Day-ahead scheduling of an active distribution network considering energy and reserve markets

Meysam Doostizadeh and Hassan Ghasemi*

School of Electrical and Computer Engineering, University of Tehran, Iran

SUMMARY

High penetration of distributed energy resources (DERs) has led to considerable evolution in the operational aspects of distribution systems. As a result, distribution companies (DISCOs) tend to utilize optimization in order to schedule their DERs to meet their demand as well as participation in the electricity markets. This study presents a comprehensive operation model for a distribution system which involves DISCO participation in energy production and reserve providing activities. The uncertainties are modeled by means of a chance constraint representing the confidence level of serving load by DISCO. The presented model can incorporate DERs (both dispatchable and non-dispatchable units) along with network constraints and load and wind uncertainties in order to achieve optimal decisions in both day-ahead energy and reserve markets. A modified 32-bus distribution network including dispatchable generators, electric energy storage, wind turbine units, interruptible loads, and interties is employed to illustrate the effectiveness and feasibility of the proposed method. Copyright © 2012 John Wiley & Sons, Ltd.

key words: DISCO operation; energy market; reserve market; distributed energy resources

1. INTRODUCTION

Recently, the nature of the distribution network is changed from a passive network with traditional problems such as feeder overloading, power losses, power quality, to an active one with high presence of various distributed energy resources (DERs). Consequently, the roles of distribution companies (DISCOs) within the context of electricity markets are not limited to purchasing energy from the market and selling it to consumers at a fixed retail price. The DISCO participation in market can be improved by optimal operation of its DERs and utilization of demand side response [1].

Each DER as an active element of distribution system provides significant controllability; however, it also adds more complexity from both technical and economical perspectives in distribution system operation. Distributed generation (DG) units, responsive loads, storage devices, along with passive loads, which are connected to the distribution networks, should be operated in a coordinated and flexible manner. Therefore, in order to coordinate scheduling of various DERs, incorporating optimization models for management of distribution system is crucial. As a result, an advanced distribution management system should include different functions such as [2]:

- Demand and generation forecast
- State estimation
- Aggregation of bids from DERs and ILs for participation in active energy management
- Day-ahead scheduler of DERs and ILs according to market rules
- Intra-day optimization of network topology
- Online communication with DERs to carry out control actions

*Correspondence to: Hassan Ghasemi, School of Electrical and Computer Engineering, Faculty of Engineering (Pardis), University of Tehran, Tehran, Iran.
†E-mail: hghasemi@ut.ac.ir

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Distribution system operators schedule the generation and plan the participation of DERs and ILs in both energy market and ancillary service market based on forecasts, contracts, and bids. Due to the level of inherent uncertainty in renewable resources production forecasts, real-time (intra-day) optimization is also required.

In this study, a comprehensive mathematical model is developed as a day-ahead scheduler of a DISCO with retail activities considering its interaction with energy and reserve markets and energy trading with neighboring DISCOs.

Most of the available research previously done on short-term operation of the active distribution network is discussed here. In [3], a day-ahead energy acquisition model for a DISCO is presented. The model determines optimal decisions on wholesale energy market, distributed generation (DG) units (both independent and utility owned) and interruptible loads (ILs) with the aim of minimizing the operational cost of distribution network.

A multi-period energy acquisition model for a DISCO with DG units and ILs in a day-ahead electricity market is presented in [4]. The DISCO strategy is modeled as a bi-level optimization problem in which the upper subproblem maximizes the DISCO’s revenues without considering distribution network, and lower subproblem simulates ISO’s market clearing problem.

A competitive market integration model for DG units in a pool-based market is proposed in [5]. The mechanism develops a market interface for DG units and formulates the participation of DG units which are located at the distribution level.

A quantification of the benefits from the systematic operation of customer-owned back-up generators to the distribution utilities is developed in [6]. Also, in [7], some of the most significant benefits of DG technologies to the DISCOs and the power system by loss reduction and capacity deferral are examined. The models in [7] develop the quantification of those benefits in economic terms.

In [8,9], a comprehensive short-term operation framework for a DISCO in both day-ahead and real-time electricity market is presented. The day-ahead stage determines the DISCO’s decisions on purchase from the grid, DG units scheduling which is owned by DISCO, and ILs contracting. The real-time stage minimizes the short-term operation cost of DISCO considering the day-ahead stage decisions.

A new paradigm for distribution system operation which is based on an optimal power flow (OPF) framework in the presence of DG sources considering the contribution of a DG unit to active and reactive distribution system losses is proposed in [10,11]. A bi-level optimization approach to determine the optimal contract price of dispatchable DG units is proposed in [12]. The outer problem points out the optimization model which seeks to maximize the benefit of the DG’s owner, and the inner problem minimizes the total payment related to the forecasted demand by DISCO.

The authors in [13] propose a short-term scheduling and control of active distribution network with high penetration of renewable resources. The procedure is composed of two levels: first is the scheduling of DER production in the following day is carried out, and the second one is the adjustment of the dispatchable DER production due to satisfying operation requirements and distribution network constraints. In [2], a network reconfiguration and active management algorithm for the active distribution network operation is presented, resulting in connecting low-cost DG sources.

An hourly-ahead profit model for an active DISCO which participates in both energy and reserve markets is presented in [14]. The model is a two-stage optimization problem: the first stage extracts a lumped financial model of the whole distribution system at the connecting point to the upstream network. The second stage determines the optimal values of power and reserve commodities to maximize the DISCO’s profit. Also, a profit-based network reconfiguration methodology is employed to increase the ability of DISCO’s in gaining more benefits from market activities.

In this paper, a day-ahead scheduling for an active DISCO is presented; in addition to including network technical constraints and being able to participate on both energy and reserve markets, this model also takes into consideration uncertainties associated with demand profile and DG production.

The main contributions of the present work with respect to previous research work are summarized as follows:

- Providing spinning reserve by DISCO’s for the ancillary service market has not, to the best of authors’ knowledge, been considered in previous literature. By applying the mathematical formulation for DISCO’s profit in day-ahead market which is developed in this paper, not only the DISCO can participate in energy market, but also it can provide spinning reserve for reserve market.
The DERs belonging to a DISCO may be connected to different points within its distribution network; therefore, network topology, impedances, losses, etc. have impacts on DISCO scheduling decisions. As a result, DISCO should consider the constraints of both network and DERs when bidding/offering to the markets. In most of previous similar studies, the DISCO schedules its DERs while neglecting distribution network characteristics; in this paper, however, network constraints are included in the proposed optimization model.

Loads and wind speed are basically random variables. Therefore, the forecasting methods applied to derive a set of data for performing the day-ahead power system studies are always combined with inherent uncertainties. In order to include uncertainties associated with renewable generation (here wind power) and demand profile which is not considered in previous research, a probabilistic formulation by means of a chance constraint is modeled in this paper. Recently, distribution network planning models have introduced new resource options such as interties and electric energy storages (EES) driven by technological developments and the new competitive structure of electricity markets. Therefore, this work considers the intertie with neighboring DISCOs as well as EES in order to maximize DISCO’s benefit.

The rest of this paper is structured as follows: the activity and information required by a DISCO to successfully schedule DERs and submit bids/offers to energy and reserve markets are described in Section 2. Mathematical formulation of the DISCO’s day-ahead operation model is presented in Section 3. Section 4 presents and discusses the results of different case studies carried out for a well-known test system to illustrate the feasibility and effectiveness of the proposed model. Conclusions are provided in Section 5.

2. DISCO SCHEDULING ACTIVITIES AND REQUIRED INFORMATION

2.1. Assumptions regarding information and operation cost

Based on the given retail energy rates, cost function of DG units, and operation cost of EES, additional information as follows are required to determine the optimal day-ahead scheduling activities:

1) Load forecasting: due to the repeated nature of demand profile, the DISCOs forecast their load pattern for the next 24 hours based on historical data, temperature forecast, and humidity. In addition, in today’s distribution network, smart metering can help provide more detailed and accurate forecasts [15]. Several techniques such as weighted least squares methods [16], neural networks, and fuzzy set techniques can be used to forecast the loads of distribution system [17–21].

2) Price forecasting: a DISCO can either forecast energy and reserve market prices for the following day based on the historical data or utilize the day-ahead electricity prices posted by system/market operators. Different techniques and models such as artificial neural networks, auto regressive integrated moving average models and least square support vector machine, and hybrid methods have been proposed to energy price forecasting [22].

3) Renewable resources forecasting: a DISCO should also forecast the output of its renewable resources. Several algorithms are available to forecast the generation of renewable DG units [23–25].

4) Power exchange price: recently, DISCOs can import power from or export power to neighboring DISCOs via interties. Therefore, the price of exchanged power via interties is assumed to be specified in terms of for example three time blocks of peak, intermediate, and base.

5) IL contract price: in this paper, customers can sign contract with DISCO to be interrupted when it is needed. IL contract is optional, that is, this kind of contract is not dependent on market price, and hence a DISCO may choose to implement it as required. Therefore, the DISCO in order to be aware of how much load can be interrupted in real-time and how much it will cost to execute it. The IL contract price \( C_{IL,t,i} \) is assumed to be known for all the loads willing to participate in DISCO load curtailment activity.

2.2. Load and wind power uncertainties

Loads and wind speed are basically random variables. Therefore, forecasting methods have been applied to derive a set of data for performing the day-ahead power system studies including unit
Forecasts are always accompanied with inherent uncertainties. In order to include these uncertainties in power system studies, a normal distribution, also known as Gaussian Distribution (GD), is assumed for the error corresponding to a forecasted variable. With this assumption, the forecasted value is the mean value of GD ($\mu$) and an appropriate value for the standard deviation of GD ($\sigma$) is also assumed. A GD is defined as follows:

$$y = f(x | \mu, \sigma) = \frac{1}{\sigma \sqrt{2\pi}} e^{-\frac{(x-\mu)^2}{2\sigma^2}}$$

(1)

Therefore, the net demand is the difference between the demand and wind power forecasts which consist of two components: a mean value ($P_{D_{\text{net}},t}^{\text{mean}}$) and a standard deviation ($\sigma_{P_{D,t}}$). Based on the probabilistic theory for the sum of two Gaussian random variables and assuming no correlation between wind power and demand forecasts, the parameters for probability density function (PDF) of net demand is determined as:

$$\mu = P_{D_{\text{net}},t}^{\text{mean}} = P_{D,t}^{\text{mean}} - P_{\text{wind},t}^{\text{mean}}$$

(2)

$$\sigma_{P_{D_{\text{net}},t}} = \sqrt{\sigma_{P_{D,t}}^2 + \sigma_{P_{\text{wind},t}}^2}$$

(3)

To handle the uncertainties of net demand forecast in the operation of distribution system, DISCO should ensure that there is enough generation capacity to meet the hourly net demand forecast. In day-ahead power system, studies including unit commitment and OPF system operators may utilize two approaches. The first approach applies scenario-based stochastic programming methods such as Monte Carlo simulations to consider a set of scenarios to describe the stochastic nature of the uncertainties [26–28]. Due to the planning horizon in the day-ahead operation of DISCO, applying such methods would lead to taking a large number of scenarios into account and long computational time which is undesirable in online applications. In addition, applying scenario reduction techniques [29] to discard part of the scenario tree remains computationally intensive for a real size system. The second approach applies the reserve requirement to handle uncertainties explicitly in the unit commitment problem formulation [30–32]. In this study, the uncertainty of net demand is considered using the reserve requirement approach and the worst case loading scenario according to the PDF of net demand. The worst case load is ideally the maximum possible net load value. In practice, however, the maximum value for net load with an acceptable probability, e.g. $\beta = 97.72\%$, is considered. This ensures that in the real-time situation, the load would be met by the mentioned probability ($\beta$). For normally distributed net load and considering that the maximum net load is $P_{D_{\text{net}},t}^{\text{mean}} + \lambda \sigma_{P_{D_{\text{net}},t}}$, this is calculated as:

$$\text{Prob}(P_{D_{\text{net}},t} \leq P_{D_{\text{net}},t}^{\text{mean}} + \lambda \sigma_{P_{D_{\text{net}},t}}) = \beta$$

(4)

where $\lambda$ denotes the desired confidence level. In other words, the probability of net demand being less than or equal to net demand forecast is $\beta$ which is the desired confidence level. For instance, when $\lambda = 2$, probabilistic confidence level of having adequate capacity to meet net demand is 97.72% (Figure 1).

![Figure 1. Graphical illustration of a chance constraint through one-sided confidence level of a normal distribution when $\lambda = 2$.](https://example.com/figure1.png)
3. DAY-AHEAD SCHEDULING FORMULATION

In this section, the mathematical formulation of the proposed scheduling model is presented. The aim of DISCO is to maximize its individual profit by making optimal bids/offers for both energy and reserve markets while satisfying its load. Besides, optimal scheduling of its DG, charging and discharging states of the EES, power exchange with its neighboring discos, and making decision on ILs options considering all economical and technical aspects have to be determined. Therefore, an optimization problem with following objective and constraints are used here.

1) Objective function

\[
\text{MAX Benefit} = \sum_{i=1}^{24} \sum_{t \in S\text{DG}} \left[ \rho_{\text{int},i} \times \left( P_{d,i} - P_{\text{IL},i} \right) \right] + \sum_{i=1}^{24} \left[ r_t \times \left( \rho_{E,i} + \rho_{R,i} \right) + \left( 1 - r_t \right) \times \rho_{R,i} \right] \times R_t

- \sum_{i=1}^{24} \sum_{t \in S\text{IL}} \left( \rho_{\text{int},i} \times P_{\text{int},i} \right) - \sum_{i=1}^{24} \left( \rho_{E,i} \times P_{\text{sub},i} \right) - \sum_{i=1}^{24} \left( C_{\text{IL},i} \times P_{\text{IL},i} \right) - \sum_{i=1}^{24} \left( r_t \times C_{\text{IL},i} \times R_{\text{IL},i} \right)

\sum_{i=1}^{24} \sum_{t \in S\text{EES}} \left\{ r_t \times C_{\text{DG},i} \left( P_{\text{DG},i} + R_{\text{DG},i} \right) + \left( 1 - r_t \right) \times C_{\text{DG},i} \left( P_{\text{DG},i} \right) \right\} \left[ L_{i,t} + STC_{\text{DG},i} M_{i,t} + SDC_{\text{DG},i} N_{i,t} \right]

- \sum_{i=1}^{24} \sum_{t \in S\text{EES}} C_{\text{EES},i} \left( P_{\text{EES},i} \right)
\]

(5)

where \( R_t \) is amount of reserve at hour \( t \), which would be offered to reserve market by DISCO, which is given by:

\[
R_t = \sum_{i \in S\text{DG}} R_{\text{DG},i,t} + \sum_{i \in S\text{IL}} R_{\text{IL},i,t}
\]

(6)

The first two components of the objective function are DISCO’s revenue from selling electricity to its consumers and providing reserve to spinning reserve market, respectively. The DISCO’s revenue from providing spinning reserve depends on probability of activating reserve \( (r_t) \) in real time [33]. The third component represents the cost of trading energy between the DISCO and its neighboring DISCOs over the interties based on the forward contract between neighboring Disco’s in which the maximum power exchange and energy prices have been determined. The remaining components represent the cost of purchasing energy from/revenue from selling it to wholesale market, the cost of generation from dispatchable DG units and their start up and shut down cost for those are utility owned, the cost of activating ILs and the operational cost of EESs, respectively.

The cost function of each dispatchable DG unit is assumed here to be a function of its real power output and is modeled as \( C_{\text{DG}}(P_{\text{DG}}) = A_{\text{DG}} + B_{\text{DG}} \times P_{\text{DG}} \) in which \( A_{\text{DG}} \) and \( B_{\text{DG}} \) are positive coefficients of the linear cost function. The short-term operation costs for renewable resources are very low and in this work are considered to be zero. In addition, it is assumed that these units only inject active power [10].

The operational cost of EES is generally associated with its maintenance costs, and it is assumed to be a linear function of the absolute of its charged or discharged capacity at each hour [34], i.e. \( C_{\text{EES}}(P_{\text{EES}}) = A_{\text{EES}} + B_{\text{EES}} \times P_{\text{EES}} \) in which \( A_{\text{EES}} \) and \( B_{\text{EES}} \) are positive coefficients of the linear cost function and \( P_{\text{EES}} \) is equal to absolute of charging \( (P_{\text{Ch},i}) \) or discharging \( (P_{\text{Dch},i}) \) of EES.

2) Constraints

- Power flow equations:

\[
P_{\text{sub},i,t} + P_{\text{DG},i,t} + P_{\text{NDG},i,t} + P_{\text{int},i,t} + P_{\text{IL},i,t} + \left( P_{\text{Ch},i,t} - \eta_{\text{dis}} \times P_{\text{Dch},i,t} \right) - P_{d,i,t} = \sum_{j=1}^{N} \left| V_{i,t} \right| \left| V_{j,t} \right| \sin(\delta_{ij} - \delta_{ij} + \theta) \forall i \in S_N, t = 1, \ldots, 24
\]

(7)

\[
Q_{\text{sub},i,t} + Q_{\text{DG},i,t} + Q_{\text{int},i,t} + Q_{\text{IL},i,t} - Q_{d,i,t} = -\sum_{j=1}^{N} \left| V_{i,t} \right| \left| V_{j,t} \right| \cos(\delta_{ij} - \delta_{ij} + \theta) \forall i \in S_N, t = 1, \ldots, 24
\]

(8)
\[ Q_{IL,i} = \tan(\cos^{-1}(PF_i)) \times P_{IL,i} \]  

(9)

- **System adequacy constraint:**

This constraint is necessary to ensure that there is enough committed capacity to meet hourly net demand. Therefore, a chance constraint similar to [26] is developed here to represent adequate capacity constraint:

\[
\text{prob}\left(\sum_{i \in \text{SDG}} P_{\text{DG},i,t}^\text{max} L_{i,t} + \sum_{i \in \text{SDG}} P_{\text{int},i}^\text{max} + \sum_{i \in \text{Ssub}} P_{\text{sub},i}^\text{max} + \sum_{i \in \text{SEES}} P_{\text{IL},i,t} + \sum_{i \in \text{SEES}} (\eta_{Dch} \times P_{Dch,i,t} - P_{Ch,i,t}) \right) \geq \beta, \, t = 1, \ldots, 24
\]

where \( P_{\text{DG},i,t}^\text{max} \) is the maximum power generation of \( i \) th DG unit during hour \( t \) which is defined as follows:

\[
P_{\text{DG},i,t}^\text{max} = \min\left(60 \times RR_{DG,i}, P_{\text{DG},i-1,t}, P_{\text{DG},i,t}^\text{max}\right)
\]

(11)

Therefore, the deterministic equivalent of equation (11) can be written by the following equation:

\[
\left(\sum_{i \in \text{SDG}} P_{\text{DG},i,t}^\text{max} L_{i,t} + \sum_{i \in \text{SDG}} P_{\text{int},i}^\text{max} + \sum_{i \in \text{Ssub}} P_{\text{sub},i}^\text{max} + \sum_{i \in \text{SEES}} P_{\text{IL},i,t} + \sum_{i \in \text{SEES}} (\eta_{Dch} \times P_{Dch,i,t} - P_{Ch,i,t}) \right) \geq P_{\text{mean}}^{\text{max}} + \lambda \sigma_{P_{\text{DG},t}}
\]

(12)

The distribution system operator can improve the confidence level by choosing a high value for \( \lambda \). Consequently, the number of committed DG units will increase and more capacity is provided to meet net demand at each hour.

- **Dispatchable DG units constraints:**

\[
P_{\text{DG},i,t}^\text{min} \leq P_{\text{DG},i,t} \leq P_{\text{DG},i,t}^\text{max}\forall i \in \text{SDG}
\]

(13)

\[
(P_{\text{DG},i,t} + R_{DG,i,t}) \leq P_{\text{DG},i,t}^\text{max}\forall i \in \text{SDG}
\]

(14)

\[
P_{\text{DG},t-1,i} - P_{\text{DG},t,i} \leq 60 \times RR_{DG,i} \forall i \in \text{SDG}, \, t = 1, \ldots, (t - 1)
\]

(15)

\[
P_{\text{DG},t,i} - P_{\text{DG},t+1,i} \leq 60 \times RR_{DG,i} \forall i \in \text{SDG}, \, t = 1, \ldots, (t - 1), P_{\text{DG},t,i} |_{t=0} = 0
\]

(16)

\[
\sum_{k=1}^{\text{MUT}} L_{t+k-1,i} \geq \text{MUT}
\]

(17)

\[
\sum_{k=1}^{\text{MDT}} (1 - L_{t+k-1,i}) \geq \text{MDT}
\]

(18)

\[
0 \leq R_{DG,i,t} \cdot L_{i,t} \leq \min\left(10 \times RR_{i}, P_{\text{DG},i,t}^\text{max} - P_{\text{DG},i,t}\right)
\]

(19)

\[
\begin{cases}
L_{i,t} - L_{i-1,t} \leq M_{t,i} \\
L_{i,t-1} - L_{i,t} \leq N_{t,i} \\
L_{i,t} - L_{i,t-1} = M_{t,i} - N_{t,i}
\end{cases}
\]

(20)

- **EES constraints:**

\[
E_{t,i} = E_{t-1,i} + \eta_{Ch} \times P_{Ch,t,i} - P_{Dch,t,i} \forall i \in \text{SEES}, \, t = 1, \ldots, 24
\]

(21)

\[
0 \leq P_{Ch,t,i} \leq P_{\text{Ch},t,i}^\text{max}
\]

(22)

\[
0 \leq P_{Dch,t,i} \leq P_{\text{Dch},t,i}^\text{max}
\]

(23)

\[
E_{t,i}^\text{min} \leq E_{t,i} \leq E_{t,i}^\text{max}
\]

(24)

\[
P_{\text{Ch},t,i} - P_{\text{Ch},t-1,i} \leq P_{\text{Ch},t,i}^\text{lim}
\]

(25)

\[
P_{\text{Dch},t,i} - P_{\text{Dch},t-1,i} \leq P_{\text{Dch},t,i}^\text{lim}
\]

(26)
3). Solving the optimization problem

The optimization problem in (5) is a mixed-integer nonlinear programming (MINLP) problem which is solved in GAMS software using DICOPT solver. The DICOPT solver is based on the extensions of the outer approximation algorithm for the equality relaxation strategy. The MINLP algorithm inside DICOPT solves a series of NLP and mixed-integer-programming (MIP) subproblems. The algorithm starts by solving the NLP in which the binary variables conditions are relaxed. If an integer solution is given by the NLP problem, the search stops. Otherwise, it continues with an alternating sequence of NLP subproblems and MIP master problems. The NLP subproblems are solved for fixed binary variables that are obtained by the MIP master problem at each iteration [35].

In this work, the solver iteratively invokes the CONOPT and CPLEX solvers for NLP and MIP solutions, respectively. The NLP solution is obtained by CONOPT which is a generalized reduced gradient-based algorithm specifically designed for large NLP problems [36]. CPLEX uses a branch and cut algorithm which solves a series of LP, subproblems, to obtain the MIP solution [37].

Under certain circumstances, the solution obtained from DICOPT solver may not be globally optimum that can happen during the iterative process of the NLP and MIP subproblems. Besides, the DICOPT algorithm has built-in provisions to handle non-convexities, and thus with a fair degree of confidence, it is reliable to give the optimal solutions to be globally optimal [38]. Despite this claim, it cannot be declared that DICOPT solver obtains the global optimum of the problem. However, it is an efficient solver used in many research works in the area, such as [38–40]. In this work, the nonlinear nature of power flow constraints makes the problem to be an MINLP one. Therefore, in order to increase the chance of obtaining more reliable solution, the MINLP problem is initialized with values obtained from an MIP problem by ignoring distribution network and assuming that all DERs are present at the point of connection to the upstream network via substation.

4. CASE STUDIES

The results of applying the proposed day-ahead scheduling model to a 32-bus radial distribution system [41] are presented and discussed in this section.

The single line diagram of the 32-bus radial distribution system is shown in Figure 2. It contains four dispatchable DG units at nodes 7, 12, 15, and 24. Also, one EES and two wind generation units
installed at nodes 20, 13, and 16, respectively. Candidate buses for DG unit installations and their capacity are selected based on [41], and the generation cost characteristics and capacity limits of the DG units and EES are provided in the Appendix. The distribution network is connected to a neighboring DISCO at node 30 with 5-MW capacity of intertie and energy contract prices for power exchange are listed in Table I. The loads at nodes 7, 13, 23, and 31 can be curtailed up to 10 percentage of their actual demand in an hour, during hours 10–22 if necessary. Note that, in this test system, the total internal generation capacity of the distribution network is less than the minimum system demand; therefore, the DISCO cannot provide further energy in order to sell it to energy market. The day-ahead energy and spinning reserve prices and forecasted load on September 1, 2010 at NYISO’s LONGIL [42] have been selected to analyze the day-ahead scheduling of the test case. In this case, the demand curve for NYISO’s LONGIL is scaled and used at all the load buses of the test system. Hourly load and wind forecasts outputs are listed in Table II. Also, the day-ahead energy and reserve market price forecasts are shown in Figure 3.

In order to show the feasibility of the proposed method, two scenarios are considered here. First, it is assumed that the DISCO only participates in the energy market. Then, it is considered that the DISCO

Table I. Energy contract prices for power exchange with the neighboring DISCO.

<table>
<thead>
<tr>
<th>Hour</th>
<th>Price ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1–9, 22–24</td>
<td>46</td>
</tr>
<tr>
<td>10–11, 18–21</td>
<td>78</td>
</tr>
<tr>
<td>12–17</td>
<td>122</td>
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Table II. Hourly load and wind power forecasts.

<table>
<thead>
<tr>
<th>Hour</th>
<th>Pd(MW)</th>
<th>Qd(Mvar)</th>
<th>Pwind(MW)</th>
<th>Hour</th>
<th>Pd(MW)</th>
<th>Qd(Mvar)</th>
<th>Pwind(MW)</th>
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<td>6.20</td>
<td>20</td>
<td>49.75</td>
<td>26.89</td>
<td>0.31</td>
</tr>
<tr>
<td>9</td>
<td>41.32</td>
<td>22.34</td>
<td>4.80</td>
<td>21</td>
<td>47.39</td>
<td>25.62</td>
<td>2.37</td>
</tr>
<tr>
<td>10</td>
<td>44.58</td>
<td>24.10</td>
<td>3.97</td>
<td>22</td>
<td>42.88</td>
<td>23.18</td>
<td>3.47</td>
</tr>
<tr>
<td>11</td>
<td>47.38</td>
<td>25.61</td>
<td>6.20</td>
<td>23</td>
<td>38.01</td>
<td>20.54</td>
<td>5.08</td>
</tr>
<tr>
<td>12</td>
<td>49.63</td>
<td>26.83</td>
<td>5.70</td>
<td>24</td>
<td>35.02</td>
<td>18.93</td>
<td>3.22</td>
</tr>
</tbody>
</table>
can participate not only in energy market, but also it can be rewarded for providing spinning reserve in the ancillary service market.

4.1. Participation in energy market

It is assumed that DISCO schedules its DERs in order to maximize its profit in the day-ahead energy market considering load and wind uncertainties along with technical network constraints. Then, in order to evaluate the impact of the proposed uncertainty model and network security constraints on DISCO’s decisions, two more cases are analyzed.

- **Case A: Including load and wind uncertainties and technical network constraints**

  Usually, the error corresponded to load and wind power forecasts are not greater than 10% of their mean value; therefore, standard deviations for load and wind power are assumed to be 5% and 10% of their expected values which are the forecast values given in Table 5. The results of solving optimization problem in (5) for $\lambda = 2$ are shown in Figure 4. The purchased power from energy market through substation is shown in Figure 4 (a); it is evident that the DISCO reduces purchasing energy from market during peak hours (hours 12–18) when energy price is high by utilizing its internal DERs. The maximum power purchased power from upstream network (i.e. substation capacity limit (45 MW)) occurs at hour 21, when energy price is relatively low and some of DG units are off and no IL is employed.

  The power exchange with neighboring DISCO is depicted in Figure 4 (b). It shows that when the energy market price is greater than the energy contract price between neighboring DISCOs, DISCO seeks to gain more profit by importing power from the neighboring DISCO and vice versa. Figure 4 (c) shows the EES level during 24 hours, EES is charged during hours 1–5 when energy price is low and is discharged during hours 13–17 when the energy prices are high.

  Optimal decision on IL contracts and the amount of the power which needs to be curtailed are shown in Figure 4 (d). The IL contract price is assumed to be 110 $/MWh. It can be observed from Figure 4 (d) that some ILs are selected to be curtailed partially at hours 12, 13, 18, and 19 hours when IL contract price is greater than market price; however, these ILs are required to respect system voltage security constraints as well as reducing losses.

  During hours 12–20, the energy market price is greater than the generation production cost of DG units; as a result, DG units are operated during these hours. As it can be seen from Figure 4 (e), DG1 and DG4 are being operated before hour 12 and after hour 20, this is due to the fact that they have lower marginal costs compared to DG2 and DG3 and due to their ramp rate, they have to be started before peak hours so that they can be fully dispatched at peak hours.

- **Case B: Neglecting wind uncertainty**

  To study the impacts of wind uncertainty on DISCO scheduling, another case is considered in which the scheduling problem in (5) is solved by neglecting the wind forecast error which would lead to less committed DERs due to less required system adequacy capacity. The results of this case are the same as before except during hours 10–13 and 18–21. The simulation results during these hours for both cases are listed in Table III. Observed that in Case B at hour 21, no DG is on, purchased power through
substation is 45 MW (maximum substation capacity limit), and DISCO can only import further power through intertie up to 2.44 MW to meet the demand in real time. As a result, if the demand increases in real time more than 5% of the expected demand value (47.39 MW), the DISCO will not be able to meet it.

Figure 4. Day-ahead scheduling for DISCO participation in energy market only. (a) Purchased power through substation. (b) Power exchange with the neighboring DISCO over intertie. (c) EES level. (d) IL. (e) DG units output power.

Table III. Comparing results of Case A and Case B.

<table>
<thead>
<tr>
<th>Hours</th>
<th>Bids for energy market (MW)</th>
<th>NO. of “on” DG units and DG’s output (MW)</th>
<th>IL options (MW)</th>
<th>EES level (MW)</th>
<th>Power exchange through intertie (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Case A</td>
<td>Case B</td>
<td>Case A</td>
<td>Case B</td>
<td>Case A</td>
</tr>
<tr>
<td>10</td>
<td>43.05</td>
<td>43.93</td>
<td>1.10</td>
<td>0.0</td>
<td>0</td>
</tr>
<tr>
<td>11</td>
<td>35.49</td>
<td>37.92</td>
<td>1.23</td>
<td>0.0</td>
<td>0</td>
</tr>
<tr>
<td>12</td>
<td>40.15</td>
<td>42.32</td>
<td>2.59</td>
<td>2.32</td>
<td>0.62</td>
</tr>
<tr>
<td>13</td>
<td>38.82</td>
<td>39.29</td>
<td>4.10</td>
<td>4.10</td>
<td>0.64</td>
</tr>
<tr>
<td>18</td>
<td>35.31</td>
<td>37.48</td>
<td>3.10</td>
<td>3.91</td>
<td>0.77</td>
</tr>
<tr>
<td>19</td>
<td>35.41</td>
<td>39.63</td>
<td>3.10</td>
<td>2.71</td>
<td>0.29</td>
</tr>
<tr>
<td>20</td>
<td>38.38</td>
<td>43.01</td>
<td>3.78</td>
<td>2.36</td>
<td>0</td>
</tr>
<tr>
<td>21</td>
<td>44.67</td>
<td>45.00</td>
<td>2.27</td>
<td>0.0</td>
<td>0</td>
</tr>
</tbody>
</table>
the demand and consequently would curtail some part of its demand. However, in Case A, DISCO can cover any wind and demand fluctuations up to 10.16 MW at hour 21 by utilizing its available DG capacity. In other words, by considering uncertainty in the optimization problem, the operation of DISCO is more reliable compared to the case that uncertainties are ignored.

- **Case C: Neglecting wind uncertainty and network constraints**

In order to show the impact of considering network constraints on DISCO’s decision and a comparison with other studies, in this case, technical network constraints are neglected. This case is similar to the one used in [8,9]. As mentioned before, in [8,9], a comprehensive short-term operation framework for a DISCO in both day-ahead and real-time energy market is presented. The day-ahead stage determines the DISCO’s decisions on purchase from the grid, DG units scheduling, and ILs contracting. In this stage, technical network constraints are neglected. The real-time stage minimizes the short-term operation cost of DISCO considering the day-ahead stage decisions. However, in [8,9], wind units, EES and intertie are not modeled. A comparison between this case and Case B is given in Table IV. The results indicate that when network constraints are respected (Case B), the purchased energy from the grid, total DG units output, and total IL are higher than Case C where mentioned network constraints are neglected, which is due to system losses and system security constraints. In Case C, DISCO should either purchase extra energy from spot market or re-dispatch its DERs in real time which usually lead to higher operation cost.

### 4.2. Participation in both energy and reserve markets

Here, DISCO participates in both energy and spinning reserve markets and seeks to optimally allocate its internal DERs to achieve maximum profit in day-ahead energy and spinning reserve markets. The uncertainties associated with load and wind are the same as before. Several cases assuming different probability of activating reserve ($r_r$) are investigated. The results of solving the problem in (5) are depicted in Figure 5.

It is observed that DISCO seeks to maximize its profit by providing spinning reserve during hours 10–21. Consequently, the amount of purchased energy from the wholesale market is varied during these hours for each scenario. The results demonstrate that by increasing $r_r$, DISCO prefers to purchase further energy from energy market and allocate additional generation capacity of internal resources for providing spinning reserve during these hours when the spinning reserve price is high.

It is worth mentioning that for $r_r=0.1$ and $r_r=0.3$ during peak hours 14–16, DISCO decides to allocate its maximum internal generation capacity to meet its internal demand instead of providing spinning reserve due to high energy price, low spinning reserve price as well as having low probability of activating reserve during these hours. Therefore, only the remaining capacity of DGs is allocated to provide spinning reserve during these hours. Note that for $r_r=0.9$, the provided spinning reserve by DG units increases up to their maximum limits, i.e. $0.03 \text{ MW/min} \times 10 \text{ min} = 0.3 \text{ MW}$ for DGs 1 and 4, and $0.025 \text{ MW/min} \times 10 \text{ min} = 0.25 \text{ MW}$ for DGs 2 and 3, during these hours.

The amount of the power which needs to be curtailed and the amount of provided spinning reserve by ILs for each scenario are shown in Figure 5(d) and Figure 5(e), respectively. It is observed that when probability of activating reserve is low, during hours 14–17, when energy market price is greater than ILs contract price, more profit can be obtained by curtailing maximum permitted ILs. Also, during the rest of hours in which ILs can be curtailed, more profit is obtained by using the rest of ILs as a reserve in the spinning reserve market. However, by increasing $r_r$, providing spinning service by ILs

<table>
<thead>
<tr>
<th>Case</th>
<th>Purchased energy from the grid (MWh)</th>
<th>Total import energy(+) or export power (−) through intertie (MWh)</th>
<th>Total DG units output (MWh)</th>
<th>Total IL (MWh)</th>
<th>Total energy (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>B</td>
<td>848.8</td>
<td>50.4</td>
<td>58.3</td>
<td>6.3</td>
<td>963.8</td>
</tr>
<tr>
<td>C</td>
<td>798.7</td>
<td>16.8</td>
<td>55.3</td>
<td>5.1</td>
<td>875.9</td>
</tr>
</tbody>
</table>

Table IV. Comparing results of Case B and Case C.
Table V. Cost, revenue, and benefit of DISCO.

<table>
<thead>
<tr>
<th>Participation in energy market</th>
<th>Participation in both energy and reserve markets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case A</td>
<td>Case B</td>
</tr>
<tr>
<td>Total DERs cost ($)</td>
<td>10771.97</td>
</tr>
<tr>
<td>Cost of purchasing energy from main grid ($)</td>
<td>59723.56</td>
</tr>
<tr>
<td>Cost (−) or Revenue (+) of power exchanging over interties ($)</td>
<td>- 4151.74</td>
</tr>
<tr>
<td>Revenue from selling power to end consumers ($)</td>
<td>168298.40</td>
</tr>
<tr>
<td>Revenue from providing spinning reserve ($)</td>
<td>-</td>
</tr>
<tr>
<td>Net benefit ($)</td>
<td>93651.12</td>
</tr>
</tbody>
</table>

Figure 5. Results of solving problem in (5) assuming DISCO participation in both energy and spinning reserve markets. (a) Purchased power through substation. (b) DG units output power. (c) Spinning reserve provided by DG units. (d) ILs. (e) Spinning reserve provided by ILs.
during hours 10–12 and 19–21 is not profitable due to the fact that payment to the ILs would be higher than its revenue from both energy and reserve markets. On the other hand, the DISCO decides to provide spinning reserve by ILs during hours 13–18 in order to very high market prices.

Finally, cost, revenue and benefit of DISCO participation only in energy market and DISCO both in energy and reserve markets for all the cases explained in Section 4.1 and 4.2 are listed in Table V. The results illustrate that the DISCO net benefit would increase by participating in both energy and reserve markets and when the probability of activating reserve is the highest.

5. CONCLUSION

This paper presents a day-ahead scheduling model for an active DISCO with DG units, EES, interties with neighboring DISCOs, and ILs. The DISCO can participate in both energy and reserve markets in order to maximize its profit. In addition to DER technical constraints, the presented model takes network technical constraints and uncertainties associated with demand and wind power production into consideration. The proposed model is formulated such that uncertainties are modeled as a chance constraint showing the confidence level of serving the loads by DISCO. The participation in only energy market and in both energy and reserve markets is examined. The results of applying DISCO scheduling model on a modified 32-bus distribution test system show that a DISCO can gain higher benefit by participating its internal DERs in both energy and reserve markets.

6. NOMENCLATURE

6.1. Sets and Indices

\(i, j\)  Index for buses.
\(t\)  Index for hours.
\(S_b\)  Set of branches of distribution network.
\(S_N\)  Set of nodes of distribution network.
\(S_{DG}\)  Set of DG unit.
\(S_{IL}\)  Set of ILs.
\(S_{EES}\)  Set of electric energy storages.
\(S_{IL,t}\)  Set of permitted hours in which interruptible load may be curtailed if necessary.
\(S_{int}\)  Set of interties.
\(S_{sub}\)  Set of substations.

6.2. Variables

\(P_{Sub,t,i}\)  Amount of power at hour \(t\) through substation \(i\) which would be offered to energy market by DISCO (positive and negative values indicate purchasing from and selling to energy market, respectively).
\(P_{an,t,i}\)  Power exchange with its neighboring DISCOs (positive sign for importing to distribution network and negative sign for export from it).
\(P_{IL,t,i}\)  Contracted amount of IL in bus \(i\) at hour \(t\)
\(P_{DG,t,i}\)  Power generated by DG unit \(i\) at hour \(t\)
\(R_t\)  Amount of reserve at hour \(t\) which would be offered to reserve market by DISCO.
\(R_{DG,t,i}\)  Amount of DG unit \(i\) generation and IL at hour \(t\) for providing spinning reserve, respectively.
\(L_{s,i}, M_{s,i}, N_{s,i}\)  Binary variable denoting DG unit commitment status, start-up, shut-down decisions, respectively.
\(P_{Ch,t,i}\)  Amount of power charged to EES \(i\)
\(P_{Disch,t,i}\)  Amount of power discharged from EES \(i\)
\(E_{t,i}\)  Energy storage level
\(P_{g,t,i}\)  Total real power production at node \(i\).
\( Q_{g,i,t} \) Total reactive power injection to node \( i \).

\( S_{ij,t} \) Apparent power flow from node \( i \) to node \( j \).

\( V_{t,i} \) Voltage amplitude at node \( i \).

\( \delta_{t,i} \) Voltage angle at node \( i \).

### 6.3. Parameters

\( \rho_{l,t} \) DISCO’s retail energy price.

\( \rho_{E,t} \) Energy market price.

\( \rho_{R,t} \) Spinning reserve market price.

\( \rho_{\text{int},t} \) Price of power exchange with neighboring DISCOs via interties

\( C_{\text{IL},t,i}(P_{\text{EES},t,i}) \) Expected interruptible load contract price

\( C_{\text{DG},t,i}(P_{\text{DG},t,i}) \) Generation cost function of a DG unit.

\( ST_{\text{DG},i}, S_{\text{DCD},i} \) Start up and shut down costs of a DG unit.

\( r_t \) Probability of activating reserve

\( P_{d,t,i} \) Real power demand at node \( i \).

\( PF \) Load power factor.

\( Q_{d,t,i} \) Reactive power demand at node \( i \).

\( P_{\text{NDG},t,i} \) Amount of power generation of a non-dispatchable DG unit

\( P_{\text{max,sub},i} \) Active power capacity of DISCO substation transformer.

\( P_{\text{max,im},i} \) Active power capacity of DISCO intertie.

\( P_{\text{max,IL},i} \) Upper limit for curtailing on interruptible load.

\( P_{\text{max,DG},i} \) Lower and upper limits on generation of a DG.

\( P_{\text{min,DG},i} \) Ramping capability for reserve of a DG in MW/min.

\( MUT, MDT \) Minimum up and down time limits of a DG in hours.

\( p_{\text{max,Ch},t,i} \), \( p_{\text{max,Dch},t,i} \) Maximum charging and discharging power limits of EES.

\( p_{\text{lim,Ch},t,i} \), \( p_{\text{lim,Dch},t,i} \) Maximum charge and discharge rate of EES.

\( E_{\text{max},i} \) Maximum and minimum limit of EES level.

\( E_{\text{min},i} \) Maximum and minimum voltage magnitude at node \( i \).

\( S_{ij} \) Capacity of the line between node \( i \) and node \( j \).

\( Y_{ij} \) Element \((i,j)\) in bus admittance matrix.

\( \theta_{ij} \) Angle of \( Y_{ij} \).

### REFERENCES

1. Rahimi F, Ipakchi A. Demand response as a market resource under the smart grid paradigm. *IEEE Transactions on Smart Grid* 2010; 1: 82–88. DOI: 10.1109/TSG.2010.2045906


DAY-AHEAD SCHEDULING OF


APPENDIX

The characteristics and cost data of dispatchable DG units and EES are provided in Table A.I and Table A.II. It is to be noted that the cost data considered in this paper is only illustrative at best and may not be closely related to those of an actual system.

Table A.I. DG units’ characteristics and cost data.

<table>
<thead>
<tr>
<th>DG no.</th>
<th>Bus number</th>
<th>A ($)</th>
<th>B ($/MW)</th>
<th>STC ($)</th>
<th>SDC ($)</th>
<th>$p_{\text{min}}$ (MW)</th>
<th>$p_{\text{max}}$ (MW)</th>
<th>R (MW/min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>7</td>
<td>27</td>
<td>79</td>
<td>35</td>
<td>15</td>
<td>1.00</td>
<td>3.5</td>
<td>0.03</td>
</tr>
<tr>
<td>2</td>
<td>12</td>
<td>25</td>
<td>87</td>
<td>25</td>
<td>10</td>
<td>0.75</td>
<td>3.0</td>
<td>0.025</td>
</tr>
<tr>
<td>3</td>
<td>15</td>
<td>28</td>
<td>92</td>
<td>25</td>
<td>10</td>
<td>0.75</td>
<td>3.0</td>
<td>0.025</td>
</tr>
<tr>
<td>4</td>
<td>24</td>
<td>26</td>
<td>81</td>
<td>35</td>
<td>15</td>
<td>1.00</td>
<td>4.1</td>
<td>0.03</td>
</tr>
</tbody>
</table>

Table A.II. EES parameters.

<table>
<thead>
<tr>
<th>Bus number</th>
<th>Capacity (MWh)</th>
<th>$p_{\text{max}}$ (MW)</th>
<th>$p_{\text{max}}$ (MW)</th>
<th>$\eta_{\text{Ch}}$</th>
<th>$\eta_{\text{DCh}}$</th>
<th>Initial and final level (MWh)</th>
<th>Available period</th>
<th>A ($)</th>
<th>B ($/MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>20</td>
<td>2.0</td>
<td>0.5</td>
<td>0.5</td>
<td>0.95</td>
<td>0.95</td>
<td>0.4</td>
<td>24/7</td>
<td>15</td>
<td>35</td>
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