective TSO borders and  $TSO_A$  - percentage of the total revenue allocated to TSO A.

Table.3 Congestion revenue for the different market areas per analysed scenario (in EUR/h)

Scenario Symbol	TSO A	TSO B	TSO C	TSO D	Total Income [EUR/h]	Average Congestion Frequency [p.u.]	Total Congestion Revenue [mil. EUR]
STC	223,23	222,39	712,79	404,9	1563,3	0.35	4.8
R4	245,86	246,62	861,52	518,3	1872,3	0.4	6.6
R5	289,50	332,22	1200,5	761,08	2583,3	0.3	6.8

With the TLCP key a higher portion of the congestion revenue is distributed to TSOs who performed the investment (TSO C and TSO D). One characteristic of the TLCP key is that it allocates congestion revenue to TSOs (and hence grid customers) in proportion to their contributions to enabling transfers, considering the underlying flow-based clearing process. As it is shown in Table 3, if the first investment is to be undertaken, total congestion revenue would increase from 1563 EUR/h to 1872 EUR/h. In the second reinforcement cases, total auction revenue would reach the level of 2583 EUR/h. Additionally, it should be observed that the main problem is congestion occurrence in the region. Namely, with both proposed investment occurrence of congestion in the region has decreased up to 30% (Table 3), although the total congestion revenue on the yearly level has increased for almost 2 mil. EUR per year.

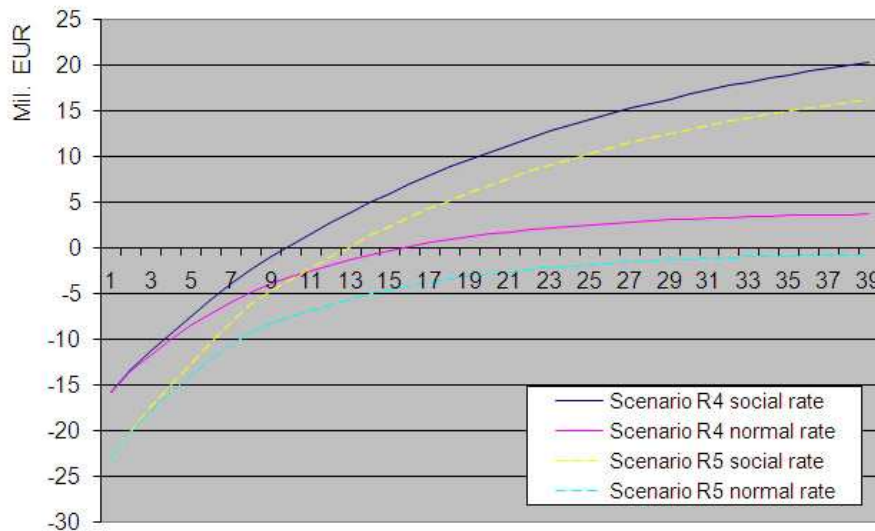


Fig. 4 Accumulated present value for scenarios R4 and R5 (with social and normal discount rate). Both investments are undertaken by neighbouring TSOs C and D, and as they are related to tie-line projects, costs are shared on a 50:50 basis. After the commissioning of the new tie-line,

congestion revenue on the regional level has been increased, especially for the TSOs which are undertaking the investment.

In order to compare different alternatives, Figure 4 shows the trend of the accumulated present value for two proposed investments and two different set of assumptions (social discount rate of 4% and normal discount rate of 10%). All scenarios, with the exception of Investment R5 with the normal discount rate, break within 15 years, and the Investment R4 with the social discount rate needs 9 years to recover the costs.

## CONCLUSION

In this paper a centralised transmission cost-benefit planning concept based on a flow-based capacity allocation model has been presented. In the model congestion revenue is collected on a regional level and shared among TSOs using the agreed sharing key. Regional transmission expansion planning is performed in order to recognise the critical point in meshed grid in regard to regional social welfare. Such a concept could support a supranational decision making process which would help in creation of internal electricity market (IEM) in Europe. The investment decisions in new power plants are taken decentralised by different market participants. Therefore, a clear indication of such decisions would support the coordinated decision about the transmission network expansion.

## References

1. Vukasovic M., Apostolovic M. (2009). A line-wise ("maximal flow") method for the allocation of physical transmission rights and its influence on physical and financial firmness, EEM-6th International Conference on European Electricity Market.
2. Regulation (EC) No 1228/2003 of the European parliament and of the council on conditions for access to the network for cross-border exchanges in electricity.
3. Bajs D., Majstorovic M., Majstorovic M., Planiranje razvoja prijenosne mreze u trzisnim okolnostima (probabilisticki pristup).
4. Gustafsson K., Nilsson M. (2008), Transparent methods to support infrastructure investments, EEM - 5th International Conference on European Electricity Market.
5. Bushnell J., Stoft S. (1996), Grid Investment: Can a Market Do the Job, The Electricity Journal (Elsevier), Volume 9, Number 1, pp. 74-79(6).
6. Verma A., Pradeep R. B., Panigrahi B. K., Transmission Network Expansion Planning with Security Constraints and Uncertainty in Load Specifications, International Journal of Emerging Electric Power Systems: Vol. 9 : Iss. 4, Article 6.