International Journal of Electrical Energy, Vol. 2, No. 4, December 2014

Preemptive Goal Formulation for the Multi-Objective Generation and Transmission Planning Model in a Deregulated Environment

Enrique B. Cedeno
Nanjing Tech University, Business School, Nanjing, China
Email: ebcedeno@njtech.cn.edu

***Abstract*—Vertically integrated utilities were unbundled after power system deregulation resulting in the ownership of assets and control of relevant planning information resting on different stakeholders. However, long term sustainability and security of supply of power sectors worldwide require some degree of joint efforts towards determining indicative generation and transmission expansion plans for the total system. In this paper this decision making problem is formulated as a multi-objective problem which allows clear identification of deviations from goals and allows trade-offs determination in decision making processes related to energy policies. It is proposed to formulate this problem as a preemptive goal program of weighted deviations. A small test case is presented detailing the proposed procedure. Test results are favorable but there is need for experimentation with problems involving larger networks with more complex and broader feasible space.**

***Index Terms*—power system deregulation, generation and transmission plan, indicative plans, preemptive goal programming, sustainability, security of supply**

I. INTRODUCTION

Deregulation of many electric power systems worldwide involved the unbundling of vertically integrated utilities; these independent companies must still work in a coordinated manner in favor of the sustainability and security of supply of the sector. These aspects involved issues of long term planning and issues of day to day operational management. Unfortunately there is no magical prescription for successful electricity sector reform. Power system failures involving brownouts, blackouts and episodes of load rationing have been reported throughout the years in countries such as Argentina, Brazil, Canada, Colombia, China, India, the U.S. and Venezuela, among others [1]. Empirical evidence suggest that most electric power markets left alone with only electricity price incentives failed to provide enough system capacity to meet all future loads [1], [2]. Then, it seems that despite the degree of deregulation designed in each market some form of integrated planning has been undertaken by an overseeing agency to propose indicative expansion plans.

This paper extends the research presented in [3] by formulating explicitly the decision making problem as a multi-objective problem in which decision variables are now on the hands of different stakeholders with competing interests most of the time. This treatment could allow easier identification of each stakeholder's objective in the decision making process for setting new policies. It is proposed to formulate this multi-objective problem as a preemptive goal programming problem with weighted sum of deficiencies [4]. These deficiencies or deviations from the objectives could be meaningful in energy policy negotiations with different stakeholders to determine possible tradeoffs.

The integrated problem of Generation and Transmission Network Expansion Planning (GTNEP) [3], [5]-[8] presented here has received less attention from researchers than the Generation Expansion Planning (GEP) [2] problem and the Transmission Network Expansion Planning (TNEP) [8] problem separately. This is due in part to the complexity of the problem and in part to the perception that after deregulation planning from these sectors must be done independently. But there is empirical evidence from deregulated power sectors suggesting that some form of integrated planning is used to propose indicative expansion plans [9]-[12]. This paper aims to make a contribution in this area by proposing a mathematical model to address this problem. The discussion presented here continues as follows: section II presents a brief description of the deregulated sector. Section III presents the multi-objective formulation. Section IV describes the approach use to solve the problem by means of a preemptive goal programming formulation with weighted sum of deficiencies. Section V presents a small test case and its formulation according to the proposed model. Section VI gives some concluding remarks.

II. DESCRIPTION OF THE DEREGULATED SECTOR

In many countries electric power deregulation was sold under the premise of price reduction from competition and less intervention from the State. This was the case in the United States and also in some Latin American countries, such as Colombia, Chile and Argentina. In these countries where power deregulation or electricity

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Manuscript received October 5, 2014; revised December 29, 2014.

doi: 10.12720/ijoee.2.4.308-313

liberalization was done with the intention to promote needed investments for infrastructure due to the limited resources from the state, any form of centralized or coordinated planning needs to be approached carefully. However, this author considers that there is scope for some form of indicative integrated expansion plans as suggested for instance by the Capacity Validation Study (CVS) [9], the Upper Midwest Transmission Development Initiative (UMTDI) [10], the CapX2020 [13], [14] study in the US and indicative plans for the energy sector performed in Colombia [15].

The electric power sector was considered a natural monopoly due to economies of scale by avoiding duplicate payments to companies performing the same activities [16]. This sector was highly regulated in the U.S. after the passage of the Federal Power and Public Utilities Holding Company Acts in 1935. In the regulated era the planning environment was very stable, all the relevant information was available to the central planner [17], prices were set by regulators at levels higher than the equivalent competitive prices to guarantee an appropriate rate of return. Technological changes in gas turbines and the deregulation of the gas sector made generation of electricity possible at lower costs [18]. Successful deregulated experiences of other industries in the U.S. and around the world increased the pressure to deregulate the electricity sector. The Public Utilities and Regulatory Policy Act of 1978 (PURPA) created incentives to increase generation from renewable sources which could be sold to vertically integrated utilities. However, competition in generation was limited since new generating companies could only sell to customers in their service territory [18]. Central planning was performed by each vertically integrated utility controlling all assets for generation, transmission and distribution. Generation capacity additions were made to meet the future demands of customers in their service territory. Transmission and distribution planning followed generation expansion planning.

In 1992 some important changes occurred in the electric market in the US and in Colombia which motive different sector reforms. In the US the 1992 Energy Policy Act expanded competitive opportunities by granting generators unregulated entry into the wholesale power energy markets. The Federal Energy Regulatory Commission (FERC) required that vertically integrated companies were unbundled into three independent sectors: generation, transmission and distribution. An open access mandate to the transmission network was also established with no discriminatory pricing rules for all generating companies. Independent System Operators (ISOs) were created in different states to manage transmission assets. Transmission owners were required to transfer the management of their transmission assets to the ISOs. On the other hand, in 1992 the electric sector in Colombia experienced a severe energy crisis due to an extremely dry season causing hydrological generation to be unavailable to cover demand resulting in a lengthy period of load rationing. The political consequences for the government at the time were very high making energy planners risk avoiders favoring over capacity [19]. In 1994, Law 142 opens competition in the provision of public services and Law 143 dictates the fundamental principles, regulatory entities and their competences for the electric market regarding regulation, overseeing and planning roles [20]. The descriptions provided from these two different countries illustrate that sector reforms have changed the way in which expansion planning must be performed since there is no single entity controlling all the relevant information but the system still must work in a coordinated manner since power demand must be in balance with power generation at all times to guarantee security of supply. This paper extends the research developed by the author in this area [3] promoting the use of integrated planning to proposed indicative expansion plans.

III. PROPOSED MODEL

The model presented here takes a macro level systemic approach assuming the position of an independent overseeing agency that acts on behalf of different stakeholders integrating individual planning studies for generation and transmission sectors [9], [10], [12]-[15]. The complexity of this integrated Generation and Transmission Network Expansion Problem (GTNEP) involves every complexity from the Generation Expansion Planning (GEP) problem and from the Transmission Network Expansion Planning problem (TNEP). The GTNEP is a Mixed Integer Non-Linear Programming Problem (MINLP) that involves cross product of decision variables. This non-convex combinatorial problem could have several local minima with the risk of the solution method being trapped in a sub-optimal decision. Author developed in [3], [21] a Constructive Heuristic Algorithm (CHA) that expands simultaneously transmission capacities from several transmission lines to decrease the likelihood of getting trapped in a local minima by jumping the search process to a different neighborhood. A modification from this CHA [3] is used to solve the test case presented here. However a full discussion of the method is beyond the scope of the present paper. There are a variety of methods used to solve the GEP and TNEP problems, such as linear programming, non-linear programming, dynamic programming, mix-integer programming, and heuristic methods [8]. In the formulation presented here the demand is assumed to be a deterministic fixed quantity, price independent and given exogenously. This assumption can be removed to include different scenarios and duration of the peak and non-peak periods as in [22].

The formulation presented below considers only four main components: generation expansion, transmission expansion, generation cost and load curtailment cost. This last aspect determines the main trade-off between adding more capacity and having some unmet demand (i.e. load curtailed). Pollution and environmental impact objectives can be easily added to this formulation. The multi-objective formulation is given in (1)-(4).

Minimize Total Cost Generation Expansion:

$$MinTC_{GE} = Min\sum_{i\in Ns} v_i m_i \tag{1}$$

Minimize Total Cost Generation:

$$MinTC_{Generation} = Min\sum_{i\in Ns} g_i p_i \tag{2}$$

Minimize Total Cost Transmission Expansion:

$$MinTC_{TE} = \sum_{(i,j)\in E} w_{ij}(e^1_{ij} - e^0_{ij}) \tag{3}$$

Minimize Total Cost Load Curtailment:

$$MinTC_{LC} = \sum_{i\in Nd} r_i s_i \tag{4}$$

Subject to:

Power flow equations:

$$\mathrm{B(E)}\ \theta + \mathrm{G(m)} + \mathrm{r} = \mathrm{D} \tag{5}$$

Generation capacity constraints:

$$g_i \le g_i^{\max} \forall i \in N_s \tag{6}$$

Generation capacity constraints for candidate generation nodes:

$$m_i g_i \le m_i g_i^{\max} \forall i \in N_s^a \tag{7}$$

Line flow capacity constrains:

$$\left| f_{ij} e_{ij} \right| \le c_{ij} e_{ij} \tag{8}$$

Line flow capacity constrains for new lines connecting candidate new generation nodes:

$$\left| m_i f_{ij} e_{ij} \right| \le m_i c_{ij} e_{ij}, i \in N_s^a, j \in N \tag{9}$$

where

$$f_{ij} = (\theta_i - \theta_j) B_{ij} \tag{10}$$

Initial line configuration constraints:

$$e^0_{ij} \le e_{ij} \tag{11}$$

Maximum number of parallel lines along lines:

$$e_{ij} \le e^{\max}_{ij} \tag{12}$$

Phase angle Constraints:

$$\theta_i \le \theta_i^{\max} \forall i \tag{13}$$

$$\theta_i \ge \theta_i^{\min} \forall i \tag{14}$$

where

B(***E***): corresponding susceptance matrix for the configuration being studied.

B_{ij}: susceptance of transmission line along line(i,j).

D: demand vector, a vector with element D_i at demand node i and 0 elsewhere.

e_{ij}: number of circuits added along transmission line connecting node i to node j given by $e_{ij} = (e^1_{ij} - e^0_{ij})$.

e^1_{ij}: number of circuits along transmission line connecting node i to node j in the final network configuration.

e^0_{ij}: number of circuits along transmission line connecting node i to node j in the initial network configuration.

f_{ij}: flow along line(i,j).

G(m): Generation vector, a vector with element g_i at generation node i and 0 elsewhere.

m_i: binary variable representing the addition of new generation at node i.

N: total set of nodes.

$\boldsymbol{N}^0$: set of existing nodes.

$\boldsymbol{N}^a$: set of alternative new nodes.

$\boldsymbol{N}_s$: set of supply nodes.

$\boldsymbol{N}_d$: set of demand nodes.

$\boldsymbol{N}_t$: set of transshipment nodes.

p_i: generation production cost at generation node i.

R: artificial generation vector, a vector with element r_i at demand node i with load curtailed and 0 elsewhere.

s_i: load curtailment cost per unit at demand node i.

θ: vector of phase angles at the nodes.

v_i: investment cost of adding new generation at node i.

w_{ij}: cost of adding a circuit along transmission line connecting node i to node j.

Decision variables in the model are of three types:

- Continuous decision variables: θ_i, g_i, r_i .
- Discrete decision variables: e_{ij}
- Binary decision variables: m_i

The proposed formulation is a Mixed Integer Non-Linear Programming Problem (MINLP) since it involves cross product of the decision vectors E and θ in the objective function (3) and in the following constraints (5), (8), and (10). Equation 5 gives the power flow equations which represent the way in which electricity flows along different transmission lines in the grid [23]. Whereas (10) gives the flow along any transmission line as the product of the susceptance of the line and the difference between the phase angles. Binary variables are used in this formulation to represent investments in generation and to restrict the flow from transmission lines until these generation projects are selected. As mentioned earlier additional objectives could be added to this formulation relatively easily. For instance, one could require minimization of pollution emissions from the future expansion in the system. Another objective could be to maximize the injections in the systems from renewable energy sources. Author considers each one of these objectives required independent treatment due to their complexity.

IV. SOLUTION APPROACH

Under preemptive optimization the most important objective is optimized before all others making them constraints in the current problem [4]. Then the second most important is optimized given the optimal solution from the first problem. The process continues until all objectives have been optimized. This approach requires providing feasible bounds for each subsequent objective function that is expressed as a constraint. This bounds could be in some cases set using budgetary constraints (i.e. total expansion cost) or desired service level (i.e. total amount of load curtailed). An alternative process requiring less restrictive assumptions is to use preemptive goal programming with deficiency variables [4]. The objective function for this formulation considering generation expansion is given by (1) rewritten below, adding constraints (2a) to (4a) subject to (5) to (13).

Minimize Total Cost Generation Expansion:

$$MinTC_{GE} = Min\sum_{i\in Ns} v_i m_i \tag{1}$$

Subject to

$$\sum_{i\in Ns} g_i p_i + d_2 \le UBTC_{Generation} \tag{2a}$$

$$\sum_{(i,j)\in E} w_{ij}(e^1_{ij} - e^0_{ij}) + d_3 \le UBTC_{TE} \tag{3a}$$

$$\sum_{i\in Nd} r_i s_i + d_4 \le UBTC_{LC} \tag{4a}$$

This approach still gives generation expansion the most important role as during the times of electricity regulation and vertical integration. This iterative process to cover all the multi objectives each one at a time can be very time consuming. An alternative approach is to minimize the weighted sum of deficiencies. Requiring (1) to be expressed as

$$\sum_{i\in Ns} v_i m_i + d_1 \le UBTC_{GE} \tag{1a}$$

The new objective function becomes,

$$Min\sum_{i} w_{d_i} d_i \tag{15}$$

where w_{d_i} represents the weights given by the decision makers to each one of the multiple objectives. This problem is subject to restrictions (1a)-(4a) and (5)-(14). For instance a decision maker considering that load curtailment is not acceptable could assign a very high weight of 100,000 to this objective, followed by let's say 10,000 for the generation expansion cost, 1000 for the generation cost and 100 for the transmission expansion cost.

V. TEST CASE

This section presents the proposed formulation for a test case introduced by the author initially in [3]. It presents the generation and transmission expansion problem for a deregulated sector in which ownership of the assets has been unbundled. Assets expand over three different regions as depicted in Fig. 1 [3] Overseeing regulatory agencies require expansion of generation capacities to be from renewable sources, in a similar way as in compliance with Renewable Energy Standards (RES) in the U.S. [12] The problem has been synthetically designed to require expansion of generation and transmission capacities to meet a future deterministic peak demand. Power systems are considered critical infrastructure and in most cases it is not possible to obtain all the relevant data to simulate planning studies as the one presented in this case.

The example presented here represents an effort from different stakeholders to put together results from their independent studies with the purpose of identifying better indicative plans. As mention in [3] this process expands the feasible space for the searching of candidate expansion plans making more likely to identify a less cost better solution. This process is similar to that realized in the US in studies such as the CVS and the UMTDI [9], [10].

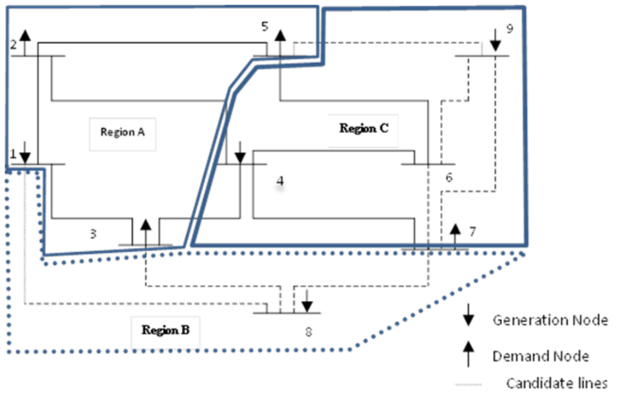

Figure 1. Network representation for test case. [3]

Region A has no potential for expansion of renewable generation capacities. However, additional coal-based capacity could be added at node 1 in this region to meet all future demand requirements as considered in this example. This alternative is not feasible given the restriction that additional generating capacity must come from renewable generation to comply with RES as in [12]. In this region there is one generation node (node 1) and three demand nodes (nodes 2, 3 and 5).

Region B is a remote area rich in renewable energy but distant from demand nodes. It is proposed to add new renewable generation at node 8. This additional generation requires acquiring rights of way for building no more than three new transmission corridors with a maximum of three circuits each one.

Region C also has potential for producing energy from renewable sources but at a more expensive cost at node 9.

Adding this generation capacity requires acquiring rights of way for building no more than four new transmission corridors with a maximum of three circuits each one. This region has one generation node at node 4 and one demand node at node 7.

The total initial demand is 11MW. Region A participates with 10MW, Region C with 1MW. The increment in capacity corresponds to 1MW in each region. The future demand to be met in the integrated region is equal to 13MW, exceeding the current installed capacity of 11MW. There are two new 3MW generation projects that could be connected to the network to meet this future demand. The initial generation capacity in Region A is

5MW, whereas the initial generation capacity in Region C is 6MW. Region A is a net importer of power since its demand exceeds its generation capacity. On the other hand Region C is a net exporter of power since its generation exceeds its demand. Addressing issues of security of supply in each region could add additional objectives to the problem formulation requiring certain minimum demand to be met locally.

In the initial network configuration there are 7 nodes connected to the grid: 4 demand nodes, 2 generation nodes and one transshipment node (a node that has zero generation and zero loads). There are two new proposed renewable generation nodes not connected to the grid. There are 8 existing transmission lines and 7 new potential transmission lines to connect these new generation nodes to the existing network configuration. The initial network configuration along with the new potential renewable generation nodes (nodes 8 and 9) and the candidate new lines are displayed in Fig. 1. Relevant costs for these new investments are as follows: v_8 = 315$, v_9 = 350$, $g_{8\ max}$ = 3MW, g_{9max} = 3MW. It is assumed that these investment costs have been annualized and that both projects have been evaluated under the same conditions including the same set of externalities. [3] The load curtailment cost is assumed to be constant at all demand nodes and is set equal to 100 $/MW. The supply conditions are presented in Table I [3]. Demands in MW are given as follows: D2 = 4, D3=3, D5=4, D6=0, D7=2. Notice that lower case letter d with subscripts represents deviation values. The transmission expansion costs, the maximum flow capacity and susceptances for the transmission lines are presented in Table II [3].

TABLE I. GENERATION CONDITIONS. [3]

Generation Nodes	Production/dispatch cost ($/MW)	Maximum Generating Capacity (MW)
1	3	5
4	5	6
8	2.5	3
9	3.5	3

TABLE II. TRANSMISSION DATA. [3]

Transmission Line	e^0_{ij}	w_{ij} ($ per line)	$f^{max}_{i,i}$ (MW)	B_{ij}
01,02	2	20	1	2.222222
01,03	1	19	1.7	1.666667
02,04	1	25	1.1	2.857143
02,05	1	17	1.1	2.325581
03,04	1	19	1	1.612903
04,06	1	21	1.3	3.333333
04,07	1	23	2.2	2.500000
05,06	2	22	1.2	2.857143
01,08	0	25	1.3	1.666667
03,08	0	37	1.6	1.754386
07,08	0	35	1.2	2.040816
05,09	0	25	1.1	1.960784
06,07	0	35	1.2	2.702703
06,09	0	40	1.6	2.127660
07,09	0	38	1.3	3.030303

The optimization problem is formulated as:

$$Min\ (10^4 d_1 + 10^3 d_2 + 10^2 d_3 + 10^5 d_4)$$

$$\sum_{i \in Ns} v_i m_i + d_1 \le 400$$

$$\sum_{i \in Ns} g_i p_i + d_2 \le 65$$

$$\sum_{(i,j) \in E} w_{ij} (e^1_{ij} - e^0_{ij}) + d_3 \le 1000$$

$$\sum_{i \in Nd} r_i s_i + d_4 \le 0$$

Subject to (5)-(14).

Bounds on additional constraints representing the multiple objectives are set by evaluating worst case scenarios for them. This process is easy for this small test problem. In the case of a larger network more complicated some suggestions for setting bounds are to use real budgetary constraints, very large arbitrary values or values for feasible non optimal solutions.

Since the process of evaluating and selecting indicative integrated generation and transmission plan requires participation of different stakeholders, the author considers that the above formulation could be useful in policy making processes that may require trade-offs from different participants. These tradeoffs can be evaluated using the deviations from each objective. The solution sets the value of d_4 at zero representing it is the most important objective [4] and that it has a zero upper bound. Therefore, the load curtailment cost is equal to zero. The optimization process adds enough capacity to meet all future demands. The best design identified using a CHA presented in [3], [21] adds generation at node 9 and adds the following transmission lines to the initial network configuration: $e_{01,02}$ = 1, $e_{01,03}$ = 1, $e_{04,07}$ = 1, $e_{05,09}$ = 3. The total expansion cost is equal to $487 as reported in [3]. Although region B is rich in renewable energy it remains unconnected to the network. Additions in generation and transmissions capacities were required only in the other two regions. The solutions identified by the proposed model comply with the practice from some power systems consisting in adding renewable energy in areas that do not require expensive additions in transmission capacities. [12]

It is worth mentioning that the GTNEP is a complex problem encompassing the TNEP problem, a non-convex non-linear problem for which alternative formulations and solution methods are still sought [8]. Then any attempt made to simplify its solution is important. In this sense the formulation presented here finds the same solution as in [3] for this small example. Test on larger networks are being conducted by the author to determine any real computational advantages for larger networks. In any case the proposed formulation adds value by being easily communicable to policy makers involved in designing indicative energy plans.

VI. CONCLUSIONS

After deregulation of electric power systems vertically integrated utilities where unbundled resulting in assets and relevant planning information to be under control of different stakeholders. However, long term sustainability and security of supply of power systems required some form of coordination or integrated planning efforts to identify indicative generation and transmission expansion plans. In this paper this decision making problem has been formulated as a multi-objective problem and it is proposed to be solved using preemptive goal programming of the weighted deficiencies. The clear identification of the deficiencies in each objective could be useful in decision making processes to determine energy policies involving different stakeholders controlling different goals. The values from deficiencies in various objective functions could be used to determine trade-offs during negotiations. A test case is presented to illustrate the proposed method. Although the results are promising more research is needed to determine the added value in simplifying the computational complexity in problems involving larger networks.

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Enrique B. Cedeno, PhD Industrial and Systems Engineering, University of Minnesota, Twin Cities campus. MSIE, University of Minnesota, Twin Cities campus. His research interest includes developing macro level systems optimization models applied to power generation and transmission sectors to improve their performance and guide energy policy decisions.