Inclusion of Short Duration Wind Variations in Economic Load Dispatch

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***Abstract*—Randomness of wind speed around a short-duration-stable mean value is commonly referred to as *short duration wind variation*. This paper investigates the effect of substantial wind-based capacity inclusion on optimal load dispatch, with the source wind susceptible to short duration variations. Analytical formulation of the economic load dispatch (ELD) problem inclusive of wind power generation is presented separately for cases with and without representation of transmission losses. In each formulation, the effect of short duration wind variations is included as an aggregate, thereby avoiding the complexity of stochastic models. Three-generator and 20-generator study cases are discussed to illustrate two distinct aspects of the ELD problem. First, the optimal cost, losses, and system-λ are presented across a range of short-duration-stable mean wind speed. Thereafter, the sensitivity of all three metrics is discussed with reference to different levels of short duration wind variations.**

***Index Terms*—Power system economics, sustainable energy, wind energy, wind power generation.**

I. Introduction

WITH significant wind-based capacity additions to power networks worldwide, operational economics continues to be a matter of prime concern to utilities [1], [2]. Among others, the classic problem of economic load dispatch (ELD) [3], [4] has evoked new interest with debate on how wind energy conversion systems (WECS) are to be taken into consideration within dispatch schedules. Questions are generally raised about the variability of wind at source, and the way the same is to be accounted for within the framework of an ELD.

The problem has been investigated for some time in the past [5]; while more recently, attempt has been made to focus on WECS units as independent sources, with appropriate cost components assigned to buy-back of power, reserve requirements, and failure to utilize available wind power [6]. In [7] and [8], probabilistic availability of wind power is used to define constraints to the ELD problem. Most works thus far [6]–[8] have used the well-known Weibull distribution [9] to represent variability of wind, which is known to be valid statistics at least across periods of long duration [10].

This paper is based on the premise that for many applications [11], the optima of an ELD is of interest across a short duration of time (referred to in the rest of the paper as the *validity interval* of ELD), within which the Weibull is not necessarily the best statistical model for wind speed variations [10]. Short duration wind variations primarily include two types of aerodynamic nonidealities, namely *turbulence* and *gusts*. Turbulence consists of random fluctuations superposed on a *short-duration-stable* mean value $\bar{u}$. The source of such fluctuations can be traced back to disturbed streamlines of wind flow. Gusts are distinct surges within turbulent wind fields, for which quantifiable features such as *amplitude*, *rise time*, *peak*, and *lapse time* can be identified. Effect of both nonidealities has been suitably modeled using simple Gaussian distributions around the short-duration-stable mean wind speed [12].

Further, as indicated by recent studies [12], [13], it is possible to aggregate the effect of short duration variations on the power output by a WECS. This allows the ideally expected output power of WECS units to be "corrected" for such variations prior to inclusion in the conventional ELD. A rigorous stochastic model for short duration wind variations may thereby be avoided within the ELD formulation.

Certain features of the conventional ELD problem almost immediately suggest the use of aggregates in preference to stochastic models. First, in practice the conventional units are not entirely free of minor dynamics over the set point of power, while the load can always undergo changes as decided by consumer behavior. The optimal generation levels that emerge when an ELD attempts to meet total power demand are, therefore, not precise instantaneous values but rather similar to aggregates. The concept of aggregate WECS-based generation, therefore, blends with conventional ELD concepts almost naturally.

Again, *loss coefficients* have been used in the conventional ELD to model aggregate system loss as a function of generation levels [3], [4]. Consequently, such representation is more compatible with the concept of aggregate generation from WECS-based units, rather than instantaneous power levels as required by stochastic methods. In fact, the conventional procedure for evaluating network loss formula in terms of loss coefficients [3] can be extended to systems with significant wind-based generation *only if* an acceptable aggregation of WECS output power is used. If this is not the case (say for example, in the presence of long duration wind variations), then the overall energy loss must be evaluated across time horizons.

Finally, questions can be raised about the appropriate use of stochastic objective or constraints when optimizing a problem with one or more random time series data as input. For an ELD problem including WECS-based generation, the primary wind speed data is random according to Weibull or Gaussian distribution. However, such a feature neither justifies nor requires that the *optimization process* should involve stochastic relations. On

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the contrary, representation of wind power as aggregates avoids any such doubts, since stochastic data or relations are avoided altogether.

Sections II and III examine the ELD problem (neglecting, and inclusive of network losses, respectively) with WECS units included as part of the utility generation portfolio. In each case, the effect of short duration variations on the ELD optima is taken into consideration without assuming any specific probability distribution.

A question that emerges almost naturally from the above discussion may be stated as: *how is the validity interval to be decided for an ELD that includes a significant share of wind-based generation?* In a broad sense, the choice of *validity interval* must permit *acceptable aggregation of wind power P_w in the presence of short duration wind variations* (say, at the generic wth WECS-based generation site) into *a crisp aggregate value* $\langle P_w \rangle$. If this applies to each wind-based generation site within the network, then applicability of conventional ELD concepts follows as a consequence.

Section IV provides a deeper treatment of the above statement leading to a definition of $\langle P_w \rangle$, which is suitable and convenient for inclusion in ELD problems. Sections V and VI present various aspects of such inclusion through three-generator and 20-generator ELD examples, respectively.

A disclaimer is perhaps in order before this section is closed. The focus of this paper is the inclusion of WECS units in the generation portfolio of utilities, its impact on optimal cost of generation, and the consequence of short duration wind variations. In order to study these aspects in an exclusive manner, some of the conventional challenges of the ELD problem have been ignored throughout the treatment as well as the examples of Sections V and VI. Among others, consideration of valve-point loading [14]–[16], and reserve margins [17], [18] are excluded; these classic problems having been exhaustively reported in the literature.

II. Economic Load Dispatch Neglecting Network Losses

Consider an interval within which a total demand of P_D is to be supplied by N conventional generating stations and W WECS stations, all of which are utility owned. In terms of P_n, the active power output of the nth conventional station, its cost of generation is given by [3], [4]

$$C_n(P_n) = c_{0,n} + c_{1,n} \cdot P_n + c_{2,n} \cdot P_n^2 \tag{1}$$

while for the wth WECS station, the cost expression is

$$C_w(P_w) = c_{1,w} \cdot P_w \tag{2}$$

where the power output P_w is subject to variations due to wind speed that need to be accounted for. It is, however, assumed that within the validity interval of ELD, whatever the values of P_w can be absorbed by the system without any congestion or reliability problems. In practice this would be the case for utilities that have WECS installed on the basis of proper planning, so that operational problems are not to be expected when dispatch follows the ELD optima. $\{P_w\}$ can then be considered as exogenous variables for the ELD problem.

If losses in the system are neglected, then the ELD can be defined as the following optimization problem:

$$\begin{aligned} \text{Minimize}: \quad & C(\{P_n\},\{P_w\}) \triangleq \sum_n^N C_n(P_n) + \sum_w^W C_w(P_w) \\ \text{Subject to}: \quad & P_n^{\min} \le P_n \le P_n^{\max}; \quad n = 1, \ldots N \\ & P_D = \sum_w^W P_w + \sum_n^N P_n. \end{aligned} \tag{3}$$

The Karush–Kuhn–Tucker (KKT) conditions for the optima of (3) are

$$\begin{aligned} &\frac{dC_{n1}(P_{n1})}{dP_{n1}} = \lambda; \quad \text{for } P_{n1}^{\min} < P_{n1} < P_{n1}^{\max} \\ &\frac{dC_{n2}(P_{n2})}{dP_{n2}} \le \lambda; \quad \text{for } P_{n2} = P_{n2}^{\max} \\ &\frac{dC_{n3}(P_{n3})}{dP_{n3}} \ge \lambda; \quad \text{for } P_{n3} = P_{n3}^{\min} \\ &\sum_{n1}^N P_{n1} = P_D - \sum_w^W P_w - \sum_{n2}^N P_{n2}^{\max} - \sum_{n3}^N P_{n3}^{\min}; \\ &\qquad \text{where } n1, n2, n3 \in \{1, 2, \ldots N\}; \quad n1 \ne n2 \ne n3. \end{aligned} \tag{4}$$

In (4), the set of conventional units has been "split" between generators with inactive power limits (index $n1$), active maximum power limit (index $n2$), and active minimum power limit (index $n3$).

For each conventional generator with inactive power limits (index $n1$), the cost-derivative relation in (4) leads to the respective *optimal generations* $\{P_{n1}^*\}$ in terms of the optimal marginal cost λ^*. Substitution in the demand constraint gives

$$\begin{aligned} &\sum_{n1}^N \frac{\lambda^* - c_{1,n1}}{2c_{2,n1}} = P_D - \sum_w^W P_w - \sum_{n2}^N P_{n2}^{\max} - \sum_{n3}^N P_{n3}^{\min} \\ &\Longrightarrow \lambda^* = \left[\sum_{n1}^N \frac{1}{2c_{2,n1}}\right]^{-1} \\ &\qquad \cdot \left[P_D - \sum_w^W P_w - \sum_{n2}^N P_{n2}^{\max} - \sum_{n3}^N P_{n3}^{\min} + \sum_{n1}^N \frac{c_{1,n1}}{2c_{2,n1}}\right] \\ &\Longrightarrow P_{n1}^* = \frac{\lambda^* - c_{1,n1}}{2c_{2,n1}}. \end{aligned} \tag{5}$$

It follows that the optimal generation level at each conventional unit is a linear function of the WECS outputs $\{P_w\}$, the latter being dependent on wind speed variables.

Evaluation of the optimal generation levels $\{P_n^*\}$ may now be simplified in view of the following:

i) At WECS installation sites, *long duration variation* of wind speed (typically modeled as Weibull distributions [9], [10]) may be assumed to have negligible impact across the validity interval of an ELD. Rather for such time spans, a *short-duration-stable mean wind speed* ($\bar{u}_w$ at the WECS hub, wth site) may be assumed with *short duration variations* superposed [10], [12].