Indian Journal of Science and Technology Vol. 5 No. 2 (Feb 2012) ISSN: 0974- 6846

New approach to congestion mitigation based on incidence matrix DCOPF

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Abstract

An incidence matrix approach for mitigating congestion in transmission network is presented in this paper. Based on this methodology, all congested power transmission lines is identified and main economical signals for investment planning is introduced. In this method, we can determine strong and weak transmission corridors in the network. The Flexible AC Transmission System (FACTS) device has been applied to enhance the controllability of power systems. New generations of FACTS device called Distributed FACTS such as distributed series impedance or distributed static series compensator have recently received increasing interests for power system control and are expected to be broadly deployed. This paper presents a detailed formulation and algorithm to find the best location and size of D-FACTS to achieve the optimal utilization of transmission capacity to mitigate congestion. This approach can be applied in market simulation and planning owing to its robustness and speed. Unlike, previous admittance based matrix methodologies, which solidly depended on the network topology, independency of network in the presented approach; it would be an effective tool for long-term expansion planning criteria or implementing D-FACTS devices in modern power systems. The simulation results show that the presented method is both satisfactory and consistent with expectation. Simulation results are presented with the PJM 5-bus system to illustrate the capabilities of presented approach in compression with previous works.

Keywords: Incidence Matrix, DCOPF, Congestion Management, D-FACTS.

Introduction

Restructuring the electricity industry typically consists of a series of reforms. Vertical disintegration of generation, transmission, distribution, and retail businesses is accompanied by the introduction of a spot market for generation. Typically, transmission and distribution remain regulated activities and rules governing open access to the transmission and/or distribution systems are implemented in order to facilitate entry by new power generators and/or retailers. Up until now, all experiences with restructured electricity markets show that electricity trading may give rise to highly volatile prices. This issue is intrinsic to electricity as a flow commodity, which cannot be economically stored. To accommodate for real-time balancing, day-ahead price formation is complemented with successive transactions or settlements for required adjustments on real-time operations. Since electrical energy is not economically storable, restructured electricity markets are more complex than the traditional commodity markets. Hence, existing economic models of price formation in commodity markets are not applicable. Moreover, the high levels of industry concentration make the occurrence of strategic behavior almost inevitable. In light of these features, theoretical economic analyses have tended to be based upon highly stylized models. Power engineers have sometimes criticized these economic models, because they fail to take into account non-trivial features such as loop-flow and reactive power. Nonetheless, these simplified models have been very useful for guiding regulatory policy-making (Momoh & Mili, 2010).

Recent developments in power system restructuring have heightened the need for a robust and strong market analyzer to manage the power market. In recent years, there has been an increasing interest to introduce precise and comprehensive tools to overcome the market challenges. DC-Optimal Power Flow (DCOPF) is an important tool in the power system analysis, and plays a key role in economic evaluation of recent power market. Conventional DCOPF methodologies all based on the admittance matrix approach which is an ordinary ones to analyzing power network. However, a major problem with traditional admittance matrix based DCOPF is modeling of parallel transmission lines and multi generating units. Another problem with the admittance matrix approach is that it fails to take modeling of reliability studies, such as outages of parallel transmission lines in an identical corridor or outages of one or more aligned generating units, into account.

With modern power system analysis software, determining that a set of transactions would make the operation of the system insecure can be computationally demanding, but is conceptually simple. Deciding which transactions should be curtailed to maintain the required level of security is a much more complex question. Administrative procedures can be established to determine the order in which transactions should be cut back. Such transmission load relief procedures take into account the nature of the transactions (firm or non-firm), the order in which they were registered with the system operator and possibly some historical factors. They do not, however, factor in the relative economic benefits of the various transactions because a decentralized trading environment does not provide a framework for evaluating these benefits. Administrative curtailments are therefore

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economically inefficient and should be avoided (Kirschen & Strbac, 2004).

One of the most important criteria of recent restructured power system is congestion management. Congestion is said to occur in a power system whenever the system state of the grid is characterized by one or more violations of the physical operational or policy constraints under which the grid operates in the normal state or under any one of the contingency cases in a set of specified contingencies (Christie *et al.,* 2000; Bompard *et al.,* 2003). In other words congestion occurs when the transmitted power exceeds the capacity or transfer limit of the transmission line or transformer. Congestion, needless to say, is undesirable. A system without congestion will have a uniform price (in nodal pricing). As soon as we have congestion, prices obtaining in different areas will be different. Congestion therefore distorts the market. Another disadvantage of congestion is increased risk of market manipulation by some participants (Lommerdal & Soder, 2003; Mwanza *et al.,* 2007).

Congestion in the transmission lines is one of the technical problems that appear particularly in the deregulated environment. There are two types of congestion management methodologies to relieve it. One is non-cost free methods and another is cost-free methods, among them later method relives the congestion technically whereas the former is related with the economics. In this paper congestion is relieved using cost free methods. Using FACTS devices, congestion can be reduced without disturbing the economic matters (Reddy *et al.,* 2006).

Applications of new enabling technologies are able to provide solutions for electricity companies to maintain the stability and reliability of power systems while handling large volumes of transactions. One example of such enabling technologies is FACTS controllers. Installations of FACTS controllers on transmission networks have been recognized as one of the cost-effective solutions for network congestion management. It is anticipated that the applications of FACTS controllers will grow in power systems of the future, particularly in the deregulated electricity market environment. The ability of FACTS controllers to control the power flow of electricity transmission networks is well known. The use of FACTS controllers is advantageous as numerous environmental concerns restrict opportunities for network reinforcement through new transmission line construction. Congestion management has become an important issue for Transmission System Owners (TSO) since the deregulation of electricity markets and the increased penetration of renewable power particularly wind power within transmission networks. Efficient congestion management has become more difficult and complex to achieve than in previous decades because of the reality of finite energy resources, the influence of environmental concerns, and policies that prevent the construction of new generating stations and transmission lines together with the investment cost constraints (Zhang *et al.,* 2007; Besharat & Taher, 2008).

A method to determine the congestion mitigation has been suggested in this paper. The approach is based on the incidence matrix DCOPF. This dissertation follows a case-study simulation, with in-depth analysis of multi generating units and also considers parallel transmission lines to illustrate the applicability and robustness of incidence matrix approach in power system and power market analysis.

Materials and methods

When the transmission becomes congested, meaning that no additional power can be transferred from a point of injection to a point of extraction, more expensive generating units may have to be brought on-line on one side of the transmission system. In a competitive market, such an occurrence would cause different locational marginal prices (LMPs) between the two locations. If transmission losses are ignored, a difference in LMPs would appear when lines are congested. Conversely, if flows are within limits (no congestion) LMPs will be the same at all buses and no congestion charges would apply. The difference in LMPs between the two ends of a congested line is related to the extent of congestion and MW losses on this line. Since LMP acts as a price indicator for both losses and congestion, it should be an elementary part of transmission pricing (Shahidehpour *et al.,* 2002).

The locational marginal pricing is a dominant approach in energy market operation and planning to identify the nodal price and to manage the transmission congestion LMP has been implemented under consideration at the number of ISO's such as PJM, New York ISO , ISO-New England, California ISO, and Midwest ISO (PJM, 2005).

Locational marginal prices may be decomposed into three components: marginal energy price, marginal congestion price, and marginal loss price (Shahidehpour *et al.,* 2002; Stoft, 2002; Li & Bo, 2007). The LMP can be calculated by the Optimal Power Flow (OPF) and DCOPF-based simulations. The DCOPF has been used by many utilities for price forecasting and system planning (Li & Bo, 2007; Davari *et al.,* 2008).

In many paper LMP calculated as a deterministic variable (Li & Bo, 2007). Considering the uncertainties associated with the input data of load flow, the LMP can be considered as a stochastic variable. Therefore calculation of LMP as a random variable can be very useful in power market forecasting studies (Davari *et al.,* 2008).

Other method is Point Estimation Method (PEM) (Su, 2005; Davari *et al.,* 2008). This method used two or more point to calculate mean and variance of desired variable and estimate PDF and CDF of this variable. Point Estimation Method (PEM) has lack of accuracy although has a good speed. It can be seen that the results of point

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estimation method in (Davari *et al.,* 2008) have a few differences from deterministic calculation .

Several earlier works (Liu & Zobian, 2002; Ramos *et al.,* 2003; Li *et al.,* 2004; Litvinov *et al.,* 2004; Zhu *et al.,* 2005) have reported the modeling of LMPs, especially in marginal loss model and related issues. Reference (Liu & Zobian, 2002) points out the significance of marginal loss price, which may differ up to 20% among different zones in New York Control Area based on actual data. Reference (Litvinov *et al.,* 2004) presents a slack-bus-independent approach to calculate LMPs and congestion components.

Reference (Zhu *et al.,* 2005) presents a real-time solution without repeating a traditional power flow analysis to calculate loss sensitivity for any market-based slack bus from traditional Energy Management System (EMS) products based on multiple generator slack buses. Reference (Ramos *et al.,* 2003) demonstrates the usefulness of dc power flow in calculating loss penalty factors, which has a significant impact on generation scheduling. The authors of (Ramos *et al.,* 2003) also point out that it is not advisable to apply predetermined loss penalty factors from a typical scenario to all cases. Reference (Li *et al.,* 2004) presents LMP simulation algorithms to address marginal loss pricing based on the dc model.

From the viewpoint of generation and transmission planning, it is always crucial to simulate or forecast LMPs, which may be obtained using the traditional production (generation) cost optimization model, given the data on generation, transmission, and load (Wood & Wollenberg, 1996; Stoft, 2002). Typically, dc optimal power flow (DCOPF) is utilized for LMP simulation or forecasting based on production cost model via linear programming (LP) owing to LP's robustness and speed. The popularity of DCOPF lies in its natural fit into the LP model. Moreover, various third-party LP solvers are readily available to plug into DCOPF model to reduce the development effort for the vendors of LMP simulators (Li & Bo, 2007).

LMP Formulation

Earlier studies of LMP calculation with DCOPF ignore the line losses. Thus, the energy price and the congestion price follow a perfect linear model with a zero loss price. However, challenges arise if nonlinear losses need to be considered in LMP calculations.

The lossless DCOPF can be modelled as the minimization of the total production cost subject to energy balance and transmission constraints. The voltage magnitudes are assumed to be unity and reactive power is ignored. Also, it is assumed that there is no demand elasticity. This model may be written as LP:

$$Min \sum_{i=1}^{NB} \sum_{ug=1}^{NU} [P(i,ug)*C(i,ug)] \qquad (1)$$

Subject to:

$$PG(i) = \sum_{ug=1}^{NU} P(i,ug) \qquad (2)$$

$$PD(i) = \sum_{ud=1}^{ND} D(i,ud) \qquad (3)$$

$$PG(i) - PD(i) = \sum_{j=1}^{NL} A(i,j)*PL(j) \ \perp \ \lambda(i) \qquad (4)$$

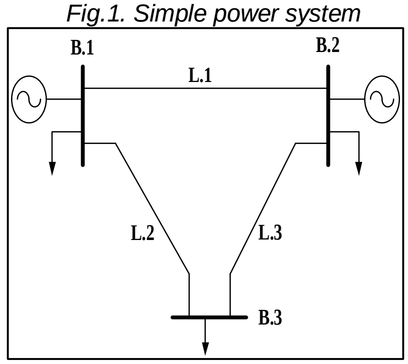
$$\sum_{i=1}^{NB} A^T(i,j)*\delta(i) = \sum_{j=1}^{NL} X(j,j)*PL(j) \qquad (5)$$

$$PL^{\min}(j) \le PL(j) \le PL^{\max}(j) \qquad (6)$$

$$P^{\min}(i,ug) \le P(i,ug) \le P^{\max}(i,ug) \qquad (7)$$

Aggregated generation and demand at each bus are represented in (2) and (3), respectively. Generation and demand balance addressed in (4) by implementing the incidence matrix, this equation corresponds with injection power through power transmission lines connected to bus *i*. Locational marginal price is the dual variable of the balance constraint at bus *i* and indicated as λ(i). Power transmitted through transmission lines is indicated as (5) using correspondence diagonal reactance matrix, X. Constraints (6) and (7) enforce the transmission capacity limits of each line and each generation unit, respectively.

Fig.1. Simple power system

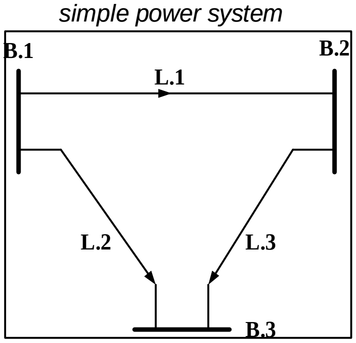


The first step is extracting corresponding incidence matrix of the network. Fig. 1 shows a simple network which consists of three buses and three lines. Each network can be represented as a graph and such a directional graph. Each bus indicated as a node and each transmission line addressed as a directed branch. In the corresponding incidence matrix, nodes and branches indicated as rows and columns, respectively. In the incidence matrix, "1" indicates if branch leaves node, "-1" if branch arrives at node and "0" if no connection.

It should be noted that the mathematical formulation in this paper extends the general formulation of single generator and single load for each bus. Aggregated production and load demand are modeled in this paper. Despite of recent papers which claim that actual implementation can be more complicated considering multiple generators and loads (Li & Bo, 2007), the incidence matrix based formulation ignores both multiple generation units and multiple transmission lines between buses.

It also should be noticed that implementing the incidence matrix methodology eliminates the network interdependencies because of admittance matrix structure in conventional power flow. This approach would be useful in contingency analysis of power network. In contingency analysis it is very important to utilize a fix algorithm and eliminating the topological changes. For multiple generation units which installed in each bus, contingency analysis would be easily carried out, but for transmission line contingencies because of changing the admittance elements but in the incidence matrix formulation this objection has been removed.

Fig. 2. Directional graph of simple power system



The incidence graph is illustrated as Fig. 2, and Table 1 represents the corresponding incidence matrix. The diagonal reactance matrix is easily extracted from grid. For example X (1, 1) indicates the first line, L.1 in the grid. Similarly, X (2,2) and X(3,3) imply L.2 and L.3, respectively.

One of the advantages of this network representation by using incidence matrix is appeared in contingency analysis which outages of both generation units and transmission lines would be modeled easily. For example, when a transmission line outage is occurred, by assigning "0" in line capacity, the entire impacts of corresponding transmission line is eliminated easily.

Table 1. Incidence matrix of simple power network

A(i,j)		Line		
		1	2	3
Buses	1	1	1	0
	2	-1	0	1
	3	0	-1	-1

Table 2. Line impedance and flow limits

Line Number	1	2	3	4	5	6
Connection	AB	AD	AE	BC	CD	DE
R%	0.281	0.304	0.064	0.108	0.297	0.297
X%	2.81	3.04	0.64	1.08	2.97	2.97
Limit(MW)	500	500	500	500	500	240

Case study and Simulation

In order to validate the proposed incidence matrix based LMP calculation, a PJM five bus, six lines test system, which is a standard test case, is considered here. The benchmark parameters are listed in Tables 2 & 3. Demanded load at buses B, C and D, are similarly 300MW. The system is slightly modified from the PJM 5-bus system (PJM, 2005) and will be used for the rest of this paper. Fig. 3.

The system can be roughly divided into two areas, a generation center consisting of Buses A and E with three low-cost generation units and a load center consisting of Buses B, C, and D with 900 MWh load and two high-cost generation units. The transmission line impedances are given in Table 1, where the reactance is obtained from (PJM, 2005) and the resistance is assumed to be 10% of the reactance. Here only the thermal flow limit of Line DE (Line 6) is considered for illustrative purpose.

Table A1. Incidence matrix of PJM 5-bus test system

A(i,j)	1	2	3	4	5	6
1	1	1	1	0	0	0
2	-1	0	0	1	0	0
3	0	0	0	-1	1	0
4	0	-1	0	0	-1	1
5	0	0	-1	0	0	-1

Table A2. Reactance matrix of PJM 5-bus test system

X(j,j)	1	2	3	4	5	6
1	0.0281	0	0	0	0	0
2	0	0.0304	0	0	0	0
3	0	0	0.0064	0	0	0
4	0	0	0	0.0108	0	0
5	0	0	0	0	0.0297	0
6	0	0	0	0	0	0.0297

Table 3. Generation unit's data

Unit	Location	Indication	Pmax	Pmin	Offer
Alta	A	1.1	110	0	14
Park City	A	1.2	100	0	15
Solitude	C	3.1	520	0	30
Sundance	D	4.1	200	0	30
Brighton	E	5.1	600	0	10

Results

Based on previous consideration, LMP of each bus is the dual variable of load balance equation. In this case, total demand is 900MW and installed capacity is 1530MW.

Incidence and reactance matrixes are addressed in appendix Tables A1 & A2 respectively. Summary of load dispatch and line flows are presented in Table 4 and 5, respectively. The results are same as which presented in (Li *et al.,* 2009).

In case 1, we consider the maximum flow of each line is limited at 500MW. LMP and line flows are presented in 6 and 7, respectively.

Case 2 deals with the addressed line flows of real case. The line flow limits are addressed in table 9. Table 8 presents the results of LMP in this case.

Table 4. Generation dispatch results and LMP (Base Case)

Bus	Indication	Generation	LMP
1	1.1	110.000	15.000
	1.2	66.0020	
2	-	-	21.144
3	3.1	0.000	23.506
4	4.1	123.998	30.000
5	5.1	600.000	10.443

Table 5.Transmission line flow (Base Case)

Line Number	1	2	3	4	5	6
Connection	AB	AD	AE	BC	CD	DE
X%	2.81	3.04	0.64	1.08	2.97	2.97
Limit (MW)	500	500	500	500	500	240
Line Flow (MW)	377.318	158.684	-360	77.318	-222.682	240-

Table 6. Generation dispatch results and LMP (Case 1)

Bus	**Indication**	**Generation**	**LMP**
1	1.1	110.00	30.00
	1.2	100.00	
2	-	-	30.00
3	3.1	0.00	30.00
4	4.1	90.00	30.00
5	5.1	600.00	30.00

Conclusion

The test results, especially in Case 1, demonstrate that the proposed formulation and algorithm tends to have each line flow away from their individual limit as much as possible to have a good mitigation of the overall congestion problem. In addition, the optimum solution for the susceptance of each line is in the reasonable region without unnecessary over compensation problem (Li *et al.,* 2009). The proposed Incidence Matrix-Based LMP calculation is simple approach to implementing for large scale power system analysis regardless of time horizon analysis. In short-term analysis, it can be implemented for congestion mitigation. This can reduce the computational effort since it does not require the algorithm to run till convergence. Therefore, it fits a simulation or planning purpose well if the accuracy is reasonably acceptable. The simulation results on the benchmark PJM 5-bus system show the feasibility and applicability of the proposed method in short-term analysis, especially in congestion management. Simulation results also show that the presented method is both satisfactory and consistent with expectation.

Table 7. Transmission line flow (Case 1)

Line Number	1	2	3	4	5	6
Connection	AB	AD	AE	BC	CD	DE
Limit (MW)	500	500	500	500	500	500
Line Flow (MW) (This Paper)	383.911	173.560	-347.470	83.911	-216.089	-252.530
Line Flow (MW) (Li *et al.,* 2009)	356.800	194.870	-375.670	56.800	-243.200	-224.330

Table 8. Generation dispatch results and LMP (Case 2)

Bus	**Indication**	**Generation**	**LMP**
1	1.1	110.00	15.00
	1.2	70.000	
2	-	-	30.00
3	3.1	67.188	30.00
4	4.1	52.812	30.00
5	5.1	600.00	15.00

Indian Journal of Science and Technology Vol. 5 No. 2 (Feb 2012) ISSN: 0974- 6846

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