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System of Systems Based Decision-Making for Power Systems Operation

Amin Kargarian Marvasti

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By

Amin Kargarian Marvasti

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By

Amin Kargarian Marvasti

Approved:

Yong Fu
(Major Professor)

Masoud Karimi-Ghartemani
(Committee Member)

Sherif Abdelwahed
(Committee Member)

Shantia Yarahmadian
(Committee Member)

James E. Fowler
(Graduate Coordinator)

Jason M. Keith
Interim Dean
Bagley College of Engineering

Name: Amin Kargarian Marvasti

Date of Degree: December 13, 2014

Institution: Mississippi State University

Major Field: Electrical Engineering

Major Professor: Dr. Yong Fu

Title of Study: System of systems based decision-making for power systems operation

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Candidate for Degree of Doctor of Philosophy

A modern power system is composed of many individual entities collaborating with each other to operate the entire system in a secure and economic manner. These entities may have different owners and operators with their own operating rules and policies, and it complicates the decision-making process in the system. In this work, a system of systems (SoS) engineering framework is presented for optimally operating the modern power systems. The proposed SoS framework defines each entity as an independent system with its own regulations, and the communication and process of information exchange between the systems are discussed. Since the independent systems are working in an interconnected system, the operating condition of one may impact the operating condition of others. According to the independent systems' characteristics and connection between them, an optimization problem is formulated for each independent system. In order to solve the optimization problem of each system and to optimally operate the entire SoS-based power system, a decentralized decision-making algorithm is developed. Using this algorithm, only a limited amount of information is exchanged among different systems, and the operators of independent systems do not need to

exchange all the information, which may be commercially sensitive, with each other. In addition, applying chance-constrained stochastic programming, the impact of uncertain variables, such as renewable generation and load demands, is modeled in the proposed SoS-based decision-making algorithm.

The proposed SoS-based decision-making algorithm is applied to find the optimal and secure operating point of an active distribution grid (ADG). This SoS framework models the distribution company (DISCO) and microgrids (MGs) as independent systems having the right to work based on their own operating rules and policies, and it coordinates the DISCO and MGs operating condition. The proposed decision-making algorithm is also performed to solve the security-constrained unit commitment incorporating distributed generations (DGs) located in ADGs. The independent system operator (ISO) and DISCO are modeled as self-governing systems, and competition and collaboration between them are explained according to the SoS framework.

DEDICATION

In dedication to my loving parents whose affection, love, encouragement and prayers make me to be who I am.

Also, I would like to dedicate this dissertation to my sister, brothers, family and friends for supporting me all the way.

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CHAPTER I

INTRODUCTION

1.1 Background

Conventional power systems were monopolistic systems in which one entity was in charge of the entire power system operation. This entity owned generation sources, transmission network, and distribution grid. The generation sources were usually large power plants connected to the transmission network. The distribution networks were passive grids playing the role of loads from the transmission system's view point. Since only one entity operates the entire grid, and it has all the information about the system, the process of decision-making in such a system is not complicated. Usually, a centralized optimization problem is formulated and solved by the operator in which the objective is to minimize the total system operating cost. The system constraints, such as power flow in the lines, capacity of the generating units, system security, etc, need to be satisfied in this optimization problem [1]-[3].

After deregulation in power systems, the electric industries have been undergoing enormous changes. The power systems have being converted from monopolistic systems into the competitive electricity markets. In such systems, many entities are introduced each of which working in the areas of generation, transmission or distribution. The entities compete with each other aiming at increasing their own benefits from the market, and this competition reduces the electricity price and the net cost [4]-[6].

Day-ahead market scheduling and hourly generation dispatch are two important tasks in the restructured power system. Usually, the market participants send their bids for producing energy to an independent system operator (ISO). After receiving all the information, the ISO solves a security-constrained unit commitment (day-ahead scheduling) problem over the 24 or 72 hour time-horizon to find the optimal and secure hourly generation schedule. In the hourly dispatch problem, an optimal power flow is formulated and solved to match the power generation and consumption in the system [4]-[6].

On the other hand, due to the economic, technical and environmental problems of the conventional power systems, use of distributed generators (DGs) to locally supply the power to the load centers has attracted more attentions during the past few decades. A cluster of loads, distributed generation sources and their links, with an energy management and automation scheme supported by a communication foundation that monitors, protects and controls distributed generation units and loads, refers to the concept of microgrid (MG) [7]-[9]. The MGs are capable of islanding from the upstream grid in case of fault occurrence. A modern distribution grid may consist of several microgrids. Therefore, compared with conventional distribution grids, distribution grids which consist of MGs are active systems being able to generate power at distribution voltage level for local loads. In such an active distribution grid, the electricity transportation through the network is bidirectional.

Solving the day-ahead market scheduling and hourly generation dispatch in the restructured power systems including active distribution networks and microgrids is more challenging compared with the systems which only include the passive distribution grids in which the power flow is unidirectional from transmission system toward distribution network. Also, the hourly power dispatch in the presence of many DG units operated by different owners is another important issue in modern power systems. The owners/operators may not want to share all of their own information, which is usually commercially sensitive, with each other. Therefore, coordination between these generation sources is a big challenge.

1.2 Literature Review

Many researchers have been working on different aspects of power systems operation and optimization. In power systems with no distributed generations, most of these works had focused on transmission systems operation [10-15]. In modern power systems in which the distribution systems are active grids, the operation of such active grids and microgrids has attracted more attention among the researchers. In order to represent the previous works related to this dissertation, we have categorized the literature review section into three subsections as follows.

1.2.1 Optimal Operation and Management of Distribution Systems and Microgrids

The daily/hourly generation scheduling for the DG units is among the most important tasks of the system operator. In general, the operator runs an optimization problem in which different economic and technical issues need to be considered in the objective function and constraints. In order to analyze the effect of operation of DG units on energy loss and the ability of distribution grids in load supply, a fuzzy evaluation tool is proposed in [16]. Reference [17] presented a centralized optimization model for a short-term distribution system operation considering incremental contribution of DG units to distribution system loss. Reference [18] introduced a two-staged optimization model for a short-term scheduling of energy resources in distribution grids. This model is a nonlinear multi-objective optimization problem that takes into account operation requirements and network constraints. To ensure stable operation of MGs, an economic dispatch problem is formulated in [19] to find the power dispatch of DGs for optimal operation of MGs. The objective of the problem is to minimize fuel cost during the grid-connected operation. A multi-agent system for real-time operation of a MG is addressed in [20] which mainly focuses on generation scheduling and demand side management. An algorithm for reactive power programming of a MG is addressed in [21]. This algorithm is a four-stage multi-objective optimization that minimizes the power loss and maximizes reactive power reserve and voltage security margin. Reference [22] addressed a coordination methodology with two layers for energy management in microgrids. According to the forecasted data, the optimal operating point of the system is obtained in layer one called schedule layer, and in layer two, dispatch layer, the controllable generating units are dispatched using the real-time data. A model predictive control approach is presented in [23] to optimally operate the microgrids as the subsystems of the distribution grid. This model is a mixed-integer linear programming (MILP) optimization problem taking into account the operation constraints. Reference [24] described a centralized controller for microgrids which intends to optimize the amount of power exchange between the distribution grid and MG as well as the power provided by local

DGs. A short-term operation framework for distribution companies (DISCOs) is proposed in [25] which included two stages, day-ahead and hour-ahead stages. The problem is a mixed integer nonlinear programming and Benders decomposition technique is applied to solve the optimization. References [26], [27] addressed a model for participating the DISCO in poll-based hour-ahead electricity markets. The DISCO could employ its own DGs in both energy and reserve markets. This model is suitable when there is high capacity of the DGs connected to the DISCO’s grid. Taking into account the impact of fuel cell power plant, an algorithm is presented in [28] for optimal operation of active distribution grids. This algorithm sought to minimize production cost, energy loss, and emission, and the fuzzy adaptive partial swarm optimization is applied to solve the optimization problem. Reference [29] proposed a two-stage stochastic model predictive control to address the uncertainty of renewable energy resources and loads in microgrids operation. This model is a mixed-integer linear programming (MIP) problem with microgrids’ operation constraints. A multi-objective nonlinear optimization problem is presented in [30] for optimal operation of active distribution grids including different microgrids. Using interline power flow controller, the MGs were connected together and then an optimal power flow (OPF) is formulated to find the optimal multi-microgrids operating point. A real-time self-tuning method is illustrated in [31] to control the optimal active and reactive power flow between the microgrid and the main grid. Indeed, day-ahead generation scheduling in the active distribution grids (ADGs) is an important issue providing the hourly plan for the operation of the system. Researchers have been working on the consideration of DGs and ADGs into the security-constrained unit commitment (SCUC) problem. Reference [32] presented a centralized optimization problem taking into account the impact of distributed energy resources in reliability constrained unit commitment. In [33], a unit commitment is formulated for distribution systems consisting of distributed generations, controllable loads, and storages. In [34], a unit commitment algorithm is addressed for the coordination between mid-term maintenance outage decisions and short-term security-constrained scheduling in active distribution grids. A bilevel optimization problem is presented in [35] to solve a multi-period energy acquisition model for a DISCO with DGs and interruptible loads in a day-ahead electricity market. A linear programming is developed in [36] to solve unit commitment of generators and storage devices of a microgrid. The objective of this optimization is cost minimization of the generating units. An energy management system is developed in [37] in order to maximize the profit of the microgrid in the day-ahead competitive electricity markets. Different types of DGs, such as wind power, PV panel, microturbine, and fuel cell, were considered in the MG operation. According to the concept of energy hubs, an energy management approach is proposed in [38] in which multiple energy carriers were addressed. In order to define the optimal day-ahead power dispatch, in this approach, the distribution companies use hub agents.

1.2.2 Security-Constrained Unit Commitment and Day-Ahead Scheduling

Security-constrained unit commitment (SCUC), which refers to a scheduling of generation resources to satisfy load demand at the least cost while considering system security, is an important decision-making tool in power systems operation. In restructured power systems, the independent system operator runs the SCUC module to schedule the hourly generation of conventional generating units connected to the transmission network

[4] and [39]. In [40], a SCUC problem is introduced for simultaneous clearing of energy and ancillary services markets. Using the Benders decomposition technique, the problem is divided into a unit commitment master problem and a network security check subproblem, and dynamic programing is applied to solve the problem. In order to find the optimal SCUC schedule in large-scale power system, a fast SCUC algorithm is proposed in [41] in which the main components consisted of single-hour unit commitment with network security, single-hour unit commitment adjustment, unit commitment, economic dispatch, and hourly network security check. This algorithm is an iterative solution procedure. A dynamic security constraint is illustrated in [42] for multi-area unit commitment in power systems. Applying the dynamic programming, the hourly schedule is obtained, and then checking the systems eigenvalues, the dynamic security is evaluated. When the dynamic security is not satisfied, an iterative algorithm is performed to redispatch the units. Reference [43] addressed a unified linear programing based approach to solve the DC security-constrained unit commitment problem. In order to check the network security, the line flow based power flow is applied to join the network security and hourly economic dispatch. A semi-definite programing model is described in [44] to solve the SCUC problem. The interior-point method is applied to directly solve the problem. The operational and optimal power flow constraints were considered in this model. Reference [45] addressed a long-term SCUC problem taking into account the fuel and emission constraints. Lagrangian relaxation is applied to decompose the problem into short-term SCUC subproblems, and to manage the Lagrangian multipliers, Dantzig–Wolfe decomposition approach is presented. A SCUC model with AC constraints is proposed in [46] in which augmented Lagrangian relaxation and dynamic programing

were applied to solve the UC problem. In this method, if there is any violation in the network constraints, Benders cuts are formed and added to the problem to adjust the UC and generation dispatch results. A SCUC problem is developed in [47] for AC/DC transmission systems. The detail formulation of high voltage direct current and transmission system with current source converters were represented in which branch flows and bus voltages were regarded in the constraints. Reference [48] presented a SCUC problem considering the generation and transmission scheduling. A mixed-integer quadratic ally constrained programming problem is illustrated in [49] for day-ahead scheduling in which the energy balance constraint, ramping cost and demand response constraints are quadratic. In this model, impact of the hourly demand response on the operation cost is taken into consideration. As an effective approach to alleviate the transmission violation and reduce the operating cost of the power system, a SCUC problem is formulated in [50] regarding the transmission switching. The optimization problem is decomposed into master problem in which the unit commitment is determined and a subproblem in which the transmission switching is performed to find the optimal generation dispatch. A SCUC formulation with compressed air energy storage and wind power generation is proposed in [51]. Emission limit and fuel constraint are included in the problem. Using the presented algorithm, both energy and ancillary services markets cab be implemented, simultaneously. Reference [52] addresses a hierarchical bidding framework for scheduling the hourly demand response in day-ahead markets. Receiving the demand response offers, the ISO runs a centralized optimization to find the optimal amount of load reduction strategies which are load shifting and curtailment. The presented day-ahead market clearing problem is a MIP problem. A profit-based fuzzy hierarchical bi-level method is proposed in [53] for coordination between the day-ahead unit commitment solution and long-term decision process. Reference [54] presents a multiobjective SCUC problem for hydro and thermal generation units. The objective function is to minimize the operation cost and emission, and the dynamic ramp rate of the thermal generating units is used instead of the fixed rate.

1.2.3 Stochastic Power Systems Operation and Scheduling

Due to the economic and environmental challenges, application of renewable energy resources, such as wind and solar power, for producing electricity has attracted more attention. However, these generation resources provide clean energies, they are usually non-dispatchable units and bring uncertainty into power systems operation and planning. This uncertainty poses more difficulties for power system operation and scheduling. On the other hand, load demand is also another uncertain variable in power systems. Different techniques, such as Monte Carlo simulation, robust optimization, chance-constrained programing, etc., have been presented in the literature in order to handle the uncertainties in power systems operation [55]-[78]. Reference [55] applied a scenario tree based Monte Carlo simulation to model inaccuracy of the load forecasting and generation outages in long term SCUC. Providing the required system reserve is taken into account into the unit commitment problem, and the algorithm sought to make a tradeoff between operating cost minimization and satisfying system reliability. Considering the wind power generation volatility, a stochastic SCUC is addressed in [56]. The forecasted wind power is used to find the hourly unit commitment solution. Then, using different scenarios for wind power, the generation dispatch is performed. A stochastic security-constrained multi-period electricity market clearing problem is presented in [57] and [58], in which the random generator and line outages are considered. A two-stage scenario based stochastic programming model is formulated in [59] to provide adequate reserve in power systems with large amounts of wind power. A dual decomposition algorithm is proposed to solve the stochastic optimization problem. In order to minimize wind power spillage, an OPF is proposed in [60] with flexible AC transmission systems (FACTS). This is a two-stage stochastic programming in which in the first stage, the decision making is implemented prior to uncertainty realization, and in the second stage, several scenarios are considered for the wind. Considering the network constraints and load shedding and the wind spillage costs, a day-ahead stochastic market clearing is presented in [61] for commutation of required reserve level. Reference [62] addresses a decentralized optimization algorithm for unit scheduling in multi-area power systems. The wind power uncertainty and the required reserve are regarded, and augmented Lagrangian algorithm is applied to solve the decentralized algorithm that requires no central operator. A two-stage stochastic convex programing algorithm is formulated in [63] for frequency-constrained economic dispatch under uncertainty. In order to find the optimal results, the problem is decomposed into smaller subproblems applying the L-shaped method. A stochastic unit commitment is formulated in [64] taking into account the impacts of large-scale renewable energy sources integration and deferrable demand. A dynamic programming algorithm is applied to coordinate the power provided by renewable energy sources and deferrable demand. A stochastic unit commitment model is formulated in [65] for the SCUC problem regarding the nodal power injection uncertainty. The problem is a two-stage robust optimization problem with wind power and price responsive demand uncertainties.

In [66], a stochastic reactive power scheduling in electricity markets is presented. The wind power uncertainty is modeled by difference scenarios obtained from quantizing the probability distribution function of the wind speed. Reference [67] addressed a probabilistic reactive power procurement for hybrid electricity markets taking into consideration the load demand. A simultaneous stochastic active and reactive power market scheduling is illustrated in [68] and [69] in which the wind power is regarded as an uncertain renewable energy. The presented problem is a multi-objective optimization objective problem that considers both economic and technical issues in the power system operation. In [70] a probabilistic optimal power flow algorithm was presented based on using the unscented transformation method. This algorithm considers the uncertainty of distributed energy resources such as wind turbines. A hybrid possibilistic–probabilistic DG impact assessment tool is developed in [71] in which the uncertainty of renewable and conventional distributed generation units is considered. Reference [72] addressed a stochastic optimization framework for power system operation. This framework is a combination of unit commitment and AC optimal power flow which takes into account the uncertainty of generation resources. In [73], an OPF is presented taking into account the load and renewable generation uncertainties. The objective function seeks to minimize the system generation cost of the most probable scenario.

Taking into account the uncertainty of the nodal power injection and random branch outages, a chance-constrained optimal reactive power dispatch is presented in [74]. This method improves the voltage security margin of the system and prevents reactive power over- and under-compensation. A chance-constrained programming algorithm is illustrated in [75] to handle the OPF problem under uncertainty. The system load is regarded as the uncertain variable having a normal distribution. The nonlinear equations are approximated by their linear model and the chance-constrained programing problem is solved. Reference [76] proposes a chance-constrained day-ahead scheduling for stochastic electricity markets operation considering load and wind power uncertainties. The line flow and reserve constraints are modeled as the chance constraints, and then are converted to a linear deterministic model. Considering the stochastic behavior of the load and its correlation structure, a stochastic unit commitment is presented in [77] using chance-constrained technique. In this method, the load requires to be supplied over the time horizon with a pre-specific probability. A sequence of deterministic unit commitment problem is solved which converges to the chance-constrained programing solution. In [78], a unit commitment problem is addressed applying the expected value and chance-constrained programming. Wind power generation is the uncertain parameter in this optimization problem, and the load balance constraint is formulated as the chance constraint. The objective function and chance constraint are converted into the sample average formulation using the sample average approximation method.

In the most of the aforementioned literatures, the transmission system, distribution networks and microgrids have been separately studied without consideration of the impact of the operating condition of one system on the operating point of other systems. Failure of considering the interaction between the systems may move the final operating point from the optimal operating point of the entire power system. In those papers that take into account the interaction and coupling constraints between the systems, (for example between the transmission system and distribution grids), usually, a centralized optimization algorithm is applied to solve the problem and optimally operate the entire system. This centralized method may result in having a huge optimization problem which is very difficult to be solved. Moreover, it is not an appropriate approach for modern power systems in which different systems have different owners and are utilized by independent operators.

1.3 Research Motivation

In the modern power systems, the individual entities are independent systems with their own operating policies and rules. The data and information of each entity are usually considered commercially sensitive, and the entities do not share all of their information with others and the system operator. Therefore, the operator accesses limited amount of information to find operating point of the entire power system, and it complicates the decision-making process in the modern power systems. Moreover, installation of the DGs in the distribution networks and introducing the MGs bring new challenges into the decision-making process in modern power systems operation, including coordination between DGs and the grid, balance between generation and consumption, and the impact of the operating cost of the DGs on the energy price.

Since in the modern power system, the entities are independent systems that can function independently with their own operation and control regulations, the competition and collaboration relationship among them can be represented by the concept of system of systems (SOS). A system of systems refers to a group of systems which are heterogeneous and independently operable with their own objectives, while they are linked together for realizing a secure and reliable operation of the entire SoS [79], [80]. Although there are similarities between systems engineering and system of systems engineering, they are different fields of study. The traditional systems engineering intends to find the optimal operation point of an individual system, and the SoS tries to find the optimal operating point of the networks including interacting systems that work together to satisfy various objectives when guaranteeing constraints of the systems. In such a SoS-based power system, the dispatching and operational independence of each system should be respected, and meanwhile, the collaboration among systems should be encouraged. Using centralized optimization algorithms which need all the information of the autonomous systems might not be the appropriate way to find the optimal operating point of such SoS-based power system since generators, loads and network information of each autonomous system, are usually considered commercially sensitive. On the other hand, determining the entire power system operation including huge numbers of design and control variables in one centralized optimization model might be challenging.

According to the above concept, the optimal power flow for hourly generation dispatch in an active distribution grid including many DGs and MGs can be effectively modeled and implemented. In such a system distribution company and MGs are independent systems. On the other hand, the day-ahead market scheduling considering active distribution grids can be performed, and a SoS-based security-constrained unit commitment can be introduced in which transmission and distribution companies are independent systems. As an important feature of this operation framework, the DGs and

MGs can confidentially participate in the market and make benefit out of their own facilities.

1.4 System of Systems Background

Recently, using the system of systems concept in the operation and optimization of complex systems has attracted more attention. Different researchers in different fields, such as health management systems, environmental systems, aerospace, robotic, disaster management, manufacturing, and so on, have focused on modeling performance of the complex systems according to the SoS framework.

A system of systems approach is presented in [81] to model healthcare systems and to prepare strategies that ameliorate the health level of a population. This approach is a nonlinear programming model intending to maximize the population's health level. A system of systems based human health care system is presented in [82] in which health management, medical diagnosis, and surgical support were described as different individual systems. These systems collaborate together to enhance the human health in the society. Reference [83] illustrated a system of systems for health care of elderly in which the independent systems include the system heart rate detector, the system respiration detector, and system cough detector. In [84], a system of systems perspective is presented to reduce the carbon emission in the residential areas. This approach is an adaptive policy design approach organizing the policy issue for interdependent relevant systems.

Reference [85] developed a system of systems framework to assess the reliability of telecommunication networks. This SoS framework combined hazard and operability analysis and fault tree analysis, and made a hybrid scheme. A system of systems framework is addressed in [86] to model the robotic-sensor system. An optimization problem is formulated for each system, and according to system interactions, a linear combination of local objective functions is obtained to formulate a global objective function for the SoS.

Reference [87] applied the system of systems engineering to China's emergency management. Since during an emergency situation many independent systems and entities should work together, using this SoS structure makes it more convenient to coordinate many systems and handle the emergency situations. Reference [88] presented a system of systems approach for modeling and simulation of a ship environment. In this approach, the complex interconnected systems of a ship such as infrastructure, crew, and workflow were regarded as individual systems, and an agent-based model is used to simulate the behavior of workflow consisting of regular maintenance, watch duty, and reporting functions. According to the system of systems engineering concept and risk analysis, an approach is addressed in [89] to manage dangerous goods transport flows through the roads. In order to govern the maritime transportation system, and to study its resilience and security, a system of systems based maritime transportation system is defined in [90]. In this model, each independent system seeks its own objectives, the interdependent systems cooperate in order to securely and safely transfer goods. Reference [91] modeled and analyzed the United States highway systems, which is a combination of highly interconnected systems, as a system of systems. In order to support aircraft protection engineering and training, a simulation-based system of systems is established in [92]. This paper discussed the individual systems in the SoS as well as their collaboration and common services. Reference [93] modeled management and operation of the unmanned aircraft system in non-segregated airspace as a complex system of systems problem.

According to the concept of system of systems, reference [94] investigated the vulnerability of smart power grids and their communication networks considering uncertainties of power generation and demand side. Reference [95] discussed a methodology to design a smarter energy and power management system. In this methodology, the transformation of power systems is based on the concept of system of systems. A smart microgrid is modeled as a system of systems in [96], and a centralized control model is presented for optimal management and operation of the system. The grid interconnection was regarded for power exchanges between the different systems. In [97], it is discussed that the future smart power grids may be modeled as a system of systems including many subsystems.

1.5 Contributions of This Dissertation

This research presents a comprehensive SoS framework for modern power systems operation. The autonomous entities are modeled as independent systems, and the collaboration between the systems are discussed. In general, the main contributions of this research are summarized as follows:

1. **The SoS-based optimal power flow (OPF):** Based on the concept of system of systems engineering, an operating framework is established for operating active distribution grids. In this framework, the DISCO and MGs are modeled as independent systems, and the process of information

exchange between the independent systems are discussed. A decentralized OPF model is formulated to maximize the benefit of each individual and autonomous system. Considering the issue that the operating point of a system in the SoS may influence the operating point of the other independent systems, a hierarchical optimization algorithm is presented to coordinate the independent systems and to find the optimal operating point of the entire SoS-based active distribution grid.

2. **The SoS-based security-constrained unit commitment:** In order to solve the SCUC problem for power systems encompassing active distribution grids, a SoS-based decision-making framework is presented. This framework is a decentralized deterministic SCUC procedure in which each independent utility or operator only deals with its own information and schedules for its own internal area and crossing borders with other systems. Thus, only a limited amount of information is exchanged among the operators of different systems, and the operators do not need to exchange all the information, which might be commercially sensitive, with each other.

3. **Chance-constrained stochastic SoS-based decision-making framework:** A decentralized stochastic decision-making algorithm is presented for day-ahead scheduling in the SoS-based power systems. The impact of uncertainties of load demand and renewable energy sources, such as wind and solar power generation, on the SoS-based decision-making is evaluated. Applying the chance-constrained stochastic

programming, reserve requirements and line flow constraints are taken into consideration in the optimization problem of each independent system.

1.6 Dissertation Organization

The rest of this dissertation is organized as follows. Chapter 2 presents a system of systems engineering framework for optimal power flow in active distribution grids. In this framework, the DISCO and MGs are regarded as the independent systems, and an AC OPF is formulated for each of them. Considering the coupling variables and constraints between the independent systems, a hierarchical optimization algorithm is presented to find the optimal operating point of the entire active distribution grid. Chapter 3 proposes a SoS-based security-constrained unit commitment for power systems including active distribution grids. The ISO and DISCOs are independent systems with their own operation rules and policies. A deterministic decentralized decision-making algorithm is presented to handle the shared variables between the systems, and to find the optimal hourly unit commitment and generation dispatch schedule for the entire SoS-based power system. Chapter 4 presents a decentralized stochastic decision-making algorithm for day-ahead scheduling in power systems encompassing active distribution grids. The uncertainty of renewable energy resources and load demand are modeled applying the chance-constrained stochastic programing. Chapter 5 provides the conclusions for the conducted work and summarizes the proposed future research directions.

CHAPTER II

SYSTEM OF SYSTEMS BASED OPTIMAL POWER FLOW IN ACTIVE DISTRIBUTION GRIDS

2.1 Introduction

In passive distribution networks, the DISCO, which is responsible for the secure operation and control of the distribution grids, purchases electricity from the wholesale energy market and sells it to the end-users. Figure 2.1 shows the power flow and cash flow directions in passive distribution networks.

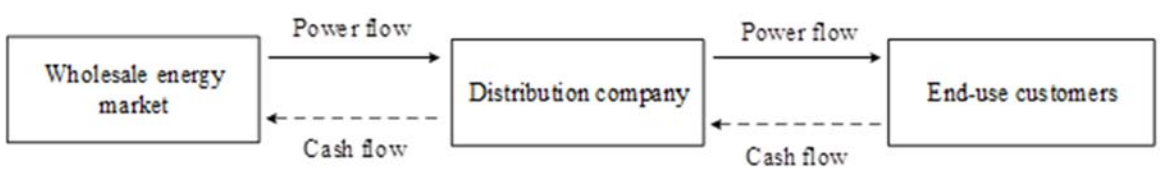


Figure 2.1 Power flow and cash flow directions in passive distribution networks

Compared with the conventional distribution networks, the distribution grids which encompass several MGs are active systems being able to produce the electric power. Power flow and cash flow directions between the entities in active distribution networks are shown in Figure 2.2, which is more complicated than that in the passive distribution systems.

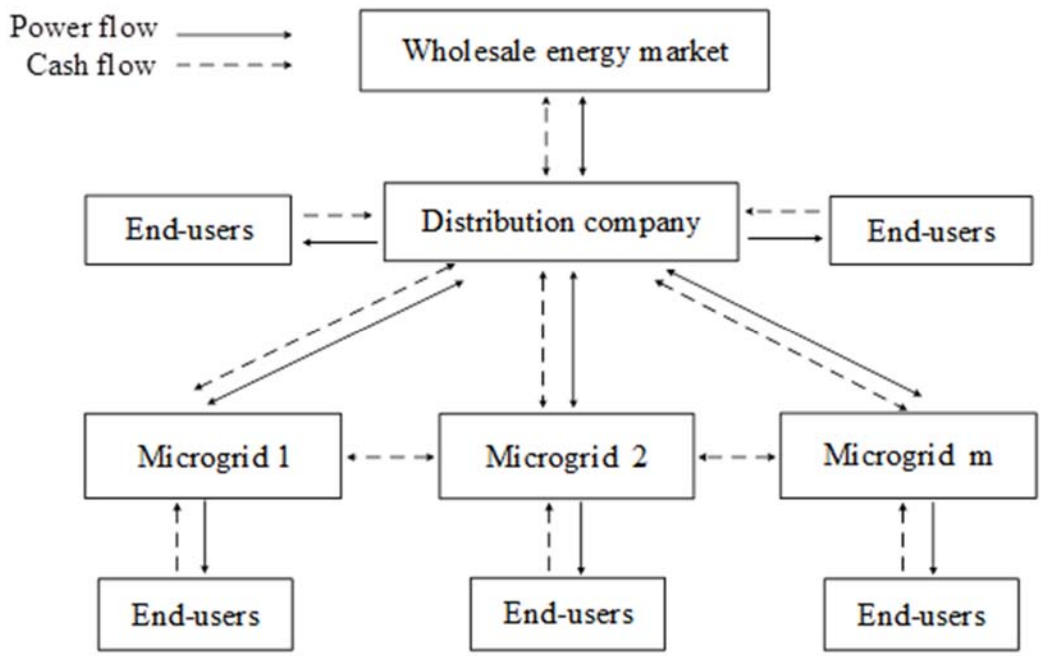


Figure 2.2 Power flow and cash flow directions in active distribution networks

The MGs might be independent systems with their own operation and control regulations, and they are connected to the DISCO that is a higher-level autonomous system to coordinate the MGs. When all the systems collaborate together to improve security and reliability of the entire distribution network, each independent system intends to increase its own benefit. Hence, the operation and control schemes of active distribution grids can be designed and implemented based on the concept of SoS.

A SoS is described as an incorporation of task-oriented or dedicated systems in a unique system in which its components: 1) collect their own resources and capabilities to construct a more complex system that has more capability and performance than simply the sum of its basic systems, and 2) are able to independently perform valid functions in their own right and continue to work to fulfill those purposes when separated from the overall system [79], [80]. Different areas are identified within the SoS research area [98], [99]. One of the most important issues in the SoS is to find the optimal operating point of the networks including interacting systems that work together to optimize various objectives while satisfying the constraints of the systems [80]. To achieve this goal, there should be suitable models and approaches for communicating and transferring information among these systems.

2.2 Active Distribution Grid as a System of Systems

In this chapter, a SoS framework for operating active distribution grid is studied. In this framework, as an autonomous system, the DISCO is responsible for the distribution grid operation. The DISCO operates its own DGs, purchases electricity from the wholesale market and even MGs, and then sells it to the down-stream customers. The DISCO is also able to sell its excess energy to the wholesale market. Each MG is a self-operated entity which aims at maximizing its own benefit. According to different factors or operational situations, the MG operator may decide to buy/sell energy from/to the DISCO. Thus, an MG may play the role of either the customer or the power provider from the viewpoint of the DISCO.

2.2.1 Required Data to Model Behaviors of Independent Systems

To model the behavior of an independent system, various types of data and information are required. In general, constant values (e.g. reactance of the lines) and decision (control and state) variables (e.g. power produced by DGs and voltage of the buses) are two types of the required data. An autonomous system defines the value of its local decision variables according to the different conditions to improve its performance and societal advantage. In the SoS framework, two other types of data are introduced here named shared parameters and shared variables. The shared parameters are those parameters that are provided for an autonomous system by other autonomous systems and have a fixed value in a certain period of system operation. However, these parameters may have different values in different intervals of system operation. For example, the limit of power exchange with MGs, which is specified by DISCO for a specific hour, is an shared parameter for the MGs. Receiving the shared parameters, an independent system is able to build its own local optimization problem. The shared variables are those decision variables that are common between at least two independent systems and link the systems together. This type of variables might be controlled by certain independent systems. In fact, the shared variables model the impact of the operating condition of the independent systems on each other. For example, the power exchange between the DISCO and an MG is a shared variable between these two independent systems, being controlled by both DISCO and MG.

2.2.2 CLIENT and ORIGIN Systems

An autonomous system may send request signals to the other independent systems and ask them for the values of the shared parameters or shared variables. The system that needs to receive information from another system is referred to as a CLIENT system. ORIGIN stands for a system that receives a request signal and responds to the signal by sending the values of some shared parameters or shared variables to another system. For example, as the CLIENT, the MG sends a request signal to the DISCO (the ORIGIN), and asks for the price of power exchange between MG and DISCO. Also, the DISCO could be the CLIENT of the information of power exchange limits which is defined by each MG as the ORIGIN.

2.2.3 Data Flow Process between the Systems

For transferring the values of the shared parameters and shared variables between the ORIGINs and CLIENTs, each autonomous system requires interaction and communication with other systems in the SoS. To specify the details, a Relationship Table shown in Figure 2.3 subdivides each system to its constituent parameters, including the constant values, decision variables, shared parameters and shared variables, and specifies the ORIGIN (o) and CLIENT (c) of the shared parameters and shared variables. Three types of data transferred between the DISCO and MGs are recognized as follows:

Type 1) DISCO specifies the shared parameters, such as price of selling/buying energy to/from the MGs, limit of power exchange with the MGs, and bilateral contracts information, and sends them to the MGs. In this case, DISCO is the ORIGIN of data and MGs are the CLIENTs.

Type 2) A certain MG defines shared parameters, such as the limit of power exchange with the DISCO and bilateral contracts information, and sends them to the DISCO and other MGs. In this case, the certain MG is the ORIGIN of data, whereas DISCO and the other MGs are the CLIENTs.

Type 3) The DISCO specifies the shared variables, such as power transferred between the DISCO and the MG, and sends it to the MG. In this case, DISCO is the ORIGIN of data and MG is the CLIENT. Conversely, the MG determines the shared variables and sends it to the DISCO.

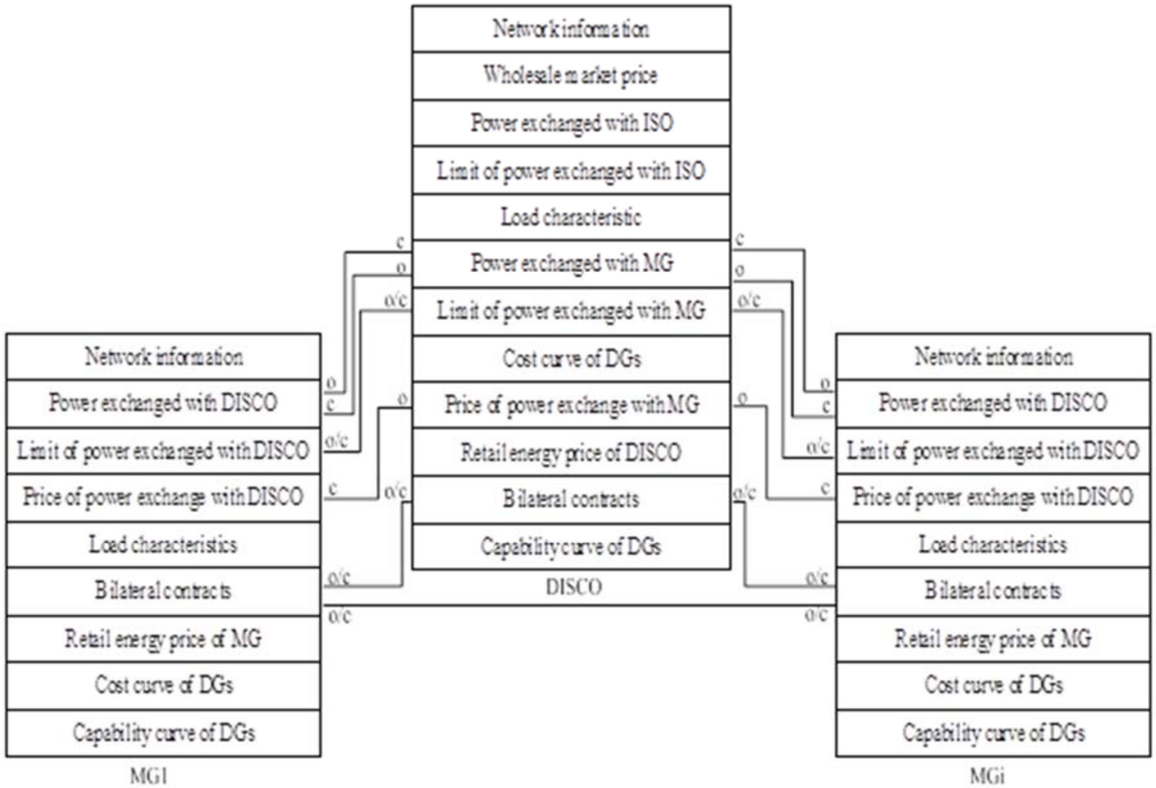


Figure 2.3 Relationship table for an active distribution grid

2.3 Decentralized Mathematical Optimization Model

Usually, a centralized optimization problem is solved to find the optimal operating point of distribution grids. The goal could be to maximize the overall benefit of the grid while meeting the operational constraints of the grid, such as bus voltage and line capacity limits. However, as both DISCO and MGs might be independent systems in an active distribution grid, exchanging information of generators, loads and network of an autonomous system is usually considered commercially sensitive. Therefore, such a centralized optimization model is no longer an appropriate approach to operate the grid.

In this section, a decentralized optimization model is formulated to determine the optimal operating point of the SoS-based active distribution grid. The proposed model is solved by a hierarchical optimization algorithm taking into account the economic and technical issues raised in the independent microgrids and distribution company operations. In the following subsections, a general hierarchical optimization model is explained based on compact formulations. Then, the optimization problem of independent DISCO and MGs, and the interactions among them are formulated and discussed in detail.

2.3.1 Hierarchical Two-Level Optimization

In this section, an algorithm is presented to decompose the optimization problem associated with an active distribution grid and to build a hierarchical two-level optimization model for its implementation. Consider the following general all-at-once optimization problem (2.1) for an active distribution grid aiming at minimizing the total operating cost (or maximizing the overall benefit) of the grid [100].

$$\begin{aligned} & Min \quad \mathrm{F}(\mathbf{x}) \\ s.t. \quad & \mathbf{G}(\mathbf{x}) \le 0 \\ & \mathbf{H}(\mathbf{x}) = 0 \end{aligned} \tag{2.1}$$

where vector **x** represents all the decision (i.e. control and state) variables, **F** is the overall objective function of the system, vector **G** represents all the inequality constraints (i.e. bus voltage and line capacity limits, generation limits of DGs), and vector **H** represents all the equality constraints (i.e. nodal active and reactive power balance equations).

A two-level SoS-based structure is illustrated in Figure 2.4 to decompose the active distribution grid into *n* independent systems. The DISCO (S1) is the only system in the first level and MGs (S2,..., Sn) connected to the DISCO are located in the second level. The DISCO may be called as the system element and MGs as the subsystem elements. As all independent subsystems are connected through one system element, the optimal operating point of the SoS-based active distribution grid can be obtained using hierarchical optimization methods. The process of modeling a hierarchical two-level optimization problem is briefly explained below.

Assume the overall objective function and constraints can be decomposed into separate elements, such as $F=f_{11}+f_{22}+\ldots+f_{2n}$, $\boldsymbol{G}=[\boldsymbol{g}_{11}, \boldsymbol{g}_{22}, \ldots, \boldsymbol{g}_{2n}]$ and $\boldsymbol{H}=[\boldsymbol{h}_{11}, \boldsymbol{h}_{22}, \ldots, \boldsymbol{h}_{2n}]$. The original all-at-once optimization problem described in (2.1) can be rewritten in the following form [101].

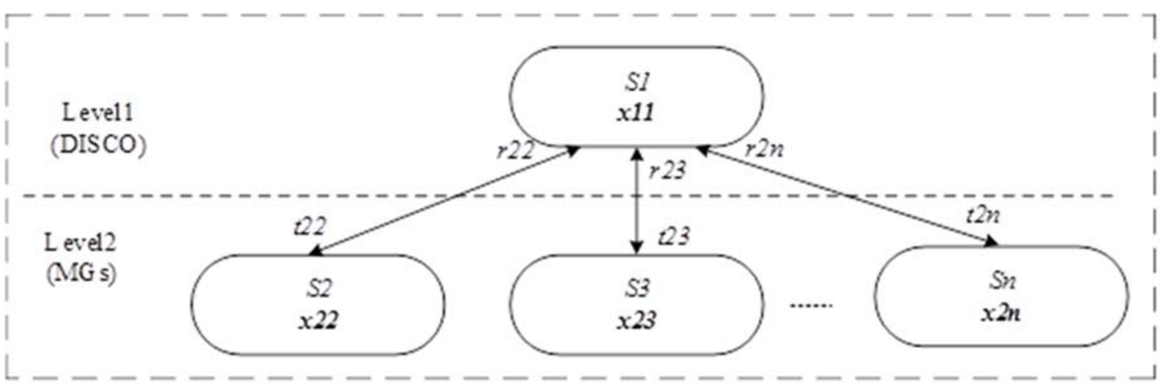


Figure 2.4 Active distribution grid in the form of a two-level SoS structure

$$Min \quad \sum_{\forall m}\sum_{\forall n} f_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) \tag{2.2}$$

$$s.t. \quad \boldsymbol{g}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) \leq 0$$

$$\boldsymbol{h}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) = 0$$

$$\forall n \in \mathrm{E}_m, \ m = \{1, 2\}$$

where the subscript *mn* denotes system *n* in level *m*, $\boldsymbol{x}_{mn}$ is the vector of local decision variables for system *n*, f_{mn} is the local objective function, $\boldsymbol{g}_{mn}$ and $\boldsymbol{h}_{mn}$ are vectors of local inequality and equality constraints related to independent system *n* in level *m*, E_m is the set of systems located in level *n*, $\boldsymbol{t}_{mn}$ is the vector of target variables shared between system *n* in level *m* and the related system in level (*m-1*), and $D_{mn} = \{d_1, ..., d_{i_{mn}}\}$ is the set of systems in level (*m+1*) that have shared variables with system *mn*. In (2.2), the vector $\boldsymbol{t}_{mn}$ represents the shared variables because of the coupling among the individual systems. To decompose the objective functions and constraints related to each independent system, response copies $\boldsymbol{r}_{mn}$ are introduced. Knowing the vector of targets, $\boldsymbol{t}_{mn}$, the consistency constraints expressed as

$$\boldsymbol{c}_{mn} = \boldsymbol{t}_{mn} - \boldsymbol{r}_{mn} = 0 \tag{2.3}$$

can be used to make the formulation in (2.2) separable. Introducing the penalty function $\pi(\cdot)$ along with (2.3) leads to a relaxed formulation of (2.2) expressed as

$$\begin{aligned} Min \quad & \sum_{\forall m}\sum_{\forall n} f_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) \\ & + \pi(\boldsymbol{c}_{22}, \boldsymbol{c}_{23,}, ..., \boldsymbol{c}_{2\mathrm{n}}) \end{aligned} \tag{2.4}$$

$$s.t. \quad \boldsymbol{g}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) \leq 0$$

$$\boldsymbol{h}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) = 0$$

$$\forall n \in \mathrm{E}_m, \ m = \{1, 2\}$$

Therefore, the optimization problem presented in (2.4) can be further decomposed into the local optimization problems corresponding to the independent systems. The optimization model for system *mn* is formulated as

$$Min \quad f_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) + \pi(\boldsymbol{c}_{mn}) \tag{2.5}$$

$$s.t. \quad \boldsymbol{g}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) \leq 0$$

$$\boldsymbol{h}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) = 0$$

where the term of $\pi(\boldsymbol{c}_{mn})$ models the impact of the operating conditions of the other independent systems on system *mn*. Using the exponential penalty function formulation proposed in [101] for modeling the $\pi(\boldsymbol{c}_{mn})$ term, the optimization problem in element *mn* is given as

$$Min \quad f_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) + \left\{\boldsymbol{\alpha}_{mn}\left(e^{(\boldsymbol{t}_{mn} - \boldsymbol{r}_{mn})} - 1\right) + \boldsymbol{\beta}_{mn}\left(e^{(\boldsymbol{r}_{mn} - \boldsymbol{t}_{mn})} - 1\right)\right\} + \sum_{d \in D_{mn}} \left\{\begin{matrix} \boldsymbol{\alpha}_{(m+1)d}\left(e^{(\boldsymbol{t}_{(m+1)d} - \boldsymbol{r}_{(n+1)d})} - 1\right) + \\ \boldsymbol{\beta}_{(m+1)d}\left(e^{(\boldsymbol{r}_{(m+1)d} - \boldsymbol{t}_{(n+1)d})} - 1\right) \end{matrix}\right\}$$

(2.6)

$$s.t. \quad \boldsymbol{g}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) \leq 0$$

$$\boldsymbol{h}_{mn}(\boldsymbol{x}_{mn}, \boldsymbol{r}_{mn}, \boldsymbol{t}_{(m+1)d_1}, ..., \boldsymbol{t}_{(m+1)d_{i_{mn}}}) = 0$$

where $\boldsymbol{\alpha}_{mn}$ and $\boldsymbol{\beta}_{mn}$ are multipliers which should be updated during the iterative solution process. As an important aspect, since the exponential penalty function is second-order differentiable, the optimization problem can be solved using any second-order method that requires the calculation of the Hessian matrix.

The optimization problem in (2.6) is for a system/subsystem element in the hierarchical structure. However, before discussing its solution process, a detailed optimization problem is formulated in the following subsections for each independent system of the SoS-based active distribution grid, in which both target and response variables, as shared variables between the systems, are identified.

2.3.2 Modeling Target and Response Variables

The target and response variables used in the proposed two-level optimization problem are shown in Figure 2.5 (a). Consider the DISCO is connected to MG_n through the line between buses B and B' as shown in Figure 2.5 (b). Buses B and B', and the linking line are modeled together as the shared connection between DISCO (level 1) and MG_n (level 2). The shared connection is taken into account in the optimization problem of both DISCO and MG_n as shown in Figure 2.5 (c) and (d), respectively. In order to address the shared connection in the hierarchical two-level optimization, the design (or state) variables $\{V_B, V_{B'}, \delta_B, \delta_{B'}\}$ influencing the power transferred through the line of shared connection are defined as the shared variables between these two independent systems, DISCO and MG_n. The power exchange between DISCO and MG_n can be calculated using these shared variables, which are regarded as target variables $\boldsymbol{t}_{2n}$ in the DISCO's optimization problem, and response variables $\boldsymbol{r}_{2n}$ in the MG_n's optimization problem. When the power is transferred from MG_n to DISCO, it is a pseudo generator for DISCO and a pseudo load for MG. However, when the power is transferred from DISCO to MG_n, it is a pseudo generator for MG and a pseudo load for DISCO.

2.3.3 Optimization Problem Model for Individual Systems

In this section, the local optimization problem for each system, MGs and DISCO, is formulated, and the sequential quadratic programming (SQP) technique is used to solve the corresponding subproblems.

2.3.3.1 Optimization Problem for MGs

To formulate the MG optimization model, MG_n (as a CILENT) needs to receive the values of the shared parameters including price of power exchange with DISCO ($\hat{\mu}$), bilateral contract information ($\hat{P}_{bc}^{sch}$), and limit of power exchange with DISCO

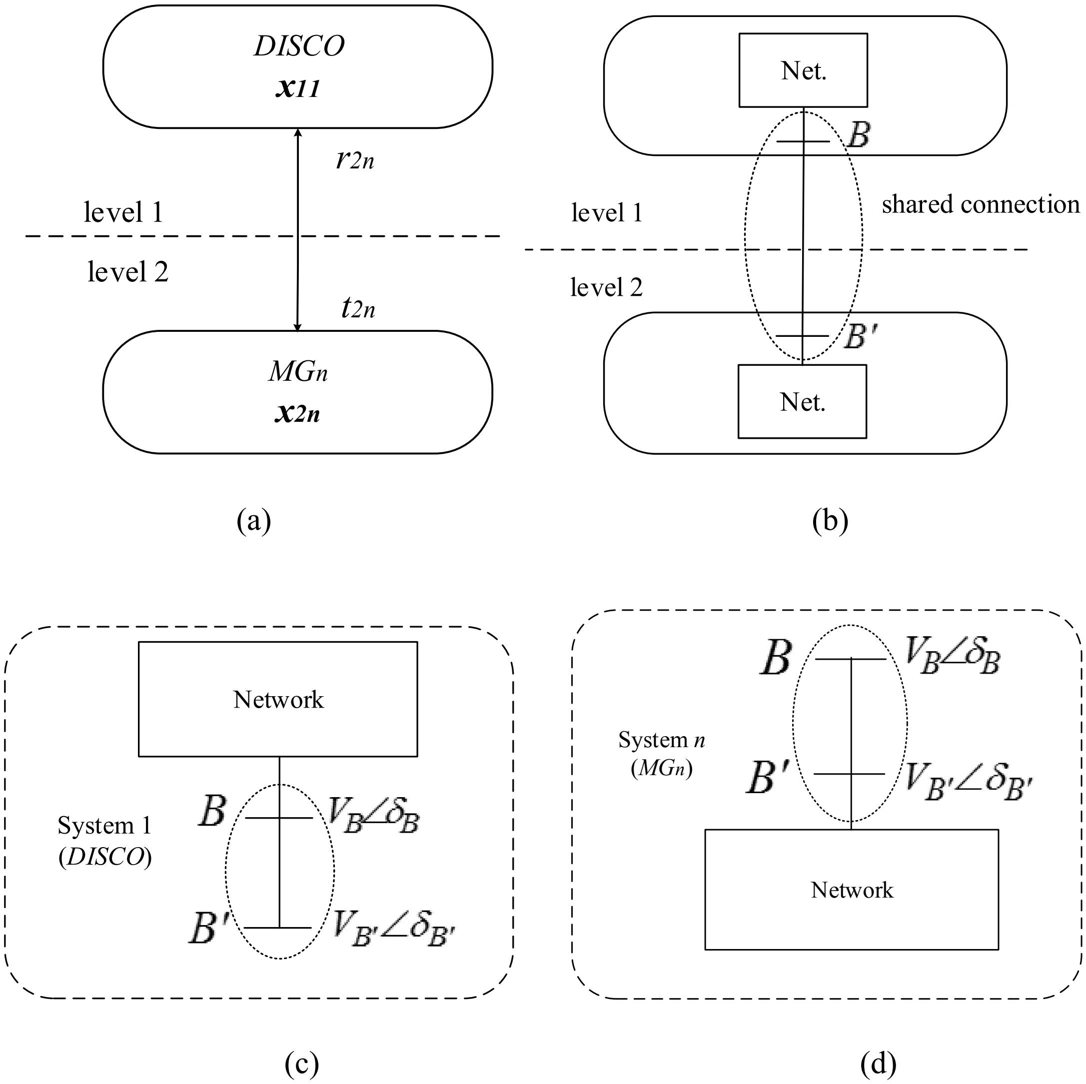


Figure 2.5 Modeling target and response variables in both Disco and MGn

($\underline{\hat{P}T_{mg,di}}$ and $\overline{\hat{P}T_{mg,di}}$) from the DISCO and other MGs (as ORIGINs). The MG optimization problem is formulated as

$$
\begin{aligned}
Min \quad & \sum_{\forall i} C_{dg,i}(P_i) - \sum_{\forall d}(\rho_M \times P_d) - \hat{\mu}(PT_{mg,di} - \sum_{\forall bc} \hat{P}_{bc}^{sch}) \\
& + \left(\boldsymbol{\alpha}_{2n} \left(e^{\left(\boldsymbol{t}_{2n}^{*} - \boldsymbol{r}_{2n}\right)} - 1 \right) + \boldsymbol{\beta}_{2n} \left(e^{\left(\boldsymbol{r}_{2n} - \boldsymbol{t}_{2n}^{*}\right)} - 1 \right) \right)
\end{aligned}
\tag{2.7}
$$

where i is index for distributed generation unit, d is index for load, bc is set of bilateral contracts, $C_{dg,i}(.)$ is generation cost function of DG i, ρ_M is retail energy price by the MG, μ is price of power exchange between DISCO and MG, P_d is real power demand of load d, and $PT_{mg,di}$ is power transferred from MG to DISCO. The first two terms in (2.7) are the generation cost of DG units and the revenue of selling the electric power to the end-users. In the third term, when $PT_{mg,di} - \sum_{\forall bc} \hat{P}_{bc}^{sch}$ is positive, the MG is selling power to DISCO, but when it is negative, the MG is purchasing power from DISCO. In this term, when the power is transferred from MG to DISCO, $PT_{mg,di}$ is positive, otherwise it is negative. And, for the bilateral transactions that MG_n provides power to the other systems, P_{bc}^{sch} is positive; otherwise, P_{bc}^{sch} is negative. As the bilateral transactions are based on long term contracts, only the cost of $PT_{mg,di} - \sum_{\forall bc} \hat{P}_{bc}^{sch}$ is included in the short-term scheduling. The last term in (2.7) is the penalty function related to the shared variables. Notice that in the penalty function, the response variables $\boldsymbol{r}_{2n}$ need to be determined, but the values of target variables $\boldsymbol{t}_{2n}^{*}$ are received from the DISCO. To meet the operational security of the MG system, the following constraints should be satisfied.

1) Nodal active and reactive power balances

$$P_{Gb} - P_{Db} = P_b(\theta, V) \quad \forall b \tag{2.8}$$

$$Q_{Gb} - Q_{Db} = Q_b(\theta, V) \quad \forall b \tag{2.9}$$

(2.8) and (2.9) show a general/compact form of the non-linear full load flow equations in which b is index for bus.

2) Generation capacity limits of the DG units

$$\underline{P_i} \le P_i \le \overline{P_i} \quad \forall i \tag{2.10}$$

$$\underline{Q_i} \le Q_i \le \overline{Q_i} \quad \forall i \tag{2.11}$$

3) Bus voltage limits

$$\underline{V_b} \le V_b \le \overline{V_b} \quad \forall b \tag{2.12}$$

4) Distribution lines capacity limits

The apparent power of all the lines including the line connecting MG to DISCO must be within the limits.

$$|S_l(\theta, V)| \le \overline{S_l} \quad \forall l \tag{2.13}$$

5) Limits of power exchange between DISCO and MG:

In the SoS-based active distribution grids scheduling, MG and DISCO, as the independent systems, may have different restrictions for the amount of power exchange between them. Thus, in addition to (2.13), the following constraint is taken into account.

$$\max\{\underline{\hat{P}T_{mg,di}}, \underline{PT_{mg,di}}\} \le PT_{mg,di} \le \min\{\overline{\hat{P}T_{mg,di}}, \overline{PT_{mg.di}}\} \tag{2.14}$$

where the shared parameters (constant for an specific period) $\underline{\hat{P}T_{mg,di}}$ and $\overline{\hat{P}T_{mg,di}}$ are minimum and maximum allowable values for the power exchange between MG and DISCO from the DISCO's perspective; and $\underline{PT_{mg,di}}$ and $\overline{PT_{mg,di}}$ are minimum and maximum acceptable values from the MG's perspective.

6) Bilateral contract transaction restrictions

An MG may have bilateral contracts with DISCO and the other MGs. The constraint (2.15) guarantees that the bilateral constraints are satisfied. For a specific period, the values of bilateral contracts (shared parameters) are known. Thus, only one of the following constraints should be applied for that operation period:

$$\begin{cases} PT_{mg,di} \geq \sum_{\forall bc} \hat{P}_{bc}^{sch} & if \sum_{\forall bc} \hat{P}_{bc}^{sch} \geq 0 \\ PT_{mg,di} \leq \sum_{\forall bc} \hat{P}_{bc}^{sch} & if \sum_{\forall bc} \hat{P}_{bc}^{sch} \leq 0 \end{cases} \tag{2.15}$$

2.3.3.2 Optimization Problem for DISCO

Receiving the shared parameters $\hat{P}_{bc}^{sch}$, $\underline{\hat{P}T_{mg,di}}$, $\overline{\hat{P}T_{mg,di}}$ from the MGs (as ORIGINs), the following optimization problem is formulated to find the optimal operating point of the DISCO (as a CLIENT). The response variables received from the MGs are used to model the penalty function. $\boldsymbol{t}_{2n}$ is treated as the vector of design variables while $\boldsymbol{r}_{2n}^{*}$ is treated as a constant term in (2.16).

$$Min \quad \sum_{\forall i} C_{dg,i}(P_i) + \sum_{\forall mg} \mu(PT_{mg,di} - \sum_{\forall bc} \hat{P}_{bc}^{sch}) + (\lambda \times PT_{ISO,di}) - \sum_{\forall d} (\rho_{\mathrm{D}} \times P_d)$$
$$+ \sum_{n \in mg} \left(\boldsymbol{\alpha}_{2n} \left(e^{\left(\boldsymbol{t}_{2n} - \boldsymbol{r}_{2n}^{*}\right)} - 1 \right) + \boldsymbol{\beta}_{2n} \left(e^{\left(\boldsymbol{r}_{2n}^{*} - \boldsymbol{t}_{2n}\right)} - 1 \right) \right)$$

(2.16)

where λ is wholesale market price, and $PT_{ISO,di}$ is power transferred from DISCO to ISO. In (2.16), the first and second terms are the generation cost of DG units and cost of power transferred from MGs to DISCO, the third and fourth terms are revenue of selling electric power to the end-users and transmission system (e.g. ISO), respectively. The last term is the penalty function related to the shared variables with MGs. Notice that in (2.16), when power is transferred from MG to DISCO, $PT_{mg,di}$ is positive; otherwise, it is negative. Also, P_{bc}^{sch} is negative when the DISCO commits power for another system based on long term bilateral transactions; otherwise, it is positive. $PT_{ISO,di}$ is positive when the power is transferred from ISO toward DISCO; otherwise, it is negative. Similarly, the following constraints should be included in this optimization model.

1) Nodal active and reactive power balances

$$P_{Gb} - P_{Db} = P_b(\theta, V) \quad \forall b \tag{2.17}$$

$$Q_{Gb} - Q_{Db} = Q_b(\theta, V) \quad \forall b \tag{2.18}$$

2) Generation capacity limits of the DG units

$$\underline{P_i} \leq P_i \leq \overline{P_i} \quad \forall i \tag{2.19}$$

$$\underline{Q_i} \leq Q_i \leq \overline{Q_i} \quad \forall i \tag{2.20}$$

3) Bus voltage limits

$$\underline{V_b} \leq V_b \leq \overline{V_b} \quad \forall b \tag{2.21}$$

4) Distribution lines capacity limits

$$| S_l(\theta,V) | \leq \overline{S_l} \quad \forall l \tag{2.22}$$

5.1) Limits of power exchange between DISCO and ISO

$$\underline{PT_{ISO,di}} \leq PT_{ISO,di} \leq \overline{PT_{ISO,di}} \tag{2.23}$$

5.2) Limits of power exchange between DISCO and MG

$$\max\{\underline{PT_{mg,di}}, \underline{\hat{P}T_{mg,di}}\} \leq PT_{mg,di} \leq \min\{\overline{PT_{mg,di}}, \overline{\hat{P}T_{mg,di}}\} \tag{2.24}$$

where the shared parameters $\underline{\hat{P}T_{mg,di}}$ and $\overline{\hat{P}T_{mg,di}}$ are respectively the minimum and maximum allowable values for the power exchanged between MG and DISCO from the MG's perspective; and the shared parameters $\underline{PT_{mg,di}}$ and $\overline{PT_{mg,di}}$ are respectively the minimum and maximum acceptable values from the DISCO's perspective.

6) Bilateral contract transaction restrictions

The following constraint satisfies the bilateral contracts that the DISCO may have with the MGs.

$$\begin{cases} PT_{mg,di} \geq \sum_{\forall bc} \hat{P}_{bc,mg}^{sch} & if \sum_{\forall bc} \hat{P}_{bc,mg}^{sch} \geq 0 \\ PT_{mg,di} \leq \sum_{\forall bc} \hat{P}_{bc,mg}^{sch} & if \sum_{\forall bc} \hat{P}_{bc,mg}^{sch} \leq 0 \end{cases} \quad \forall mg \tag{2.25}$$

2.3.4 Solution Procedure

Figure 2.6 illustrates the solution procedure of the proposed hierarchical optimization algorithm which determines the optimal operating point of all independent systems in the SoS-based active distribution grid. This algorithm has two iteration loops, inner and outer, which are explained as follows.

<u>Step 1</u>: Set the iteration index j=0 for the inner loop and k=0 for the outer loop, and choose initial values for $\boldsymbol{t}_{2n}^{*j}$, $\boldsymbol{\alpha}_{mn}^{k}$ and $\boldsymbol{\beta}_{mn}^{k}$.

<u>Step 2</u>: Set j=j+1. Solve the optimization problem (2.7)-(2.15) for each MG with $\boldsymbol{r}_{2n}^{j}$ as the design variables and the values of $\boldsymbol{t}_{2n}^{*j-1}$ from the previous iteration.

<u>Step 3</u>: Solve the local optimization problem (2.16)-(2.25) for DISCO with $\boldsymbol{t}_{2n}^{j}$ as the design variables and the values of $\boldsymbol{r}_{2n}^{*j}$ obtained in Step 2.

<u>Step 4</u>: Use (2.26) and (2.27) to check the inner loop convergence. If they are not satisfied, return to Step 2 for the next iteration; otherwise, go to Step 5.

$$\boldsymbol{t}_{2n}^{j} - \boldsymbol{t}_{2n}^{j-1} \leq \varepsilon_1 \quad \forall n \tag{2.26}$$

$$\boldsymbol{r}_{2n}^{j} - \boldsymbol{r}_{2n}^{j-1} \leq \varepsilon_1 \quad \forall n \tag{2.27}$$

Step 5: Check the following necessary-consistency (2.28) and sufficient (2.29) stopping criteria for the outer loop. If they are not satisfied, go to Step 6; otherwise, the converged optimal result is obtained and the solution procedure stops.

Necessary-consistency condition:

$$\boldsymbol{t}_{2n}^{j} - \boldsymbol{r}_{2n}^{j} \le \varepsilon_2 \quad \forall n \tag{2.28}$$

Sufficient condition:

$$\left| \frac{f_{mn}(\mathbf{x}^{(k)}) - f_{mn}(\mathbf{x}^{(k-1)})}{f_{mn}(\mathbf{x}^{(k)})} \right| \le \varepsilon_3 \quad \forall m, \forall n \tag{2.29}$$

Step 6: Set k=k+1 and update the values of multipliers $\boldsymbol{\alpha}_{mn}^{k}$ and $\boldsymbol{\beta}_{mn}^{k}$ using (2.30) and (2.31).

$$\boldsymbol{\alpha}_{mn}^{k+1} = \boldsymbol{\alpha}_{mn}^{k}\, e^{\left(\boldsymbol{t}_{2n}^{j} - \boldsymbol{r}_{2n}^{j}\right)} \tag{2.30}$$

$$\boldsymbol{\beta}_{mn}^{k+1} = \boldsymbol{\beta}_{mn}^{k}\, e^{\left(\boldsymbol{r}_{2n}^{j} - \boldsymbol{t}_{2n}^{j}\right)} \tag{2.31}$$

Step 7: Set $\boldsymbol{t}_{2n}^{*0} = \boldsymbol{t}_{2n}^{j}$, j=0, and return to Step 2.

Note that in practice the following stopping criteria may be added to the inner and outer loops in order to avoid facing the dead loop.

$$j \ge \overline{J} \tag{2.32}$$

where $\overline{J}$ is maximum allowable number of inner loop iterations.

$$k \geq \overline{K} \tag{2.33}$$

where $\overline{K}$ is maximum allowable number of outer loop iterations.

2.4 Numerical Results

The active distribution grid is shown in Figure 2.7. This grid includes one DISCO and three MGs. The system description of the DISCO and the MGs are summarized in Table 2.1. Assume that the resistance and reactance of all lines are 0.05 and 0.1 p.u., respectively; the capacity of the lines is 7 MW; the prices λ and μ are 50 $/MWh, the prices ρ_D and ρ_M are 25 ct/KWh, the limits of power exchange among transmission system (ISO), DISCO and MGs, $\underline{PT_{di,ISO}}$, $\overline{PT_{di,ISO}}$, $\underline{\hat{P}T_{mg,di}}$ and $\overline{\hat{P}T_{mg,di}}$ are defined as -50MW, 50MW, -10MW and 10MW, respectively. The reference bus is bus B1 in DISCO. The range of voltage of the buses is 0.9-1.1 p.u. The simulations are implemented on a PC with Intel(R) Core(TM) i7 with two processors at 2.8GHZ.

To test the effectiveness of the proposed SoS framework for operating the active distribution grid, the following four cases are studied:

Case 1: Only MG1 is connected to the DISCO grid

Case 2: All three MGs are connected to the DISCO grid

Case 3: Sensitivity analysis for the inner loop convergence criterion

Case 4: Sensitivity analysis for the initial condition

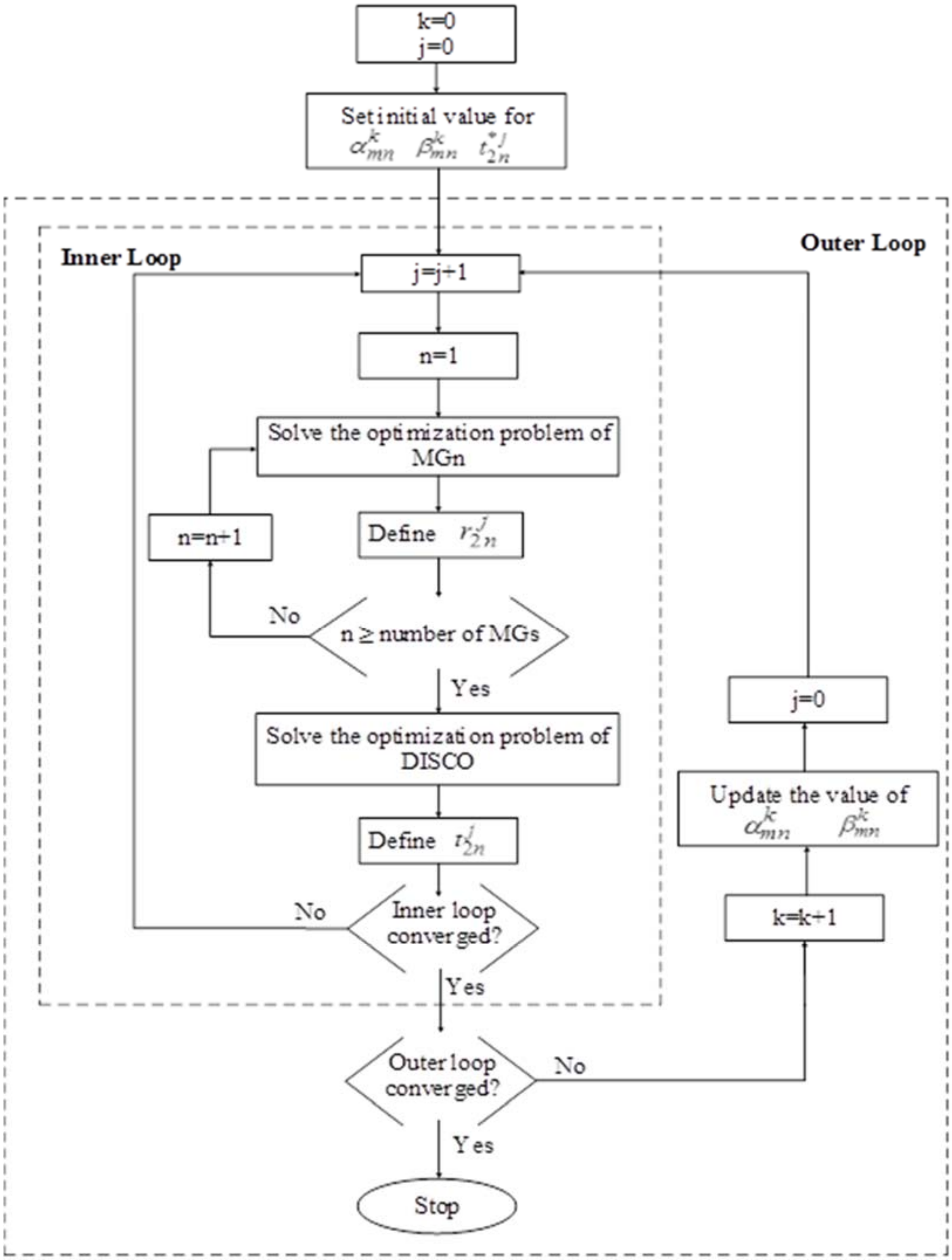


Figure 2.6 Flowchart of the solving process

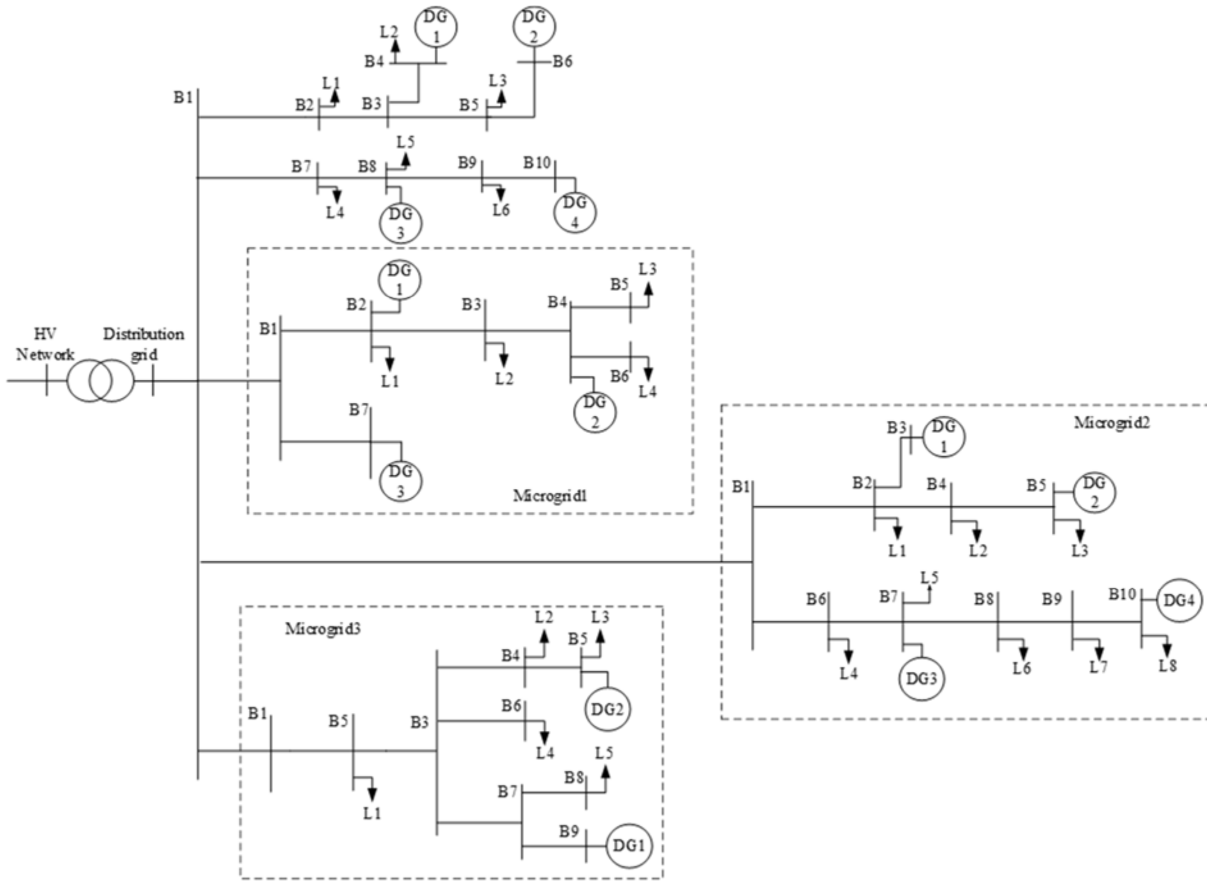


Figure 2.7 The test case active distribution grid

2.4.1 Case 1

The active distribution grid used in this case consists of the DISCO and MG1. According to the SoS concept, the entire grid is separated into two independent systems, one for DISCO and one for MG1. The initial value for $\boldsymbol{t}_{21}^{*0} = 0$ and $\boldsymbol{\alpha}_{22}^{0} = \boldsymbol{\beta}_{22}^{0} = 1.0$; and convergence thresholds ε1, ε2 and ε3 are set to 0.01, 0.001 and 0.001, respectively. Figure 2.8 shows the amount of power exchange between DISCO and MG1 in each iteration (outer loop). After 8 outer loop iterations, the converged optimal power exchange is obtained. The total calculation time is 34 seconds.

Table 2.1 Active Distribution System Description

Ind. Syst.	# of DGs	# of Buses	# of Lines	# of Loads	Total Capacity of DGs (MW)	Total MW Load	Total MVar Load
DISCO	4	10	9	6	10	3.30	3.30
MG1	3	7	6	4	9	1.79	1.79
MG2	4	10	9	8	8.5	2.63	2.63
MG3	2	9	8	5	5.5	1.75	1.75

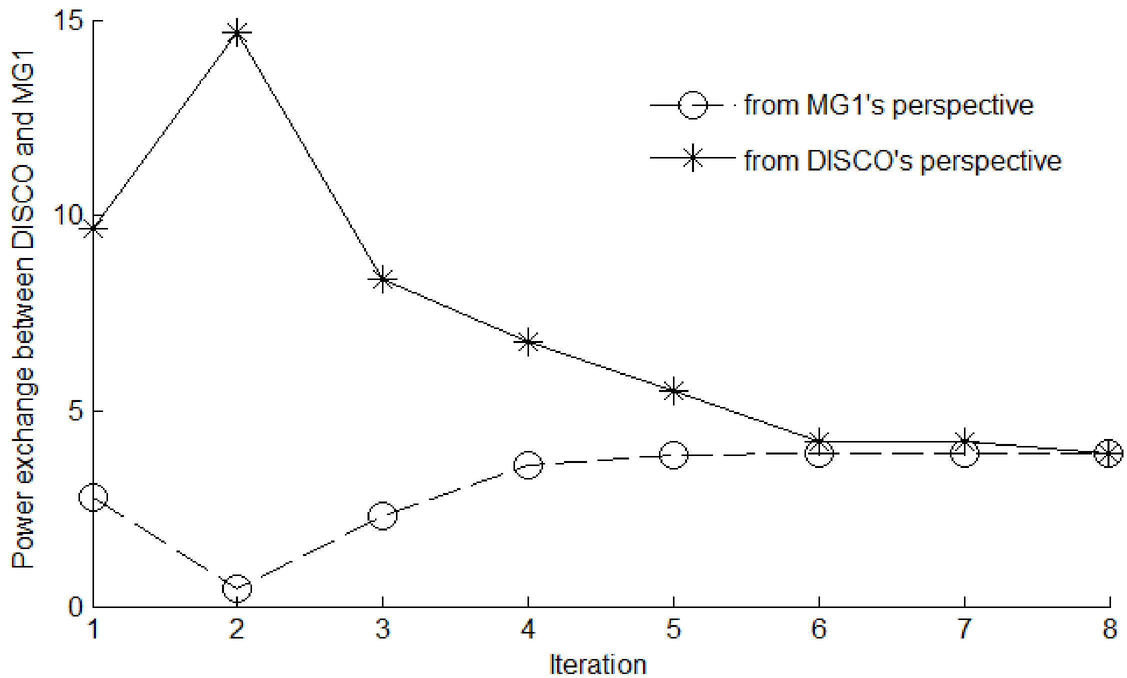


Figure 2.8 Updating process of power exchange between DISCO and MG1

Table 2.2 Active (MW) and Reactive (MVar) Power Provided by DGs

Centralized Model						Decentralized Model					
DISCO			MG1			DISCO			MG1		
No.	P	Q	No.	P	Q	No.	P	Q	No.	P	Q
HV	-5.7	5.9	DG1	3.0	2.0	HV	-5.7	5.9	DG1	3.0	2.0
DG1	3.0	0.67	DG2	3.6	-0.1	DG1	3.0	0.67	DG2	3.7	-0.1
DG2	1.85	0.22	DG3	0.0	0.15	DG2	1.85	0.22	DG3	0.0	0.16
DG3	2.5	0.55	-	-	-	DG3	2.5	0.54	-	-	-
DG4	0.65	-0.2	-	-	-	DG4	0.62	-0.2	-	-	-

The decentralized optimal power flow results, including active and reactive power provided by generation sources and bus voltages and angles, are listed in Tables 2.2 and 2.3, respectively, which is very close to the conventional centralized results. The maximum relative errors between the centralized and the decentralized results for active

Table 2.3 Bus Voltage and Angle of the Systems

Centralized Model						Decentralized Model					
DISCO			MG1			DISCO			MG1		
No.	V (pu)	δ (rad)	No.	V (pu)	δ (rad)	No.	V (pu)	δ (rad)	No.	V (pu)	δ (rad)
B1	1	0	B1	0.95	0.45	B1	1	0	B1	0.95	0.45
B2	0.90	0.32	B2	1.09	0.85	B2	0.90	0.32	B2	1.08	0.85
B3	0.97	0.70	B3	1.06	1.09	B3	0.97	0.7	B3	1.05	1.11
B4	1.1	0.89	B4	1.1	1.33	B4	1.1	0.89	B4	1.1	1.36
B5	1.01	0.85	B5	1.08	1.32	B5	1.01	0.85	B5	1.08	1.35
B6	1.1	1.00	B6	1.05	1.31	B6	1.1	1.00	B6	1.05	1.33
B7	0.99	0.17	B7	0.95	0.45	B7	0.99	0.16	B7	0.95	0.45
B8	1.1	0.39	-	-	-	B8	1.1	0.38	-	-	-
B9	1.09	0.43	-	-	-	B9	1.09	0.41	-	-	-
B10	1.1	0.50	-	-	-	B10	1.1	0.48	-	-	-

and reactive power provided by generation sources, and bus voltages and angles are 3%, 1.5%, 0.9% and 3%, respectively. Notice that in Table 2.2, the negative value for the exchanged power between DISCO and transmission system indicates that the DISCO is selling energy to the wholesale market. Using the centralized model, the power transferred from DISCO to transmission system is 5.67MW, the power exchange between DISCO and MG1 is 3.89MW, and the total benefit of distribution grid is $1414. Applying the proposed SoS framework, the DISCO is selling 5.68 MW to the wholesale energy market, the power exchange between DISCO and MG1 is 3.93MW, and the benefit of DISCO and MG1 are $832.8 and $580.6 (total benefit of the SoS is $1413.4), respectively. Note that the relative errors for the power exchange between DISCO and wholesale market, the power exchange between DISCO and MG1, and total benefit of the grid, are 0.17%, 1% and 0.04%, respectively.

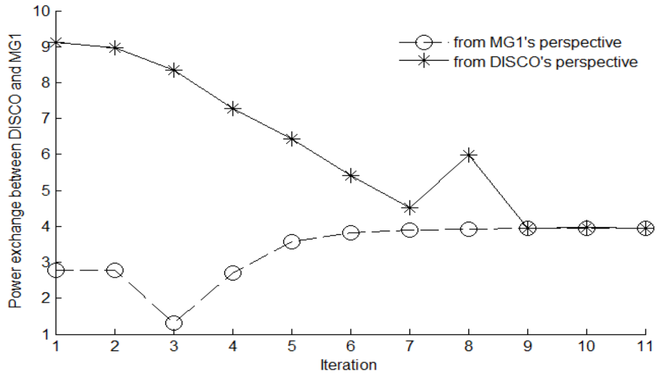
2.4.2 Case 2

In this case, the proposed SoS framework is applied on an active distribution grid in which one independent DISCO is linked with three independent MGs as shown in Figure 2.7. Again, based on the SoS concept, the entire grid is separated into four different independent systems. Set the initial values $\boldsymbol{t}_{2n}^{*0}= 0$, $\boldsymbol{\alpha}_{2n}^{0}= 1$, and $\boldsymbol{\beta}_{2n}^{0}$ =1 (n=1, 2, 3), and pick the values 0.01, 0.001, and 0.001 for the convergence thresholds ε1, ε2, and ε3, respectively. The amount of power exchange between the DISCO and three MGs in each outer loop iteration is shown in Figure 2.9. The algorithm converges after 11 iterations, and the total calculation time is 98 seconds. The scheduled active and reactive power generations of DGs are summarized in Table 2.4. In order to check the validity of the results of the proposed decentralized algorithm, the active and reactive power output of the generation sources obtained from the conventional centralized algorithm are depicted in Table 2.4. Also, the optimal power exchange between DISCO and three MGs, and total benefit of each independent system are listed in Table 2.5.

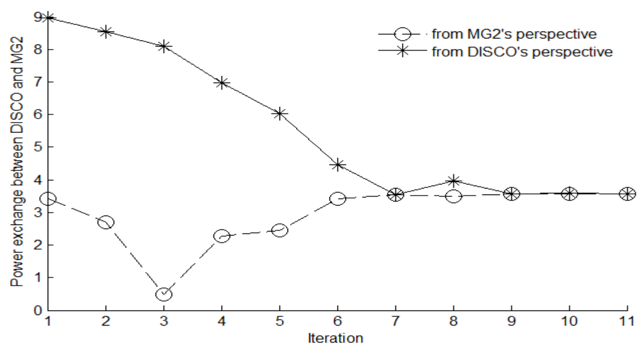
The maximum relative errors between the centralized and the decentralized results for active and reactive power are 2.7% and 4%, respectively. Note that the power is transferring from the MGs toward the DISCO. Thus, the DISCO is purchasing energy from the MGs, and the shared lines between the DISCO and the MGs behave as pseudo generations for the DISCO and as pseudo loads for the MGs. In addition, the DISCO is selling the power (9.20MW) to the wholesale energy market, including the power (9.01MW) purchased from three MGs plus the power (0.19MW) generated by its own DGs. The total benefit of the DISCO and the MG1 to 3 are $754.1, $581.1, $750, and $460, respectively, and, thus, the total benefit of the entire active distribution grid is $2545.2. The relative errors for the power exchange between DISCO and wholesale market, the power exchange between DISCO and MGs 1-3, and total benefit of the grid, are 0.44%, 1%, 0.85%, 1.3% and 0.1%, respectively.

Table 2.4 Active and Reactive Power Produced by Power Providers

Ind. Syst.	Gen. Sources	Centralized Model		Decentralized Model	
		P (MW)	Q (MVar)	P (MW)	Q (MVar)
System1 (DISCO)	HV Network	-9.15	9.53	-9.20	9.50
	DG_1	3.00	0.64	3.00	0.66
	DG_2	1.79	0.21	1.82	0.22
	DG_3	2.50	0.58	2.50	0.57
	DG_4	0.72	-0.20	0.70	-0.20
System2 (MG1)	DG_1	3.00	2.00	3.00	2.00
	DG_2	3.82	-0.10	3.85	-0.10
	DG_3	0.00	0.29	0.00	0.30
System3 (MG2)	DG_1	2.00	0.16	2.00	0.16
	DG_2	1.42	0.37	1.40	0.36
	DG_3	1.00	1.00	1.00	1.00
	DG_4	2.50	0.12	2.50	0.12
System4 (MG3)	DG_1	1.21	0.74	1.20	0.72
	DG_2	2.42	0.24	2.40	0.25



(a)



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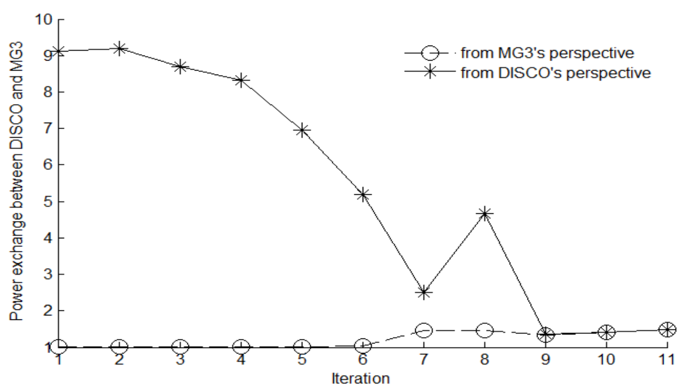


(c)

Figure 2.9 Power exchange between DISCO and MG a) 1, b) 2 and c) 3

Table 2.5 Amount of Power Exchange and Total Benefit of Each System

Ind. Syst.	Centralized Model		Decentralized Model	
	Power exchange with other systems (MW)	Total benefit ($)	Power exchange with other systems (MW)	Total benefit ($)
System1 (DISCO)	-8.97	752.8	-9.01	754.1
System2 (MG1)	3.92	579.4	3.96	581.1
System3 (MG2)	3.53	750.9	3.56	750
System4 (MG3)	1.51	459.5	1.49	460

2.4.3 Case 3

In order to analyze the sensitivity of the solution process to the convergence criterion for the inner loop, Case 1 was repeated using different values for ε1. However, the necessary-consistency and sufficient criteria ε2 and ε3 are fixed to 0.001 in order to guarantee an acceptable result for all the simulations.

Setting different values for ε1 and implementing the proposed hierarchical two-level algorithm gives the results shown in Table 2.6 with respect to each value of ε1, including the number of iterations of inner loop (J) and outer loop (K), the total calculation time (T), as well as the power exchange between DISCO and MG1 ($P_{d,m}$ from the DISCO's perspective, and $P_{m,d}$ from the MG1's perspective), and the benefit of the DISCO and MG1.

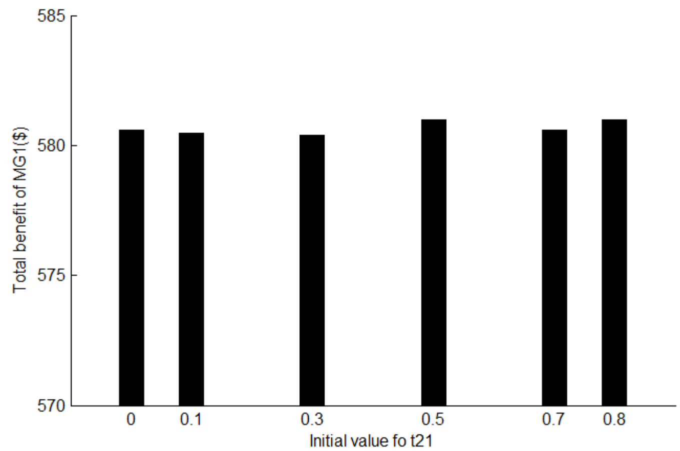
Observe that the number of outer loop iterations, *K* is almost unchanged, but the inner loop iterations J and the total calculation time T are increased by setting a smaller value for ε1 (increasing precision of the inner loop). In other words, the computational cost of the algorithm increases with decreasing ε1. When ε1 is 0.1, the difference between Pd,m and Pm,d is 0.13%. However, for ε1 equal to 0.01-0.00001, that difference is reduced to 0.008%, 0.002%, 0% and 0%, respectively, but the calculation time is increased significantly. The total benefit of the grid is almost the same for all the values of ε1. Comparing the results in Table 2.6 shows that the computational cost of setting ε1 equal to 0.01 is slightly more than setting 0.1 for ε1, but it results in more accurate results. Consequently, we have chosen 0.01 for ε1 in Cases 1 and 2 to make a trade-off between solution accuracy and calculation effort.

Table 2.6 Impact of ε_1 Variations on the Performance of the Proposed Algorithm

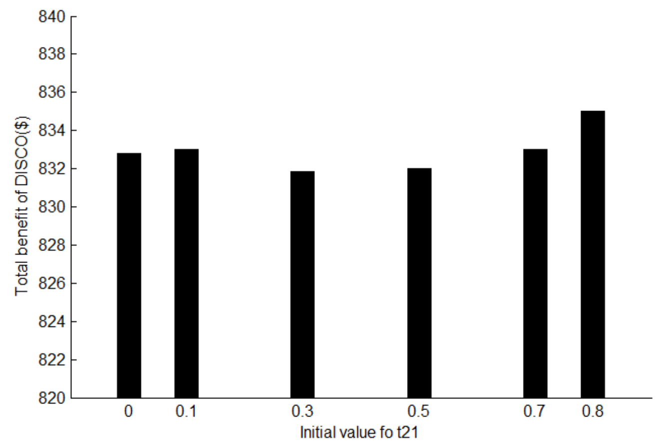
Value of ε_1	J (#)	K (#)	T (sec.)	$P_{d,m}$ (MW)	$P_{m,d}$ (MW)	Benefit of DISCO ($)	Benefit of MG1 ($)
0.10000	5	7	30	3.9304	3.9253	832.6	580.8
0.01000	7	8	34	3.9267	3.9264	832.8	580.6
0.00100	26	8	71	3.9276	3.9275	832.8	580.6
0.00010	87	8	315	3.9340	3.9339	832.5	580.7
0.00001	716	7	1175	3.9230	3.9230	832.9	580.5

2.4.4 **Case** 4

Similar to Case 3, in this case, a sensitivity analysis is performed to study the impact of initial values of the shared variables on the final operating point of the ADG. The initial value for $\boldsymbol{\alpha}_{22}^{0} = \boldsymbol{\beta}_{22}^{0} = 1.0$; and convergence thresholds ε1, ε2 and ε3 are fixed to 0.01, 0.001 and 0.001, respectively. Different values are selected for the he initial value of the shared variable $\boldsymbol{t}_{21}^{*0}$, and the proposed hierarchical two-level algorithm is implemented. The total benefit of DISCO and MG1, as well as the total benefit of the



(a)



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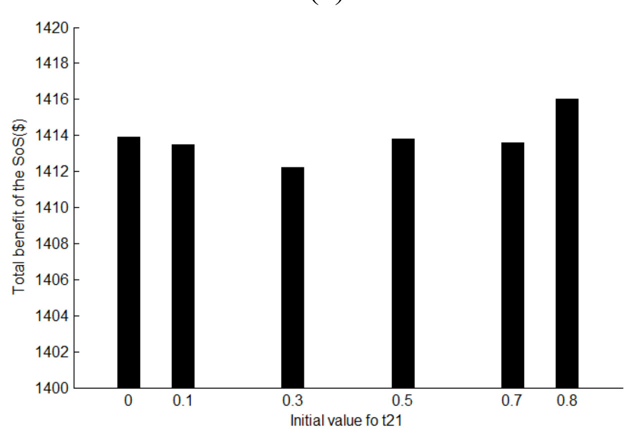


(c)

Figure 2.10 Total benefit of a) MG1, b) DISCO, and c) SoS based ADG obtained by setting various initial values for the shared variables.

SoS based ADG are computed. As it is shown in Figure 2.10, the final results slightly vary for different values of $\boldsymbol{t}_{21}^{*0}$ which is negligible. Note that the reasonable values ought to be selected for the shared variables according to the systems characteristics. As we study the power systems, 1 could be a good initial guess for the voltage magnitude of the buses, and the values of the voltage angle could be set in the range of 0~0.5.

2.5 Summary

Nowadays, the distribution grids are moving toward decomposition into many small-scale smart microgrids which locally support the load centers. Therefore, the SoS-based optimization problems can be very promising for the collaboration between the systems. In this chapter, a SoS framework was presented for optimizing the operation of active electric power distribution grids. In this framework, the DISCO and microgrids were regarded as the self-governing systems that were autonomously managed and operated aiming at maximizing their own benefits. The data flow process of communicating and transferring data between the systems were discussed. And, the concept of ORIGIN and CLIENT systems, shared parameters and shared variables were defined in this chapter. The decentralized optimization problem was formulated to model the SoS-based operation. A hierarchical two-level algorithm was applied to solve the proposed problem and coordinate the operating points of all independent systems. The numerical results showed the accuracy and convergence performance of the proposed SoS framework for operating active distribution grids.

CHAPTER III

SYSTEM OF SYSTEMS BASED SECURITY-CONSTRAINED UNIT COMMITMENT

3.1 Introduction

Security-constrained unit commitment (SCUC), which refers to a scheduling of generation resources to satisfy load demand at the least cost while considering system security, is an important decision-making tool in power systems operation [4], and [102]-[107]. In general, the SCUC is a constrained optimization problem intending to minimize the operating cost of the system including units' generation and startup/shutdown costs. The equality and inequality constraints consist of unit commitment constraints such as power balance, system spinning and operating reserve requirements, generating unit capacity, and units' ramping up/down and minimum on/off time limits, as well as power flow equations and transmission network security constraints.

In power systems without DGs and active distribution grids, the independent system operator (ISO) runs the SCUC module to schedule the hourly generation of conventional generating units connected to the transmission network. In such a model, the passive distribution grids are considered as the constant loads. In restructured power systems including active distribution grids, similar to the ISO, the distribution company, as an autonomous system, would like to optimally operate the ADG. Therefore, the

DISCO can run its own SCUC, which is formulated according to the ADG's characteristics, to find the hourly generation schedule of the DGs.

The regular SCUC problem can be individually applied for each autonomous system, ISO and DISCOs. However, there are a few differences in characteristics of the generating units and network of the ISO and DISCOs, which result in differences in their individual SCUC formulations. For example, there might be many fast DG units in the ADGs, and the ramping constraints and the minimum on/off time requirements of such units may be negligible in its hourly SCUC problem. The transmission network is meshed while the distribution network is usually radial. The ISO and DISCOs solve their own individual SCUC problem in order to find their own optimal operating point. Note that in an ADG, there might be several DG units which have different owners, the DISCO or customers. Beside its own DG units, the DISCO can play the role of aggregator and handle the DGs owned by the customers in the proposed commitment and dispatch problems. Different approaches have been presented to solve the SCUC problem, like Lagrangian relaxation and mixed-integer programming (MIP) methods [4], and [102]-[106]. In this research, the MIP model presented in [104] is applied to solve the regular SCUC of each independent system.

3.2 Modern Power System as a System of Systems

As shown in Figure 3.1, in a modern power system encompassing active distribution grids, the electricity transportation, information and cash flow are bidirectional, from transmission system to active distribution grids or vice versa, and it complicates system analysis. The conventional centralized optimization algorithm might be applied to solve the SCUC problem in such a power system. To implement this algorithm, the operator needs to receive all the information about ADGs and DGs. Since the information in a restructured power system might be commercially sensitive, it is not appropriate that a DISCO provides all the information for the systems operator (as another entity in the market). On the other hand, there are many ADGs and DGs in distribution grids, and considering the entire power system in a single optimization problem, we might encounter a very large optimization which is difficult to be solved.

In this research, we define the transmission system operator (ISO) and ADG operator (DISCO) as the independent system regulators, and design and implement a decentralized security-constrained unit commitment for the restructured power systems in accordance with a system of systems framework. In this framework, each independent utility or operator only deals with its own information and schedules for its own internal area and crossing borders with other systems. Thus, the operators do not need to exchange all the information, and only a limited amount of information is exchanged among them.

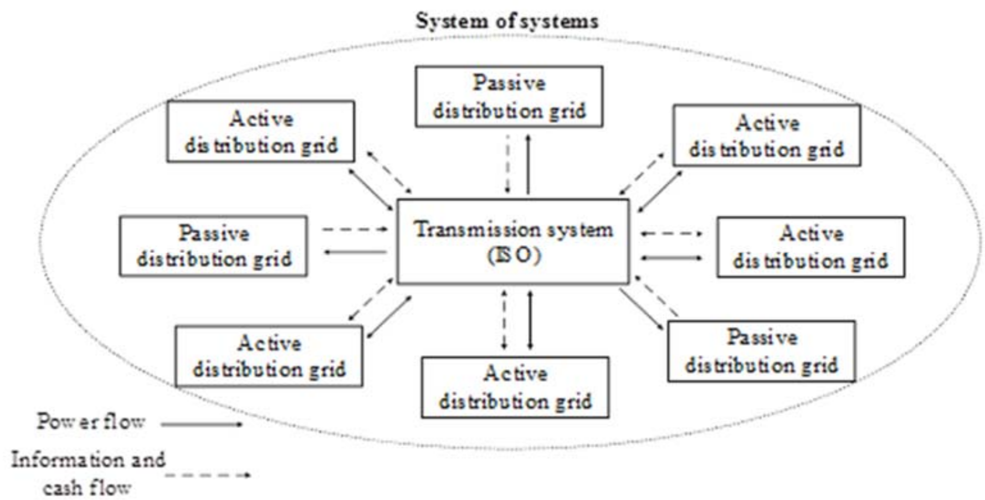


Figure 3.1 Power system as a system of systems

3.3 Decentralized Decision-Making Solution

If there is no connection between the transmission network and ADGs, the ISO and DISCOs can apply the existing SCUC algorithms to find the hourly generation schedule of their own generating units. However, when the transmission network and ADGs are indeed linked together, the optimal operating point of one of them impacts the operating point of others. In order to model this interaction between the systems in the SoS-based SCUC problem, and to find the optimal operating point of the ISO and DISCOs, a decentralized decision-making solution is presented in this section, which will better accommodate distributed technologies and active distribution grids participation into the market. A hierarchical two-level optimization algorithm can be applied to implement the decentralized decision-making solution to the SoS-based SCUC problem.

3.3.1 Hierarchical Two-Level Optimization Problem

Figure 3.2 (a) shows an ADG physically connected to the transmission system. Assume that the formula (3.1) expresses the general SCUC problem for the ISO.

$$\begin{aligned} Min \quad & f(\mathbf{x}) \\ s.t. \quad & \boldsymbol{g}(\mathbf{x}) \leq 0 \\ & \boldsymbol{h}(\mathbf{x}) = 0 \end{aligned} \tag{3.1}$$

where $\mathbf{x}$ represents the design variables for the ISO, f is overall objective function, and $\boldsymbol{g}$ and $\boldsymbol{h}$ are all inequality and equality constraints for the ISO. The same general optimization problem is written for the DISCO as an independent system.

$$\begin{aligned} Min \quad & f(\mathbf{y}) \\ s.t. \quad & \boldsymbol{g}(\mathbf{y}) \leq 0 \\ & \boldsymbol{h}(\mathbf{y}) = 0 \end{aligned} \tag{3.2}$$

In (3.2), $\mathbf{y}$ represents the design variables for the DISCO, f is the objective function, and $\boldsymbol{g}$ and $\boldsymbol{h}$ are constraints for the DISCO. The transmission system and ADG are linked through the substation system, and have shared variables with each other. Introduce $\tilde{\mathbf{x}}$ and $\tilde{\mathbf{y}}$ as the local design variables which are exclusively for ISO and DISCO, respectively. Also, introduce the set of design variables $\mathbf{z}$ which represents the shared variables between these two independent systems. Then, (3.1) and (3.2) can be rewritten as (3.3) and (3.4), respectively.

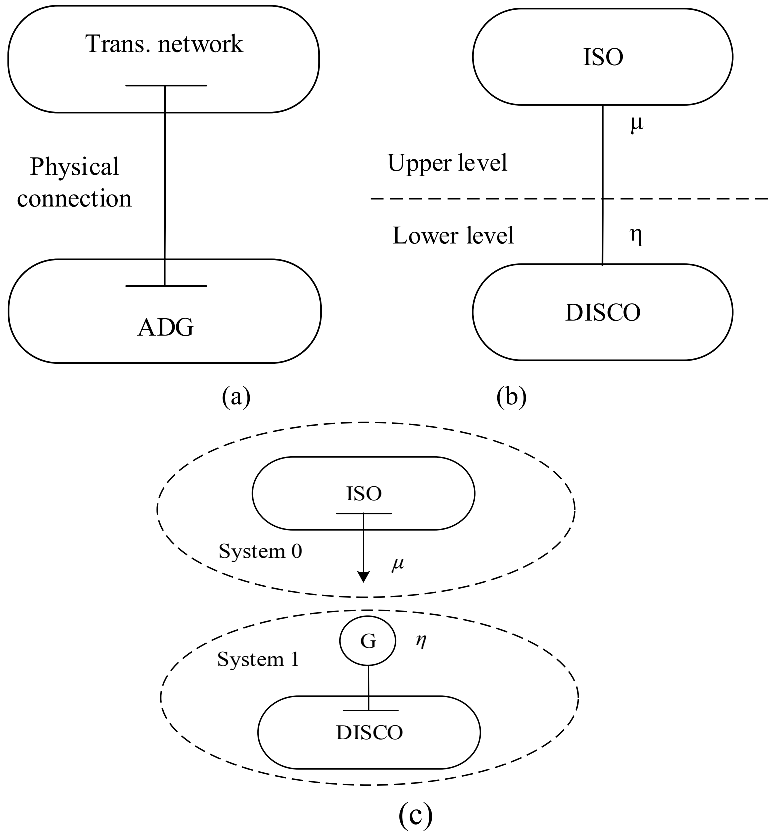


Figure 3.2 a) An ADG physically connected to ISO, b) hierarchical two-level SoS structure, and c) modeling target and response variables

$$
\begin{aligned}
&Min \quad f(\tilde{\mathbf{x}},\mathbf{z}) \\
&s.t. \quad \boldsymbol{g}(\tilde{\mathbf{x}},\mathbf{z}) \le 0 \\
&\qquad\; \boldsymbol{h}(\tilde{\mathbf{x}},\mathbf{z}) = 0
\end{aligned}
\tag{3.3}
$$

$$
\begin{aligned}
&Min \quad f(\tilde{\mathbf{y}},\mathbf{z}) \\
&s.t. \quad \boldsymbol{g}(\tilde{\mathbf{y}},\mathbf{z}) \le 0 \\
&\qquad\; \boldsymbol{h}(\tilde{\mathbf{y}},\mathbf{z}) = 0
\end{aligned}
\tag{3.4}
$$

Because of the shared variable $\mathbf{z}$, (3.3) and (3.4) cannot be solved separately. In order to decompose the above optimization problems and make them independently solvable, a hierarchical two-level SoS structure is presented in Figure 3.2 (b) in which the ISO is located in upper level and DISCO is in lower level. Two different sets of variables are introduced to model the shared variables and formulate the self-governing objective functions and constraints related to each independent system. The first variable, $\boldsymbol{\eta}$, is called target variable which is vector of the shared variables between two systems sending from ISO to DISCO. In fact, $\boldsymbol{\eta}$ is transmitted from the system in upper level toward the system in lower level. Response variable, $\boldsymbol{\mu}$, is the second variable which is vector of the shared variables sending from DISCO in the lower level toward the ISO in the upper level. According to the target and response variables, the consistency constraint expressed by (3.5) is introduced [100].

$$\boldsymbol{c} = \boldsymbol{\eta} - \boldsymbol{\mu} = 0 \tag{3.5}$$

Constraint (3.5) should be regarded in the optimization problems of ISO and DISCO. Using the penalty function, the consistency constraints can be relaxed. Then, the separated ISO and DISCO's local optimization problems are (3.6) and (3.7), respectively.

$$\begin{aligned} Min \quad & f(\tilde{\mathbf{x}}, \mathbf{z}) + \pi(\mathbf{c}) \\ s.t. \quad & \boldsymbol{g}(\tilde{\mathbf{x}}, \mathbf{z}) \le 0 \\ & \boldsymbol{h}(\tilde{\mathbf{x}}, \mathbf{z}) = 0 \\ & \forall \mathbf{z} \in \{\boldsymbol{\eta}, \boldsymbol{\mu}\} \end{aligned} \tag{3.6}$$

$$\begin{aligned} Min \quad & f(\tilde{\mathbf{y}}, \mathbf{z}) + \pi(\mathbf{c}) \\ s.t. \quad & \boldsymbol{g}(\tilde{\mathbf{y}}, \mathbf{z}) \le 0 \\ & \boldsymbol{h}(\tilde{\mathbf{y}}, \mathbf{z}) = 0 \end{aligned} \tag{3.7}$$

$$\forall \mathbf{z} \in \{\boldsymbol{\eta}, \boldsymbol{\mu}\}$$

3.3.2 Modeling Target and Response Variables

In this subsection, both target and response variables, as shared variables between the systems, are identified based on the physical connection between the transmission system and ADGs. As shown in Figure 3.2, the power exchange through the physical connection is the shared variable between these two independent systems. This variable links the SCUC problems of ISO and DISCO together. Assume that the power is transferred from the ISO toward DISCO. The target and response variables can be modeled as shown in Figure 3.2 (c) where ISO is the independent system 0 and DISCO is system 1. From the DISCO's perspective, the line flow is modeled as a pseudo generator supplying to DISCO; from the ISO's perspective, the line flow is modeled as a pseudo load supplied by ISO. Therefore, η is the pseudo generation for the DISCO, and μ is the pseudo load for ISO. It should be noted that the pseudo generation might be negative which means the power is delivered to the ISO by DISCO, and the pseudo load of ISO, μ, may also be negative.

Here, the power demanded by DISCO and supplied by ISO in the DISCO's optimization problem is defined in (3.8); the power generated by ISO and supplied to DISCO in ISO's optimization problem is (3.9). In addition, both variables PG_D and PD_S should be between minimum and maximum capacity of the line connecting the transmission network to ADG_j.

$$\mu = PG_D \tag{3.8}$$

$$\eta = PD_S \tag{3.9}$$

3.3.3 Multi-ADGs and Multi-Period Model

When there are many ADGs connected to the transmission network, Figure 3.2 can be extended to Figure 3.3. The only system in upper level is ISO and all DISCOs are located in lower level. The ISO has shared variables with many DISCOs, and its optimization problem (3.6) is modified by (3.10) which includes the penalty function modeling consistency constraints between ISO and all DISCOs.

$$\begin{aligned}
&Min \quad f(\tilde{\mathbf{x}},\mathbf{z}_1,\mathbf{z}_2,...,\mathbf{z}_j)+\pi(\mathbf{c}_1,\mathbf{c}_2,...,\mathbf{c}_j)\\
&s.t. \quad \boldsymbol{g}(\tilde{\mathbf{x}},\mathbf{z}_1,\mathbf{z}_2,...,\mathbf{z}_j)\le 0\\
&\qquad \boldsymbol{h}(\tilde{\mathbf{x}},\mathbf{z}_1,\mathbf{z}_2,...,\mathbf{z}_j)=0\\
&\qquad \forall \mathbf{z}_j \in \{\boldsymbol{\eta}_j,\boldsymbol{\mu}_j\} \quad \forall j=1,2,...,NA
\end{aligned} \tag{3.10}$$

where j is index for active distribution grids. NA is number of active distribution grids. Considering multi time intervals and using a second-order function to model the penalty function π [100], the ISO's optimization problem (3.10) is further modified by (3.11).

$$\begin{aligned}
&Min \sum_{t=1}^{NT} f(\tilde{\mathbf{x}},\mathbf{z}_{1t},\mathbf{z}_{2t},...,\mathbf{z}_{jt})\\
&\qquad +\sum_{t=1}^{NT}\sum_{j=1}^{NA}(\boldsymbol{\alpha}_{jt}(\boldsymbol{\eta}_{jt}-\boldsymbol{\mu}_{jt})+\left\|\boldsymbol{\beta}_{jt}\circ(\boldsymbol{\eta}_{jt}-\boldsymbol{\mu}_{jt})\right\|_2^2)\\
&s.t. \quad \boldsymbol{g}(\tilde{\mathbf{x}},\mathbf{z}_{1t},\mathbf{z}_{2t},...,\mathbf{z}_{jt})\le 0
\end{aligned} \tag{3.11}$$

$$\boldsymbol{h}(\tilde{\mathbf{x}}, \mathbf{z}_{1t}, \mathbf{z}_{2t}, \ldots, \mathbf{z}_{jt}) = 0$$

$$\forall \mathbf{z}_{jt} \in \{\boldsymbol{\eta}_{jt}, \boldsymbol{\mu}_{jt}\} \quad \forall j = 1,2,\ldots,NA,\ \forall t$$

Similarly, the optimization problem of DISCO$_j$ can be rewritten in (3.12).

$$\begin{aligned} Min \sum_{t=1}^{NT} f(\tilde{\mathbf{y}}, \mathbf{z}_{jt}) & \\ + \sum_{t=1}^{NT} \left(\boldsymbol{\alpha}_{jt} (\boldsymbol{\eta}_{jt} - \boldsymbol{\mu}_{jt}) + \left\| \boldsymbol{\beta}_{jt} \circ (\boldsymbol{\eta}_{jt} - \boldsymbol{\mu}_{jt}) \right\|_2^2 \right) & \end{aligned} \tag{3.12}$$

$$s.t. \quad \boldsymbol{g}(\tilde{\mathbf{y}}, \mathbf{z}_{jt}) \le 0$$

$$\boldsymbol{h}(\tilde{\mathbf{y}}, \mathbf{z}_{jt}) = 0$$

$$\forall \mathbf{z}_{jt} \in \{\boldsymbol{\eta}_{jt}, \boldsymbol{\mu}_{jt}\} \quad \forall t$$

where NT is number of studied period. In (3.11) and (3.12), $\mathbf{z}_{jt}$, $\boldsymbol{\eta}_{jt}$, and $\boldsymbol{\mu}_{jt}$ are respectively shared, target and response variables between ISO and DISCO$_j$ at time *t*. The penalty function consists of two terms, linear and quadratic. $\boldsymbol{\alpha}_{jt}$ and $\boldsymbol{\beta}_{jt}$ are multipliers associated with linear and quadratic terms, respectively, and they will be updated during the iterative solving process. An important feature of the second-order penalty function is that it is a convex quadratic curve. Thus, the problem can be easily solved using the quadratic optimization solvers.

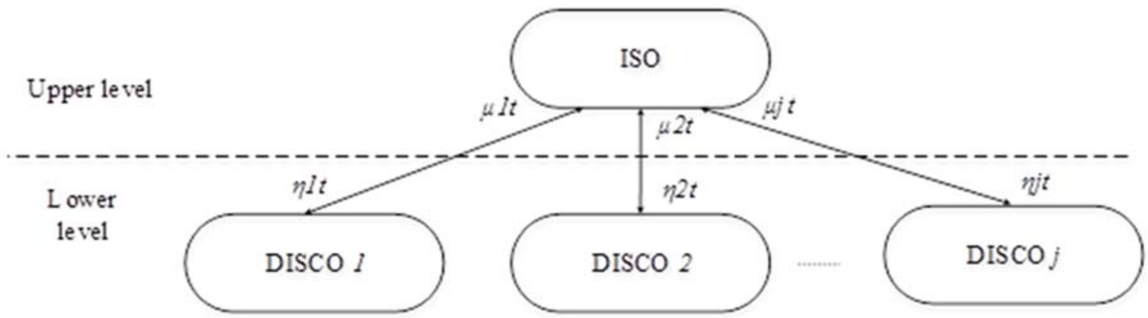


Figure 3.3 Power system in the form of a hierarchical two-level SoS

3.3.4 Coupling Constraints Handling in SCUC Problems

SCUC problems of independent systems are connected together using the penalty function and target and response variables in order to find the results for the entire power system. Therefore, the following SCUC problem (3.13) is formulated for DISCO$_j$.

$$\begin{aligned} & Min\sum_{t=1}^{NT}\sum_{i=1}^{NG_j} F_i(P_{it})I_{it} + SUD_{it} \\ & +\sum_{t=1}^{NT}(\alpha_{jt}(PD^*_{S,jt} - PG_{D,jt}) + \left\|\beta_{jt} \circ (PD^*_{S,jt} - PG_{D,jt})\right\|_2^2) \end{aligned} \tag{3.13}$$

where NG_j is number of generating units in DISCO$_j$, $F_i(.)$ is generation cost curve of unit *i*, I_{it} is ommitment state of unit *i* at time *t*, P_{it} *is* generation of generating unit *i* at time *t*, and SUD_{it} is startup and shutdown cost of unit *i* at time *t*. The first term of (3.13) is for the production cost, startup and shutdown costs of DISCO$_j$'s generating units. The second term is the penalty function related to the shared variables with ISO. Notice that in the penalty function, the response variables $PG_{D,jt}$ need to be determined, but the values of target variables $PD^{*}_{S,jt}$ are received from the ISO. Meanwhile, the regular SCUC constraints should be satisfied.

The SCUC problem (3.14) is for the ISO. The response variables received from the DISCOs are used to model the penalty function. In this problem, $PD_{S,jt}$ is treated as the vector of design variables while $PG^{*}_{D,jt}$ is treated as a constant term.

$$\begin{aligned}&Min \sum_{t=1}^{NT}\sum_{i=1}^{NG} F_i(P_{it})I_{it} + SUD_{it}\\&+\sum_{t=1}^{NT}\sum_{j=1}^{NA}(\alpha_{jt}(PD_{S,jt}-PG^{*}_{D,jt})+\left\|\beta_{jt}\circ(PD_{S,jt}-PG^{*}_{D,jt})\right\|_2^2)\end{aligned} \tag{3.14}$$

Similarly, in (3.14), the first term represents the production cost, startup and shutdown costs of ISO's generating units, the second term is penalty function related to the shared variables with DISCOs, and the regular SCUC constraints should be satisfied.

In the SoS-based SCUC problem, the ISO and DISCO$_j$, as the autonomous systems, may have different restrictions for amount of power exchange between them. Thus, in addition to regular SCUC constraints, the following constraint is regarded in the above SCUC problems of DISCO$_j$ and ISO.

$$\begin{aligned}\max\{\underline{PT_{S,jt}},\underline{PT_{D,jt}}\} &\le \{PD_{S,jt}, PG_{D,jt}\}\\&\le \min\{\overline{PT_{S,jt}},\overline{PT_{D,jt}}\}\end{aligned} \tag{3.15}$$

where $\underline{PT_{S,it}}$ and $\overline{PT_{S,jt}}$ are minimum and maximum allowable values for the power exchange between ISO and DISCO$_j$ at period t from the ISO's perspective; and

$\underline{PT_{D,jt}}$ and $\overline{PT_{D,jt}}$ are minimum and maximum acceptable values from the DISCO_j's perspective.

3.3.5 Solution Procedure

Figure 3.4 illustrates the solution procedure of the proposed hierarchical two-level optimization algorithm which determines the optimal SCUC results for the ISO and DISCOs. This algorithm has two iteration loops, inner and outer, which are explained as follows.

Step 1: Set the iteration index w=0 for the inner loop and k=0 for the outer loop, and choose initial values for $PD_{S,jt}^{*w}$, α_{jt}^{k} and β_{jt}^{k}.

Step 2: Set w=w+1. Solve the SCUC problem for each DISCO with $PG_{D,jt}^{w}$ as the design variables and the values of $PD_{S,jt}^{*w-1}$ from the previous iteration.

Step 3: Solve the SCUC problem for ISO with $PD_{S,jt}^{w}$ as design variables and the values of $PG_{D,jt}^{*w}$ obtained in Step 2.

Step 4: Use (3.16) and (3.17) to check the inner loop convergence. If they are not satisfied, return to Step 2 for the next iteration; otherwise, go to Step 5.

$$PD_{S,jt}^{w} - PD_{S,jt}^{w-1} \leq \varepsilon_1 \quad \forall j, \forall t \tag{3.16}$$

$$PG_{D,jt}^{w} - PG_{D,jt}^{w-1} \leq \varepsilon_1 \quad \forall j, \forall t \tag{3.17}$$

Step 5: Check the following necessary-consistency (3.18) and sufficient (3.19) stopping criteria for the outer loop. If they are not satisfied, go to Step 6; otherwise, the converged optimal result is obtained and the solution procedure stops.

Necessary-consistency condition:

$$PD_{S,jt}^{w} - PG_{D,jt}^{w} \le \varepsilon_2 \quad \forall j, \forall t \tag{3.18}$$

Sufficient condition:

$$\left| \frac{f_s(\mathbf{x}^{(w)}) - f_s(\mathbf{x}^{(w-1)})}{f_s(\mathbf{x}^{(w)})} \right| \le \varepsilon_3 \tag{3.19}$$

where f_s is the objective function of the independent system S.

Step 6: Set k=k+1 and update the values of multipliers α_{jt}^{k} and β_{jt}^{k} using (3.20) and (3.21).

$$\alpha_{jt}^{(k+1)} = \alpha_{jt}^{(k)} + 2(\beta_{jt}^{(k)})^2 (PD_{S,jt}^{w} - PG_{D,jt}^{w}) \tag{3.20}$$

$$\beta_{jt}^{(k+1)} = \lambda \beta_{jt}^{(k)} \tag{3.21}$$

where the coefficient λ is necessary to be equal or larger than one in order to get the converged optimal results. This method for updating Lagrangian multipliers is proven to converge to the optimal solution in [20].

Step 7: Set $PD_{S,jt}^{*0} = PD_{S,jt}^{w}$, $\forall j, \forall t$, w=0, and return to Step 2.

Note that in the inner loop process of this algorithm, the penalty multipliers are fixed, and only $PD_{S,jt}$ and $PG_{D,jt}$ need to be updated. Such process helps to improve the accuracy of the final results, especially when we do not have a good initial guess for the shared variables between the systems. Also, in practice, the following stopping criteria may be added to the inner and outer loops in order to avoid facing the dead loop.

$$w \geq \overline{W} \tag{3.22}$$

$$k \geq \overline{K} \tag{3.23}$$

where $\overline{W}$ and $\overline{K}$ are the maximum allowable number of inner and outer loops iterations, respectively.

In the proposed decentralized decision-making framework, as there are many DISCOs collaborating and communicating with one ISO, the ISO can be committed as the entity that is in charge of updating the penalty multipliers and send them to the DISCOs. It is assumed that the systems are working in a fair and clear market, and they accept the penalty multipliers defined by the ISO. However, an active distribution system can have its own right to refuse the penalty multipliers and can work in islanded mode without power exchange with the ISO. In this condition, there is no need to consider this system in the decentralized optimization process.

3.3.6 Penalty Function Linearization

In order to linearize the problem and use the MIP solvers, we can piecewise linearize the quadratic penalty functions in the problem objectives. Assume the quadratic penalty function used in (3.13). In each iteration of the solution procedure, the multipliers

α and β, and the value of PD are known, and PG is the only variable in this penalty function. Thus, this convex quadratic penalty function can be piecewise linearized in each iteration using the following steps:

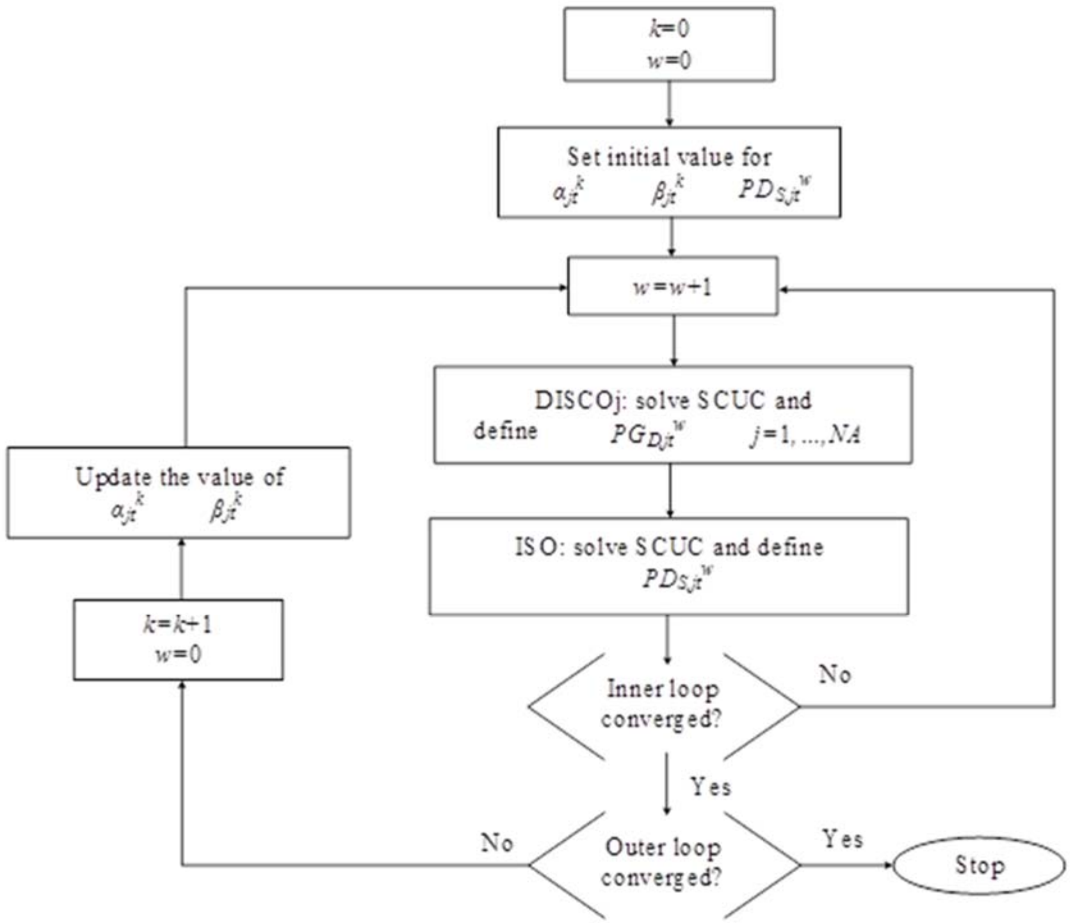


Figure 3.4 Flowchart of the solving process

Step 1: Find the minimum point of the curve by $PG^0 = \frac{2\beta * PD + \alpha}{2\beta}$.

Step 2: The convex penalty function is approximated by a set of piecewise linear functions. Figure 3.5 shows an example of the piecewise linear approximation in which the convex penalty function between $PG^{-3} = PG_{\min}$ and $PG^3 = PG_{\max}$ is divided into six segments represented by straight lines. The negative and positive superscripts are respectively used for the left and right hand sides of the minimum point on the curve. The pseudo power generated by DISCO at the d^{th} breakpoint is represented by PG^d. And the power dispatched at segment d is PGx^d which is between zero and $[PG^{d+1} - PG^d]$. The incremental cost at segment d is $IF^d = \frac{F^{d+1} - F^d}{P^{d+1} - P^d}$. Thus, the penalty function can be replaced as $\pi = \sum_d (IF^d * PGx^d)$.

The above linearization process needs to be implemented at each time interval in each iteration. A similar procedure can be applied to linearize the penalty function of (3.14).

3.4 Case Studies

A six-bus, the modified IEEE RTS 24-bus and IEEE 118-bus test systems are applied to illustrate the performance of the proposed hierarchical two-level optimization algorithm for the SoS-based SCUC. All cases utilize ILOG CPLEX 12.4's MIQP solver on a 2.8GHZ personal computer. Note that we can also use ILOG CPLEX 12.4's MIP

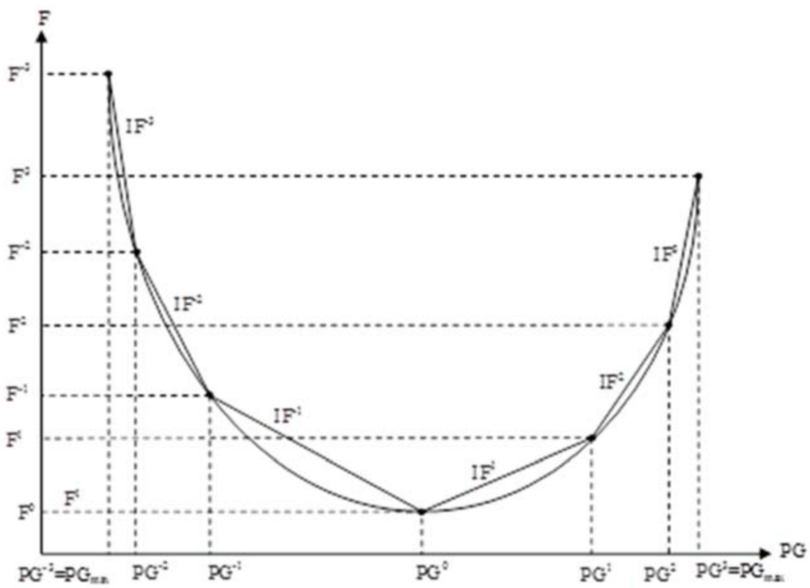


Figure 3.5 Piecewise linear approximation of the quadratic penalty function solver once the quadratic penalty functions in the problem objectives are piecewise linearized as explained in Section 3.3.6.

3.4.1 Six-Bus System

The system topology is shown in Figure 3.6. The six-bus test system has 3 generating units, 7 branches, and 3 demand sides in the transmission system. The characteristics of generating units, network information, and the hourly load distribution over 24-h horizon are given in Tables 3.1 to 3.3. Two active distribution grids are connected to the transmission system through buses 3 and 4, and one passive distribution grid is connected to bus 5. ADG1 consists of 9 buses, 8 distribution lines, 5 loads and 2 DGs. And ADG2 includes 7 buses, 6 distribution lines, 4 loads and 2 DGs. DG unit and network characteristics of the ADGs are shown in Tables 3.4 and 3.5. The percent of load distribution at each bus is indicated in Figure 3.6.

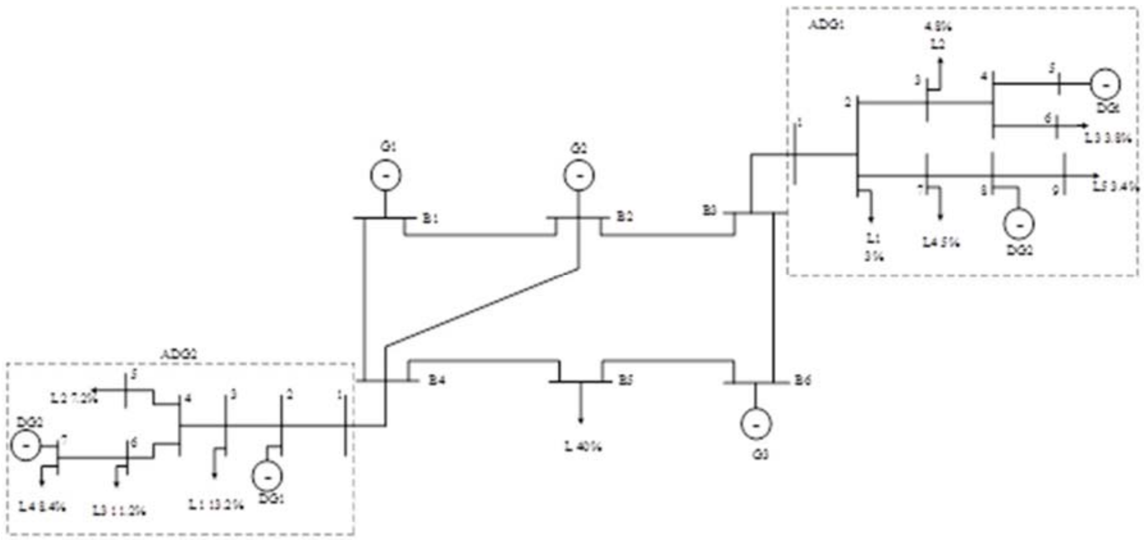


Figure 3.6 Six-bus test system with two active distribution grids

Table 3.1 Generator Data

Unit	P_{min} (MW)	P_{max} (MW)	a (MBtu)	b (MBtu/MWh)	c (MBtu/MW^{2}h)	Min OFF (hr)	Min ON (hr)
1	40	220	100	7	0.03	4	4
2	10	100	104	10	0.07	3	2
3	0	25	110	8	0.05	1	1

Table 3.2 Network Information

From Bus	To Bus	X (pu)	Flow Limit (MW)
1	2	0.170	200
1	4	0.258	200
2	3	0.037	190
2	4	0.197	200
3	6	0.018	180
4	5	0.037	190
5	6	0.140	180

Table 3.3 Hourly load over 24-h horizon

Hour	Pd(MW)	Hour	Pd(MW)	Hour	Pd(MW)	Hour	Pd(MW)
1	175	7	173	13	242	19	246
2	169	8	174	14	244	20	237
3	165	9	185	15	249	21	237
4	155	10	202	16	256	2	233
5	155	11	228	17	256	23	210
6	165	12	236	18	247	24	210

Table 3.4 Distributed Generator Data

ADG No.	DG	P_{min} (MW)	P_{max} (MW)	a (MBtu)	b (MBtu/MWh)	c (MBtu/MW^{2}h)
ADG1	1	0	15	100	7	0.08
	2	0	18	65	3	0.03
ADG2	1	5	25	140	5	0.04
	2	0	19	50	25	0.00

Table 3.5 Distribution line data for ADG 1 and 2

ADG1				ADG2			
From	To	X (pu)	Flow Limit (MW)	From	To	X (pu)	Flow Limit (MW)
B3	1	0.2	60	B4	1	0.2	70
1	2	0.19	60	1	2	0.15	70
2	3	0.21	30	2	3	0.20	90
2	7	0.21	30	3	4	0.16	70
3	4	0.20	40	4	5	0.18	40
4	5	0.18	20	4	6	0.18	50
4	6	0.18	30	6	7	0.16	40
7	8	0.19	20	-	-	-	-
8	9	0.19	20	-	-	-	-

In order to analyze the effectiveness of the proposed algorithm, we consider the following three case studies:

Case 1: Without active distribution grids

Case 2: With active distribution grids, but no network security

Case 3: With active distribution grids and network security

3.4.1.1 Case 1

In this case, there is no DG in the system and all distribution grids are passive, which are modeled as the constant (forecasted) loads connected to buses 3, 4 and 5. The conventional centralized SCUC problem is solved to find the optimal operating point of the system. Table 3.6 shows hourly ON/OFF states of the units. The generation dispatch is listed in Table 3.7. During the off-peak load, unit 2 which is an expensive unit, is not committed, and when it is within the peak hours, this unit is scheduled to be ON. The total operating cost is $65,414.44.

3.4.1.2 Case 2

As shown in Figure 3.6, two ADGs are connected to the transmission system through buses 3 and 4, respectively. According to the SoS concept, the ISO and each DISCO are modeled as the independent systems. The power transferred between the ISO and DISCOs are limited by the capacity of the line connecting the systems together. The initial value for $\boldsymbol{\alpha}_{jt}^{0} = \boldsymbol{\beta}_{jt}^{0} = 1$ (j=1, 2, and t=1:24); and convergence thresholds ε_1, ε_2 and ε_3 are set to 0.01, 0.001 and 0.001, respectively. The decentralized SoS-based SCUC is applied to find the optimal operating point of the transmission system and ADGs. Notice that in this case, the transmission and distribution network security is not taken into account. In other words, it is a UC problem incorporating ADGs.

Table 3.6 UC Solution in Case 1

Units	Hours (1-24)
1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
2	0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
3	3 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

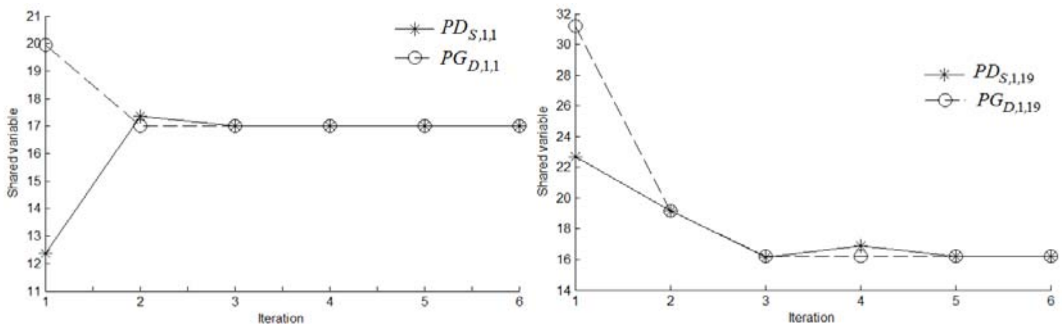
Table 3.7 Generation Dispatch (MW) in Case 1

Hour	Unit1	Unit2	Unit3	Hour	Unit1	Unit2	Unit3
1	150.0	0	25	13	166.9	50.1	25
2	144.0	0	25	14	168.3	50.7	25
3	140.0	0	25	15	171.8	52.2	25
4	130.0	0	25	16	176.7	54.3	25
5	130.0	0	25	17	176.7	54.3	25
6	140.0	0	25	18	170.4	51.6	25
7	148.0	0	25	19	169.7	51.3	25
8	149.0	0	25	20	163.4	48.6	25
9	127.0	33.0	25	21	163.4	48.6	25
10	138.9	38.1	25	22	160.6	47.4	25
11	157.1	45.9	25	23	144.5	40.5	25
12	162.7	48.3	25	24	144.5	40.5	25

After 6 outer loop iterations, the converged optimal power exchange is obtained. As the examples, Figure 3.7 shows the shared variable (amount of power exchange (MW)) between ISO and DISCO1 at hours 1 and 19; and Figure 3.8 depicts the shared variable (amount of power exchange (MW)) between ISO and DISCO2 at hours 11 and 18 in each outer loop iteration. Table 3.8 shows the ON/OFF states of each generating unit, and the generation dispatch is depicted in Table 3.9. The highlighted values in these tables show differences between the UC and generation dispatch of Case 2 and that of Case 1. In the off-peak hours, the expensive generating units, unit 2 of transmission system and DG1 of ADG1 and DG2 of ADG2, are OFF. When it is around peak load hours, unit 2 of transmission system and DG1 of ADG1 is scheduled to be ON but DG2 of ADG2 which is very expensive should stay OFF. The operating costs of ISO, DISCO1, and DISCO2 are $46,113.62, $6,434.28, and $6,960, respectively; and the total system operating cost is $59,507.90. Compared with the cost ($65,414.44) of Case 1, the total operating cost is reduced due to incorporation of cheap DG units in the SCUC problem. As the network capacity is not considered in Case 2, the lines 1-2 and 4-6 in ADG2, and the tie-line connecting the transmission grid to ADG2 are overloaded according to the generation dispatches obtained in this case.

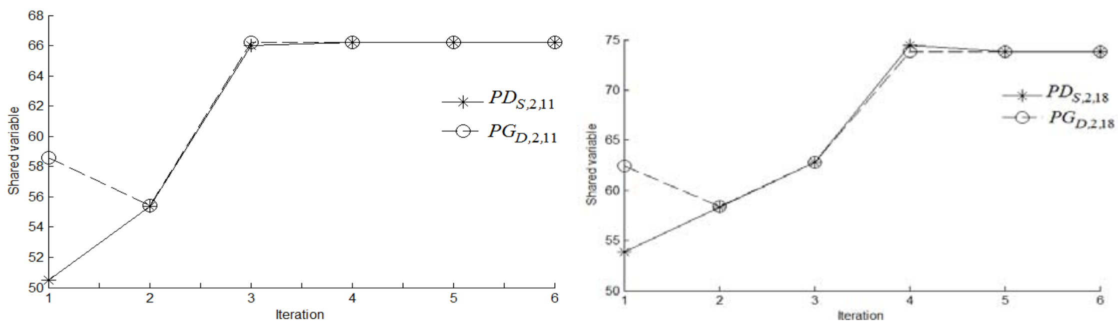
3.4.1.3 Case 3

In order to meet the network security for each independent system, the capacity limit of lines is considered in this case. Using the initial values $\boldsymbol{\alpha}_{jt}^{0} = \boldsymbol{\beta}_{jt}^{0} = 1$ (j=1, 2, and t=1:24); and setting the values 0.01, 0.001, and 0.001 for the convergence thresholds ε_1, ε_2, and ε_3, respectively, the proposed SoS-based SCUC is implemented. The algorithm converges after 5 outer loop iterations. The UC schedule for the generating units of each independent system is shown in Table 3.10. The generation dispatch is listed in Table 3.11. The highlighted values in Tables 3.10 and 3.11 show differences between these tables and Tables 3.8 and 3.9. Compared with case 2, to remove the congestion on the lines 1-2 and 4-6 in ADG2, and the tie-line connecting the transmission grid to ADG2, unit 2 is scheduled to be OFF in hours 13-15 and 18-19, and DG2 of ADG2, which is an expensive generation source, is committed ON from hour 11 to 22.



(a) (b)

Figure 3.7 Power exchange between ISO and ADG1 at hours a) 1, b) and 19



(a) (b)

Figure 3.8 Power exchange between ISO and ADG2 at hours a) 11, b) and 18

Table 3.8 UC Solution in Case 2

Ind. Syst.	Units	Hours (1-24)																							
ISO	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2	0	0	0	0	0	0	0	0	**0**	**0**	**0**	**0**	1	1	1	1	1	1	**1**	**0**	**0**	**0**	**0**	**0**
	3	1	1	**0**	**0**	**0**	**0**	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DISCO1	1	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DISCO2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The operating costs of ISO, DISCO1, and DISCO2 are $44,817.94, $6,434.28, and $9,670, respectively; and the total system operating cost is $60,922.22 which is $1,414.5 more than that in Case 2, and $4,492.2 less than that in Case 1.

Notice that in order to check the validity of the results of the proposed decentralized optimization algorithm, both Cases 2 and 3 are also solved considering the entire power system as a single system and applying centralized optimization algorithm. Its results are same as those shown in Tables 3.8, 3.9, 3.10 and 3.11, which are obtained based on the decentralized optimization algorithm.

3.4.2 Modified IEEE-RTS 24-Bus System

A modified IEEE-RTS 24-bus test system is used to study the SOS-based SCUC. The transmission network has 10 generators and 34 lines, and it encompasses 8 passive distribution grids, and 9 independent active distribution grids connected to buses 1, 2, 3, 5, 6, 7, 10, 13, and 19. The total 25 distributed generators are installed near to the load centers in ADGs. The peak load of 1,869 MW occurs at hour 11. The general information about IEEE 24-bus transmission system is given in [108], and the other input data used in the case studies is listed in Tables 3.12 to 3.15. Set the initial values $PD_{S,jt}^{0} = \boldsymbol{\alpha}_{jt}^{0} = \boldsymbol{\beta}_{jt}^{0} = 1$

(j=1:9 and t=1:24), and pick the values 0.01, 0.001, and 0.001 for the convergence thresholds ε1, ε2, and ε3, respectively. The algorithm takes 5 seconds to obtain the optimal results after 5 outer loop iterations. Table 3.15 shows the ON/OFF states of the generating units. Generating unit 3 of the ISO is a very expensive unit and is committed to be OFF all over the operating time horizon. Unit 4 which is an expensive unit is only committed to be ON when the load is near the peak. Also, DGs 4 of DISCO2, 3 of DISCO3, 2 of DISCO6, 4 of DISCO7, and 2 of DISCO9 are very expensive and are scheduled to be OFF over 24 hours in this case. The operating cost of each independent system, ISO and DISCOs, is depicted in Table 3.16. The total operating cost of the SoS-based power system is $463,729.80.

Table 3.9 Generation Dispatch (MW) in Case 2

Hour	ISO			DISCO1		DISCO2	
	Unit1	Unit2	Unit3	DG1	DG2	DG1	DG2
1	107	0	25	0	18	25	0
2	101	0	25	0	18	25	0
3	122	0	0	0	18	25	0
4	112	0	0	0	18	25	0
5	112	0	0	0	18	25	0
6	122	0	0	0	18	25	0
7	105	0	25	0	18	25	0
8	106	0	25	0	18	25	0
9	117	0	25	0	18	25	0
10	119	0	25	15	18	25	0
11	145	0	25	15	18	25	0
12	153	0	25	15	18	25	0
13	126.30	32.7	25	15	18	25	0
14	127.70	33.30	25	15	18	25	0
15	131.19	34.78	25	15	18	25	0
16	136.10	36.90	25	15	18	25	0
17	136.10	36.90	25	15	18	25	0
18	129.80	34.20	25	15	18	25	0
19	129.1	33.90	25	15	18	25	0
20	154	0	25	15	18	25	0
21	154	0	25	15	18	25	0
22	150	0	25	15	18	25	0
23	127	0	25	15	18	25	0
24	127	0	25	15	18	25	0

Table 3.10 UC Solution in Case 3

Ind. Syst.	Units	Hours (1-24)
ISO	1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	2	0 0 0 0 0 0 0 0 0 0 0 0 **0 0 0** 1 1 **0 0** 0 0 0 0 0
	3	1 1 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
DISCO1	1	0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	2	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
DISCO2	1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	2	3 0 0 0 0 0 0 0 0 0 **1 1 1 1 1 1 1 1 1 1 1 1** 0 0

Table 3.11 Generation Dispatch (MW) in Case 3

Hour	ISO			DISCO1		DISCO2	
	Unit1	Unit2	Unit3	DG1	DG2	DG1	DG2
1	107	0	25	0	18	25	0
2	101	0	25	0	18	25	0
3	122	0	0	0	18	25	0
4	112	0	0	0	18	25	0
5	112	0	0	0	18	25	0
6	122	0	0	0	18	25	0
7	105	0	25	0	18	25	0
8	106	0	25	0	18	25	0
9	117	0	25	0	18	25	0
10	119	0	25	15	18	25	0
11	143.79	0	25	15	18	25	1.20
12	148.59	0	25	15	18	25	4.40
13	152.19	0	25	15	18	25	6.80
14	153.39	0	25	15	18	25	7.60
15	156.39	0	25	15	18	25	9.60
16	124.42	33.18	25	15	18	25	12.40
17	127.42	33.18	25	15	18	25	12.40
18	155.19	0	25	15	18	25	8.80
19	154.59	0	25	15	18	25	8.40
20	149.19	0	25	15	18	25	4.80
21	149.19	0	25	15	18	25	4.80
22	146.76	0	25	15	18	25	3.20
23	127	0	25	15	18	25	0
24	127	0	25	15	18	25	0

Table 3.12 Hourly load over 24-h horizon

Hour	Pd(MW)	Hour	Pd(MW)	Hour	Pd(MW)	Hour	Pd(MW)
1	1190	7	1400	13	1813	19	1750
2	1211	8	1701	14	1785	20	1785
3	1183	9	1715	15	1834	21	18200
4	1190	10	1820	16	1855	2	1736
5	1225	11	1869	17	1785	23	1540
6	1295	12	1813	18	1771	24	1288

Table 3.13 ISO's Generators Data

Unit	P_{min} (MW)	P_{max} (MW)	a (MBtu)	b (MBtu/MWh)	c (MBtu/MW^{2}h)
1	30	192	155	10	0.09
2	30	192	130	6	0.03
3	50	00	240	10	0.07
4	200	591	115	5	0.06
5	50	215	150	8	0.05
6	40	155	165	6	0.04
7	80	400	130	7	0.06
8	80	400	110	5	0.07
9	60	300	120	6	0.05
10	200	660	105	4	0.01

3.4.3 Modified IEEE 118-Bus System

A modified IEEE 118-bus test system, as a relatively large power system, is used to study the proposed SoS-based SCUC algorithm. The system has 30 independent active distribution grids each of which is operated by a DISCO. And 61 passive distribution grids are also connected to the transmission network. The initial values of $PD_{S,jt}^{0}$, $\boldsymbol{\alpha}_{jt}^{0}$, and $\boldsymbol{\beta}_{jt}^{0}$ (j=1:30 and t=1:24) are set to be 1. The decentralized decision-making algorithm takes 2 minutes to converge to an optimal solution after 7 outer loop iterations. Table 3.17 depicts the total operating cost of the entire SoS-based power system which is \$1,257,170. To check the validity of the results, the centralized algorithm is also implemented and the total operating cost is \$1,254,586. The difference between the operating costs obtained by these two algorithms is 0.2% which is acceptable. Although the SoS-based decentralized algorithm could result in a slight increase in operating cost, it needs a limited information to be exchanged between the independent systems which can meet the privacy of the systems.

Table 3.14 Distributed Generator Data

ADG No.	DG	P_{min} (MW)	P_{max} (MW)	a (MBtu)	b (MBtu/MWh)	c (MBtu/MW^{2}h)
ADG1	1	0	15	100	7	0.08
	2	0	18	65	3	0.03
ADG2	1	0	8	110	6	0.07
	2	0	10	80	4	0.04
	3	0	5	60	5	0.05
	4	0	5	100	7	0.03
ADG3	1	0	10	100	5	0.06
	2	0	15	65	3	0.03
	3	0	5	100	7	0.08
ADG4	1	0	15	120	7	0.07
	2	0	18	50	6	0.06
ADG5	1	0	10	100	4	0.05
	2	0	10	65	8	0.08
	3	5	10	100	7	0.08
ADG6	1	5	25	140	5	0.04
	2	0	19	50	25	0
ADG7	1	0	5	80	6	0.05
	2	5	20	140	5	0.04
	3	0	10	100	7	0.07
	4	0	15	50	25	0
ADG8	1	5	15	110	4	0.05
	2	0	10	60	6	0.04
	3	0	15	90	2	0.09
ADG9	1	5	25	150	6	0.03
	2	0	20	60	24	0

Table 3.15   UC Solution for IEEE-RTS 24-Bus System

Ind. Syst.	Units	Hours (1-24)
ISO	1	0 0 0 0 0 0 0 1 1 0 1 0 0 0 0 0 0 1 1 0 0 1 0 0
	2	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	3	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0
	4	0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 0 0 1 1 0 0 0
	5	0 1 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	6-10	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
DISCO1	1-2	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
DISCO2	1-3	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	4	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
DISCO3	1-2	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	3	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
DISCO4	1	0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
	2	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
DISCO5	1-3	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
DISCO6	1	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	2	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
DISCO7	1	0 0 0 0 0 0 0 1 1 0 0 0 0 0 0 1 0 1 1 0 0 1 0 0
	2-3	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
	4	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
DISCO8	1-3	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
DISCO9	1 2	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 3 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

Table 3.16   Operating Cost of ISO and DISCOs

Independent System	Operating Cost ($)
ISO	383,660.20
DISCO1	8,441.28
DISCO2	8,945.52
DISCO3	6,546.00
DISCO4	8,351.31
DISCO5	11,424.00
DISCO6	6,960.00
DISCO7	11,059.50
DISCO8	10,692.00
DISCO9	7,650.00

Table 3.17 Operating Cost of SoS-Based Power System

Solution Algorithm	Operating Cost ($)	# of outer loop
Centralized	1254586	-
Decentralized	1257170	7

3.5 Summary

Incorporation of generation sources of active distribution grids in power systems operation enhances the economic and security in restructured power systems. As the transmission and distribution grids are utilized by different system operators in the electricity market, making a collaborative and optimal operation among these systems is an important problem. In this chapter, the power system was modeled as a system of systems, in which the ISO and each DISCO were autonomous and independent systems. And, a decentralized decision-making framework was proposed to find the optimal SoS-based SCUC schedule for ISO and DISCOs. In order to solve the problem, a hierarchical optimization algorithm was presented taking into account the shared variables/information between the independent systems. The numerical tests on a six-bus and an IEEE-RTS 24-bus test systems showed the accuracy and convergence performance of the proposed algorithm. The hourly results of day-ahead market verified that considering the DG units in SCUC problem improves the market efficiency in terms of economic and security issues. Consequently, this decentralized decision-making framework can facilitate the participation of active distribution grids into the market.

In this chapter, the dispatchable DGs like gas turbines and diesel generators were studied, and we did not discuss the generation uncertainty of renewable energy sources like wind turbines and solar PVs. Next chapter will incorporate the uncertainty of renewable energy sources into this SoS-based decentralized SCUC problem.

CHAPTER IV

CHANCE-CONSTRAINED STOCHASTIC POWER SYSTEM OPERATION

4.1 Introduction

Due to the economic and environmental issues coming from fossil fuels, there has been a growing interest in using renewable energy resources in electric power industries to provide energy for the customers [109]-[113]. These sources of energy are usually being utilized as the small-scale generating units which are installed in distribution grids close to the load centers. They provide clean energy and have less environmental impact compared with conventional power plants.

Among different types of renewable energy resources, wind and solar power generation have been attracted more attention. Global Wind Energy Council (GWEC) reported that in 2005, the wind energy installation around the globe was 11531 MW that shows 40.5% annual increase [114]. Also, the installed solar capacity around the globe grew from 1,425 (MW) in 2000 to 69,684 (MW) in 2011 [115]. Beside many advantages of these types of generating units, they are non-dispatchable generators and result in increasing uncertainty in the generation side of the power systems [116]. This generation uncertainty complicates the process of decision-making in the system. The operator needs to apply stochastic optimization techniques to find the optimal operating point of the system. The system operator's failure to consider volatility of non-dispatchable units in power system scheduling may result in power system vulnerability [66]. On the other hand, the electric power consumption on each bus is another uncertain variable/parameter in power systems. This demand-side uncertainty should also be regarded in the system scheduling.

In Chapters 2 and 3, the presented OPF and SCUC algorithms are decision-making procedures in which all the generation sources are dispatchable and the load demand is assumed to be zero. Thus, we have deterministic decentralized optimization problems with no uncertain variable. In this chapter, we model and evaluate the impact of the uncertainty of renewable energy sources as well as load demand in the day-ahead (SCUC) power system scheduling presented in Chapter 3. The chance constraint and risk analysis techniques are applied to model the stochastic constraints which are power balance, reserve requirements and power flow limit. The chance constraints are converted into the linear deterministic constraints. Moreover, the impact of the stochastic decision variables on the shared variables between the independent systems is taken into consideration.

4.2 Stochastic SoS-Based Power System Operation

Assume the deterministic SCUC problem presented in Chapter 3 in which the ISO and DISCOs collaborate with each other to optimally operate the entire SoS-based power system. Considering the uncertainty of wind and solar power generations as well as load demand, the deterministic SCUC model is extended to be a SoS-based stochastic day-ahead scheduling algorithm.

4.2.1 Stochastic Generation Scheduling for Autonomous Systems

In this section, an individual stochastic optimization problem is formulated for transmission system/active distribution grid considering the uncertainty brought by variable load demands, and volatile wind and solar power generations. Suppose there is no tie-line (connection) between the transmission network and the active distribution grid. It means that these two systems are separated and the operating point of one does not impact the operating point of another. The ISO minimizes (4.1) as the objective function of its own generation scheduling problem.

$$Min \sum_{t=1}^{NT} \sum_{i=1}^{NGo} \left(F_{Pi}(P_{it}^{o}) I_{it} + SUD_{it}^{o} \right) \tag{4.1}$$

This objective function includes operating and startup/shutdown costs of the thermal generating units over the scheduling horizon (e.g. 24 hours). The optimization constraints are formulated by (4.2)-(4.10). (4.2) is maximum/minimum generation limits; reserve provided by generating units are presented in (4.3); unit ramping up/down time is formulated by (4.4) and (4.5); and (4.6) and (4.7) represent minimum up/down time constraints. Because of the load demand and renewable generation uncertainty, some of the constraints have stochastic behavior. Using the expected values of the stochastic variables and applying the chance constraint technique, the corresponding stochastic constraints are formulated by (4.8)-(4.10). Constraint (4.8) indicates the power balance constraints in which the expected (forecasted) values of the load and non-dispatchable renewable generation (wind and solar) are considered. Thermal generating units require to provide to provide adequate reserve to accommodate renewable generation and load demand uncertainties with a prescribed probability. This constraint is modeled by (4.9) in which the ISO needs to set a proper value for loss of load probability at time t ($LOLP_t^o$) to guarantee the availability of the adequate spinning reserve during the real-time dispatch [76]. Note that $LOLP_t^o$ should be appropriately selected by the ISO through a long-term study in order to compromise between economics and reliability of the system operation. In order to ensure the network security, constraint (4.10) requires to be satisfied. This constraint guarantees that the stochastic line flow will stay within the capacity limit of the line with a prescribed probability. In (4.10), $TLOP_{lt}^o$ (probability of transmission line overload) has the same meaning as $LOLP_t^o$ in (4.9), and should be properly selected to make a trade-off between economics and reliability [76].

$$I_{it}\underline{P}_i \le P_{it} \le I_{it}\overline{P}_i \qquad \forall i, \forall t \tag{4.2}$$

$$R_{it} = I_{it}\min\left\{\overline{R}_i, \overline{P}_i - P_{it}\right\} \qquad \forall i, \forall t \tag{4.3}$$

$$P_{it} - P_{i(t-1)} \le RU_i + M(2 - I_{i(t-1)} - I_{it}) \qquad \forall i, \forall t \tag{4.4}$$

$$P_{i(t-1)} - P_{it} \le RD_i + M(2 - I_{i(t-1)} - I_{it}) \qquad \forall i, \forall t \tag{4.5}$$

$$(X_{i(t-1)}^{on} - T_i^{on})(I_{i(t-1)} - I_{it}) \ge 0 \qquad \forall i, \forall t \tag{4.6}$$

$$(X_{i(t-1)}^{off} - T_i^{off})(I_{it} - I_{i(t-1)}) \ge 0 \qquad \forall i, \forall t \tag{4.7}$$

$$\sum_{i=1}^{NGo} P_{it}^o + \sum_{w=1}^{NWo} E(P_{wt}^o) + \sum_{s=1}^{NSo} E(P_{st}^o) = \sum_{b=1}^{NBo} E(PD_{bt}^o) \quad \forall t \tag{4.8}$$

$$\Pr\left\{\sum_{i=1}^{NGo}(P_{it}^o + R_{it}^o) + \sum_{w=1}^{NWo} P_{wt}^o + \sum_{s=1}^{NSo} P_{st}^o \ge \sum_{b=1}^{NBo} PD_{bt}^o\right\} \ge 1 - LOLP_t^o \tag{4.9}$$

$$\Pr\left\{\begin{array}{l} -\overline{PL_l} \le \\ \sum_{i=1}^{NGo} SF_{li}^{o} P_{it}^{o} + \sum_{w=1}^{NWo} SF_{lw}^{o} P_{wt}^{o} + \sum_{s=1}^{NSo} SF_{ls}^{o} P_{st}^{o} - \sum_{b=1}^{NBo} SF_{lb}^{o} PD_{bt}^{o} \\ \qquad \le \overline{PL_l} \end{array}\right\} \ge 1 - TLOP_{lt}^{o} \quad \forall l, \forall t \tag{4.10}$$

where R_{it} is reserve of thermal unit *i* at time *t*, RU / RD is ramping up/down, T^{on} / T^{off} is minimum on/off time of the units, $\Pr\{.\}$ is probability measurement, P_{st} is power produced by solar power *s* at time *t*, P_{wt} is power produced by wind power *w* at time *t*, **SF** is shift factor matrix, NB is number of bus, NW is number of wind power generation unit, and NS is umber of solar power generation unit. Here, we use superscript (o) in $LOLP_t^o$ and $TLOP_t^o$ denoting that these values are selected by the ISO to be use in its own optimization problem. We will further explain this issue in the next section.

4.2.2 Deterministic Model of Chance Constraints

Different probability distribution functions have been proposed in the literature to model load demand, wind and solar power generation uncertainties. In general, the distribution function is obtained based on using the historical data and statistical techniques. Here, the wind and solar generation uncertainties are represented by the normal distribution function, and the load demand uncertainty is presented as a truncated normal distribution as shown in (4.11)-(4.12).

$$P_{wt}^{o} \sim E(P_{wt}^{o}) + PDF(0, (\sigma_{wt}^{o})^2) \quad \forall w, \forall t \tag{4.11}$$

$$P_{st}^{o} \sim E(P_{st}^{o}) + PDF(0, (\sigma_{st}^{o})^2) \quad \forall s, \forall t \tag{4.12}$$

$$PD_{bt}^{o} \sim E(PD_{bt}^{o}) + PDF(0, (\sigma_{bt}^{o})^2) \quad \forall b, \forall t \tag{4.13}$$

where E(.) is the expected value of the uncertain variable (the mean value) and σ is the standard deviation of the distribution function. In order to handle the chance constraints in the scheduling problem, we convert them to the equivalent deterministic constraints. Note that, however, the power balance constraint (4.8) is a stochastic constraint, it uses the expected values of the uncertain parameters and can be directly considered in the scheduling problem in the present form without any need to be converted to another model. Considering the PDF of each stochastic variable in (4.9) and (4.10), and using its mean value and standard deviation, the chance constraints can be converted into the linear constraints by performing some manipulations. For more detail, please see [17] and [18]. (4.14) and (4.15) are equivalent linear inequality constraints which respectively replace chance constraints (4.9) and (4.10) in the system's generation scheduling problem [76], [117, 118].

$$\begin{aligned}&\sum_{i=1}^{NGo}(P_{it}^{o}+R_{it}^{o})+\sum_{w=1}^{NWo}E(P_{wt}^{o})+\sum_{s=1}^{NSo}E(P_{st}^{o})\geq\sum_{b=1}^{NBo}E(PD_{bt}^{o})\\&\quad+Z_{LOLP_t^o}\left[\sum_{w=1}^{NWo}(\sigma_{wt}^{o})^2+\sum_{s=1}^{NSo}(\sigma_{st}^{o})^2+\sum_{b=1}^{NBo}(\sigma_{bt}^{o})^2\right]^{1/2}\quad\forall t\end{aligned}\tag{4.14}$$

$$\begin{aligned}&\sum_{i=1}^{NGo}SF_{li}^{o}P_{it}^{o}+\sum_{w=1}^{NWo}SF_{lw}^{o}E(P_{wt}^{o})+\sum_{s=1}^{NSo}SF_{ls}^{o}E(P_{st}^{o})-\sum_{b=1}^{NBo}SF_{lb}^{o}E(PD_{bt}^{o})\\&\quad+Z_{TLOP_{lt}^o}\left[\sum_{w=1}^{NWo}\left(SF_{lw}^{o}\sigma_{wt}^{o}\right)^2+\sum_{s=1}^{NSo}\left(SF_{ls}^{o}\sigma_{st}^{o}\right)^2+\sum_{b=1}^{NBo}\left(SF_{lb}^{o}\sigma_{bt}^{o}\right)^2\right]^{1/2}\\&\quad\leq PL_{lt}^{\max}\quad\forall l,\forall t\end{aligned}\tag{4.15}$$

where Z_{LOLP} and Z_{TLOP} are $100*(1-LOLP)$th and $100*(1-TLOP)$th percentile of the standard normal distribution. Similarly, the chance-constrained stochastic generation scheduling problem can be also formulated for the ADG. Notice that since in the SoS-based power systems, the ISO and the DISCO are independent systems, the security level (*LOLP* and *TLOP*) selected by them to be used in their own generation scheduling problem could be different. For example, the ISO may prefer to have a high security level and select a small value of *LOLP* and *TLOP* of its own transmission lines, however, this issue restricted the constraints and may increase the operation cost of the ISO. Likewise, as an independent system, the DISCO may prefer to reduce its own operating cost rather than increasing the security level of the distribution system, and so it may select larger values for *LOLP* and *TLOP* compared with the ISO. Hence, in the DISCO's problem formulation, superscript (d), which shows the variables/parameters are exclusively for DISCO, should be used instead of (o) denoting the variables/parameters of the ISO.

4.3 Collaborative Stochastic Decision-Making Solution

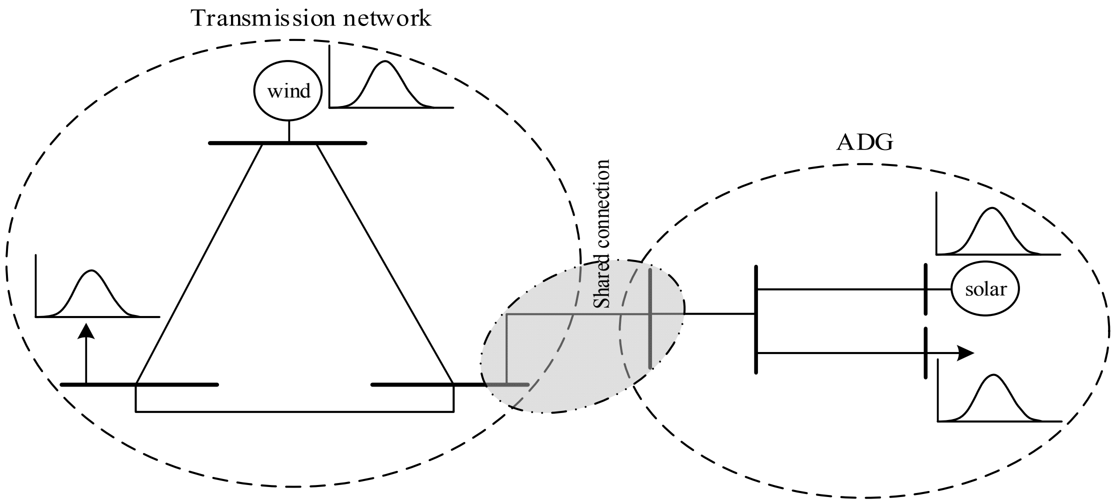
According to the above assumption that the transmission network is not connected to the active distribution grid, both ISO and DISCO can separately solve their own local chance-constrained based optimization problem to find the hourly generation schedule of their own generating units. However, when the transmission network and ADGs are indeed linked together, the optimal operating point of one of them impacts the operating point and security margin of others. In this section, to model the interaction between the systems in the SoS-based stochastic generation scheduling problem, and to find the optimal operating point of the ISO and DISCOs, a pseudo generation/load model is presented for the shared variables between the systems. Then, a collaborative stochastic decision-making solution is presented considering uncertainties brought by both load demands and renewable power supplies.

4.3.1 Shared Variables Modeling

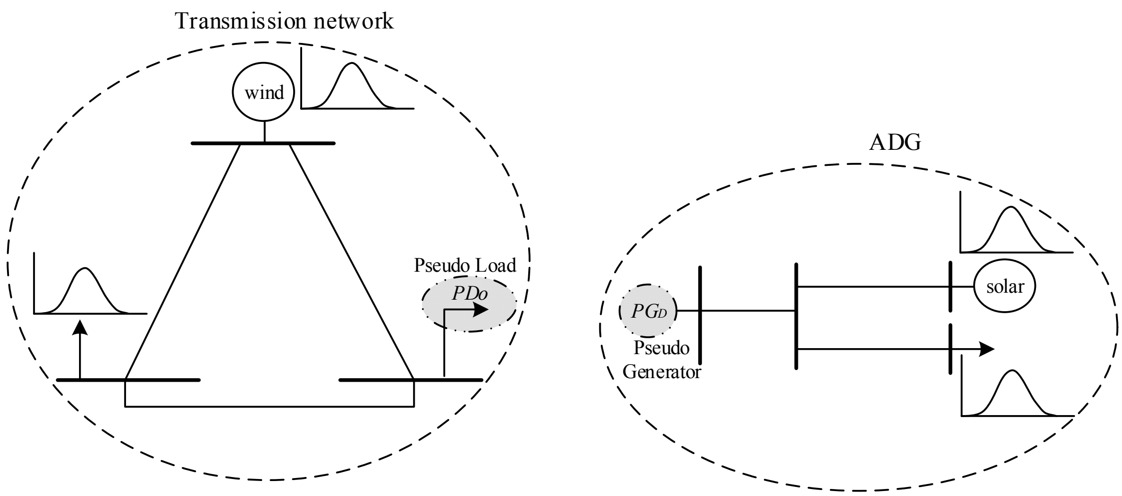
Assume the ISO and ADG are connected together as shown in Figure 4.1 (a). The power exchange between the ISO and DISCO (power flow in the tie-line connecting the transmission and distribution systems together) is the shared variable between these two independent systems. Considering a hypothetical power flow direction in the tie-line, the shared variable can be modeled using a pseudo generation source and a pseudo load. Suppose that the power is transferred from the transmission system toward ADG_j. In order to separate the independent systems, as shown in Figure 4.1 (b), from the DISCO's perspective, the line flow is modeled as a pseudo generator supplying to DISCO; and from the ISO's perspective, the line flow is modeled as a pseudo load supplied by ISO. Thus, PG_D is the power demanded by DISCO and supplied by ISO in the DISCO's optimization problem; and PD_o is the power generated by ISO and supplied to DISCO in ISO's optimization problem. Note that we are modeling the power flow in the tie-line by two pseudo variables and both variables PG_D and PD_o should be between minimum and maximum capacity of the line connecting the transmission network to ADG_j. However, as the load demand, wind and solar power uncertainties influence the power flow in the tie-line, we cannot only restrict pseudo variables PG_D and PD_o between the maximum capacity of the tie-line using the deterministic constraints. Therefore, we formulate a chance constraint for pseudo generation in the DISCO's optimization problem, and similarly a chance constraint for pseudo load in the ISO's scheduling problem. These constraints model the influence of the uncertainties on the power flow in the tie-line and guarantee that the power flowing does not exceed the maximum capacity of the tie-line with a specified probability (level of security). The corresponding chance constraints are presented in the next section to model the uncertainties on the shared variables.

4.3.2 Coupling Constraints Handling in the Day-Ahead Scheduling

According to the above modeling, the generation scheduling problems of ISO and DISCO get separated from each other using pseudo generation and load. As the ISO and DISCO are located in two different levels in the power system (ISO is in the upper level, and DISCO is in the lower level), a hierarchical two-level optimization technique can be implemented to perform the collaborative generation scheduling problem for the entire SoS-based power system [100]. Assume the optimization problem of the $DISCO_j$, located in the lower level. A set of penalty functions are added to the objective function of the $DISCO_j$'s problem each of which represents impact of a pseudo generation (a shared variable with ISO) at a specific time period. Using these penalty function as well as penalty multipliers [100], $DISCO_j$ can individually solves its own local SCUC problem receiving a prescheduled value for the pseudo load from ISO.



(a)



(b)

Figure 4.1 Modeling shared variables between an ADG physically connected to ISO

$$
\begin{aligned}
& Min \sum_{t=1}^{NT} \sum_{i=1}^{NGd_j} \left(F_i(P_{it}^d) I_{it} + SUD_{it}^d \right) \\
& + \sum_{t=1}^{NT} (\alpha_{jt} (PD_{o,jt}^* - PG_{D,jt}) + \left\| \beta_{jt} \circ (PD_{o,jt}^* - PG_{D,jt}) \right\|_2^2)
\end{aligned}
\tag{4.16}
$$

The first term of (4.16) is summation of operating and startup shutdown costs of the dispatchable generating units located in $DISCO_j$, and the second term is the quadratic penalty function related to the shared variables with ISO over the time horizon. Notice that in the penalty function, variables $PG_{D,jt}$ need to be determined, but the values of $PD^*_{O,jt}$ are pre-scheduled received from the ISO. Meanwhile, the SCUC constraints (4.2)-(4.8) as well as (4.14) and (4.15) should be satisfied. Moreover, in order to model the stochastic characteristics of the load demands and renewable power generations on the shared variables between $DISCO_j$ and the ISO, a new chance constraint (4.17) needs to be satisfied in the $DISCO_j$'s problem.

$$\Pr\left\{PG_{D,jt} \le PL_{lt}^{\max}\right\} \ge 1 - TLOP_{lt} \quad \forall t, l \in tie-line \tag{4.17}$$

Note that as we mentioned before, the $DISCO_j$ and ISO may select different values for loss of load probability and probability of line overload to model the uncertainty in their own optimization problem, but they do need to together work out the same $TLOP_{lt}$ for the chance constraints modeling the shared variables between them.

In order to solve the stochastic constraint (4.17) in the DISCO's optimization problem, it can be converted into a deterministic model as (4.18). This constraint guarantees that the power exchange between the $DISCO_j$ and ISO is within the acceptable range with a pre-specified probability.

$$PG_{D,jt} \le PL_{lt}^{\max} - Z_{TLOP_{lt}}\left[\sum_{w=1}^{NW}\left(SF_{lw}^{d}\sigma_{wt}^{d}\right)^2 + \sum_{s=1}^{NS}\left(SF_{ls}^{d}\sigma_{st}^{d}\right)^2 + \sum_{b=1}^{NB}\left(SF_{lb}^{d}\sigma_{bt}^{d}\right)^2\right]^{1/2} \tag{4.18}$$

where SF_{lw}^{d}, SF_{ls}^{d} and SF_{lb}^{d} are local shift factors of the ADG representing the impact of wind power, solar power, and load demand on each bus on the power flow in the tie-line connecting ADG$_j$ to the ISO; and σ_{lw}^{d}, σ_{ls}^{d} and σ_{lb}^{d} are standard deviations of the uncertain variables (wind and solar power as well as load demand) located in ADG$_j$. Note that only the local uncertain variables of the DISCO$_j$'s (load demand and non-dispatchable units located in ADG$_j$) are used in (4.18).

The optimization problem (4.19) is for the ISO in which the objective is the summation of operating and startup shutdown costs of the dispatchable generating units of the ISO as well as the penalty function associated with the shared variables. The prescheduled values for the pseudo generation received from the DISCOs are used to build the penalty function. Thus, in this problem, $PD_{O,jt}$ is treated as the vector of decision variables while $PG_{D,jt}^{*}$ is treated as a constant term.

$$
\begin{aligned}
&Min \sum_{t=1}^{NT} \sum_{i=1}^{NGo} \left(F(P_{it}^{o}) I_{it} + SUD_{it}^{o} \right) \\
&+ \sum_{t=1}^{NT} \sum_{j=1}^{NA} (\alpha_{jt} (PD_{o,jt} - PG_{D,jt}^{*}) + \left\| \beta_{jt} \circ (PD_{o,jt} - PG_{D,jt}^{*}) \right\|_2^2)
\end{aligned}
\tag{4.19}
$$

The regular SCUC constraints (4.2)-(4.8) as well as (4.14) and (4-15) should be satisfied. Similar to the DISCO's optimization problem, the following chance constraint for the tie-line should be satisfied in the ISO's problem.

$$
\Pr\left\{ PD_{o,jt} \le PL_{lt}^{\max} \right\} \ge 1 - TLOP_{lt} \quad \forall t, l \in tie-line \tag{4.20}
$$

which can be converted to a deterministic constraint as (4.21):

$$PD_{o,jt} \le PL_{lt}^{\max} - Z_{TLOP_{lt}} \left[\sum_{w=1}^{NW} \left(SF_{lw}^{o} \sigma_{wt}^{o} \right)^2 + \sum_{s=1}^{NS} \left(SF_{ls}^{o} \sigma_{st}^{o} \right)^2 + \sum_{b=1}^{NB} \left(SF_{lb}^{o} \sigma_{bt}^{o} \right)^2 \right]^{1/2} \quad (4.21)$$

where SF_{lw}^{o}, SF_{ls}^{o} and SF_{lb}^{o} are local shift factors of the ISO representing the impact of uncertain wind power, solar power, and load demand on the power flow in the tie-line connecting ISO to the ADG_j; and σ_{lw}^{o}, σ_{ls}^{o} and σ_{lb}^{o} are standard deviations of the uncertain variables located in transmission network. Similar to the DISCO's problem, only the uncertain variables of the ISO's are used in (4.21). Assume that ADG_j is connected to the transmission network through one tie-line. Thus, it can be proved that the shift factors associated with all buses of the transmission network on the tie-line connecting ISO to ADG_j are zero. It means that any change in the power injected to the buses of the transmission network has no influence on the tie-line. Also, under this condition, the shift factors associated with all buses of the distribution system on the tie-line is minus one which means any changes on the power injected on buses of the ADG directly impacts the power flow in the tie-line. Therefore, the power flow in the tie-line connecting DISCO_j to the transmission network from the DISCO_j's perspective, $PG_{D,jt}$, can be rewritten as (4.22).

$$\begin{aligned} PG_{D,jt} &\le PL_{lt}^{\max} \\ &- Z_{TLOP_{lt}} \left[\sum_{w=1}^{NWd} \left(-\sigma_{wt}^{d} \right)^2 + \sum_{s=1}^{NSd} \left(-\sigma_{st}^{d} \right)^2 + \sum_{b=1}^{NBd} \left(-\sigma_{bt}^{d} \right)^2 \right]^{1/2} \end{aligned} \quad (4.22)$$

And similarly, the power flow in that tie-line from the ISO's perspective, $PD_{o,jt}$, is written as follows:

$$PD_{o,jt} \le PL_{lt}^{\max} \tag{4.23}$$

4.3.3 Solution Algorithm

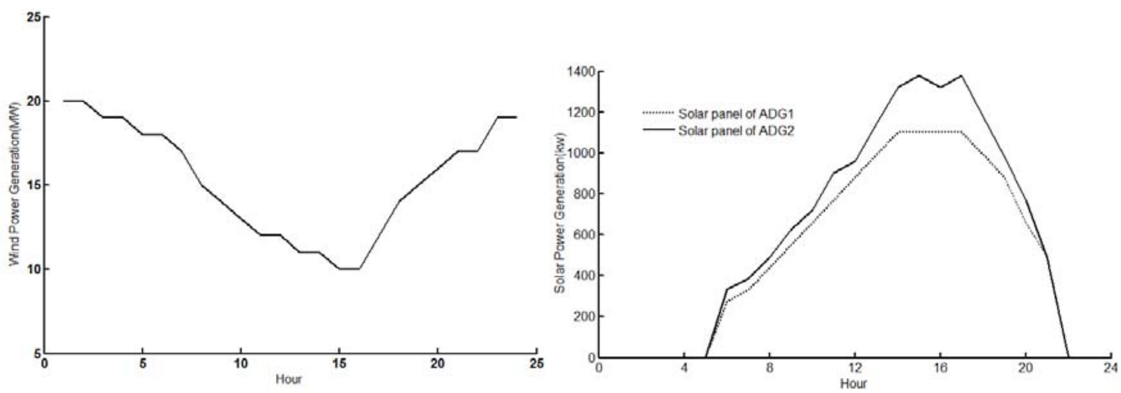
In order to find the optimal operating point of the entire SoS-based power system, the similar solution algorithm presented in Chapter 3 can be applied. However, the inner loop is ignored and the decentralized solution algorithm includes one loop which is equal to outer loop of the algorithm presented in Chapter 3. Note that inner loop only may improve the accuracy of the final results when we do not have a good guess for the initial starting point, but it may increase the calculation time.

4.4 Numerical Results

The proposed decentralized stochastic SoS-based optimization algorithm is applied on a six-bus and the modified IEEE 118-bus test systems and the results are discussed. All cases utilize ILOG CPLEX 12.4's MIQP solver on a 3.4GHZ personal computer.

4.4.1 Six-Bus Test System

The system topology and the characteristics of generating units, network information, and the hourly load distribution over 24-h horizon are given in the case study section of Chapter 3. The six-bus test system has 3 thermal generating units, 7 branches, and 3 demand sides in the transmission system. A wind farm is located at bus 3 with the forecasted hourly generation shown in Figure 4.2 (a). Two active distribution grids are connected to the transmission system through buses 3 and 4, and one passive distribution grid is connected to bus 5. ADG1 includes 9 buses, 8 distribution lines, 5 load points, 2 dispatchable DG units, and 1 solar power generation (non-dispatchable unit) located at bus 4; and ADG2 has 7 buses, 6 distribution lines, 4 loads, 2 dispatchable DG units, and 1 solar power generation located at bus 5. The forecasted hourly generation of the solar panels are shown in Figure 4.2 (b).



(a) (b)

Figure 4.2 Forecasted generation of a) wind farm, and b) solar panel of ADG1 and ADG2

In order to analyze the effectiveness of the proposed algorithm, we consider the following three case studies:

Case 1: The proposed decentralized day-ahead scheduling with $\sigma_D = \sigma_w = \sigma_{s1} = \sigma_{s2}$ =0%.

Case 2: The proposed decentralized day-ahead scheduling with σ_D =1%, σ_w =20%, $\sigma_{s1} = \sigma_{s2}$ =25%, and $LOLP_t$ = $TLOP_{lt}$ =25%.

Case 3: The proposed decentralized day-ahead scheduling with σ_D =1%, σ_w =20%, $\sigma_{s1} = \sigma_{s2}$ =25%, and $LOLP_t$ = $TLOP_{lt}$ =5%.

4.4.1.1 Case 1

Based on the SoS concept, in this case, ISO and both ADGs are regarded as three independent systems with their own operation rules and information privacy. The standard deviation of hourly load demand (σ_D), generation forecast error of wind (σ_w), and solar panels of ADG1 (σ_{s1}) and ADG2 (σ_{s2}) is 0. Hence, there is no stochastic constraint and we have deterministic optimization problems for each independent system. The constraint related to power transferred between the ISO and ADGS (shared variables) are also deterministic. The initial value for $\boldsymbol{\alpha}_{jt}^{0} = \boldsymbol{\beta}_{jt}^{0} = 1$ (j=1, 2, and t=1:24); and convergence thresholds ε_1 and ε_2 are set to 0.01 and 0.001, respectively. The decentralized SoS-based SCUC is applied to find the optimal operating point of the transmission system and ADGs. The algorithm converges after 5 iterations. The ON/OFF states and generation dispatch of the generating units are depicted in Tables 4.1 and 4.2. Unit 2 of the ISO is a very expensive unit and is scheduled to be OFF all over the scheduling horizon; and DG1 of ADG1 and DG2 of ADG2 are (expensive) committed to be ON when the load is near the peak hours. During off-peak hours, unit 1 of the ISO, DG2 of ADG1 and DG1 of ADG2 are ON to supply the power consumed by the loads and spinning reserve. When the load is near the pick hours, unit 3 of the ISO provides power for the loads, however, it does not provide spinning reserve, and the required reserve is provided by unit 1 of the ISO and DG2 of ADG2. The operating cost of the independent systems is shown in Table III, and the total operating cost of the SoS-based power system is $55,360.

4.4.1.2 Case 2

The standard deviations of hourly load demand (σ_D), generation forecast error of wind (σ_w), and solar panels of ADG1 (σ_{s1}) and ADG2 (σ_{s2}) are 1%, 20%, 25%, and 25%, respectively; and $LOLP_t$ and $TLOP_{lt}$ are 25%. Compared with Case 1, in this case, there are several stochastic constrains, and we need to apply the chance-constrained concept for day-ahead scheduling of the SOS-based power system. The proposed decentralized algorithm converges to the optimal operating point after 5 iterations. The unit commitment results are the same as those presented in Table 4.1. In this case, in order to ensure that the stochastic constraints are within the acceptable range with pre-specified probability, the hourly power dispatch of unit 1 of the ISO, and DGs of both ADGs 1 and 2 have changed compared with Case 1. These changes are depicted in Figure 4.3. For example, in hour 24, the power generated by unit 1 of the ISO has decreased almost 1 MW. The operating cost of the ISO, DISCO1 and DISCO2 is shown in Table 4.4. The total operating cost of the SoS-based power system is \$55,510 which is \$150 larger than that in Case 1. These differences between Cases 1 and 2 are because of considering load and renewable generation uncertainties in optimization problems of the independent systems in Case 2, and taking into account the chance-constrained to satisfy the risk level of the systems in accordance with the value of $LOLP_t$ and $TLOP_{lt}$ indices.

Table 4.1 UC solution in Case 1

Ind. Syst.	Units	Hours (1-24)																							
ISO	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DISCO1	1	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0
	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
DISCO2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	2	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0

Table 4.2 Generation Dispatch (MW) in Case 1

Hour	ISO			DISCO1		DISCO2	
	Unit1	Unit2	Unit3	DG1	DG2	DG1	DG2
1	112	0	0	0	18	25	0
2	106	0	0	0	18	25	0
3	103	0	0	0	18	25	0
4	93	0	0	0	18	25	0
5	93	0	0	0	18	25	0
6	103.4	0	0	0	18	25	0
7	112.3	0	0	0	18	25	0
8	115.1	0	0	0	18	25	0
9	101.8	0	25	0	18	25	0
10	119.7	0	25	0	18	25	0
11	128	0	25	15	18	25	3.3
12	132.7	0	25	15	18	25	6.4
13	137.2	0	25	15	18	25	8.7
14	138.3	0	25	15	18	25	9.3
15	142.3	0	25	15	18	25	11.2
16	146.5	0	25	15	18	25	14.1
17	144.5	0	25	15	18	25	14
18	137.2	0	25	15	18	25	10.6
19	135.7	0	25	15	18	25	10.4
20	129.5	0	25	15	18	25	7
21	138.7	0	25	15	18	25	7.3
22	126.8	0	25	15	18	25	6.2
23	123	0	25	0	18	25	0
24	123	0	25	0	18	25	0

Table 4.3 Operating cost of the Independent Systems in Case 1

Independent system	Operating cost($)
ISO	39,321
DISCO1	5,765
DISCO2	10,274

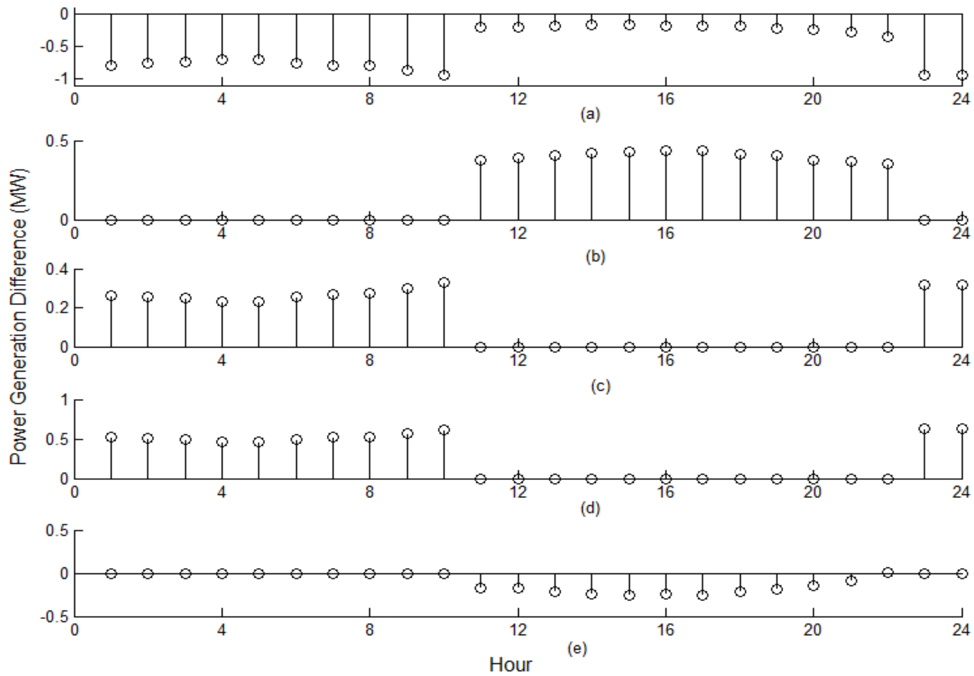


Figure 4.3 Difference between power generated by, a) unit 1 of ISO, b) DG1 of ADG1, c) DG2 of ADG1, d) DG1 of ADG2, and e) DG2 of ADG2 in Cases 1 and 2

Table 4.4 Operating cost of the Independent Systems in Case 2

Independent system	Operating cost($)
ISO	39,493
DISCO1	5,715
DISCO2	10,302

4.4.1.3 Case 3

Using the same standard deviations as Case2, $LOLP_t$ and $TLOP_{lt}$ are set to 5%. It reduces loss of load and transmission congestion expectation, and makes more limitation for the chance-constrained stochastic day-ahead scheduling. The decentralized algorithm converges after 5 iterations. Reduction of $LOLP_t$ and $TLOP_{lt}$ from 25% to 5% changes the power generated by dispatchable generating units. Figure 4.4 shows these changes compared with Case 2. For example, the power output of unit 1 of the ISO at hour 16 increases by 0.32MW; and DG2 of ADG2 requires to provide 0.44MW more power at hour 17 compared with that in Case 2. As shown in Table V, the operating costs of ISO, DISCO1 and DISCO2 are \$39, 580, \$5,681 and \$10,189, respectively. The total operating cost of the SoS-based power system is \$55,580 which is \$220 more than that in Case 1.

Notice that in order to check the validity of the results of the proposed stochastic SoS-based optimization algorithm, all three cases are also solved considering the entire power system as a single system and applying conventional centralized optimization algorithm. Its results are almost same as those shown in Tables 4.1 to 4.5 obtained based on the decentralized optimization algorithm.

4.4.2 Sensitivity Analysis on the Tie-Lines Chance Constraints

In order to analyze the impact of chance constraints of the tie-lines connecting the ISO to the DISCOs on the SoS-based decentralized scheduling algorithm, a sensitivity analysis is performed. The $LOLP_t$ and $TLOP_{lt}$ of all independent systems are 25%. Setting different values for the $TLOP_t$ of the tie-lines (100% to 10%), the proposed algorithm is implemented. In fact, we vary the chance that the power flow in each tie-line is less than its maximum capacity (the security level of each tie-line). Moreover, different values are considered for the standard deviation of the PDFs of the wind and solar power generations, which means we have different accuracy levels for wind and solar power prediction. The standard deviation of the wind power varies from 15% to 65% of the wind power output; and it varies from 20% to 70% of solar power production. The total operating point of the SoS-based power system is shown in Figure 4.5. The operating cost increases by decreasing the $TLOP_t$ (increasing the security level of the tie-lines). Also, the results show that better prediction for the wind and solar power generation causes reduction in the total operating cost of the SoS-based power system.

Table 4.5 Operating cost of the Independent Systems in Case 3

Independent system	Operating cost($)
ISO	39,560
DISCO1	5,700
DISCO2	10,320

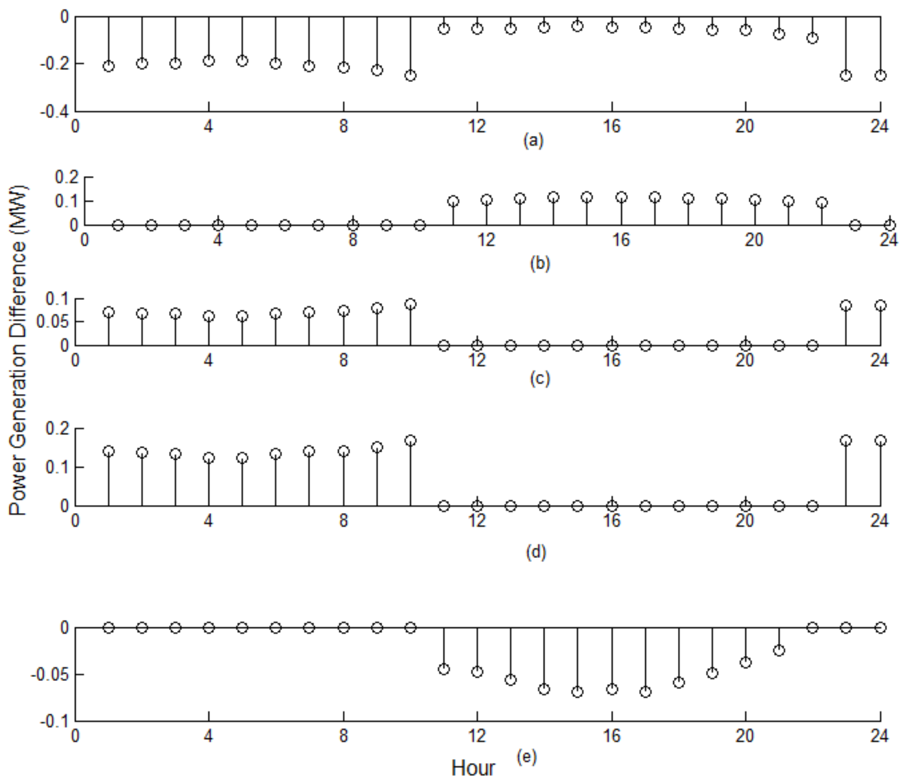


Figure 4.4 Difference between power generated by, a) unit 1 of ISO, b) DG1 of ADG1, c) DG2 of ADG1, d) DG1 of ADG2, and e) DG2 of ADG2 in Cases 2 and 3

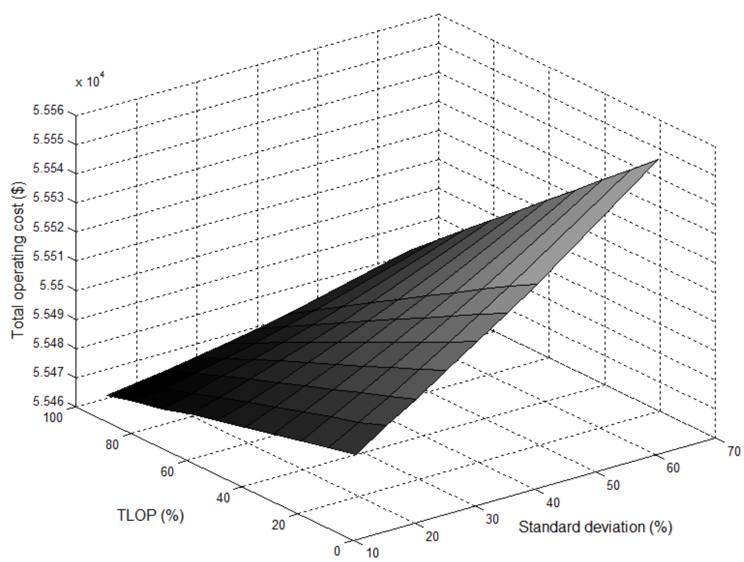


Figure 4.5 Total operating cost versus TLOP and standard deviation

4.4.3 The IEEE 118-Bus System

The proposed chance-constrained SoS-based generation scheduling has been applied to the modified IEEE 118-bus test system. We have considered 30 active distribution grids connected to the transmission network each of which is operated by an independent DISCO. Therefore, in the SoS-based generation scheduling, there are 31 independent systems (30 DISCOs and one ISO) collaborating together to operate the entire power systems in a secure and economic manner. The ISO has 54 thermal generating units, 61 loads (or inactive distribution grids), 187 branches, and 3 wind farms connected to buses 10, 70 and 110, respectively. There are 30 solar power farms connected to the ADGs. The standard deviations of hourly load demands (σ_D), wind generation (σ_w), and solar generation (σ_s) of ADGs are 1%, 20%, 25%, and 25%, respectively; and $LOLP_t$ and $TLOP_{lt}$ are 5%. To find the optimal hourly unit commitment and generation dispatch, the proposed algorithm is implemented setting the initial values $\boldsymbol{\alpha}_{jt}^{0} = \boldsymbol{\beta}_{jt}^{0} = 1$ (j=1, 2, and t=1:24), $\varepsilon_1 = 0.01$, and $\varepsilon_2 = 0.001$. The algorithm converges to an optimal solution after 17 iterations. As an example, Figure 4.6 shows the converged amount of power exchange (shared variables) between ISO and DISCO1 at hour 19 in each iteration. Operating costs of individual DISCOs are shown in Figure 4.7; and operating cost of the ISO is $1,058,000. As listed in Table 4.6, the total operating cost of the SoS-based power system is $1,186,200. To check the validity of the results, the conventional centralized algorithm is implemented and the total operating cost is $1,184,000. The difference between the operating costs obtained by these two algorithms is 0.18% ($2,200) which is acceptable. Although the proposed algorithm could result in a slight increase in operating cost, it needs a limited information to be exchanged between the independent systems which can meet the information privacy of the systems.

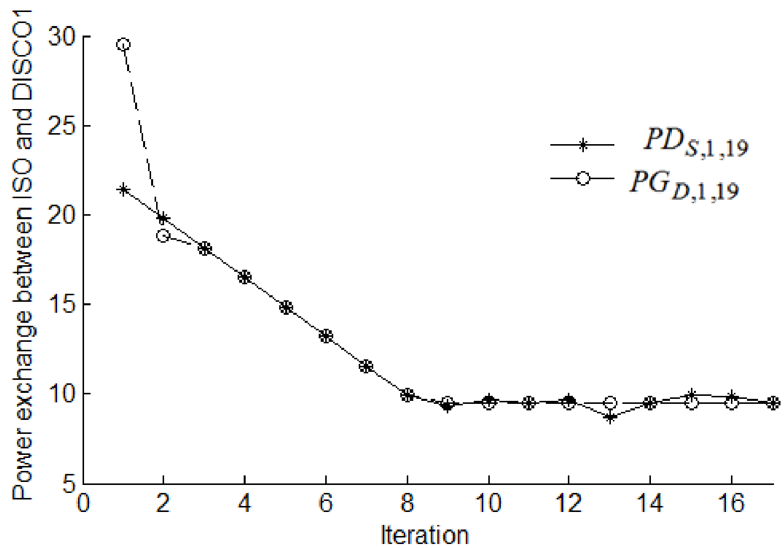


Figure 4.6 Power exchange (shared variable) between ISO and ADG1 at hour 19

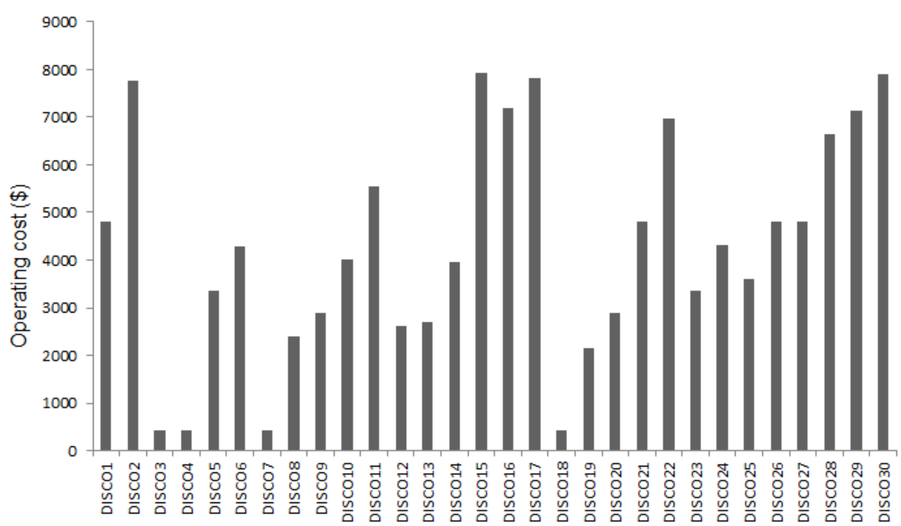


Figure 4.7 Total operation cost of the DISCOs

Table 4.5 Total Operation Cost of SoS-Based Power System

Solution Algorithm	Operation cost($)	# of outer loop
Centralized	1,184,000	-
Decentralized	1,186,200	17

4.5 Summary

In modern power systems, incorporation of generation sources of active distribution grids in the power system operation enhances the economic and security of the entire system. Since the transmission and distribution grids are utilized by different system operators in the electricity market, making a collaborative and optimal operation among these systems is an important and challenging problem. This becomes more challenging when there are uncertain decision variables in the systems such as load demand and renewable power generation uncertainties. A power system was modeled as a system of systems in which the ISO and each DISCO were autonomous systems. Considering the uncertainties, the expected stochastic power balance constraint was regarded, and the chance-constrained stochastic programing was applied to model the reserve requirements and line flow limits for each independent systems. In the proposed framework, only a limited amount of information related to the tie-lines connecting the ISO to DISCOs was exchanged among the independent systems. Thus, there is no need to share all the systems' information, which is usually commercially sensitive, between the ISO and DISCOs, and the information privacy of each autonomous system was guaranteed.

CHAPTER V

CONCLUSIONS AND FUTURE WORKS

5.1 Conclusions

In this dissertation, the modern power systems are modeled according to the concept of system of systems engineering. In Chapter 2, for the active distribution grid, the DISCO and microgrids are regarded as the self-governing systems that are autonomously managed and operated aiming at maximizing their own benefits. The data flow process of communicating and transferring data between the systems are discussed, and the concept ORIGIN and CLIENT systems, shared parameters and shared variables are defined. The decentralized optimal power flow problem is formulated to model the SoS-based operation, and a hierarchical two-level optimization algorithm is applied to solve the proposed problem and coordinate the operating points of all independent systems.

In Chapter 3, a SoS-based deterministic security-constrained unit commitment is addressed in which the ISO and each DISCO are autonomous and independent systems. A decentralized decision-making framework is proposed to find the optimal SCUC schedule for ISO and DISCOs. In order to solve the problem, a hierarchical optimization algorithm is presented taking into account the shared variables/information between the independent systems. The hourly results of day-ahead market verify that considering the

DG units in SCUC problem improves the market efficiency in terms of economic and security issues. Consequently, this decentralized decision-making framework can facilitate the participation of active distribution grids into the market.

In Chapter 4, we discuss the impact of uncertainty of renewable energy resources and load demand on the operating condition of each independent system in the SoS-based power system. A collaborative stochastic day-ahead scheduling algorithm is presented applying the chance constraint and risk analysis technique to model the load and generation uncertainties in each independent system. The load balance, reserve requirements, and power flow limits are stochastic constraints being modeled by chance constraints. The chance constraints are converted into a linear deterministic model. Considering the impact of uncertain decision variables on the shared variable between the independent systems, a decentralized stochastic algorithm is formulated for day-ahead scheduling.

5.2 Future Works

The suggested future works are listed as follows.

- The distribution network and microgrids are assumed to be balanced. However, the unbalance distribution feeders can be further considered in the SoS-based OPF algorithm.
- The SCUC algorithm proposed in Chapter 3 is formulated for collaboration between ISO and DISCOs. It can be further improved to solve the SCUC problem in multi-area interconnected power system. In this case, the ISOs cooperate together to find the entire power system

operating point. Cost of power exchange between the ISOs may be considered.

- Other stochastic programing techniques such as robust optimization can be employed to model the uncertain parameters and variables in the decentralized decision-making algorithm.
- The presented SoS-based algorithm in this dissertation is for system operation purposes. As the future work, it can be applied for power systems planning problems regarding impact of the planning scheme of an independent system on the planning scheme of other systems.

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