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RESEARCH ARTICLE

Total Transfer Capacity Calculation with Consideration of Reactive Power Constraints

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Abstract
In spite of the benefits of the implementation of the power market, the biggest threats for the security and safe working of power grids still rests in the congestions of cross-border lines, as well as the network itself. The occurrence of the congestion is a result of the limited network transfer capacities that are result of increased power transactions. There are other measures that can mitigate the congestion, but still it is a problem and cancelling or lowering the power transactions should be no solution. This problem arises from the assumptions and simplifications made in the methodologies for total transfer capacity calculation which reflects to unreal cross-border capacities. In this paper, we propose an iterative optimization algorithm for a total transfer capacity calculation in case of market-based units, which consider the reactive power flow and all the constraints that, comes forward. The results and the conclusion that shall be presented in this paper are made on the IEEE test network, RTS_96.

Keywords
Power system, total transfer capacity

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1 Introduction

More than thirty years ago, started the process of liberalization of the electricity market. About twenty years ago European Union started a union wide process with the intention to create Internal Electricity Market. As expected, the main motivation to introduce the power markets was to increase the competitiveness of the power sector, reducing the prices, attracting new investments and developing new efficient technologies.

The benefits of the implementation of the power market are obvious, but the biggest threats for the security and safe work of the power grids still rest in the congestions of cross-border lines as well as the network itself. The occurrence of the congestion is a complex problem that derives from the limited network transfer capacities which comes forward by increased power transactions, as a cheaper generation gain the advantage and the methodology for cross-border capacity calculation. Therefore, the network congestion threats power transactions to be cancelled or lowered and that is not a solution in the liberalized power market. To sort-out this problem, auxiliary services measures were introduced as an apparatus to lower the consequences in case of congestion. Nevertheless, there are still technical challenges in the methodology for cross-border capacity calculation in a market based environment [1] that need to be solved.

From technical aspect, this problem arises from the assumptions and simplifications in the methodologies for total transfer capacity calculation which reflects to unreal cross-border capacities merely to get results in real-time even in case of large systems. The Available Transmission Capacity (ATC) is defined as a part of the Net Transfer Capacity that remains available after each phase of allocation procedure, for further commercial activity. The ATC is given by the following equation, [2]:

$$\mathrm{ATC} = \mathrm{NTC} - \mathrm{AAC} = \mathrm{TTC} - \mathrm{TRM} - \mathrm{AAC}, \qquad (1)$$

where NTC is the Net Transfer Capacity, AAC is the Already Allocated Capacity, and TTC is the Total Transfer Capacity and TRM is the Transmission Reliability Margin.

Computation of the ATC should be considered as a limit imposed by the system components, the thermal line limits, bus voltage limits and stability limit, as well as load forecast uncertainties. In addition, the methodology for calculation of TRM, indirectly affects the final result in (1).

In the beginning deterministic approach was favoured, and to acquire fast results in real-time for ATC, DC model was used as a simple and fast solution [9, 12, 13]. One of the deficiencies of this approach was a result of the assumptions and simplifications of the network model that were leading to unreal ATC values. For more accurate computations the AC model was introduced. Another approach for the ATC computation was introduced by the continuous power flow (CPF) algorithm, that trace the power flow solution, starting at the base load and leads to a steady-state voltage stability limit or critical maximum loading point of the system. The CPF overcomes the possible singularity of the Jacobian matrix, but on other hand, it involves complex parameterization, predictor and corrector factors [3]. The Monte-Carlo method also could be used for computation of the ATC as a representative of probabilistic methods [4]. Another technique of getting results that are more accurate is by applying the optimization method (OPF) in the procedures of obtaining ATC. In all, all well-known methods have their positive and negative sides but somehow the OPF-based methods might be the most promising for computation of the ATC's values.

In this paper, an algorithm based on the OPF linear programming is introduced with consideration of reactive power flow and all the constraints that follow to sustain system's stability in case of market based units (generators). The proposed algorithm provides solutions in cases, when for a network set point we would like to utilize as much as possible cross-border line capacities.

This paper is organized as follows. In Section 2, the formulation of the problem is introduced and followed by the system's constraints, as in Section 3 the network model is presented. In Section 4, the proposed algorithm is introduced as well as the results from the applied methodology. The Conclusion is given in Section 5.

2 Problem formulation

For clarity reasons let us classify the nodes into three categories: source nodes, sink nodes and other nodes. Source nodes are the generators that shall increase their generation while sink nodes are the generators that shall decrease theirs. Other nodes are the generators that shall retain their generation unchanged. We need to highlight that loads and generators could be connected at same node, but only generators can shift their power in the market-based environment. In case of power market targeted generators, the generators are able to shift their active power in both directions (increase and decrease) appropriately of their cost.

Let us assume that TTC calculations are made for a given network set point, for which the system has sufficient large stability margin that provides system voltage stability. In the process of generation shifting, limits as power generation, thermal branch and bus voltage limits must not exceed set limits.

Mathematical formulation of the TTC problem is expressed by the following equation:

$$TTC = \max \sum_{i=1}^{ng} x_i, \tag{2}$$

where, x_i is the active power injection change for generator i; ng is the number of generators that can change their production.

In market based systems, the computation of the TTC should be related to generation costs, as well. In the network model (Section 3), along with the generation cost curves represented with the second order polynomials, the optimization problem is simplified to a quadratic program [15], with linear constraints and quadratic cost function (2). With this in mind, the mathematical formulation of the problem (2) can be redefined as

$$TTC = \min \sum_{i=1}^{ng} \left(a_i \cdot P_i^2 + b_i \cdot P_i + c_i \right). \tag{3}$$

The active power generation of generator i is denoted by P_i, while its generation costs are represented by a_i, b_i and c_i. While generators change their generation, the system must stay stable and operate without violation of the constraints. The first constraint that imposes from power generation shifts (decision variables) is defined as

$$SG\min_i \le SG_i \le SG\max_i, \quad i = 1,\ldots,ng, \tag{4}$$

where SG_i is the apparent power generation, whereas $SG\min_i$ and $SG\max_i$ are the respective lower and upper generation limit of generator i. The Equation (5) may be rewritten as

$$PG\min_i \le PG_i^{(0)} + x_i \le PG\max_i, \quad i = 1,\ldots,ng, \tag{5}$$

$$QG\min_i \le QG_i^{(0)} + y_i \le QG\max_i, \quad i = 1,\ldots,ng. \tag{6}$$

$PG\min_i$ and $PG\max_i$ are the minimum and maximum active power generation limits and $PG_i^{(0)}$ is the base case active power generation of generator i. Similar notation applies to the reactive power generation. If we express generator's apparent power by its power factor, the base case active power and the generation shifting, Equation (5) could be rewritten in a matrix form as

$$\left[SG\min \cdot \cos\varphi - PG^{(0)} \right] \le x \le \left[SG\max \cdot \cos\varphi - \mathrm{PG}^{(0)} \right], \tag{7}$$

where x is the vector-column of generation shifts for the generators which are included in power transactions.

$$x = \begin{bmatrix} x_A \\ x_B \end{bmatrix} = \Delta P_{TOTAL} \cdot \begin{bmatrix} \alpha_1^A \\ \vdots \\ \alpha_{nA}^A \\ -\alpha_1^B \\ \vdots \\ -\alpha_{nB}^B \end{bmatrix}, \sum \alpha_A - \sum \alpha_B = 0 \begin{cases} x_A \ge 0 \\ x_B \le 0 \end{cases}. \tag{8}$$

In their final form, all constraints shall be expressed in accordance to the active power generation shifting.

In term of the power flow direction, for each branch, we define starting node as *from* and ending node as *to*, denoted as f and t, respectively. For each branch-end, the branch constraints are expressed as

$$\begin{aligned} -PB\max_k^f \le PB_k^{(0),f} + \Delta PB_k^f \le PB\max_k^f, \quad k = 1,...,nb \\ -PB\max_k^t \le PB_k^{(0),t} + \Delta PB_k^t \le PB\max_k^t \end{aligned}, \tag{9}$$

where $PB_k^{(0),f}$ and $PB_k^{(0),t}$ are the branch active power flows in the base case for branch k, ΔPB_k^f and ΔPB_k^t are changes in the branch active power flows, $PB\max_k^f$ and $PB\max_k^t$ are the branch active power flows limits at both branch ends respectively and nb is the number of lines.

The limits for the branch active power flows are calculated using the base case solution and MVA branch limits in the following way

$$\begin{aligned} PB\max_k^f = \sqrt{\left(SB\max_k\right)^2 - \left(QB_k^{(0),f}\right)^2} \\ PB\max_k^t = \sqrt{\left(SB\max_k\right)^2 - \left(QB_k^{(0),t}\right)^2} \end{aligned}, \tag{10}$$

where $PB\max_k^f$ and $PB\max_k^t$ are the branch k MVA limits, $QB_k^{(0),f}$ and $QB_k^{(0),t}$ are the branch k reactive power flow in the base case at both ends, respectively. If we introduce the PTDF matrix for the active (HGP) and the reactive (HGQ) power generation (Section 3), we could express the branch constraint in terms of the generation shifting as

$$\begin{aligned} & -PB\max_k^f - PB_k^{(0),f} \le \left(HGP + HGQ \cdot tg\varphi\right) \cdot x \le \\ & \le PB\max_k^f - PB_k^{(0),f}, \\ & PB\max_k^t + PB_k^{(0),t} \le \left(HGP + HGQ \cdot tg\varphi\right) \cdot x \le \\ & \le -PB\max_k^t + PB_k^{(0),t} \end{aligned}. \tag{11}$$

By doing so, we take into consideration the effect of the branch reactive power flow as it is neglected in many cases [4]-[8]. To sustain the system stability during the generation shifting, the nodes voltage must be in the defined limits as it is an essential system voltage stability not to be affected. The node voltage constraint is given by

$$U\min_j \le U_j \le U\max_j, \quad j = 1,\cdots,nj, \tag{12}$$

where $U\min_j$ and $U\max_j$ are the lower and the upper node voltage boundary for a given node j and nj is the number of nodes in the network. If we acknowledge the sensitivity of the bus voltage from the reactive power shifting, the constraint expressed by (12) could be rewritten in a matrix form as

$$\begin{aligned} & \left[U\min - U^{(0)}\right] \le Cg \cdot y \le \left[U\max - \mathrm{U}^{(0)}\right], \\ & Cg = -\left[Fdg\right]^{-1} \cdot tg\varphi \end{aligned}, \tag{13}$$

where Cg is the diagonal sensitivity matrix in terms of the reactive power generation shifting y. Fdg is the matrix with dimension nj x ng and its elements represents the nodes voltage change in accordance to the reactive power generation shifting and $tg\varphi$ is the diagonal matrix formed by the power factors of generators which are involved in the power transaction.

3 Network model

In general, differing on the network model, two classes of transmission network models are used. The AC model is the "accurate" power flow model, where all network peculiarities are taken into account. With this model, the voltage magnitudes and angles as well as the active and the reactive power flows are obtained. On the other hand, the approximate DC model takes into account only the voltage angles and the active power flows. The main advantage of the DC model include non-iterative approach, which is reliable, gives unique solutions with acceptable accuracy for heavily loaded branches that might constraint the system operation and simple and efficient optimization procedures [14].

In this paper, we use the standard AC power flow. Net active and reactive power injections in node j are

$$P_j = U_j \cdot \sum_{m=1}^{nj} \left[U_m \cdot \left(G_{jm} \cdot \cos\theta_{jm} + B_{jm} \cdot \sin\theta_{jm}\right)\right], \tag{14}$$

$$Q_j = U_j \cdot \sum_{m=1}^{nj} \left[U_m \cdot \left(G_{jm} \cdot \sin\theta_{jm} - B_{jm} \cdot \cos\theta_{jm}\right)\right], \tag{15}$$

where U denotes voltage magnitude and θ_{jm} is the difference in the voltage angles of the nodes j and m; and G and B denote real and imaginary elements of the Y bus matrix. To achieve linearization of the optimization model, we use the assumptions of the standard fast-decoupled load flow model [16].

It should be noted that nodal power injections increments occur only at generator nodes, since only the generators that are eligible for power transactions can shift their generation. Consequently, from (14) and (15), the perturbed system for a set of independent nodes is represented by two sets of linear equations, represented in matrix form as

$$\Delta P = E \cdot \Delta\theta, \tag{16}$$

$$\Delta Q = F \cdot \Delta U, \tag{17}$$

where E and F are the sensitivity matrices, while $\Delta\theta$ and ΔU are the voltage phase angle and the voltage increments, respectively [10]. The general equations for the active and the reactive power flows in the branch that directly connects the nodes j and m respectively, are

$$\begin{aligned} PB_{j-m} = U_j^2 \cdot G_{j-m} - U_j \cdot U_m \cdot \\ \cdot\left(G_{j-m} \cdot \cos\theta_{jm} + B_{j-m} \cdot \sin\theta_{jm}\right) \end{aligned}, \tag{18}$$

$$QB_{j-m} = -U_j^2 \cdot \left(B_{j-m} + B_j^{sh}\right) - U_j \cdot U_m \cdot \\ \cdot \left(G_{j-m} \cdot \sin\theta_{jm} - B_{j-m} \cdot \cos\theta_{jm}\right) \quad (19)$$

By applying the assumptions in [16], (18) and (19) can be written in matrix form as [10]

$$\Delta PB = D \cdot \Delta\theta, \quad (20)$$

$$\Delta QB = H \cdot \Delta U. \quad (21)$$

Since the network model is linear, it yields linear sensitivities of the branch flows to change in the node power injections [10] and [14]. These sensitivities are packed in a matrix called PTDF. If we express voltage and voltage-phase angle increments from (16) and (17), (20) and (21) can be expressed in terms of the generator's active power shifts, as

$$\Delta PB = HGP \cdot x, \quad (22)$$

$$\Delta QB = HGQ \cdot tg\varphi \cdot x, \quad (23)$$

where ΔPB and ΔQB are the active and reactive branch power flow increments as a result of the active power generation shifting respectively, HGP and HGQ are the active and reactive generation PTDF matrices respectively, $tg\varphi$ are the power factors of generators that are involved in the power transaction. The concept of the PTDF matrix is well explained in [10].

4 Proposed algorithm and results

The proposed algorithm is based on the OPF linear programming code packed in a suitable form for the program package MATPOWER. Figure 1 depicts the algorithm, which is comprised of five steps.

Step 1: Reads the input file and makes routine checks for input errors.

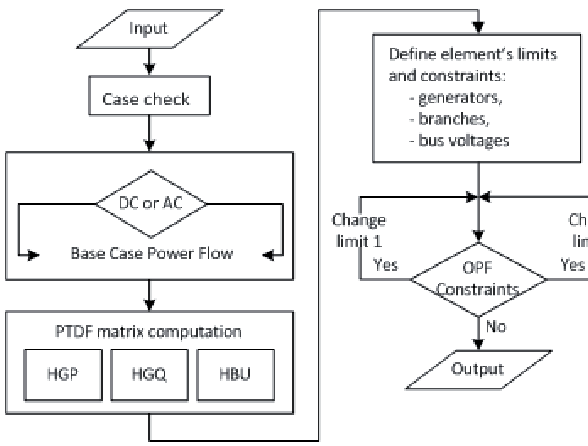

Fig. 1 Principle schematics of proposed algorithm

Step 2: AC power flow for the base case scenario is calculated. Furthermore, the correction procedure for zonal power losses is implemented under the assumption that every zone needs to cover its own power losses. The base case exchange procedure, base case cost analyses are administrated as well as the base case solution check

Step 3: for determining shifting limits (capabilities) for the generator's active and reactive power, the branch free space and the node voltages are performed.

Step 4: Procedure for non-linear constraints runs before optimization. Global limits are defined, as the total generation active power shifting shall be in these limits. At the beginning, the lower limit is set to zero and the upper limit is set to the total sum of the generator's active power shifting reserves. These limits shall change with the optimization process as we are nearing to the global solution during optimization. The global solution is obtained in few iterations. During the iterations, every solution is checked by the AC power flow and correction steps are made in the constraints as a result of the reactive power. In addition, correction procedures for zonal power losses, exchange procedure, cost-function as well as global limits correction procedure, are implemented. As a global solution is reached, no constraints shall be violated and the system's security shall not be impaired (compromised). The optimization problem defined with (3) associated by (7), (8), (11) and (13) is solved using the MATPOWER's active-set solver (QUADPROG) implemented in the Matlab code, derived from the MEX implementation of the corresponding algorithms in [17].

Step 5: After the optimization process, the output data is sublimated in a proper output file.

For testing purposes, the IEEE RTS 96 test network was used. The IEEE RTS-96 is able to provide a single-area, two-area, and three-area configurations. The full system consists of 73 buses, 120 branches, and 96 generating units with a total generating capacity of 10 215 MW (3 405 MW in each area) for a system peak load of 8 550 MW (2 850 MW in each area), [15]. For an easier network losses allocation, we added a fictitious zone. This zone consists of a single node (generator) that represents the global slack bus. Based on a previous statement in this paper, that every zone needs to cover its own zonal losses, practically the active power generation in this fictitious zone should be zero. The value at this fictitious node represents the precision of applied algorithm. The global slack bus is connected to the original slack bus, by a branch with very low (practically zero) impedance, so it does not affect real power flows of the test network.

Results from base case calculations are presented in Table 1. For each zone, total generation, load and losses are given as well as zone export/import active power. Exchanges between each zone, calculated before correction procedure, are shown in Table 2. The total exchange in the base case between the zones is 11.9 MW without zone 4, as the purpose of the fourth zone is to cover total system's power losses.

Generators 1, 2, 7, 13, 14, 15, 16, 18, 21, 22 and 23 in zone 1 and generator 74 in zone 4 are export generators, while generators 25, 26, 31, 37 and 39 in zone 2 and generator 71 in zone 3 occurs are import generators.

Table 1 Results for AC Base Case Scenario (in MW)

Zone	Generation	Load	Losses	Export/Import
1	2653.4	2565	33.5	88.4
2	2360.6	2565	55.5	–204.3
3	2680.9	2565	53.5	115.9
4	142.5	0	0	142.5

Table 2 Exchanges Between Zones in Varouse Scenarious (case 1, case 2 and case 3) (in MW)

Scenario	Zone exchange				Total
	1-2	1-3	2-3	1-4	
DC base case	8.0	80.4	–196.3	0	–107.9
DC Case 1	250.0	250.0	–215.8	0.3	284.2
AC base case	74.4	122.9	–185.4	0	11.9
AC Case 2	173.2	245.1	–175.8	–0.1	242.5
AC Case 3	129.4	179.7	–208.5	0.2	100.6

Table 3 Active Power Generation Cost in Varouse Scenarious (in Currency Units)

	DC base case	DC Case 1	AC base case	AC Case 2	AC Case 3
Cost	237 346	228 754	240 767	238 573	239 691
Benefit	–	8 592	–	2 194	1076

The functionality of the algorithm was tested on the IEEE RTS_96 test network using both DC and AC load flows, and with and without taking into consideration the impact of reactive power flows. In case of the DC load flow (case 1) the number of constraints is 238. After the optimization, the increase of generation at source nodes is 411.6 MW, while the decrease of generation at sink nodes is –411.6 MW, which results in increase of total exchange between zones of by 392,1 MW (from –107,9 MW to 284.2 MW). The generation costs in various scenarios are given in Table 3.

In case of AC load flow without taking into consideration the reactive power constraints of the generators (case 2), the number of constraints is 476. In this case, after the optimization, the increase of generation at source nodes is 274.5 MW, while the decrease of generation at sink nodes is –274.5 MW, which results in increase of total exchange between zones of by 230.5 MW(from 11,9 MW to 242,5 MW) The optimal solution was obtained in three iterations. In addition, the algorithm was tested taking into consideration constraints related to reactive power – generator var limits and voltage constraints (case 3). The number of constraints in this case is 624. After the optimization, the increase of generation at source nodes is 167.4 MW, while the decrease of generation at sink nodes is –167.4 MW, which results in increase of total exchange between zones of by 88.6 MW (from 11.9 MW to 100.5 MW). The optimal solution was obtained after seven iterations.

Generation cost data for active power were taken from IEEE RTS_96. The advantage of taking the reactive power constraints are perceived in more accurate computation of total transfer capacities of interconnected lines. In such cases, it is possible to avoid possible congestion appearance, which shall cause to lower/cancel power transactions.The benefits of taking reactive power flows in the TTC calculations are recognized in more accurate TTC values, avoid possible congestion, indirect financial benefits, etc.

5 Conclusion

In this paper, we propose an iterative optimization algorithm for total transfer capacity calculation that can be used market driven power systems. The algorithm considers reactive power flows and all related constraints. The algorithm is based on OPF linear programming, which provides global solution for a given network configuration in case to realize additional power transactions. This is done in such manner by using network linear model, supplemented with consideration of reactive power flow. Taking reactive power flows into consideration, as constraints in the optimization procedure, we are able to obtained more accurate total transfer capacities of the interconnected lines and in that manner to prevent possible congestions in the network. By this we gain indirect financial benefit as we are able to prevent possible congestion which shall reflect by lowering/ cancelling power transactions. In this case, we have used large testing network for obtaining the results of implemented algorithm, which in most cases the proposed methods offers a smaller problem size and faster calculation times.

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