Electric Power Systems Research 79 (2009) 959–972

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

A market based active/reactive dispatch including transformer taps and reactor and capacitor banks using Simulated Annealing

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ARTICLE INFO

Article history:
Received 3 October 2007
Received in revised form 29 May 2008
Accepted 19 December 2008
Available online 30 January 2009

Keywords:
Integrated active/reactive dispatch
Transformer taps
Capacitor and reactor banks
Synchronous generator capability diagram
Simulated Annealing
Metaheuristics
SLP—Sequential Linear Programming

ABSTRACT

This paper describes an optimization model to be used by System Operators in order to validate the economic schedules obtained by Market Operators together with the injections from Bilateral Contracts. These studies will be performed off-line in the day before operation and the developed model is based on adjustment bids submitted by generators and loads and it is used by System Operators if that is necessary to enforce technical or security constraints. This model corresponds to an enhancement of an approach described in a previous paper and it now includes discrete components as transformer taps and reactor and capacitor banks. The resulting mixed integer formulation is solved using Simulated Annealing, a well known metaheuristic specially suited for combinatorial problems. Once the Simulated Annealing converges and the values of the discrete variables are fixed, the resulting non-linear continuous problem is solved using Sequential Linear Programming to get the final solution. The developed model corresponds to an AC version, it includes constraints related with the capability diagram of synchronous generators and variables allowing the computation of the active power required to balance active losses. Finally, the paper includes a Case Study based on the IEEE 118 bus system to illustrate the results that it is possible to obtain and their interest.

1. Introduction

The electricity sector in several countries was submitted to a restructuring process in the last decades in order to incorporate competitive mechanisms. This process lead to the unbundling of traditional utilities into a number of entities responsible for activities identified along the value chain of the sector. These activities correspond to generation (in normal regime or according to subsidized mechanisms, namely regarding renewables), transmission, distribution and retailing. Apart from these activities, they also emerged entities responsible for coordination activities, namely from the economic point of view as the Market Operators and from the technical point of view as System Operators. Finally, network transmission and distribution providers typically act on a monopoly basis, which corresponds to one of the reasons justifying the emergence of independent regulation.

Apart from this, it should be recognized that in recent years there was also a move towards a certain unbundling of the formulations used by different agents. In fact, the operation planning of power systems witnessed an integration move from the 50th till the 90th since from simple active power dispatch problems, they were then developed models including network constraints, afterwards it was developed the concept of OPF integrating the AC power flow equations as well as security and technical constraints and then the OPF formulations got enlarged with contingency constraints. With the advent of electricity markets, the economic and the technical visions of the problem got separated again. Typically, the Market Operator runs day-ahead auctions and the results of these trading mechanisms together with Bilateral Trading correspond to the economic schedule of the generation system regarding active power. Then, still on the day before operation, this information is conveyed to the System Operator that checks the feasibility of this schedule considering network constraints, which means that some changes may be required. Finally, when talking about electricity markets it should not be forgotten that we are typically referring to active power trading. This means that during the day before operation the System Operator will also have to schedule a number of other elements, usually known as ancillary services that are crucial to maintain the high standards of quality and continuity of service typical of well developed systems.

In any case, it should be recognized that planning power system operation during the day before operation in terms of a set

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0378-7796/$ – see front matter
doi:10.1016/j.epsr.2008.12.014

of chronological sequence of activities may lead to several problems. In the first place, the pure economic active power schedule identified by the Market Operator together with Bilateral Contracts can originate congestion or voltage problems to be identified and addressed afterwards by the System Operator. Then, given the regional nature of reactive power and its coupling with active power (in terms of the AC power flow equations, branch limits and the capability diagram of synchronous generators, for instance), the System Operator can issue a reactive power requirement to a generator that, together with its previously set active power, can originate an unfeasible operation point, given its capability diagram. These aspects, together with the coupling between active and reactive power, justify the development of formulations to be used by System Operators that remarry active and reactive power and determine the reactive power allocation on a regional basis while using as much as possible market mechanisms in order to increase the transparency of the whole process. These aspects together with their inherent coupling in terms of the AC power flow equations correspond to the main advantages of remarrying active and reactive powers.

In this sense, this paper is the continuation of [1,2]. In [1] we presented an initial formulation based on adjustment bids submitted by generators and demand to be used off-line on the day before operation by the System Operator if necessary to enforce technical and security constraints. In [2] we enlarged this approach considering the allocation of active power to balance active losses while admitting there were two trading platforms (Market Operator bids and Bilateral Contract injections) that should be kept balanced, even after the adjustments required by the System Operator. Reference [2] also details the computation of active and reactive power nodal marginal prices as a sub-result of the Sequential Linear Programming based algorithm. This paper enhances and completes this off-line operation planning formulation when including discrete components as transformer taps and reactor and capacitor banks. This contributes to increase the realism of the formulation while transforming the problem into a mixed integer one. In this case, we adopted Simulated Annealing together with Sequential Linear Programming to solve it.

Apart from this initial section, this paper is structured as follows. Section 2 refers formulations in the literature to value and assign reactive power support. Section 3 details the developed formulation briefly referring a number of aspects fully explained in [2] and fully addressing the integration of discrete components. Section 4 describes the adopted solution algorithm, based on Simulated Annealing and on Sequential Linear Programming, together with the computation of active and reactive power nodal marginal prices. Section 5 presents the results obtained for a Case Study based on the IEEE 118 Bus Test System and finally Section 6 draws the most relevant conclusions.

2. Reactive power allocation approaches

In this section we will revise some contributions related with reactive power allocation in the scope of electricity markets. In the first place, from a practical point of view, it should be referred that in some countries the provision of reactive support is considered a mandatory non-paid ancillary service while in some others [3] part of its provision is mandatory and another part is subjected to auction mechanisms. In England and Wales reference [4] details the provisions initially established for the reactive power support in terms of an utilization and a capacity payment that were expected to be able to develop a full reactive power mechanism. In recent years, there are auctions each semester to allocate reactive power and there is a trend to remunerate the reactive metered term that is, the use of the equipments, rather than their capacity.

When talking about reactive power, it is important to address two topics. In the first place, reactive power is not as directly valued as active power. Regarding cost elements and structures, references [5–7] describe its most relevant costs components. In this scope, [5] suggests that reactive power support costs could be set as a percentage of active power generation costs that would then be allocated to network users according to limits of absorption of reactive power together with the definition of nodal or zonal reactive power locational prices. As for [6], it groups reactive power costs in a capital cost term related with the provision of reactive capability and operating and maintenance costs associated with the reactive output. Reference [7] considers explicit or direct costs and implicit or indirect costs. Explicit costs correspond to fixed investment costs and to variable operation and maintenance costs while implicit costs are related with the reduction of profits due to the alteration of the operation point of the generator required to ensure a specified reactive output. Related with this issue, references [8–12] detail the concept of opportunity cost as the cost incurred by generators due to the fact that the System Operator issues a reactive power requirement that may be unfeasible given the active power previously scheduled. This will then originate an alteration of the active power output leading to a reduction of the generator's remuneration that is termed as opportunity cost. References [11–13] also propose a structure for reactive power remuneration in terms of three zones. Till a first specified level, the reactive generation is used by the generator itself or by its auxiliary systems and so the generator is not entitled to receive any extra payment. Then, till a second level, the reactive output does not imply changing the active generation. In this case, the generator should receive a fixed payment related with the availability of this service. Finally, beyond this second level the reactive power output implies a reduction of the active generation due to the capability diagram of the generator. In this case, the payment should be proportional to the reactive output at a rate determined by the incurred opportunity cost. This type of cost structure can be included in optimization problems to allocate reactive power generation aiming at minimizing the payments while enforcing a number of constraints as the AC power flow equations, voltage and branch limits.

The second topic to be addressed is related with the well known geographical dispersed nature of reactive power as referred in [3,5,9]. This leads to the definition of zones or control areas, for instance related with voltage control capabilities. In an attempt to define meaningful values for reactive power prices, reference [5] proposed the use of zonal multipliers in order to adjust the reactive power capacity value from one zone to another. This concept of zonal and then nodal marginal reactive power prices is further developed in [14–18] as a way to include network constraints in the reactive power allocation and so to inherently incorporate the impact of the grid. In general, these optimization approaches aim at minimizing active power losses and compute nodal or zonal prices using the value of the Lagrangean coefficients available when the final solution is obtained.

Apart from the above approaches, there are still a variety of formulations and solution approaches as the ones reported in [19,20]. These references describe approaches using physical flow based mechanisms to allocate the reactive support to generators or to allocate the corresponding costs using circuit theory and the system admittance matrix. References [21–23] describe formulations that explicitly include capacitor banks. Reference [21] adopts a continuous formulation that is solved using Sequential Quadratic Programming while [22] incorporates the cost of adjusting control devices along time and it uses Genetic Algorithms to solve the resulting mixed integer problem. Finally, [23] also describes a mixed integer formulation considering OLTC transformers and capacitor and reactor banks and it is solved by Evolutionary Programming.