DEVELOPMENT OF OPTIMAL GENERATION SCHEDULING ALGORITHM FOR DAY AHEAD MARKETS

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ABSTRACT

DEVELOPMENT OF OPTIMAL GENERATION SCHEDULING ALGORITHM FOR DAY AHEAD MARKETS

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In a liberalized electricity market structure, private generation companies play an important role and their attendance must be encouraged. In this study, an optimal generation scheduling algorithm is developed for the generation companies attending day ahead markets who aim to utilize their portfolio more efficiently and to provide low-cost energy to the consumers. The algorithm employs Lagrange relaxation and dynamic programming techniques. Generation capacities of units, ramp limitations, minimum on and off durations are handled as unit constraints. Generation scheduling is performed for hourly forecasted power demand. Different cases are solved with the developed algorithm to observe the results. Outputs of the algorithm are compared with other methods used in the literature.

Keywords: Unit commitment, Generation scheduling, Day ahead markets, Cost minimization.

ÖZ

GÜN ÖNCESİ PİYASALARDA FAALİYET GÖSTEREN ÜRETİM ŞİRKETLERİ İÇİN OPTİMUM ÜRETİM PLANLAMASI ALGORİTMASI GELİŞTİRİLMESİ

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Liberal elektrik piyasalarında, özel elektrik üretim şirketleri büyük öneme sahiptir ve piyasaya katılımları desteklenmelidir. Bu çalışmada, gün öncesi elektrik piyasalarında faaliyet göstererek hem kendi portfolyolarını değerlendirmeyi, hem de tüketiciye düşük maliyetli elektrik enerjisi sunmayı hedefleyen üretim şirketleri için bir optimum üretim planlaması algoritması geliştirilmiştir. Bu algoritma içerisinde 'Lagrange Relaxation' yöntemi 'Dinamik Programlama' yöntemi kullanılmıştır. Ünitelerin üretim kapasiteleri, tırmanma limitleri, minimum açık ve kapalı kalma süreleri kısıtlayıcı etkenler olarak ele alınmıştır. Üretim planlaması, tahmin edilmiş olan talep yükü miktarına göre saatlik olarak yapılmıştır. Algoritmanın çıkardığı sonuçları gözlemlemek için farklı durumlar ele alınmıştır. Sonuçlar aynı zamanda literatürde kullanılan farklı metotlar ile de kıyaslanmıştır.

Anahtar Kelimeler: Ünite ataması, Üretim planlama, Gün öncesi piyasaları, maliyet minimizasyonu.

to my grandmother,

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DEFINITION	SYMBOL	UNIT
Total cost of the whole time horizon to be scheduled	F	\$
Total number of generation units	N	-
Cost of unit i at time interval t	$F_{i,t}$	\$
Power output level of unit i at time interval t	$P_{i,t}$	MW
Start-up cost of unit i	SU_i	\$
Commitment status of unit i at time interval t	$I_{i,t}$	1/0
Shut-down cost of unit i	SD_i	\$
Minimum generation capacity of unit i	$P_{i,min}$	MW
Maximum generation capacity of unit i	$P_{i,max}$	MW
Spinning reserve of unit i at time interval t	$R_{i,t}$	MW
Non-spinning reserve of unit i at time interval t	$N_{i,t}$	MW
The time duration which unit i has been ON at the beginning of time interval t	$T_{i,t}^{on}$	hour
The time duration which unit i has been OFF at the beginning of time interval t	$T_{i,t}^{off}$	hour
Minimum ON time duration of unit i	MON_i	hour
Minimum OFF time duration of unit i	MOF_i	hour
Ramp-up rate of unit i	UR_i	MW/hour

Ramp-up rate of unit i	DR_i	MW/hour
Forecasted demand quantity at time interval t	D_t	MWh
Number of generating level intervals of unit i	RL_i	-
First cost coefficient of unit i	a_i	-
Second cost coefficient of unit i	b_i	-
Third cost coefficient of unit i	c_i	-
Total cost of time interval t	F_t	$
Tolerance for the equilibrium of forecasted demand and generated power	ε	MW
Lagrange multiplier	λ	-
Lagrange multiplier – Incremental cost of time interval t	λ_t	-
Lagrange multiplier of kth iteration	λ_k	-
Cost of the transition from time interval $t-1$ to time interval t	$TC_{t-1,t}$	$
Transition cost from state m at hour t to state n at hour $t+1$	$TC_{m,n}$	$
State number	n	-
Total cost of a state n at time interval t	$STC_{n,t}$	$
Ramp state number of unit i at time interval t	$rs_{i,t}$	-

CHAPTER 1

INTRODUCTION

There is no contradiction that electricity becomes the irrevocable type of energy that people use. It has always been a crucial necessity for human beings and civilizations in terms of the improvement of socialization right after it has been invented. Especially after the industrial developments, in almost all part of the life, from agriculture to transportation, from education to medicine, from houses to cars, there is an alternative and more efficient choice for a device or a service which works with electricity. Therefore investments to the production of electrical energy are never to be ended. Conversion of some other types of energies obtained from fossil sources like natural gas and any type of coal to the electrical energy has been basic generation system. For sustainability of the nature and world, uninterrupted increase in necessity of electricity must be tolerated mainly from the renewable energy sources like hydro, solar, wind, geothermal, bio-organic wastes. Managing this growing electrical system is getting more and more complicated because of the increasing number of stakeholders. As known, electricity is not a type of energy that can be stored in anyway. It must be securely available whenever required in the desired quantity. This brings main difficulty into the sector like expertise, financing and planning. Hopefully, if a way of storing the electrical energy in excessive amounts would be found, most of the problems in this sector would be solved and a huge decrease in required labor would occur.

Traditionally, monopolistic and vertically integrated management system which is own by a foundation has been used commonly in the world. This foundation was belonging to the government in general. Generation was the first task to be completed. However, producing the electricity was not the end point of responsibility of governments about electricity. Generated electricity which is in high voltage is needed to be transmitted via transmission lines. Nevertheless, establishing the transmission lines requires a huge investment alone. Beside these, produced and transmitted energy has to be distributed to the variety of consumers at lower voltages, which is called “distribution”. As a result, governments were in charge of not only generation, but also transmission and distribution and they were the monopoly in managing the electricity sector. The structure of the vertically integrated system could be seen in Figure 1.

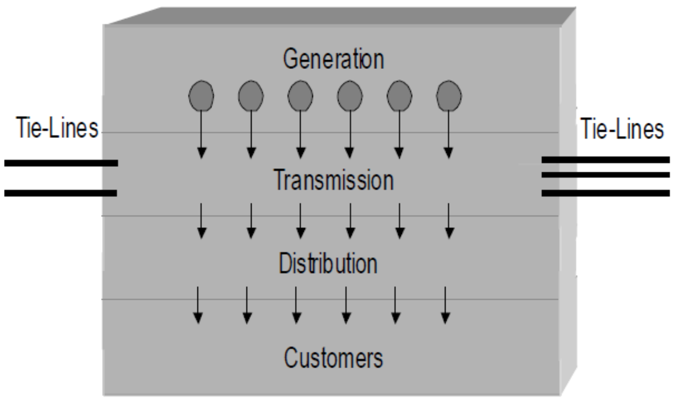

Figure 1: Vertically integrated structure of electricity market [1].

This system was able to supply the demanded quantity of energy and required ancillary services till the end of 1970s [2]. After those years, these monopolist actions have exposed to some substantial problems that had to be solved for the continuity of the system [3]. Primarily, customers had no choice for buying electricity from different sellers. Thus, economical diversity was low. Together with that, the efficiency of production was quiet low under monopoly. That is because of the noncompetitive market structure. In order to solve these problems, some countries contemplated privatization and electricity industry underwent a major transition around the world. New attitudes and new management strategies are developed. Increasing investment costs, high electricity prices, safety inadequacy, environmental approaches and shortage in the energy sources can be counted as main reasons of this restructuring process [2].

The revolution in the system, which is deregulating the electricity market, involves privatization, restructuring, deregulation and competition. Main objective of these reforms are to serve cheap, enhanced qualified, uninterrupted electricity to the customers. In addition, private investments and public finances were also encouraged to take part in the electricity sector.

It is widely believed that conducting electricity markets in a competitive manner is the preferred way to decrease the costs and enhance the service quality. In this purpose, most countries around the world have proposed various restructuring processes all of which aimed at liberalizing their electricity business. In addition, there are countries that still in the phase of the progressive liberalization of their electricity markets [4].

In the deregulated power markets, vertically integrated structure of utilities is disbanded. Generation, transmission and distribution services are operated by different foundations. Therefore investment costs and operation and maintenance (O&M) costs are financed by different resources which can enlarge budget of the market. No relation or responsibilities between generation, distribution and transmission companies exist except the contracts. Electricity could be sold to the customer by three of the communities. By this way, variety of seller options is increased for the customers. A sample explanation of deregulated market structure is given in the Figure 2. And the energy and money flow between the entities could be followed in Figure 3.

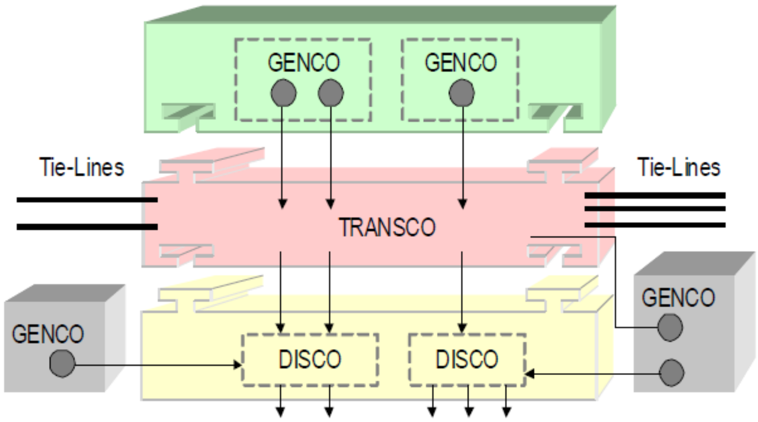

Figure 2: Structure of the deregulated power market [1].

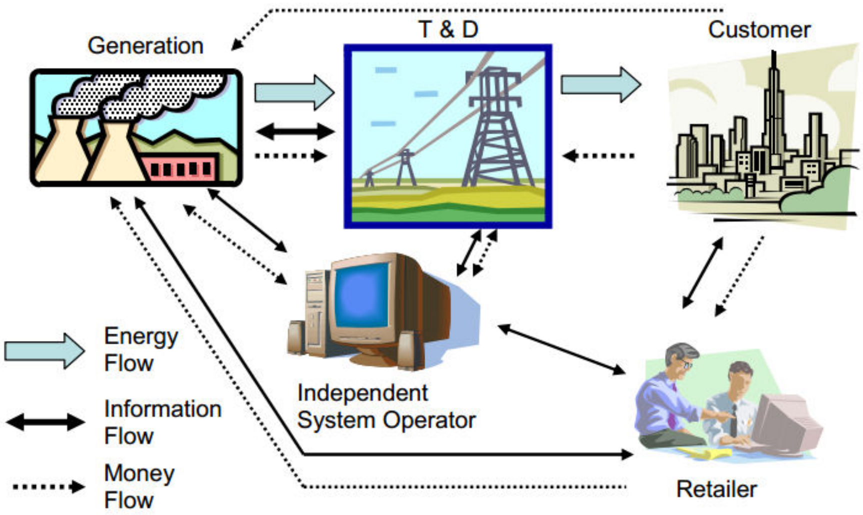

Figure 3: Energy and money flow diagrams between entities [5].

In deregulated markets, Independent System Operator (ISO) or Transmission System Operator (TSO) is the entity responsible for independent operational control of the grid. ISO makes decision for committing and scheduling some or all of the generating sources. It can also curtail loads whenever required in order to maintain the supply-demand balance. Acceptable frequency is served and transmission line capacity violation is prevented by this way [1].

A Distribution Company (DISCO) is responsible for conducting the part of the distribution network. It has to make the investment to meet the demand of widening cities and settle the infrastructure to distribute the energy from facilities of transmission to the residential. DISCOs may also purchase electricity by making bilateral contracts with the GENCOs and sells it to its residential or industrial customers.

A Generation Company (GENCO) conducts and manages its generating power plants. It can sell the energy it produced to the distribution companies, retailers or directly to the customers which have a large consumption. GENCOs are not affiliated with any other ISO or TSO. They can set their own tariffs and attains the energy or ancillary service markets in order to maximize their own profit. With this purpose, generation scheduling becomes one of the most important issues for GENCOs. They need to manage the generation planning among the generating units they have in order to minimize their production cost. The objective of this scheduling is to satisfy the total system load and to operate and maintain the system security and reliability with a minimized cost. At this point, a complex problem which generation entities have to deal with emerges, unit commitment. Unit commitment problem is evaluated to determine the ON/OFF decisions and generation levels of each unit for a specific time interval. While scheduling the generating units, unit and system constraints must be satisfied. This makes the problem more complicated. As a whole, unit commitment of a power system is a task with thermal, hydro and pumped-storage generation units, and bilateral contracts to determine when to startup and/or down generation units, or take contracted energy, and how to dispatch the committed units and contracts to meet system demand and reserve requirements over a particular time period. Each unit or contract may have limited energy, minimum up/down times, and/or other constraints. The objective is to minimize the total generation cost [6].

In other words, unit commitment is mainly an optimization problem that minimizes the total cost to meet the load demand while considering the relevant constraints. As a result, it can be defined in detail as “to determine the start-up, shut down, and generation levels of all units, and durations and megawatt levels of all transactions over a specified time period t to minimize the total cost including the generation cost and contracted transaction cost, subject to system demand and reserve requirements and individual thermal unit and transaction constraints" [6].

Unit commitment task is approached as an optimization problem. And several solution methods have been developed up to now to solve this kind of optimization problems. Each method brings its own advantages and disadvantages when reaching the solution. Some methods are better than the others in handling with the constraints. On the other hand, some other ones could give faster solutions with lack of little bit optimality. Ultimately, GENCOs must choose a solution technique according to their generating units, economic plan and market structure in which they trade. Generally, a combination of the optimization methods is employed to obtain a more optimal and faster solution in some situations.

In this thesis, unit commitment problem is investigated in depth and an optimal generation scheduling algorithm for GENCOs who attains the day ahead market is developed. In the next chapters of the study, the evolution of the electricity market structure and history of it is explained firstly. Then, general information about the day ahead markets is given. Commonly used optimization techniques involving the Lagrange relaxation and dynamic programming are also described. These two methods are used in development of the solution algorithm. Chapter 4 includes formulation of the unit commitment problems. The function to be minimized involving unit constraints, system constraints and other factors are formulated mathematically. The solution methodology of the MATLAB based scheduling algorithm is explained in detail with its all difficulties in chapter 4. Different case studies ranging from single generating unit to multiple options with compelling constraints are performed to show the applicability of the developed algorithm. And finally, the study is summarized with its base points and outstanding results. Possible future works are mentioned in order to improve this study in the conclusion chapter.

CHAPTER 2

OVERVIEW OF TURKISH ELECTRICITY STRUCTURE AND MARKET MODELS

2.1 Turkish electricity structure

Turkey is settled geographically at the intersection of Europe and Asia which is a very strategic region for routing the energy sources. Turkey has an electricity markets which is one of the fastest growing markets in the world. Although an economic crisis occurred in Turkey in 2009 caused shrinkage in the sector, for the last two decades, with a 9 % average annual growth rate is realized. And this growth trend seems to be continued till 2020 at an average increase of 6.5-7.5 % per year [7]. In order to overcome this excessive growth rate, Ministry of Energy and Natural Resources (MENR) foresees the need for enlarging the transmission and distribution systems as well as constructing new power plants, requiring an average $5.5 to $6.5 billion investment in a year for the energy sector [8].

History of Electricity sector of Turkey starts with the establishing of Electricity Authority (TEK), in 1970. This foundation was a governmental monopoly until 1984. After 1984, participation of private sector started under the modes of Build-Operate-Transfer (BOT), Build-Own-Operate (BOO) and Transfer of Operating Rights (TOOR). In 1993, TEK was divided into two state-owned companies. One of them was Turkish Electricity Generation-Transmission (TEAS) and the other one is Turkish Electricity Distribution Company (TEDAS). This step was necessary but not enough for an effective deregulation of energy market. Finally

TEAS was unbundled into three different entities responsible for different sub-sectors with Electricity Market Law issued in year of 2001. EUAS was responsible for managing the generation stations which belongs to government. TEIAS was the conductor of transmission lines and TETAS was performing the trade action as wholesale. The unbundling of monopolistic structure is followed by the privatization plan of other state-owned electricity sector companies, except for TEIAS. These reforms bring the necessity of an independent supervision authority. Therefore Energy Market Regulation Agency (EMRA) which will oversee the electric power and NG markets including setting tariffs, issuing licenses, and assuring competition was established in 2001 [1].

Turkish Government was the active player in the Turkish energy sector a few decades ago and still the energy policies is largely conducted by MENR. After the deregulation process, it is presently being transformed into a liberalized market in order to inject private investments to the sector and to deregulate market structure in parallel with the energy policy of the European countries.

During the deregulation process in the energy sector, Turkey mainly inspired from the Electricity Directives of European Union and takes financial support from the international foundations such as the World Bank and the International Monetary Fund (IMF).

2.1.1 Installed capacity and demand values

Turkey is listed among the fastest developing energy markets in the world. Turkey’s energy consumption has been increasing around 6% per year for the last three decades [7]. This increasing demand is caused by national facts such as the ignorance in energy sector in the past, young population having a low average age, huge urbanization rate and growing economy coming up with these developments. Researches and statistical data show that this increase in demand of electricity will be accelerated in coming years.

Numerical values of the installed capacity of Turkey from 2000 to 2012 are given in Table 1.

Table 1: Total installed capacity of years from 2000 to 2012, rate of renewable plants and portion of the private sector [9].

Years	Total installed capacity	Portion of the renewables	Owned by private sector
2000	27264,1	41	22,1
2001	28332,4	41,2	25,7
2002	31845,8	38,5	43,9
2003	35587	35,4	48,8
2004	36824	34,4	40,8
2005	38843	33,3	41,9
2006	40564	32,4	41,5
2007	40777	33,2	41,4
2008	41817	34	42,7
2009	44761	34,45	45,9
2010	49524	34,82	51,1
2011	52911	35,9	54,4
2012	57059	38,6	56,6

The overall portfolio of privately owned generation facilities accounts 56.6 % of the total electric generation capacity and they are from Build Operate Transfer (BOT), Build Operate (BO), generation companies and auto producers. The rest is provided by the governmental enterprises. It means that although the liberalization process has been prevailed for almost three decades, governmental authority is still the biggest player in the market. Hence, encouragements and stimulus must be increased to have a fully deregulated system.

In terms of energy demand, Turkey has an impressive potential as stated earlier. It can be seen obviously in Table 2 giving the electrical energy demand and peak power which represents the maximum required power for a moment in Turkey from 2003 to 2012. According to the report of MENR, Turkey's total electricity demand in 2013 is 245.501 GWh. And over 408.500 GWh of demand is expected in 2022 with a peak demand of 62930 [9].

Table 2: Peak Power and Energy Demand in Turkey between 2003 and 2012 [9]

Years	**Peak demand**	**Increase**	**Energy demand**	**Increase**
2003	21729	3,4	141151	6,5
2004	23485	8,1	150018	6,3
2005	25174	7,2	160794	7,2
2006	27594	9,6	174637	8,6
2007	29249	6,0	190000	8,8
2008	30517	4,3	198085	43
2009	29870	-2,1	194079	-2,0
2010	33392	11,8	210434	8,4
2011	36122	8,2	230306	9,4
2012	39045	8,1	242370	5,2
2013	-	-	245501	1,3

Table 2 is extracted from a report published by TEIAS annually. At the time when this study is conducted, the report of 2014 had not been released. Therefore the peak demand data of year 2013 is missing. The dramatic increase between the years of 2009 and 2013 in energy demand could be seen in graph. Predicted energy demands considering high and low scenarios which are given in Table 3 are also from the same report.

Table 3: prediction of peak power and total energy demand until 2022 [9].

	High scenario		**Low scenario**	
Years	**Peak power demand**	**Total Energy demand**	**Peak power demand**	**Total Energy demand**
2015	46420	301300	42900	278160
2016	49370	320470	44570	289330
2017	52490	340710	46270	300390
2018	55780	362100	48500	314850
2019	59260	384670	50900	330440
2020	62930	408500	53380	346510
2021	66320	430510	55790	362130
2022	69880	453560	58230	378000

When anyone looks at the peak power demand and total energy consumptions at the Table 3 for both of the high and the low scenarios, it can be expressed that danger of power shortages in the system in the short and long term exists. Turkey will need a significant amount of energy in immediate future. Therefore new investments have to be done in all of the generation, transmission, distribution areas in order to handle growth of demand. In the future, lack of investments especially in generation capacity may not only cause service interruption leaving the people in dark, but also prevent the economic development of the country and social welfare. This issue has been the top priority of the MENR and other policy-maker authorizations for recent years, as it must be.

Energy policy of Turkey must be managed to remove the obstacles and uncertainties in the investments of energy sector. Private investors are also as responsible as government for a national development because of two reasons. The first one is that a liberalized and fully deregulated market mechanism which can provide cheap, high quality electrical energy to the customers could be obtained if the governmental entities take hands off fully from the market. Secondly, the government has to deal with other areas like education, transportation, health etc.

Importance of generation companies having more than one power plant that may be conducted with different kind of sources is tried to be explained in the above parts. In order to encourage these enterprises and to increase number of them, beneficial tools in terms of engineering view must also be developed in addition to the financial and political conveniences. Developing an optimal generation scheduling algorithm could be one those engineering tools that would try to decrease production costs of the GENCOs who trades in day ahead markets. Now general information about day ahead markets, structure of it, advantages and disadvantages will be summarized in next chapter.

2.2 Market Structures

It is declared in the previous chapters that the energy markets are needed to be deregulated in order to supply cheap and high quality energy in a competitive manner. This deregulation brings some management complexities together with its advantages. Lots of companies get chance to sell energy whether they generate or not. Also any entity could buy energy whether he consumes or sells. Multiple Seller Multiple Buyer Model is the name given to operation conducted in this kind of markets. This model represents an unbundled structure in opposition to the Vertically Integrated Systems. GENCOs act as independent power producers in this market model. They make investments to construct feasible power plants and produce electrical energy. Then they sells the energy to the different types of buyers such as market operator, system operator, private wholesalers or private retailers and distribution companies depending on the deregulation level.

2.2.1 Electricity Market Models

Two different models, pools and bilateral contracts, define the frameworks of the sales contracts between the sellers and buyers in the Multiple Seller Multiple Buyer Model [3].

2.2.1.1 Pool Model

In pool model, energy generated by GENCOs is presented to the system operator which is an independent company responsible for dispatch of generation among the producers. In most countries, system operators are governmental. Buyers have to purchase energy from this system operator. Total quantity of energy to be generated is mostly decided based on the forecast performed by system operator. Therefore matching of supply and demand is done by the system operator. Market clearing price then arises to define the tariff. Any bids are given by neither producers nor buyers. All transactions are realized at market clearing prices. Producers also do not have the option to make their own unit commitment schedules. The system operator performs the unit commitment solution and decides how much amount and at which location energy should be produced. For a cost minimizing, a healthy decision, all the data related with all IPPs' start-up costs, generation costs, shut down costs and other costs should be submitted to the system operator. This causes difficulties in large markets to calculate the schedule. Besides, when the energy transfer day comes, unplanned situations such as fluctuations in demand and shortages in supply side may occur. System operator is responsible to solve such unplanned events and to match the supply and demand. Day ahead markets could be involved in such situations. Bids are given to the system operator one day ahead of the exchange day.

In fact, pool model is open the high energy tariffs because producers may not reflect their cost data truly to the system operator. They are totally independent entities anyway. In addition, in pool model, buyers do not have any rights and options on prices. They do not have the chance to bid to buy energy at the price they desire. Therefore pool model are forsaken in most of the countries. Instead, bilateral contract model, which is more close to the liberalization, takes place.

2.2.1.2 Bilateral Contract Model

Bilateral contract model has been the most commonly used method for energy trading in the world in recent years. Its necessity aroused after high electricity prices have started to dominate the pool model markets. In bilateral contract model, producers have the chance to sell the energy they produced via contracts either in long term or in short term. Similarly, buyers can freely purchase energy for either long term or short term. All the entities make their own decision to make profit and make bilateral contracts. Hence a liberalized and competitive market is approached for both suppliers and consumers for energy trading. GENCOs make their generation plans and try to make agreements with suppliers in order to sell energy and make profit. Therefore energy prices are driven by both of the sides. Or, it can be said that market makes its price by itself. Both buyers and sellers have effect on prices. In such a transparent mechanism, electricity prices do not have the chance to drop or rise from its actual value.

When a bilateral contract is signed, neither seller nor buyer is interested in the transmission issues. Turkey is a country in which no market splitting is applied. Therefore a buyer and a seller whose facilities are far away from each other attend to the same market. If a contract is signed between such two sides, the energy is needed to be transferred via the grid lines. The capacity of these grid lines is limited as ordinary. Hence a transmission allocation is necessary for each contract. Transmission dispatch control is performed by an impartial system operator which collects the all signed contracts in the market.

In bilateral contract model, generation companies are free to sell or buy energy. They could take places in the both sides of an agreement. Answer of the question to be on which side is mostly seller side. But they can also buy energy if any maintenance problem occurs in the units or if they found a seller which presents energy with lower price than their production cost. Owing to this flexibility, majority of the investor prefer to invest energy generation areas.

Bilateral agreements are made based on the willingness principle. No obligations exist for both sides. A bilateral contract means nothing than that the seller will be supplying an agreed amount of electrical energy during an agreed time interval. Also the buyer assures to be ready to pay for and to consume the agreed amount of electrical energy during the agreed time interval.

It is not necessary for a GENCO to utilize all of its capacity in bilateral agreements. Producers may regard bilateral agreements not as profitable as they desire and not leave their capacity unused. Or even if they have signed contract, they still could have capacity remaining outside of the contract. Similarly buyers also could not find a seller presenting affordable prices for making a bilateral contract. A balancing mechanism is obviously necessary for such situations to prevent both the scarcity and surplus of electrical energy.

Day ahead market takes the stage at that point. It provides a second chance to the sellers to utilize their available capacity to make more profit and a buyer can wait for the day ahead market to obtain its demand in the short term. Day ahead market also helps the sellers which are dealing with a problem in generation units by purchasing energy to meet its customer's demand with which they made a bilateral contract. There is not any obligation in day ahead markets to be in only one of the sides. A participant can both sell and buy energy in the market. For supplying the quantity they have to because of bilateral agreements, sellers also could purchase energy in day ahead markets if they found the prices more feasible than cost of producing. Thus, Day Ahead Market is a rewarding mechanism for trading efficiently with the remaining capacity and making more profit for sellers. It is also act as a rescuer for the buyers who made a bilateral agreement for the forecasted quantity and then faced with more demand than they forecasted because of either errors or extra demands. These sellers could buy more energy from the day ahead markets to fulfill their demand portfolio. By this way, both sides of an energy transaction agreement win by utilizing the full capacity and trading at real valued prices.

Day ahead markets can also be taken as reference for determining the price of electricity which is a necessity to be used in long term contracts and short term bids. When trying to decide on the prices of a long term bilateral contract, sellers and buyers can be inspired from the prices used in the day ahead markets.

2.2.2 Day Ahead Markets

In day ahead markets, energy trading agreements are completed one day ahead of the real usage day of energy. Four different actors take the roles in this structure. First of them is the sellers. Sellers submit their bids to take part in energy transaction. Secondly, buyers also submit their purchasing bids in order to buy energy. The third player is the market operator and he is responsible for matching the bids. He operates financial side of the market. The last agent is the system operator. System operator cares for the feasibility of energy transfer agreements in terms of transmission capability.

All the rules and processes of day ahead markets are defined by the laws and legislations. Market operator and system operator are responsible for managing the market according to these rules. While doing this managing task, they have to be impartial and fair to provide a perfect competition in the market. Although both the system and the market operators are from the governmental entities which also have got the majority of generation pie in Turkey, they must be independent from any of the market participants for a better deregulated market. In Figure 4, agents of a day ahead market can be seen. Left side represents the sellers while right shows buyers in the figure.

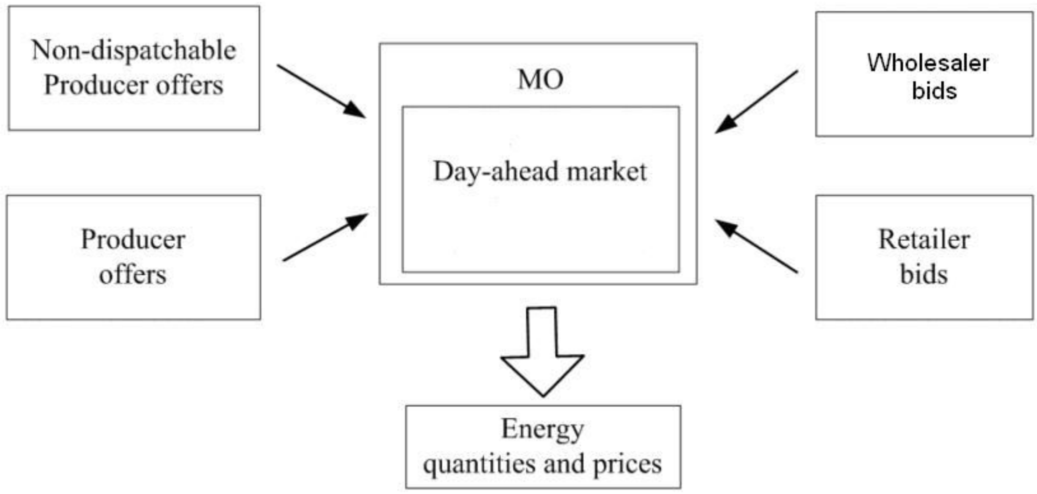

Figure 4: structure of day ahead markets [3].

In all day ahead markets applied in the world, market operators are responsible for managing and controlling the market. They need to prepare and publish regulations for the market to operate more effectively. They should inform the authorized law competent entities when a problem about the system or about participants occur in application and should be able to bring solutions. Informing the participants about the transmission capabilities, collecting bids from them, evaluating bids and matching the sellers with the buyer by determining market clearing price, accepting the objections or participants and evaluating them, informing participants about the dispatch are other official functions of the market operator.

When it comes to the system operator, they have three important responsibilities. First of all, system operator should establish balance of the supply and demand in a market. For this purpose, every day, system operator makes demand forecast of the next day in an hourly basis. Market participants use this forecast information as a clue in order to make more realistic bids and offers. Then secondly, system operator calculates the transmission capability of the grids for the next day knowing the forecasted data and bilateral contracts among traders. Market operator is also informed about the usable transmission capability to prevent transmission congestions and poor dispatching. After matching the sellers and buyers and dispatching the generators have been completed, system operator checks the feasibility of planned operation in terms of transmission. As the third mission, system operator is also responsible for defining the borders of regions for different day ahead market if market splitting is involved.

In day ahead market, agreements are conducted in an hourly basis. 24 hours of a day are divided to 24 equal periods and participants submit their bids for each one of these hours. Market participants offer their bids for 24 different hour periods. Therefore bids of different hours can be valid for different quantities of power.

2.2.2.1 Operations in Day ahead Markets

Every day, system operator makes hourly forecasting of the system for the next day. These forecasting results are shared with the participants and give them a clue in making decisions for bidding and hedging strategies. Buyers and sellers themselves also try to predict the demand and supply quantities of the next day to calculate possible values of marginal price of electricity. They finalize their bidding according to these estimations and calculations.

System operator is the authority which is responsible from managing the transmission lines in grid. In Turkey this entity is National Load Dispatch Center which is an organization of TEIAS. System operator has the information of transmission capacities of the grid in addition to bilateral contracts signed between the suppliers and buyers. Hence, he also has the ability of calculating the remaining capacities for any part of the grid. System operator shares the information of usable transmission capacity in all parts of the grid with the market operator in an hourly basis. This information is utilized bearing in mind the transmission congestions and bilateral contracts by the market operator. Market operator is also has to declare this transmission capacity information to the market participants. Deadline of this declaration is 09.30 a.m in Turkey’s day ahead market.

Operators of generation plants calculate their production costs if they have capacity remained from bilateral agreements. Then they decide to join the day ahead market or not, according to cost values they calculated. If desired to participate, they submit their capacity bids to the market operator through the software program devoted to this task. In same manner, if buyers need energy that they cannot get from the bilateral contracts, they also submit their bid to the market operator. 11.30 a.m is the deadline for submitting bids for market participants in Turkey. If the opening time is to be asked, it is5 days ahead of the actual energy transfer day so that participants could submit their bids 5 days ahead in case of vacations. Specific applications might be involved for longer national holidays. All bids are evaluated by the market operator so that they are convenient to regulations. Market operator has to check all bids till 12.00 a.m and decide to accept or reject each bid. After all bids have been evaluated, market operator matches the buyers and sellers and determines uniform market price of electricity in hourly basis using matching algorithm. Right after the matching of selling and buying bids are done, all matched quantities and market clearing price is declared to the market participants so that they have chance to check results of matching the bids and make objections if necessary. Participants have to raise their objections till 1.30 p.m if there is any. And market operator is supposed to evaluate and conclude all objections till 2.00 p.m [10]. Therefore, at 2.00 p.m, all energy transactions agreements are completed one day before the physical energy transmission day within transparency. All participants have the right to make objections to trading results and market operator is obligated to accept reasonable ones. Each participant whether a seller or a buyer, is responsible from his own calculations of cost, forecast result, bids and hence profit. None of the players is interested in others' bids. So a liberalized, fair, efficient market mechanism is obtained in day ahead markets.

Dispatching energy among sellers in an efficient way is the responsibility of the market operators. They collect the selling and buying bids from the participants and then start dispatching among the sellers from the lowest bid to the highest bid. By this way, minimum market price of electricity in the market is obtained.

Sellers are supposed to submit their marginal costs as selling bids. This might not happen in some cases. Hardness and competitiveness of the market determine the transparency in selling bids.

2.2.2.2 Bidding

Market operator lists each submitted selling bids increasingly for every specific 1 hour time interval. Bids of day ahead markets, mainly involves 3 important parameters. These parameters are quantity of energy to be supplied or bought which is in MW, price for per amount of energy which is $/MWh, and lastly the time interval which the bid is valid for. '$' sign represents money in here, not the American dollar necessarily. For each supplier, increasing listing is started from the lowest price and its corresponding quantity value. It ends when the highest bid and its corresponding quantity value is reached. This list of bids is converted to a continuous supply curve by using linear interpolation method. An example of bids for a specific hour of a sample seller which trades in both seller side and supplier side is given in the Table 4.

Table 4: Sample bids for specific hour of a seller.

Price ($/MWh)	0	14	15	29	30	49	50	69	70
Quantity (MW)	15	15	0	0	-15	-15	-30	-30	-50

Up to the table above, the energy producer company finds the energy prices lower than 15 $/MWh feasible to buy energy. 15 $/MWh could be a value lower than the prices of energy he sells in a bilateral contract. Therefore the producer accepts to buy energy for 0-15 $/MWh price interval. Between the 15-29 $/MWh interval, joining the day ahead market may not profitable as desired for this producer so he submit the quantity as zero for this interval. After 30 $/MWh, the producers wants to sell 15 MWh energy, which is denoted by '-' sign, unless prices exceeds the 49 $/MWh. If prices are between 50 and 69 $/MWh or higher than 70 $/MWh, the producer wishes to sell 30 MWh and 50 MWh respectively.

Buying bids are also listed in a decreasing manner. Similarly a linear interpolation is performed from the highest bid corresponding to a small quantity till the lowest quantity corresponding to a huge quantity. Demand curve of a buyer is obtained in after interpolation process. A sample buyer bidding example for a specific hour is given in the Table 5.

Table 5: A sample buyer bidding example for a specific hour

Price ($/MWh)	0	14	15	29	30	49	50	69	70
Quantity (MW)	50	50	40	40	30	30	20	20	10

According to the table, a buyer company accepts to buy 50 MWh of energy if prices are lower than 15 $/MWh, 40MWh of energy if prices are between 15 and 29 $/MWh, 30 MW if prices are between 30-29 $/MWh, 20 MW if prices are between 50-69 $/MWh and 10 MW if prices are higher than 70 $/MWh for a specific hour.

A buyer or a seller can also submit bid for a consecutive full time period as blocked bid. This bidding method is useful for producers which have high starting up or shutting down costs in generating units like thermal power plants. Or it can be used in case of inflexible consumption and demands. Blocked bids, consisting only one quantity and one price values, are valid for more than 1 hour time interval. A blocked bid might involve different time intervals and each of these time intervals contain one quantity and one price value. A company can make block bids as both a buyer and a seller. In Turkey, there is an obligation saying that a block bid must cover at least 4 hours. Moreover, market operator is allowed to accept or reject a block bid as a whole period according to legislations. A sample block bid is given in Table 6**Error! Reference source not found.**.

Table 6: Example of a block bid

Block hours	Price	Quantity
00:00-04:59	60	30
05:00-11:59	90	-50
12:00-19:59	120	-50
20:00-23:59	60	30

According to prices and quantities in the table above, this company accepts to buy 30 MW of power during the hours of 00:00-04:59 and 20:00-23:59 if the prices are below the 60 $/MWh. Total amount of energy is calculated as 9 hours times 30 MW power equal to the 270 MWh of energy. The company accepts also to sell 50 MW power during the block hours of 05:00-11:59 and 12:00-19:59 if the prices are higher than 90 and 120 $/MWh respectively.

Moreover, one can offer bids as blocked bids. Blocked bids includes more than 1 hour period. So, for more than 1 hour interval, one participant can have bid. However, this bid has only one quantity of power and price per power. That is for a specified time interval, participant make only 1 bid. This means, each and every time interval in this blocked time has the same quantity and price offered. 3rd type of bid is flexible bids. For flexible bids, external from hourly buying and selling bids, should include selling prices without regarding a specific time interval for the next day.

All selling bids curves are aggregated in one graph after obtaining individual supply graphs and all selling bids curves are aggregated in another graph after obtaining individual demand graphs. Sketching the total supply and total demand curves in the same axis gives us an intersection of supply and demand point. This point defines the supplied and demanded quantities together with the market clearing price for a specific one hour period. Therefore balancing the supply and demand task is performed eliminating the scarcity and surplus of electrical energy in the whole system. In the Table 7, for a specified hour, sample bids of all participants submitted to market operator are given.

Table 7: Sample specific hour bids submitted to a market operator by all participants [3].

Price ($/MWh) =>	0	100	110	120	130	140	150	160	300	500
Quant.of firm A	-30	-30	-30	-30	-30	-30	-30	-30	-30	-30
Quant.of firm B	400	400	250	0	0	0	-100	-130	-170	-170
Quant.of firm C	80	80	80	80	30	30	-30	-30	-30	-30
Quant.of firm D	90	90	90	90	90	90	60	30	30	30
Quant.of firm E	120	120	100	100	100	100	100	100	100	100
Total Buying Qua.	690	690	520	270	220	220	160	130	130	130
Total Selling Qua.	-30	-30	-30	-30	-30	-30	-160	-190	-230	-230
Energy balance	660	660	490	240	190	190	0	-60	-100	-100

As can be seen from the Table 7 above, 5 participants attend day ahead market and submit their bids. Prices are ranked from the lowest to the highest value. Quantities of energy to be sold are denoted by '-' sign. For each value of prices, quantities to be sold are added. Similarly, quantities to be bought are also added. By this way, an equilibrium point is obtained where energy balance is established. This point is shown in the table with the zero in the energy balance row corresponding to a price of 150 $/MWh. An interpolated total supply and total demand curves sketched to same graph will look as given below in Figure 5.

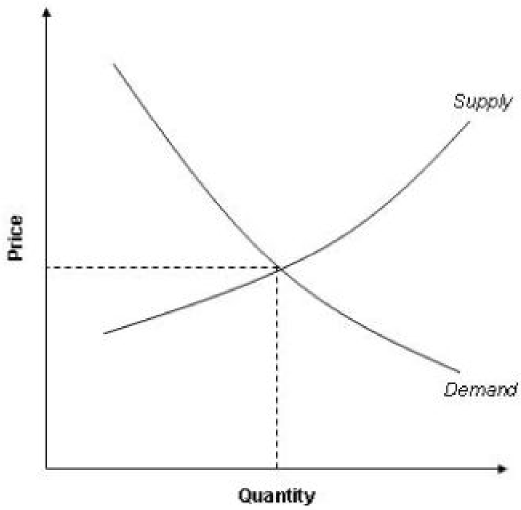

Figure 5: Supply demand curves

Intersection points seen in the figure defines the quantity as 160 MWh and the price as 150 $/MWh in our day ahead market sample.

There might be some cases which supply and demand curves do not intersect. In this cases, market operator shifts the demand curve to the supply curve so that all buyers are affected equally in terms of prices. Consumers and hence buyers are the one who had to trade energy because they need electricity for daily life. However, sellers do not have an obligation to sell energy. Therefore supply curve stay where it is. Alternatively, market operator might ask participants to submit bids again in order to make supply and demand curves intersect.

Once price and quantities are decided to be traded in an hour period by market operator's matching algorithm, suppliers are liable to supply agreed amount quantity of power to the system grid physically. Similarly, buyers are also liable to buy the agreed quantity of energy during relevant time interval in day ahead markets.

2.2.2.3 Market splitting

Another issue that should be revised in this part is market splitting issue. Market splitting is a method that helps to establish the supply demand balance in a country. This method divides the whole system into regions in which different electricity prices are applied. Differences in price are caused by transmission congestions. Market operator must take in into consideration the transmission line capacities while balancing the supply and demand. This is because balancing task is performed around the whole country.

In a region of a market, in which market splitting is applied, if the difference between total electricity supply and total electricity demand is equal to or less than the transmission line capacity, market clearing price stays constant. If the difference between supply and demand is higher than the transmission line capacity, market clearing price in that region has to be changed by market operator depending on the scarcity or surplus inside the region. If scarcity of electricity exists, market clearing price is increased in order to lower the demand and to be contented with the energy coming from other regions. On the other hand, market clearing price can be decreased to lower the supply in case of energy surplus because energy which could be transferred to the other regions is limited.

Market splitting facilitates both to establish the energy balance in the whole country and to control the transmission congestion by using the grids and conveying the energy in the country. In the countries in which market splitting is not involved like Turkey, transmission congestion cannot be handled easily because dispatch among sellers are not performed by taking the transmission line capacities into consideration. The whole country is considered as one region. There might be energy scarcities in some areas of this huge region although some regions have energy surplus.

In the markets which apply market splitting, sellers and buyer are totally free to submit bids to market of any region. There is not an obligatory to attend to all markets because all regions are independent from each other in terms of prices and quantities of energy. This gives flexibility to participants to bid in different market prices. Market operator schedules the transmission lines when dispatching among sellers after collected all submitted bids.

2.2.2.4 Day ahead markets models

Day ahead market is a common method of trading electricity throughout the world. Two different types with a little differences of day ahead market mechanism are used in common.

2.2.2.4.1 Auction Trading

The first and simpler one is the auction trading model. In this model, participants cannot change or update their bids after submitted to the market operator and they do not have a chance to see each other's bids. Thus, it can be regarded as one round auction. This model is also the applied one in Turkey.

Two different methods are used in determining the price of electricity in auction market model. These are market clearing price and pay as bid method.

2.2.2.4.1.1 Market Clearing Price Model (Uniform Price Model)

Market Clearing Price is the more common method than the pay as bid method. In fact processes of this method are explained in the following chapters. Once all quantities of submitted bids are added, supply and demand curves are plotted on a graph. Intersection point of two curves defines the electricity price as well as the quantity to be traded and all transactions are realized using this market clearing price. Main advantages of this method can be count as ease of processing and application, productive efficiency and reference price for bilateral contracts.

2.2.2.4.1.2 Pay as Bid model

In pay as bid model, there is no any unique price of electricity. Once the bids are submitted by the participants, market operator matches the quantities of supply and demand. Then each seller winning the auction is paid as its submitted bid. Thus, each supplier are paid in different price rate. At first, this method may look as a more deregulated model because buyers get chance to decrease sellers' over profits. However, if there is not enough competition in the market, a supplier can forecast the price of electricity and bid in higher prices to get more profit. So an inefficient and unfair market structure may arise in this model.

2.2.2.4.2 Continuous Trading model

In continuous trading model, on the contrary to auction trading model, participants are allowed make alterations on their bids after the submission deadline. They can change their bid in terms of both price and quantity according to the situations of prices and quantities. Participants are allowed to see each other bids on the order book in this model. This flexibility gives opportunity for sellers to make more profit by utilizing all of their capacity and for buyer to buy energy at cheaper prices [11].

The second difference between the auction model and continuous trading model, in addition to opportunity of changing the bids, is emerges at the point of determining the price. In fact, there is not any existing bid submission deadline in continuous trading model. Transactions are realized based on the 'who comes first, win the auction'. It means that if the price matching conditions are satisfied, priorities are defined according to the submission time of bids. Hence, lots of transactions that are all in different prices might be realized for an hourly time period. It is not possible to talk about a unique market price.

There are different applications of price determination techniques in different countries with little nuances. Main purpose is to match the suppliers' bids with accepting prices of buyers. Matching principles are like that selling bids without price limits have priority over the bids coming with price limits and selling bids having a lower price limit will have the priority over the ones having a higher price limits. In the same manner, buying bids which include higher limits have the priority over the ones having lower limits. In case of having the same price limit for any two bid, the one coming first will win the auction. One may refer to [3] to get detailed information about price determination techniques applied in different countries.

To sum up, it is obvious that continuous trading model of day ahead market is much more prone to competition than auction trading model. The more competition means more liberalized market structure. Visibility of all bids and accepting prices provides traders to make more profit by utilizing capacity more efficiently. Any supplier also does not have to sell energy at a price lower than the bid it submitted as in uniform price model. In addition to this efficient and economical market, numbers of the agreements and hence the liquidity in day ahead markets is increased in this model [11].On the contrary to these advantages, continuous trading model involves many complexities in application. It is difficult to follow the bids and to yield transactions because of high fluidity. In this model, another difficulty arises in the real time monitoring mechanism that should be provided to all participants. In addition, seeing other players' bids may cause some unfair participants to make virtual bids in order to manipulate the energy prices.

CHAPTER 3

COMMON OPTIMIZATION TECHNIQUES USED FOR GENERATION SCHEDULING

Solution methods for optimization problems have always been a living topic in the literature during years [12]. Various optimization techniques ranging from simple rule-of-thumb method to reasonably complicated logical approaches are developed such as priority list, integer and mixed integer programming, exhaustive enumeration, dynamic programming, network flow programming, branch-and-bound, Lagrange relaxation, linear and nonlinear programming, artificial neural networks, evolutionary techniques, simulated annealing etc. In an optimization problem, one of these solutions or any combinations of them could be involved to find the solution [13, 14]. Basic principles and brief explanations of most commonly used optimization techniques for unit commitment problem is given in the following sections.

3.1 Priority List method:

According to the Priority List method, generators with a lower heat rate will have the priority for committing. If heat rate ratios of generators are same, one which has a higher maximum generating capacity will be of higher priority. Heat rate, abbreviated as HR, is calculated as given in the following formula [15].

$$HR = \frac{F_i(P_{i,max})}{P_{i,max}} \qquad (1)$$

$F_i(P_i)$: Fuel cost function of the i^{th} unit with generation output P_i. Usually, it is defined with a quadratic polynomial with coefficients αi, βi and γi as follows:

$$F_i(P(i,t)) = a_i + b_i P(i,t) + c_i P^2(i,t) \tag{2}$$

Based on priority list in Table 8, the units are committed according to their priority. The highest priority (lowest cost) unit is firstly committed, followed by other units in the list accordingly. Units are committed sequentially and generate power at maximum capacity until the load demand requirements are supplied in the priority list order during every time interval [15].

Table 8: Priority order table

Unit Number	Maximum Generated Power	HR ($/MW)	Priority Order
1	455	18.6	1
2	455	19.5	2
3	130	22.2	5
4	130	22	4
5	162	23.1	3
6	80	27.5	7
7	85	33.5	6
8	55	38.1	8
9	55	3.5	9
10	55	40.1	10

Priority List Method can handle the system and unit constraints like minimum-maximum generating capacity total power demand. It could give fast solutions with small computational memory and operation. But it is not interested in with the ramp-rates and start-up costs. Therefore the solutions found using this method are not optimal enough in terms of total operational cost [16, 17, 18]. This method could be improved with dynamic priority list, including start-up costs and Commitment Utilization Factor in order to get more optimal solutions [19].

3.2 Stochastic Programming

Stochastic Programming is a framework for modelling the optimization problems which involve ambiguity and uncertainty. Although explicit optimization problems are modelled with pre-known parameters, problems in real world are mostly involve parameters that can deviate from the predictions. Main goal in optimization is to find a policy or a principle that is valid for all predictions and data sets and satisfying an expectation by minimizing or maximizing a function.
Because of that the Power Market Structure involves uncertainties in price, demand and generation sources like solar and hydro, Stochastic Programming approach is a way to join these uncertainties to the cost minimizing unit commitment problem. Multi-stage operation representing the generating levels of generator is conducted during the time intervals to be planned as seen in the Figure 6 and probabilities of events are considered to reach the end of the problem [20].

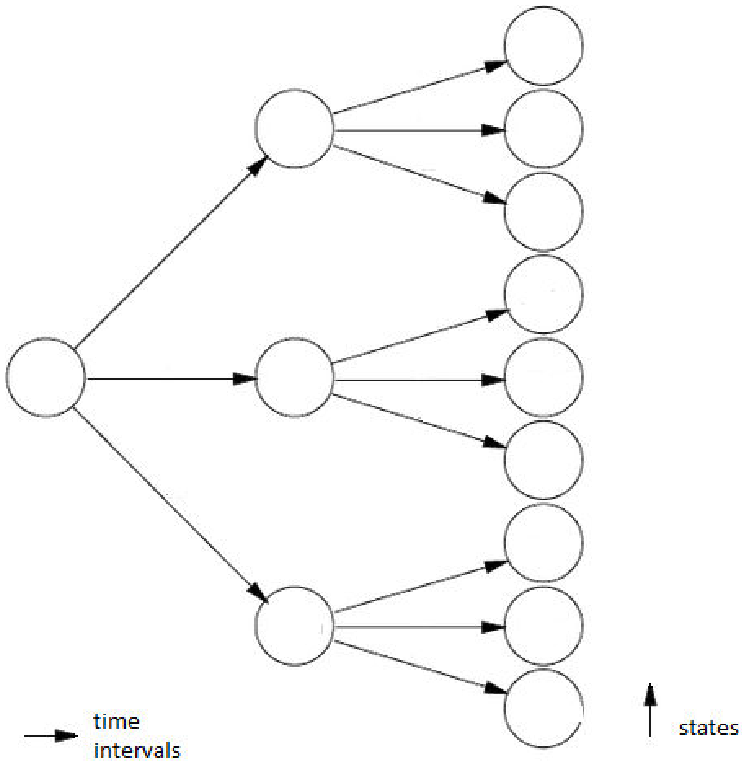

Figure 6: Multi-Stage Operation of Stochastic Programming

3.3 Exhaustive enumeration

As it can be understood from the name, this method enumerates all the possible commitment state combinations of the generating units over the planning time intervals. A committing progress which has the least total operating cost is chosen as unit commitment solution. Although it is a computationally work-loaded and a time consuming optimization method because of examining the excessive amount of unit commitment combinations, exactly the optimal solution is provided in any cases with the help of straightforward operation. Assuming N units and T hours to be planned, number of the combinations to be evaluated becomes $(2^N-1)^T$. The number of combinations may be decreased by the constraints like unit ramp rates and minimum off and minimum on times eliminating the unfeasible unit commitment combinations. But its long computational time and huge size of computer memory are still the main obstacles for this method to be used in unit commitment problem solution.

3.4 Sequential method

This method is asserted in order to make an improvement in the solution quality and computation time of the short term thermal unit commitment problems solved with priority list and dynamic programming methods. The main idea behind the sequential unit commitment method is to decompose the combinations by grouping the generators. Grouping is done according to the minimum on and minimum off times, generating capacities, initial conditions and suchother unit constraints. Generators which have similar generating capacities or similar minimum on and minimum off times are grouped together. Within each group, generating units are arranged by their consistent cost index which indicates relative operating cost per MWh of useful spinning capacity, in ascending order [17]. The key element when calculating the consistent cost index is system marginal cost [17].

At each time interval, the units which are on top of the list and having the comparatively least consistent cost index in their own groups are selected to be committed. Selection is continued with the next units on the list with same criterion until the hourly demand requirement is supplied. The unit commitment schedule could be determined with this method. After that, economic dispatch is applied among the committed units at each hour to find the most economical operating cost for all planning horizon.

In sequential method, iterative operation is employed to reach a solution that can satisfy all the constraints and convergence criteria. In each iteration calculation of operating costs, arranging the units and selecting the one at the top, economic dispatch steps are performed for the entire planning horizon. The iteration that results with the least total production cost involving production costs, start-up costs and operation & maintenance is the solution of unit commitment. For detailed information one may refer to [17].

3.5 Genetic Algorithm

Genetic algorithm is kind of an optimization method which inspired by the model of evolutionary adaptation and genetic theory in the universe [21]. On/Off states of the generating units are indicated with binary 1 and 0's in the genetic algorithm. First step of the genetic algorithm is generating the genotypes. Genotypes are matrices and each of them contains N string for total number of N generating units. These strings represent the commitment state of the units for each hour. For total T hours to be planned in the planning horizon, a T-bit string is produced. Therefore a genotype involves N strings and each string is a T-bit string [22]. Size of genotypes become 1 by N*T. It could also possible to write the states of all generating units in a string and then derivate the genotype with these strings. Then the genotypes include T strings each of them involving the commitment states of unit from 1 to N. In both of the arrangements total number of possible genotype become 2^{N*T} because of the possibility of each unit to be on and off. This is a huge number of combinations and there is a need to reduce the search area by creating a few initial genotypes. The initials genotypes could be selected heuristically or it can be done with knowledge based system [23].

Secondly, the genotypes which result with infeasible unit commitment plan should be sifted. Economic dispatch is performed in this process and genotypes causing infeasible state combinations are eliminated by checking the ramp rates, minimum on and minimum off times etc. Remaining genotypes are called parents and new generation genotypes are created by two basic operators which are crossover and mutation [23, 24]. Mutation operators works based on the principle that no string position will ever be fixed at a certain value through the course of the process. It toggles the states of generating units using the probability of mutation. Probability of mutation could be a function of total number of generating units[24]. The crossover operator on the other hand, exchanges the bits between two parent strings so that all requirements and constraints are satisfied. In addition to these two methods, some other advanced techniques are developed like elitism, fitness scaling, adaptation of operator probabilities in order to enhance the result of genetic algorithm solution. Once the new generation genotypes are produced, some of them will be selected and will be parents of new generation offspring. Unit commitment solution is reached with this iterative operation.

Genetic algorithm method is relatively complicated and it involves excessive computational operation. Therefore it takes a long time to converge. Beside this, optimal solution is not guaranteed because the search space is open to change. But there are studies in literature that incorporates the genetic algorithm into other optimization techniques like Lagrange relaxation [25].

This method will be used in the case studies part in order to compare the result and performance of the proposed algorithm with genetic algorithm.

3.6 Mixed Integer Programming

Mixed integer programming is a technique which can be used for solving linear optimization problems. Non-linear terms such as multiplication of two variables to be decided, the maximum of more than one variables or absolute value of a variable are not allowed in this method [26]. Non-differentiable and non-convex operating costs, exponential start-up costs ramp rates, minimum on and minimum down time constraints could be modeled in this method [27].

Basically, three-step looped process is conducted in mixed integer programming. First step involves defining a set of variables that stands for choices to be optimized in the system. Secondly, statements of the constraints in the models are defined and with the third step requiring the statement of an objective function. The second and the third steps could be done in either order. During this process, it is very common to recognize when constructing the model that initial set of decision variables defined for the model are inadequate. Mostly, new decision variables which seem to be implied results of other actions must also be defined. The addition of new variables after a failed attempt is the loop section of whole process [26].

Mixed integer Programming could give enhanced solutions compared to the Lagrange relaxation method in terms of modeling capabilities of cost functions and constraints, optimality and flexibility of the solution. On the other hand, it brings complexity of computation and therefore long computational time with large memory requirement because of the exponential increase in the size of the problem.

3.7 Branch and Bound

Branch and bound method approaches the solution by decomposing the problem into sub-problems. It finds out minimum value of a cost function through a feasible region in a search tree. The whole operation involves five steps [41]. In the first step which is the branching step, problem is decomposed into sub-problems and each of them is assigned to a node. By this way, a search tree is constructed. Each of these sub-problems is bounded by the upper and lower limits in the bounding step which is the second one. Thirdly, minimum cost solution of each problem are solved using the methods of Lagrange relaxation or linear programming. In this elimination step, sub-problems consisting infeasible unit commitment planning solution are rejected. At the next step which is the selection, sub-problems which have lower bounds than the predetermined upper bound are selected. The least cost level between the selected problems becomes the new predetermined upper bound for next iteration, meaning for the next branching, bounding, and elimination and selection steps. Finally termination step is reached if the terminating criterion is satisfied. The terminating criterion is that only one sub-problem whose upper bound is equal to lower bound remains. And this sub-problem which yields lowest bound is defined as the optimal solution [41, 42]. Like other several Unit commitment optimization methods, branch and bound method has also long computational time. Therefore it is not suitable for large scaled unit commitment problems [42].

This method has been combined with cutting plane method by some developers and takes the name branch-and-cut algorithm which is the basic algorithm used in linear mixed integer programming method [28, 31]. By this way, usage area of this method is enlarged for thermal, combined cycle and hydro units.

Global optimum solutions can be found with branch-and-cut algorithm. Therefore this method is also employed in the scope of this thesis. Sample cases are solved with this method and results are compared with the proposed algorithm.

3.8 Tabu Search

Tabu search method tries to find an optimal solution by searching iteratively for a good solution among a set of possible solutions [17]. The main idea behind this method is metaheuristic algorithm [32]. A sample solution is discussed as the current solution and then neighborhood of this current solution are examined. If there is a better solution than the existing one, the better solution takes place of the current one. Data of these movements are stored as tabu list so that unnecessary search results are prevented. The tabu search algorithm is terminated when there is no better solution in the neighborhood of the current solution. In this method, globally most optimal solution is not guaranteed because the regions of the worse solutions at the neighborhood of the existing solution are evaluated and they could consist the way which goes to the most optimal solution. There are some studies suggesting the algorithm may occasionally receive the worse solutions instead of better ones [32]. This is the metaheuristic side of this algorithm. This approach may increase the optimality of the schedule. Yet, this technique is still not appropriate for large-scaled systems.

3.9 Expert Systems / Artificial Neural Network

These two methods are discussed in the same section because both of them use the results of past operations and statistical data. Expert systems are intelligent computer programs that utilize knowledge of power system operators and programming developers to solve problems that are difficult enough to need human works to solve. Human experts construct its knowledge in the domain and the system tries to simulate their methodology to find an optimal solution [14, 42]. More skilled human practice yields better unit commitment solutions because expert systems approach the solution by adjusting the programs' parameters through the interaction with the programming developer [16].

Like expert systems, artificial neural network makes computations on the basis of experiences and historical data. It has become one of the most widely used techniques for solving optimization problems. Its parameters are adjusted according to the database of the program. Typical load demand curves and corresponding unit commitment schedules are stored in this database [16]. Artificial neural networks could converge quickly with the help of parallel operations [17]. In order to obtain more optimal solutions, enlarged dimension of historical data should be employed. For high quality schedules, neural networks need to be well trained. As much as possible case should take place to handle the different constraints. But this will make the training time excessively long [33, 34].

3.10 Lagrange Relaxation

Lagrange relaxation is a mathematical tool for mixed-integer programming problem [16]. This optimization technique regards each constraint as a sub-problem. It could overcome the dimensionality problem encountered in other optimization techniques by temporarily relaxing the coupling constraints and considering the each unit separately [17]. It creates a dual function by integrating the coupling constraints into the primal problem which is the objective function of the unit commitment problem [43]. The coupling constraints are multiplied by the Lagrange multipliers and the dual problems are constructed. The dual and primal sub-problems are solved independently. The dual sub-problem could be solved to receive the maximum cost by maximizing the Lagrange function with respect to the Lagrange multipliers and minimizing with respect to the cost of generation [17]. The whole solution process consists of repeated iterations which successively solve the dual sub-problems and conduct proper adjustments for updating Lagrange multipliers [16].

An advantage of the Lagrange relaxation method is that the duality gap between the solutions of dual problem and primal problem could be set down as desired in order to increase quality of the unit commitment solution. The iterative process terminates when the duality gap becomes smaller than the predefined error parameter. The smaller duality gap means the better quality solution but of course the higher computational effort and huger memory will be required.

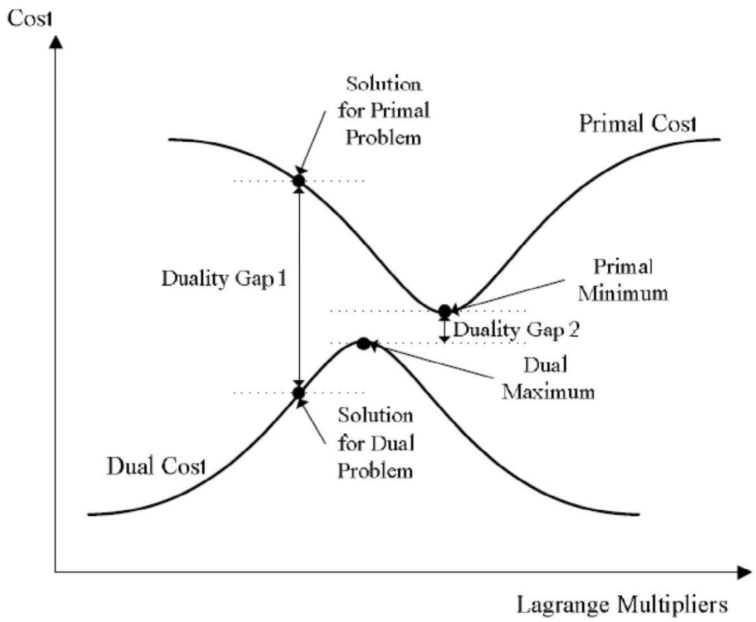

Figure 7: A graphical explanation of the Lagrange Relaxation – Duality Gap [17]

As illustrated in the Figure 7, the relative size of duality gap between the upper line representing the primal solutions and the lower line representing the dual solution gives the convergence aspect of the solution. The duality gap 2, which is smaller than duality gap 1 and called optimal duality, is difference between the global primal solution and global optimal solution as given in the Figure 7 [17]. Generally, primal and dual cost functions are non-convex and non-differentiable. Therefore graphs of them are not as smooth as given.

Main actors of the Lagrange relaxation algorithm are Lagrange multipliers. Unit commitment schedule is observed by updating the multipliers in each iteration. Therefore, convergence of the solution highly depends on the initial settlements and method of updating multipliers. If they are not updated appropriately, results of iterations oscillate around the level of optimal solution and the algorithm cannot be terminated. Three main updating approaches have been widely used in the literature. They are sub-gradient method, column generation techniques of the simple method and multiplier adjustment methods. Among these, the sub-gradient method is promising and mostly used in unit commitment problems [35].

Lagrange relaxation optimization technique is a proper method for large-scaled power systems. It can handle the demand and reserve constraints as well as other constraints like line capacity. In this thesis, Lagrange relaxation or simply Lambda iteration method is employed for solving the economic dispatch problem among the pre-known generators commitment combinations. To show the solution approach to the economic dispatch problem, a graphical explanation is given in Figure 8 [36]. Assuming three generation units with different cost characteristics are to be economically dispatched to generate a certain quantity of power, incremental cost characteristics of these units are plotted on the same cost axis as given in the graph [36]. Then, a line parallel to the power level axis is scratched. That is, an incremental cost rate is assumed and the power outputs of each of the three units for this value of incremental cost are found. Intersection points with this line and each of the cost line gives the operation points of the generators. Sum of the powers generated by three generators could be found with this method.

Being the first assumption of the incremental cost rate to be incorrect is indispensable. If the assumed value of the incremental cost rate is such that the total generated power is lower than the required demand, incremental cost rate value must be increased at the next iteration. The algorithm terminates when the total power output level approaches the desired value of power within the limits of toleration. This process becomes a little bit more complicated when operating limits of the generation units are injected to the course of computation. This integration may highly increase the number of iterations depending on method of updating incremental cost value. There are various techniques to update the multipliers and they will be given in the chapter 4 together with the computer implementation algorithm of this method.

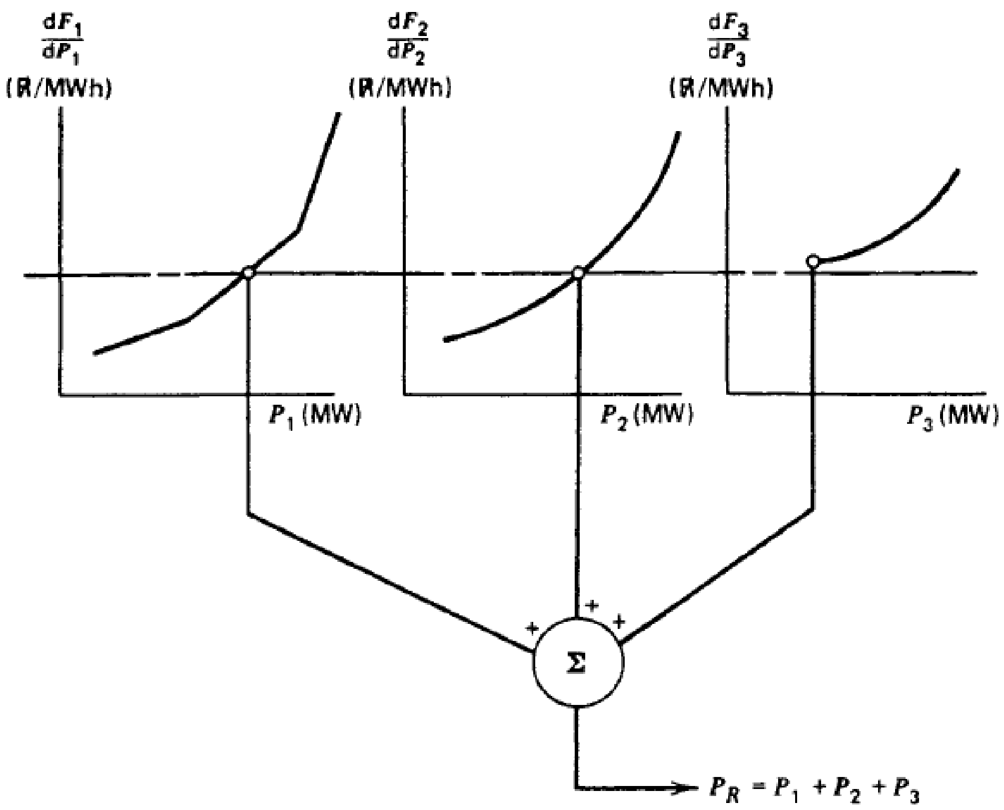

Figure 8: Graphical Solution to Economic Dispatch [36]

3.11 Dynamic Programming

Dynamic programming is one of the useful optimization techniques that can be utilized for solving a variety of problems. This method could reduce the computational workload enormously in finding optimum schedules. It can be employed in the practical solutions of the unit commitment problem [36].

The basic idea behind this method is defining the possible unit commitment combinations that will influence the rest of the algorithm for each time interval [17]. Typically, each time interval being a part of planning horizon is called 'stage' in dynamic programming approach. Similarly, each possible commitment combination is called 'state' for each hour. A sample explanation of dynamic programming schematic is given in the Figure 9. Once, the feasible commitment combinations are calculated at each hour regarding the all constraints like minimum on and minimum off times and generating capacities, a schedule giving the minimum total cost will be searched.

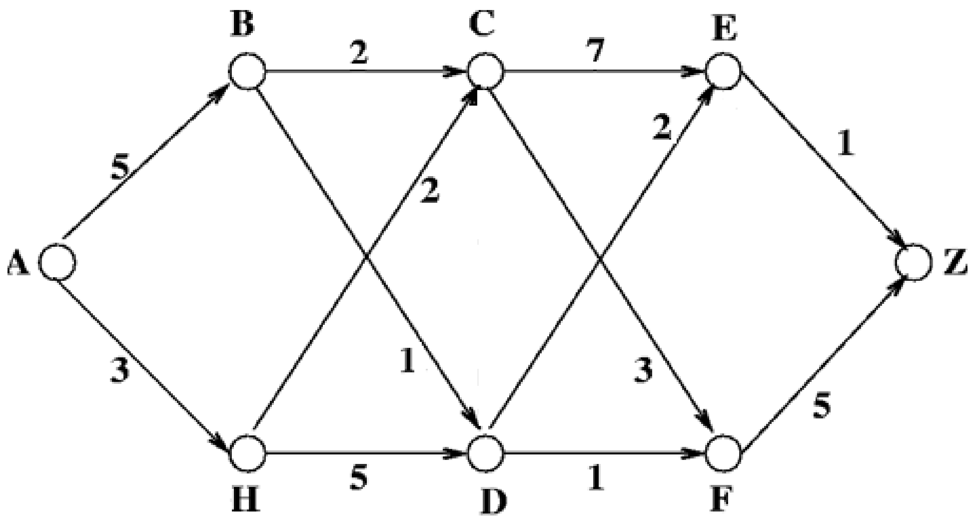

Figure 9: Schematic diagram of dynamic programming method

States, represented with letters, are given a number which is the minimum cost of reaching that state. Only this minimum cost is saved for each state and the rest is disregarded. In the figure given above, it is obvious that costs of reaching the states B and H are 5 and 3 respectively because only possible way to reach these states is to come from state A. Possibilities for other states are given below;

For state C : B => C = 5+2 =7

Or : H => C = 3+2 =5

The second way is smaller than the first way. Therefore cost of reaching state C is 5. Similarly cost of reaching state D is found as 6.

For state E : C => E = 5+7 =12;

Or : D => E = 6+3 =8;

The second way is cheaper than the first way. Therefore cost of reaching state E is 8. Similarly cost of reaching state F is found as 7.

For final state Z : E => Z = 8+1 = 9

Or : F => Z = 7+5 = 12

The first way is cheaper than the second way. Therefore cost of reaching final state Z is founded as 9. The path can be found by tracing the states that are passed through. This process is called back propagation. It is found with back propagation that the path is Z <= E <= D <= B <= A. By starting form A, it becomes A => B => D =>E => Z.

Two different approaches may be conducted in this method. One is the forward dynamic programming and the second is the backward dynamic programming. The forward one runs the algorithm starting from the initial hour to the final hour and the backward one goes through the reverse direction. In unit commitment scheduling problems, it is better to use the forward approach because knowing the commitment states of units in time t-1 is a must to calculate the transitions cost to come to t. This transition costs come from starting up or shutting down (if included) of a unit. Commitment information of previous hours is also necessary to obtain the infeasible transitions caused by minimum on and minimum off times. Therefore forward dynamic programming is mostly used in solutions of unit commitment problems.

In the forward dynamic programming approach, the algorithm records minimum costs of each state at the previous hour and these costs are added with transition costs to the next hour and operating cost of the state to be examined. In the Figure 9, minimum cost of coming to the state B can be calculated as sum of the operation cost of state A, transition cost which is given as 5, and the operating cost of state B. Similarly, cost of coming to state H can be calculated as sum of operating cost of state A, transition cost which is given as 3, and the operating cost of state H. When the minimum costs of coming to the states in stage 3, i.e. states of C and D are to be calculated, same procedure is followed except first term. For instance, minimum cost of coming to the state D is found by choosing the minimum one between costs of coming from states B and H. Mathematical formulation of this summation and keeping the minimum procedure will be explained in the problem formulation section. Basically, the choice of the route is made in this sequence until the last hour is reached. Most of transitions between successive hours are traversed. The optimum sequence called *optimal policy* involves subsequences which are called *sub-policy*. This theorem is called *theorem of optimality* [36]. It means that the optimal policy consists of only optimal sub-policies. Developers named Bellmon and Dreyfus state this theorem as, "A policy is optimal if, at a stated stage, whatever the preceding decisions may have been, the decisions still to be taken constitute an optimal policy when the result of the previous decisions is included [36].

In this method, even though the number of unit commitment combinations to be evaluated is decreased by eliminating the unfeasible combinations, there is still a quantity of combinations remaining especially if the number of generating units is much. Hence, the computational workload and required memory are high enough for algorithm to take a long time to terminate. Additional techniques had been proposed for dynamic programming in order to decrease the number of combinations for every period in which the optimal scheduling was searched. One of them is the dynamic programming – truncated combination [37]. In this method, some of the generating units which are grouped as a must run unit or an excessive unit according to their cost efficiency and power demand. And the optimal scheduling route is searched in remaining units [16]. Another method is called sequential dynamic programming. This approach firstly creates a priority list table as described in related section. Then, the subsets of combinations to be evaluated are obtained by committing each unit according to the sequence in the priority list table [38]. The third method which is the integration of truncated and sequential approach is named sequentially truncated dynamic programming. This method can solve the problem by generating a window to cover a set of available units whose commitment may violate the priority commitment order [38].

CHAPTER 4

OPTIMAL GENERATION SCHEDULING ALGORITHM

Liberalized and deregulated energy markets are market models that must be followed in contemporary societies. Monopolistic power comprehension and obligations should be quitted to have a cost efficient, competitive and fair energy market, in fact not only energy market but also other sectors of other commodities. But, introducing a competitive structure to energy market might be more difficult than that of other commodities. It is because of nature of the electricity. Electrical energy cannot be stored anyway in huge quantities. It is required to be produced in a certain quantity whenever needed and it is required to be transferred at that amount to wherever needed. This difficulty brings the necessity of a real time, active control mechanism in order to observe and manage the balance between suppliers and customers. Such a mechanism prevents energy shortages for all of customers and provides uninterrupted electricity in uniform frequency and voltage.

In this modern energy market structure, all players whether the seller side or buyer side have same rights as a player in the market. No one of them has privilege in trading. Having equal advantages with governmental entities is an important reason for investors to take place in the energy sector. Besides, each participant is responsible from its own trading plan. Signing bilateral contracts, joining balancing markets, bidding to day ahead markets, making self-scheduling are all permissive actions in modern energy markets. Thus all players have equal chance to make more profit.

Making more profit could be achieved by two ways. Increasing the revenues and decreasing the expenses are purposes of all market players. When it is thought in view of a generation company, these two ways of making more profit could be integrated in specific conditions.

As described earlier in chapter 2, day ahead market is a market model that is used for balancing the supply and demand. It gives an opportunity to the suppliers who have still generation capacity remained from bilateral agreements. In day ahead markets, sellers who will utilize its remaining generation capacity are detected in an auction. GENCOs have to submit efficient bids to win the auction. While lowering bids, they should consider the feasibility of prices. Submitting bids unconsciously may cause them to make a loss because of high production costs. Indeed, although the way of making an effective bid goes through making an accurate demand forecast, its starting point is decreasing the production costs.

At this point, importance of having an optimal generation schedule arises for a GENCO. A generation company attending the day ahead market should be able to schedule its generating units daily to win auctions and utilize its capacity.

Generation scheduling is a complex task including different type of constraints. Main purpose of generation scheduling is to minimize the cost of production so that lower bids are submitted to market operator in day ahead market. Generation scheduling consists of unit commitment which is an optimization problem that minimizes the total production cost to meet the load demand while considering the system and unit constraints.

This thesis suggests an optimal generation scheduling method for GENCOs attending day ahead market to make more profit. This method is indeed a MATLAB based algorithm which finds the optimum scheduling of generating units for a specified time interval while taking the system and unit constraints into consideration. It determines the ON/OFF status and generating levels of each unit. Outputs of this proposed algorithm will be compared with the traditional genetic algorithm and mixed integer programming branch-and-cut algorithm that are used in the literature to solve unit commitment problem.

In the following chapter, firstly the objective function involving total cost of production will be constructed step by step. These steps represent the constraints which will be handled. Then the MATLAB based developed algorithm for optimal generation scheduling will be explained in detail.

4.1 Objective Function

In the solution of a unit commitment problem, all cost factors that affect the generation cost should be taken into consideration since aim is minimizing the cost. A GENCO might have different kinds of cost elements but in general, production costs and transition costs are two basic ones which are valid for all types of electricity generation plants. Therefore production cost and transition cost must be always included in the formulation of unit commitment problem. The objective function of minimizing the total cost over a time horizon then becomes like following.

$$F = \sum_{t=1}^{T} \sum_{i=1}^{N} F_{i,t} \qquad (3)$$

Equation (3) represents the sum of cost of each generating unit during the time interval to be scheduled. A generating unit yields different cost values depending on the commitment status and generating levels for each specific division of the whole time interval. Generally, the time interval handled in a generation scheduling is on an hourly basis. Specific time division is 1 hour period for a GENCO bidding in day ahead market. The time interval could be 24 hours at most. It might be reasonable shorter than 24 hours because of the bilateral agreements and other restrictions like operating and maintenance. If the above equation (3) is to be extended, then equation (4) is obtained.

$$F = \sum_{t=1}^{T} \sum_{i=1}^{N} \left[F_{i,t}\left(P_{i,t}\right) + SU_i \times \left(1 - I_{i,t-1}\right)\right] \times I_{i,t} \quad (4)$$

This equation represents the production cost of each generating unit to be scheduled at each time interval, plus the start-up cost of that generating unit if it is not committed at previous hour. Although it is accepted as zero for simplicity in this study, shut-down costs could be inserted to this equation easily as following.

$$F = \sum_{t=1}^{T} \sum_{i=1}^{N} \begin{array}{c} \left[F_{i,t}\left(P_{i,t}\right) + SU_i \times \left(1 - I_{i,t-1}\right)\right] \times I_{i,t} \\ +\left[SD_i \times I_{i,t-1}\right] \times (1 - I_{i,t}) \end{array} \quad (5)$$

Equation (5) is the main form of the optimization problem that the developed algorithm will be dealing with while considering the relevant constraints. These constraints are formulated one by one in following parts.

Generation companies have to deal with different types of constraints while scheduling their generation. These constraints may vary depending on the types of the generating units, technical infrastructure and qualifications of units ability of crew etc.

4.1.1 Generating Capacity

Generating capacity is the first constraint that a GENCO has to consider when scheduling the generation. It is totally related with the generating units. A generating unit has a maximum generating capacity that cannot be exceeded. GENCOs take the disadvantage of not loading up a unit working with maximum capacity even if it is economically feasible. Moreover, there is also a minimum generating limit especially for thermal units under which the unit is not able to generate electricity. Minimum generating capacity problem arises when a generator with a high production cost is desired to be committed at level close to zero. A GENCO may have to commit such a generator to meet a level of demand which is slightly higher than the total capacities of cheap units. Or the company may want to prevent shutting down and starting up costs of an expensive unit by committing it at low power levels. Generating capacity constraint can be formulated as follow.

$$P_{i,min} \leq P_{i,t} \leq P_{i,max} \qquad \text{if the} \quad I_{i,t} \quad \text{is equal to 1} \tag{6}$$

If the ancillary services like spinning reserves and non-spinning reserves, which utilize the available capacity of a generating unit in addition to generated power, are involved in the unit commitment scheduling problem, they also must be inserted to the inequality (6). Ancillary services are not involved in the scope of this thesis.

$$P_{i,min} \leq \left(P_{i,t} + R_{i,t}\right) \times \left(I_{i,t}\right) + N_{i,t} \ \leq P_{i,max} \tag{7}$$

Equation (7) means that sum of the generated power level and quantities of spinning and non-spinning reserves cannot exceed the maximum generating capacity of the unit if it is committed in relevant time interval. If it is not committed, meaning no generated power and spinning reserve, quantity of non-spinning reserve is limited with the starting up- time and ramping capabilities of the unit.

4.1.2 Minimum ON and minimum OFF durations

Minimum ON duration refers to the period of time that is required for a generating unit to keep its ON state before it is shut-down. Likewise, minimum OFF duration refers to the period of time that is required for a generating unit to keep its OFF state before it is started-up. This constraint becomes compelling when large thermal generating units are involved in the generation scheduling. Because thermal units might need long times for warming-up and cooling-down processes. Demanded power quantities of further hours could affect the schedules of previous hours just because of minimum ON and minimum OFF duration constraints. Therefore generation scheduling should be performed by considering the market conditions through the whole time interval to provide a relaxed minimum ON and OFF duration constraint. Mathematical expressions of these constraints are given in the inequalities (8) and (9).

$$\left[T_{i,t-1}^{on} - MON_i\right] \times \left[I_{i,t-1} - I_{i,t}\right] \geq \; 0 \text{ For the minimum ON constraint} \quad (8)$$

$$[T_{i,t-1}^{off} - MOF_i] \times \left[I_{i,t-1} - I_{i,t}\right] \leq \; 0 \text{ For the minimum OFF constraint} \quad (9)$$

If a generating unit is started up between the successive hours, it must be provided that the generator has been being committed in previous hour as long as its minimum OFF duration. Similarly if a generating unit is shut down between the successive hours, it must be provided that the generator has not been being committed in previous hour as long as its minimum ON duration.

4.1.3 Ramping limits

Ramping limit represents the maximum change allowed in the generation level of a unit in a specified time interval. In generation scheduling, ramping limit constraint prevents GENCOs to commit a unit by changing its generation levels of successive hours over a defined quantity which is the ramp rate. All generating units might have a ramping limit in order not to damage its rotor. An amount of torsion is applied to the rotors of a generator while the output of the generator is increasing or decreasing. Ramping limit of a generator emanates from the maximum torsion that the rotor could stand. Beside torsion, another reason could be the heat change for a thermal generator. It may take many hours for a thermal generating unit to reach its maximum generating capacity from zero level because of low ramping limits. On the other hand, wind and thermal units have fast response capability meaning that a high ramping limit.

Ramping limit is a critical constraint because in day ahead markets, forecasted prices and demand may change in high amounts frequently. To keep up with this change while minimizing the production cost, a GENCO has to consider ramping limits of its' generating units. The GENCO may want to keep the outputs of thermal units at a certain level even if its high costs while changing output of hydro units in order to obtain a more feasible solution and to make more profit. Equations of ramping up or ramping down of a unit are given in (10) and (11).

$P_{i,t} - P_{i,t-1} \leq UR_i$ For the case of increasing generation (10)

$P_{i,t-1} - P_{i,t} \leq DR_i$ For the case of decreasing generation (11)

4.1.4 Forecasted Demand Constraint

Day ahead markets play a critical role in balancing the supply and demand quantities together with the real time markets. GENCOs which have available capacity can submit bids to day ahead markets. Buyers like a wholesaler, retailer, distribution companies or even a consumer which have consumption over a predefined level take places on the opposite sides of the market. Their need for electricity is mainly supplied with the long term bilateral agreements. They attend the day ahead markets for unplanned demand quantities or forecast errors. Thus, quantity of demand limited. Aim of the sellers must be predicting demanded energy and calculate their bid effectively. At this point, forecasted demand quantity is inserted to the unit commitment problem as a market constraint. GENCOs should make their generation scheduling with the aim of generating the forecasted amount of demand. Total amount of generated power must be equal to the forecasted demand at each hour as mathematically given in Equation (12).

$D_t = \sum_{i=1}^{N} P_{i,t} \times I_{i,t}$ For each time interval t (12)

Type of constraints that are encountered by almost all generation companies and involved in the developed generation scheduling algorithm are described above.

In addition to these constraints, there might be some other type-dependent limitations. Rate of emission can be one of those constraints because it may inhibit production of a thermal power plant if the emission limits are exceeded. On the other hand amount of reservoir could be a crucial constraint for a hydro power plant and so is shortage of wind for a wind farm. A GENCO should integrate all type-dependent constraints in addition to the more general constraints explained above in to the unit commitment problem in order to obtain a more feasible scheduling solution and hence to make more profit.

After all constraints are explained, the overall unit commitment problem with its constraints that will be handled in this thesis are given below;

Minimize the objective function:

$$F = \sum_{t=1}^{T} \sum_{i=1}^{N} \left[F_{i,t}\left(P_{i,t}\right) + SU_i \times \left(1 - I_{i,t-1}\right)\right] \times I_{i,t}$$

Subject to:

1. $P_{i,min} \leq P_{i,t} \leq P_{i,max}$

2. $\left[T_{i,t-1}^{on} - MON_i\right] \times \left[I_{i,t-1} - I_{i,t}\right] \geq \ 0$

3. $\left[T_{i,t-1}^{on} - MON_i\right] \times \left[I_{i,t-1} - I_{i,t}\right] \geq \ 0$

4. $P_{i,t} - P_{i,t-1} \leq UR_i$ and $P_{i,t-1} - P_{i,t} \leq DR_i$

5. $D_t = \sum_{i=1}^{N} P_{i,t} \times I_{i,t}$

4.2 Solution Algorithm

Optimal generation scheduling, or unit commitment in other words, is a complex problem involving both discrete and continuous variables. It is an optimization problem that yields minimum cost of producing an amount of energy in a limited time with limited sources. Different constraints described above make this problem complicated to solve. There are lots of studies in the literature dedicated to unit commitment problem. These studies use different optimization techniques as explained in chapter 3. The developed algorithm that is to be explained in following parts uses the Lagrange relaxation for continuous variables and dynamic programming technique for discrete ones.

Lagrange relaxation method is crucial in solving a problem having a system constraint which couples all of the units contributing to aim of the problem. In unit commitment, sum of generations of all units must be equal to the forecasted demand. This requirement couples all generating units to each other. Therefore Lagrange relaxation is employed in the algorithm.

Dynamic programming is another method used in literature. It is used in stepwise problems like one hour divided time interval scheduling. It decreases the number of combinations to be evaluated by only keeping the states that will affect the decision of following stages. Thus, it is indispensable in finding the optimal path of committing the units.

A MATLAB code is programmed to find an optimal unit commitment schedule for a GENCO submitting bid to day ahead market. In this code, firstly, possible unit combinations are found considering the unit capacities, forecasted demand and ramping limitations. Then, economic dispatch is conducted to obtain the most economic dispatch among the committed generators using Lagrange relaxation technique. Two different lambda iteration methods are employed at this point. Afterward, Dynamic programming task is performed and minimum ON and minimum OFF durations and ramp limitations are checked. If there is no violation, results of dynamic programming can be regarded as final solution. If violation exists, transitions cost between the states disobeying the minimum ON and OFF limitations and ramping constraints are increased to infinity so that related transition costs are eliminated in the next iteration of dynamic programming. Details of this process will be explained in detail in the following sections.

4.2.1 Inputs of Unit Commitment Problem

To start with, required information about the characteristic of all generating units and market structure must be entered as input to the algorithm. Required input sets are given below one by one.

1. Total number of generating units is the first input. This number will be used in some calculations in the algorithm.
2. Secondly, cost coefficients of each generating unit are entered. These coefficients are main factors that the scheduling is adapted to.
3. Ramping limitations of each generating unit is another input. Optimal schedule may change according to ramping limitations of unit as described earlier.
4. Minimum and maximum generation capacities of each generating unit are also entered to algorithm. These capacities will be considered when economic dispatch is performed.
5. Minimum ON and minimum OFF durations of each generator must be defined to conduct unit commitment by obeying this constraint.
6. Start-up costs of each generator are also another input. These costs can cause major changes in scheduling.
7. Forecasted energy demand for each one hour time interval to be scheduled should be also known because it is the constraint that couples all of the generators to each other.
8. Initial power generation levels of each generator are the eighth input that must be entered to find an optimal schedule. These initial levels will be used in calculating the generation levels of the first hour so that ramp limits are not violated.

9. Initial commitment status of each generator is the last input of the algorithm. These status data give information about how long the units have been being committed or not committed. Of course it is expected commitment status data must be compatible with the input of initial power generation levels. For instance, entering the initial status as not committed for a unit having an initial power output higher than zero makes no sense. Or similarly, entering zero initial output for a committed generator means inconsistency.

After all inputs are entered, the algorithm creates the related matrices to store inputs so that they can be easily used whenever required. Then, generation scheduling operation is started.

4.2.2 Finding Possible Unit Commitment Combinations

For each hour of the time interval, all possible combinations of units that can generate the forecasted energy demand must be obtained. Including the all combinations in this step is important for finding the most optimal unit commitment solution. To find the possible combinations, a matrix covering all binary combinations of commitment status of units is constructed. Size of this matrix is 2^{GN} x GN. Here, GN stands for the number of generating units. Examples of transposed version of this matrix for two and three units are given in the Table 9.

Table 9: All combinations of commitment status

	Commitment Status		
G1	0	1	1
G2	1	0	1

	Commitment Status						
G1	0	0	1	0	1	1	1
G2	0	1	0	1	1	0	1
G3	1	0	0	1	0	1	1

As can be seen from the table of two and three generators, binary matrix is expanding highly as the number of generating units is increasing. This means that the number of states to be evaluated at each hour is increasing. Fortunately, maximum and minimum generation capacities limit this increasing number of states.

If the constructed binary matrix is multiplied with another one consisting of minimum and maximum generating limits, then minimum and maximum generating capacities of each combination are calculated. Now it is quite simple for each hour to check whether the forecasted demand could be supplied with a commitment combination or not. By this way, possible unit commitment combinations are obtained for each hour separately.

In further calculations, ramping limit constraints are also handled in this part. For each unit, generating level of an hour is highly depends on the generating levels of next hour and previous hour. Although its high production cost, a unit may be required to be committed at low generation level in order to meet the high forecasted demand in upcoming hours. Inversely, a unit with low productions cost may be required to be committed at low levels because of the low forecasted demand in the upcoming hours. Therefore ramping limits are one of the main constraints that should be handled carefully.

There exist different ways for dealing with the ramp limitations. One of them uses multipliers to bring the production level from an infeasible level to feasible level. The difficulties in this method occur in initializing and updating the multipliers [39]. Poor convergence frame is the other disadvantage of this method. Another method to incorporate the ramp limits into unit commitment problem is dynamical adjustment starting from the final hour to the first hour throughout the entire planning horizon [40]. This is not applicable because forward dynamic programming technique is employed in the developed optimal generation scheduling algorithm in order to keep the ON/OFF status of the generator at previous hours. Therefore instead of using these methods, ramp limitations inserted to the problem by defining new generation limits to each generator.

For the generating units which have a generation level range larger than its ramp limits, new minimum and maximum generation limits are introduced. These new limits divide the generation level range into smaller intervals equal to the ramping limit. On the basis of assumption that ramp up and ramp down limitations are equal to each other for all generators, these intervals start from the minimum generating level of the unit and goes step by step till the maximum generating capacity is reached. Hence, the last interval may be smaller than the ramp limit of generator because it is limited by the maximum generating capacity. Division of generating level range is explained mathematically in the equations below.

If $P_{i,max} - P_{i,min} > UR_i$ (13)

Number of generating level intervals is calculated following;

$$RL_i = round - up[\ (P_{i,max} - P_{i,min})/RL_i\ ] \tag{14}$$

As an example, generating level intervals of a unit having minimum generating level of 10 MW, maximum generating level of 30 MW and ramp limit of 8MW/Hour is shown below in the Figure 10.

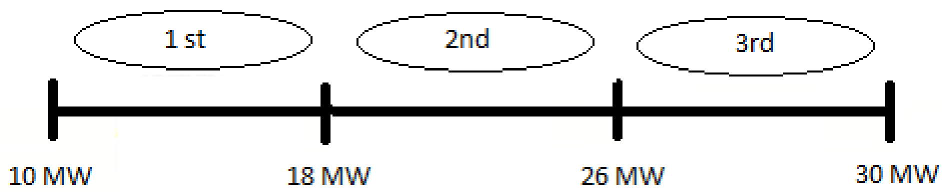

Figure 10: Divided generation level intervals of a sample generator

Once the generation range division task is performed for all generators, number of possible unit commitment combinations is increased enormously. It seems to bring a huge computational load because the number of combinations to be evaluated is multiplied by number of generating level intervals of each generator.

However, most of the combinations are eliminated because of not able to supplying forecasted demand.

After economic dispatch is completed among committed generators that are going to be explained in detail, each generator is given a number, which is called ramp state, corresponding to the generating level interval. Ramp state numbers define the generating interval in which the unit generates energy. Ramp state number of the unit given in Figure 10 when working at 15 MW is ‘1’. It will be ‘2’ if it would work at 25 MW. This ramp states will be taken into consideration when transitions are evaluated. It is unfeasible for a unit to pass through the ramp states whose difference is more than two. For the unit given in Figure 10, it will be unfeasible to make transition from first ramp state to third one or vice versa. These kinds of transitions will be eliminated during the dynamic programming.

For the transitions which are realized between neighbor ramp states may also yield an infeasible transition. For instance, if a transition occurs from generation level of 12MW to the generation level of 25 MW, which exceeding the ramp limit, between the successive hours for the unit given in Figure 10, it will not be eliminated because ramp states are sequential. Such cases are checked separately and eliminated in the algorithm that is going to be explained in further sections.

In order to increase the susceptibility of ramping limitations, number of generating level intervals of each unit might be increased. To have more optimal generation schedule, this method could be employed complying with more computational load and longer time. By increasing the number of intervals, wider working range is offered to a generator. Effects of this application will be observed in the case studies chapter. Increased intervals of unit given in Figure 11 is shown below

$$RL_i = round - up[\ (P_{i,max} - P_{i,min})/(RL_i \div 2)\ ] \tag{15}$$

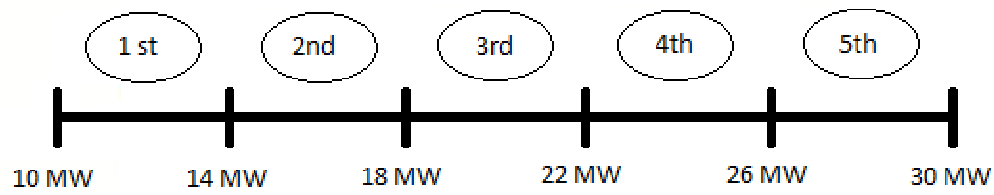

Figure 11: Increased generation level intervals of a sample generator

To sum up, generation level range division brings much computational load to the algorithm because committing combination of generators, meaning the binary matrix explained above, is searched as many times as the multiplication of generating level intervals of all generators. On the other hand, this is a necessity to provide a guaranteed convergence for solution. This task is performed only one time during the whole process and most of the combinations is eliminated with its relevant generation limits because of not supplying the forecasted demand.

4.2.3 Lagrange relaxation for Economic Dispatch

In part 1, the combinations of generators which cannot supply the demand forecast because of maximum and minimum generating capacities were eliminated. In this part of the algorithm, economic dispatch is performed for each commitment combinations that passed from part 1. There could be combinations to handle which committing the same units in this part. The difference between these same unit combinations emerges at the point of minimum and maximum generating capacities of each unit. Therefore, it is expected that more than one economic dispatch results are obtained for one committing combinations. These different economic dispatch results let the operator to handle the scheduling problem in terms of ramp limits.

The problem to be solved is that finding the most economical dispatch for one hour interval among the committed generators whose cost functions and maximum-minimum generating capacities are known. Economic dispatch is conducted by using the Lagrange relaxation method as stated earlier. Lagrange relaxation method involves a multiplier called lambda. Solution is found iteratively by updating lambda. When solving economic dispatch problems, lambda is regarded as incremental cost of each generator. Main idea behind this method is to search for a value of incremental cost at which sum of outputs of all units is equal to the forecasted demand. In time interval t, cost function of unit i generating an output of $P_{i,t}$ is given in equation (16).

$$F_{i,t} = a_i + (b_i \times P_{i,t}) + (c_i \times P_{i,t}^2) \tag{16}$$

Then, objective function covering all units becomes minimizing the following;

$$F_t = \sum_i^N [a_i + (b_i \times P_{i,t}) + (c_i \times P_{i,t}^2)] \tag{17}$$

Subject to the constraint;

$$D_t = \sum_i P_{i,t} \text{or} \sum_i P_{i,t} - D_t = |\varepsilon| < Tolerance \tag{18}$$

Therefore Lagrange function becomes;

$$\mathcal{L} = \sum_i^N [a_i + (b_i \times P_{i,t}) + (c_i \times P_{i,t}^2)] + \lambda \times (\sum_i P_{i,t} - D_t) \tag{19}$$

Incremental cost means the price that will be charged if one more additional unit of energy is demanded. Mathematically, in the cost function vs. generated power graph, it is slope of the tangent line at the operating point. To find the most economic dispatch under the constraint of total demand which couples all committed units together, incremental costs of all committed units must be equaled to each other ignoring the generating capacities. Then, from derivation of equation (17), following equation (20) is obtained and it is solved together with equation (18).

$$\frac{dF_{i,t}}{dP} = b_i + \left(2c_i \times P_{i,t}\right) = \lambda_t \tag{20}$$

For an hour with three committed unit and forecasted demand of 1000 MW, below equations can be solved easily knowing cost coefficients.

$$\mathcal{L} = \left(F_{1,t} + F_{2,t} + F_{3,t}\right) + \lambda_t \times (P_{1,t} + P_{2,t} + P_{3,t} - 1000) \tag{21}$$

$$\frac{dF_{1,t}}{dP_{1,t}} = b_1 + (2c_1 \times P_1) = \lambda_t \tag{22}$$

$$\frac{dF_{2,t}}{dP_{2,t}} = b_2 + (2c_2 \times P_2) = \lambda_t \tag{23}$$

$$\frac{dF_{3,t}}{dP_{3,t}} = b_3 + (2c_3 \times P_3) = \lambda_t \tag{24}$$

$$P_1 + P_2 + P_3 = 1000 \tag{25}$$

Values found for P_1, P_2 andP_3 may not satisfy the generating capacities. Generating levels which are outside the limits will be taken as equal to the limits as given below.

If $\quad P_{i,t} \leq P_{i,min}$, $\qquad P_{i,t} = P_{i,min}$ (26)

If $\quad P_{i,t} \geq P_{i,max}$, $\qquad P_{i,t} = P_{i,max}$ (27)

After the output levels are brought into the limits, sum of all outputs deviate from the demand forecast normally. Depending on the sum of power output values, lambda is updated to be used in the second iteration. Computational algorithm of the Lagrange relaxation part of the developed algorithm is given below in Figure 12.

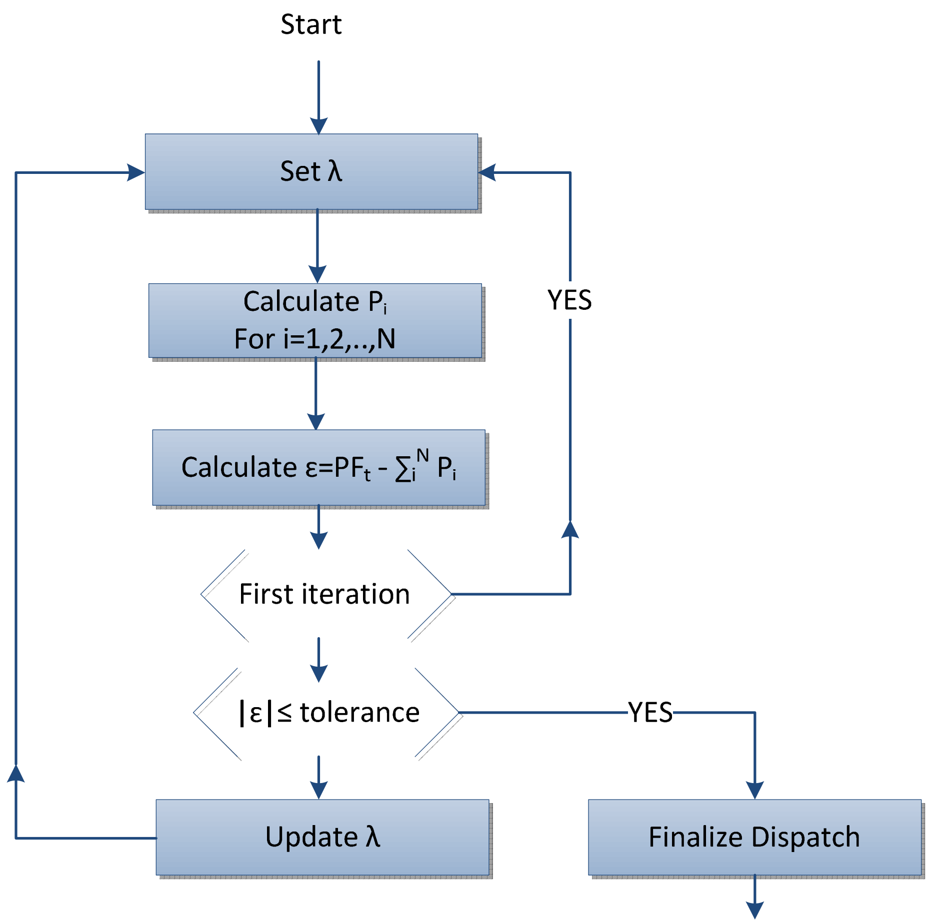

Figure 12: Algorithm of economic dispatch with lambda iteration

A starting value for lambda is chosen to initialize the process. Starting value of lambda is crucial for the speed of the solution. A starting value close to final value of lambda which yields most economic dispatch could decrease the number of iteration enormously. In the developed algorithm, initial value of lambda is chosen by disregarding generating capacities and solving the dispatch problem which does not require any iteration.

Second important operation which can highly affect the solution time is updating method of lambda. Updating method also does define the convergence. Poor methods may cause the solution to oscillate around the constraint of forecasted demand and may not give a feasible dispatch solution.

There are different methods for updating the lambda. In the developed algorithm, two different methods are employed. Firstly, most common one called interpolation technique is used. This method basically defines next value of lambda by interpolating between last and previous values of it. Interpolation is done according to the difference between the total production and forecasted demand. Sample graphical presentation is given below for interpolation method.

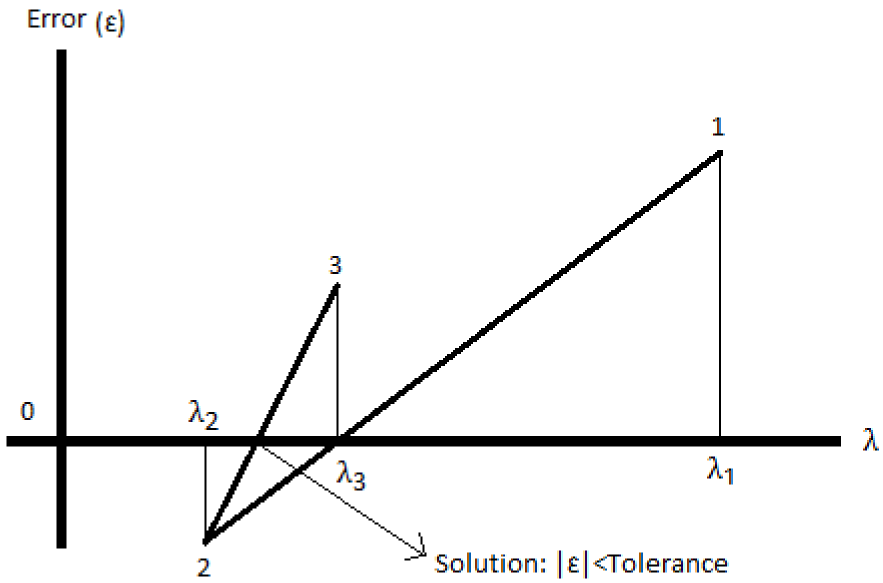

Figure 13: Graph of interpolation of lambda

Once lambda is initialized as explained above, second value of it is found by increasing or decreasing it by %10 according to the sign of error. This provides two successive errors one below zero and the other one above zero. Third value of lambda is then calculated by interpolating these two values. In preceding iterations, extrapolation may be necessary because of two successive errors both are positive or negative.

In most cases, final solution giving a production of energy in limits of tolerance is found by interpolation method. But, there might be situations that another method called Newton-Raphson must be employed. Newton-Raphson method updates the lambda by subtracting the derived Lagrange function divided by Lagrange function from last value of lambda. It is expressed in below equation (28);

$$\lambda_{k+1} = \lambda_k - \frac{(\sum_i P_{i,t} - PF_t)}{\sum_i^N [a_i + (b_i \times P_{i,t}) + (c_i \times P_{i,t}^2)] + \lambda \times (\sum_i P_{i,t} - PF_t)} \quad (28)$$

In order to find the solution of economic dispatch problem quickly, the algorithm uses both of the methods explained above. Interpolation method can find solution quickly, however its convergence is poor compared to other method. On the other hand, main advantage of Newton Raphson method is that its convergence is guaranteed even if a high number of iteration is required. To have an efficient and guaranteed method, lambda is iterated with interpolation method until a predefined number of iteration is reached. If the solution is not achieved yet, iteration method is switched to the Newton-Raphson and lambda is iterated until solution is found.

This process is performed for all unit combinations obtained in previous part for all time intervals. The algorithm creates a cell[1] containing a number of columns equal to the total hours to be scheduled. In fact, number of rows of this cell is equal to the multiplication of number of the generating level intervals of all units which is described in finding possible unit commitment combinations part. Results of economic dispatch task are saved in this cell at related matrices. After this, it is easy to calculate the production costs of each commitment combinations at each hour. Cost of each generator at each hour is found using the equation (28). Production costs are the main elements together with the transitions costs. These two cost elements will be joined in the solution to find an optimal dispatch.

4.2.4 Calculating Transition Costs between Successive Hours

Transition costs means that the cost of starting up or shutting down of a unit. In order to find an optimal schedule, it is so normal that some units might be started

[1]Cell is kind of a variable in MATLAB in the form of matrix and each entry of it involves different sized matrices.

up and shut down during the planning horizon because power demand is always tend to be supplied by more economical units. On the other hand, during a low demand hour between two high demand hours, it could be more feasible to commit an uneconomical unit that have to be committed at next hour. This is because of avoiding its high start-up cost. To deal with such cases, all possible transition costs among unit commitment combinations are evaluated.

Transition costs is the sum of the start-up cost of units that are not committed in previous hour and committed in present hour, plus sum of the shut-down cost of units that are committed in previous hour and not committed in present hour. In the developed algorithm, shut down costs are taken as zero for all generators which is the common case in real. Equation of transition cost of a state is given below.

$$TC_{t-1,t} = \sum_{i}^{N} (1 - I_{i,t-1}) \times I_{i,t} \times SU_i \tag{29}$$

Following figure tries to give idea about the process of calculating transition costs.

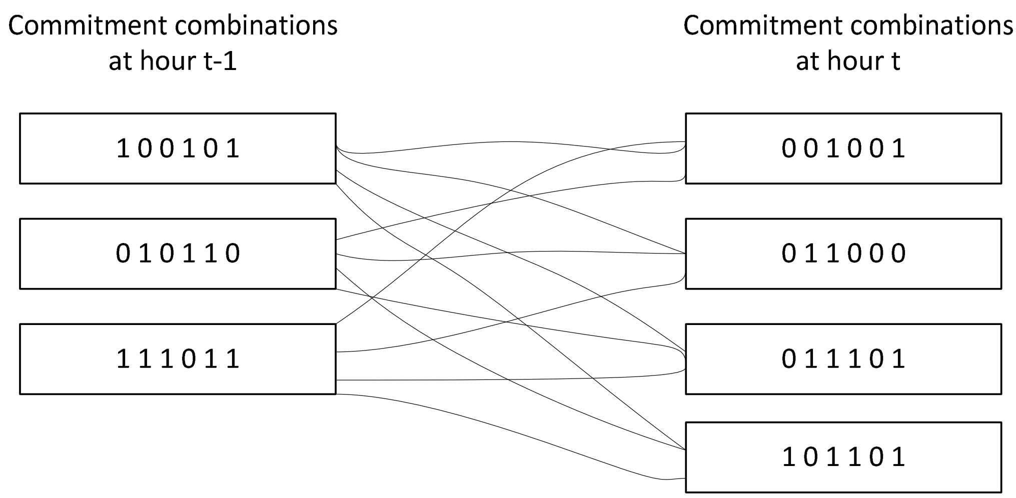

Figure 14: Sample transition cost

Transition cost for a unit commitment combination represents the cost of transition from another combination belonging to previous hour. Therefore, number of transition costs for a unit is equal to the number of possible unit combinations at previous hour. For the first hour, transition cost is calculated by considering the initial commitment status of units which is one of inputs of the algorithm. After transition costs are calculated for all unit combinations at each hour, another cell is created in this part in order to keep the transition costs of each unit combination in the memory. Calculated values are kept in the related matrices of the cell.

4.2.5 Dynamic Programming Process

Both of the basic cost elements, production costs and transition costs, are calculated and kept in the memory at two different cells that are in the same size. The algorithm continues by adding production costs and transitions costs of each combination. Then, dynamic programming process is initialized. Dynamic programming algorithm is explained in earlier in detail. In example given there, 4 stages exist and 8 states are represented. In unit commitment scheduling problems, hours are regarded as stages and commitment combinations are regarded as states of dynamic programming. Total cost of a state is found by adding its production cost and the cheapest way of reaching that state. In preceding stages, only total cost of each state is used. Mathematical equation of this operation is given below.

$$STC_{n,t} = \sum_{i}^{N} F_{i,t} + min \begin{cases} STC_{1,t-1} + TC_{1,n} \\ STC_{2,t-1} + TC_{2,n} \\ STC_{3,t-1} + TC_{3,n} \end{cases} \quad (30)$$

Total cost of each state is calculated with the above operation and calculated values are saved in a matrix together with the information of state number of previous hour from which transition is realized. Saving the number of the state at time *t-1*, which gives minimum cost of the state at time t, facilitates the process of back propagation.

After total cost of all unit commitment combinations, i.e states, are calculated, dynamic programming process is completed without considering the unit constraints. In the final hour *t*, total cost of the state which has minimum total cost among all states in final stage gives the total cost of whole scheduling process. It also gives a clue about the scheduling path. State number of previous hour *t-1* is saved in the same matrix with state of final hour. And the state number of hour t-2 is saved in the matrix of minimum cost state of hour *t-1*.By tracing the state numbers saved during the dynamic programming process from last hour to the first hour, optimal generating schedule is found because state numbers give the unit commitment combinations. Power generating levels can also be defined from the corresponding entries of the cell that had already been created as explained earlier. This solution does not handle the unit constraints yet. Only forecasted demand which is a system constraint coupling all units to each other is considered till now. Therefore next task is to check whether the committed units are convenient in terms of minimum ON and OFF times or not.

4.2.6 Checking the Minimum ON and Minimum OFF Durations

Optimal generation schedule for a system regardless of unit constraints like minimum ON and minimum OFF times and ramp limits could be found with the process explained above. If the ramp limitations and minimum starting up and shut down times are to be considered, a feedback mechanism that checks these constraints is necessary. In the developed algorithm, firstly minimum ON and minimum OFF times are handled.

Result of first run of dynamic programming process yields a scheduling solution. In order to check all units whether they have enough time in the planning horizon for minimum ON and minimum OFF times, a variable called timer is created for each generating unit. Timers are updated at every hour according to commitment status of the generators. If a generator is committed during successive hours, 1 is added to its timer at the second hour. If it is not committed during successive hours, 1 is subtracted from its timer at the second hour. If it is not committed during an hour and started up to be committed at next hour, its timer is equaled to 1 at the second hour whatever the value of timer is. Inversely, if a generator is committed during an hour and shutdown to be not committed at next hour, its timer is equaled to -1at the second hour whatever the value of time is.

The algorithm calculates the timer of each generator using the generation schedule obtained from the first run of dynamic programming process. Timer values of the units at the first hour are found by updating the initial timer status of the generators which is given to the algorithm as an input. In the second hour, timer values of the first hour are updated. This process continues by updating the timers till the last hour is reached. Before updating the timer value of a generating unit, its minimum ON or minimum OFF requirements are checked. If a generating unit keeps it's ON state or it's OFF state, its timer is updated directly. However, if the generator is tend to be started up during the transition, absolute value of its timer is supposed to be equal or greater than the minimum OFF duration. As an example, timer of a generator which has not been working for 3 hours is '-3'. If it's minimum OFF time is given as '4', this transition is regarded as unfeasible because '|-3|' is smaller than '4'. Three hours is not enough to start up the generator which requires at least 4 hour keeping its OFF state. In a similar manner, if a generator is tend to be shut down during a transition, value of its timer is supposed to be greater than its minimum ON time. Assuming that a generator which has '2' hours of minimum ON duration has been working for only one hour, it is unfeasible to change its ON state to OFF because its timer value is '1' smaller than '2'. When the algorithm encounters with such a transition between successive hours violating minimum ON and minimum OFF constraints, it quits checking the transitions of following hours and update the transition cost of relevant state as infinite. This transition cost updating is done because an infinite transition cost will definitely be eliminated during the next iteration of the dynamic programming. The total cost of the relevant state at relevant hour is then updated. The second least cost option among the states of previous hour is employed. Now an updated cell is ready for next iteration of the dynamic programming. Dynamic programming task is performed again with this new cell. A new generation schedule which is totally different from the initial one might be founded as a result of next run of dynamic programming. With this new result, timer checking algorithm is started again to search for an infeasible transition. This process involving a feedback mechanism continues until a schedule which does not yield any infeasible transition and gives enough time to all units for their minimum ON and minimum OFF durations is found.

When a feasible schedule in terms of min-ON and min-OFF durations are found, the next part starts which is checking the ramp limitations of the generators.

4.2.7 Checking Ramp Limitations of the Generators

In addition to min-ON and min-OFF durations, ramp limitation is another constraint that is caused by nature of the generating units. This limitation defines the difference of generation levels of a unit between successive hours. Allowed difference could be very for a hydro unit because hydro units can quickly ramp-up with the help of increased water input. On the other hand, a thermal generating unit needs a long time to increase or decrease its generation level because it takes time to heat-up or cool-down a heat tank. Therefore, especially thermal ones, output levels of generating units cannot be changed as desired. Ramp limitations of units are an indispensable constraint that has to be considered when making generation scheduling.

It was explained in detail that how ramp limitations are handled in the developed algorithm. All units are regarded as they all have more than one minimum and maximum generation levels. Ramp limitation of each generator brings new generation level intervals to the unit. Number of these intervals depends on the ratio of total generation level range divided by the ramp limitation for each unit. Therefore, number of possibilities to be evaluated for each unit is increased as the number of intervals. Instead of two states, which are ON and OFF, additional states are involved. Each of generating level intervals is considered as a separate state and they are given a number which is called ramp state. Checking the constraint of ramp limitations are done through these ramp state numbers. As explained earlier, between successive hours, it should not be allowed to make a transition between the ramp states whose difference is equal or greater than 2. Such transitions in both directions of ramp-up and ramp-down, will be eliminated by the algorithm assuming the ramp-up and ramp-down limitation values are same. In order to perform this elimination, generation scheduling results obtained from dynamic programming and then passed from min-ON and min-OFF checking mechanisms are considered. A new matrix is created whose rows are representing the hours and columns are representing the generating levels of each generator. Generating levels for the units which are not committed is given as 0. The ramp checker algorithm then finds out the ramp states of each generating unit at each hour and keeps these ramp states in memory. Ramp states are found with the formula given below.

$$rs_{i,t} = round\ up\left(\frac{P_{i,t} - P_{i,min}}{UR_i}\right) \qquad (31)$$

All ramp state values are calculated as explained above. Besides, initial generation levels of the units which are given as input to the algorithm are also saved at top of the ramp states matrix. Then all transitions that a generating unit made are checked from the first hour till the last hour. For a unit, if any transition between the ramp states whose difference is equal or greater than 2 is detected, the algorithm directly updates corresponding transition cost for that state as infinite so that the state is eliminated in the next iteration of the dynamic programming process. Then total cost of the relevant state is updated according to the second least cost of state at previous hour and dynamic programming process is performed again. This may result with a schedule which is totally different from the result of previous iteration of dynamic programming.

Transitions which are realized between the successive ramp states could also disobey the ramp limitations. Therefore the difference between generation levels must be checked for all transitions. The ones violating ramp limits are also regarded as unfeasible. Their corresponding transition costs are updated as infinite too.

There is a chance to increase the optimality of the solution which is explained earlier. It is to increase the number of ramp states. Normally, for a generating unit, all generating level intervals are equal to ramp limit except the final interval which is interrupted by the maximum capacity of unit. These intervals might be taken as half of the ramp limits multiplying the number of interval by 2. In this case, transitions realized between ramp states whose difference is 2 are allowed. The ones equal to or greater than 3 must be eliminated. The allowed difference is also increase with the number of ramp states. This operation provides user with a chance to obtain more optimal schedules. Because number of the possible unit commitments is increased and units get more relax to operate at a wider range. As the number of intervals approaches to infinite, more optimal solutions are achieved. However, increasing the number of ramp states might bring a huge computational workload and hence requires a long time to find the solution. Developed algorithm, automatically adjust the size of the generating level intervals. If the total number of the possible unit commitments is above pre-definite limit, size of intervals is decreased. Inversely, size is increased if total number of possibilities is below the limit in order to have a more optimal schedule.

Ramp limit checker mechanism is the last part of the algorithm. A generation schedule obtained from dynamic programming process and passed from the min-ON and min-OFF checking mechanism comes to the ramp limit checker. If all transitions employed in the schedule are within the limits of ramp limitations, the schedule becomes the output of the optimal generation scheduling algorithm. Block diagram of the whole algorithm including flows are given below.

In the following chapter, some cases will be solved in order to show the effects of constraints and other inputs to the solution of the problem. Besides the solution, different results like ramp states and total cost of whole planning horizon will also be given.

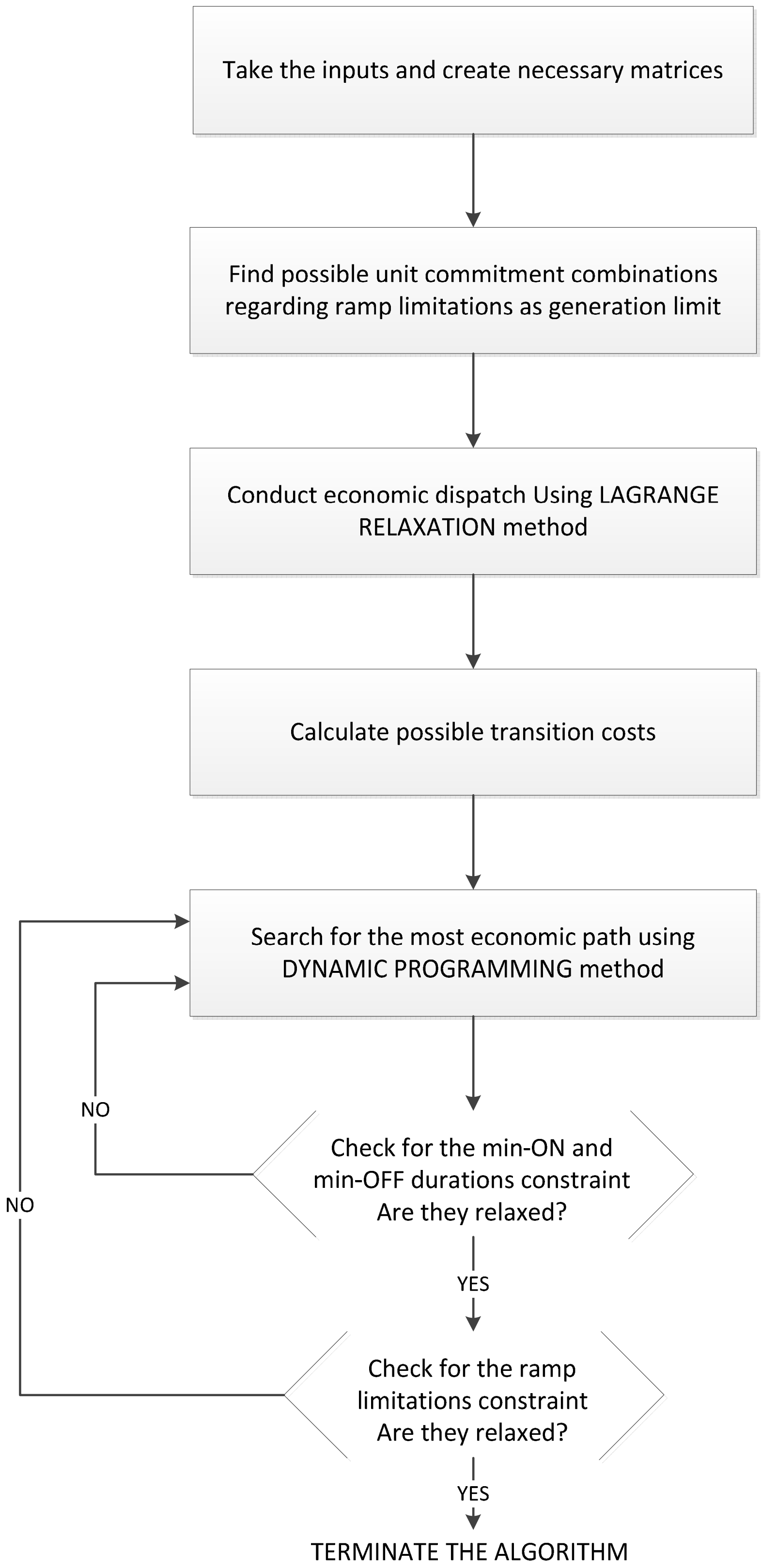

Figure 15: Flow diagram of optimal generating scheduling algorithm

4.3 Evaluation of inputs and results with sample cases

In this part, performance of the algorithm will be evaluated by handling different sample cases. Constraints will be introduced to the cases one by one to observe their effects on the schedules. How the algorithm handles these constraint will be showed by some sub-outputs like ramp states and matrix of timers. In the further cases, solution performance of developed algorithm will be compared with some other methods involving genetic algorithm and mixed integer branch-and-cut algorithm. Same input set will be given to these three different algorithms and results will be examined.

4.3.1 Case 1 – non-constrained simple problem

In this case, 2 generators are handled to be scheduled during 6 hours planning horizon. For the simplicity, ramp limitations are not included in this case. Min-ON and min-OFF times are taken as 1 hour meaning that all generators can be started up after one hour duration of OFF state. Similarly they also can be shut down after one hour duration of ON state. Start-up costs are also taken as zero so that they do not affect the scheduling solution. Their effects on the solution will be showed in a different case. Initial states and initial output levels of the generators are disregarded because they are effective only when the ramp limitations and min-ON and min-OFF durations are involved in the problem. All inputs of the first case are given in the table below.

Table 10: Input parameters of the first case

inputs	Generator 1	Generator 2
Cost coefficient a	459	310
Cost coefficient b	6.48	7.85
Cost coefficient c	0.00128	0.00194
Maximum generating capacity	6 MW	4 MW
Minimum generating capacity	1.5 MW	1 MW

Table 10 (continued)

Minimum ON duration	1	1
Minimum OFF duration	1	1
Ramp limitation	4.5 MW	3 MW
Start-up costs	0 $	0 $

In the table above, [36] is taken as reference for cost coefficients of generators and maximum and minimum generating capacities in order to have realistic cost rates and rational results. Rest of the inputs including constraints and unit parameters are adjusted according the results so that comparative changes could be done on these inputs to compare results easily.

Forecasted demands for the whole planning horizon which is 6 hours are given in Table 11 below.

Table 11: Forecasted demand quantities in case 1

Hours	1	2	3	4	5	6
Forecasted demand (MW)	5	9	6	4	7.5	10

When the algorithm runs with given inputs above, following scheduling results given in Table 12 are obtained.

Table 12: Scheduling results of case 1

hours	1	2	3	4	5	6
Output of G1 (MW)	5	5	6	4	3.5	6
Output of G2 (MW)	0	4	0	0	4	4
Cost of production at the end of each hour	62	187	258	312	424	557

It can be seen from the table that total cost of producing 41.5MW total amount of energy during 6 hours is calculated as 557 $. Total production cost at the end of each hour is also represented in the table. Cost of production for a specific one hour period can be calculated by subtracting the total cost of previous hour from the total cost of relevant hour. Result of his calculation normally involves also the transition cost between the hours. But transition cost in this case is 0 because start-up costs of all generators are taken as 0.

4.3.2 Case 2 (a) – problem including min ON and OFF times constraint

In this case, minimum ON and minimum OFF durations are introduced to the generation scheduling problem. They will be given to the algorithm as different than 1. All inputs are considered as same as that of case 1 except for the minimum ON and minimum OFF durations. When minimum ON and minimum OFF durations are considered, initial status of the units becomes an important input because they can affect the solution by eliminating the possible commitment combinations in the first hour. In this case 2-a, initial status of units is taken as 3 for both units meaning that units had been working for 3 hours just before the first hour. This value is chosen so that initial status does not affect the schedules. In case 2-b, different initial state values will be employed to show their effects on the solution. New values of minimum ON and minimum OFF durations are given in the table below together with the initial status.

Table 13: Minimum ON and minimum OFF durations of generator in case 2

	Generator 1	Generator 2
Minimum ON duration	1	2
Minimum OFF duration	2	1
Initial Status	3	3

When the algorithm is conducted with new minimum ON and minimum OFF durations, results of generation schedule is expected to changes because it is seen on the result of case 1 that unit 2 is started up at hour 2 and shot down at hour 3. Results of case 2-a are given in the table below.

Table 14: Scheduling results of case 2-a

Hours	1	2	3	4	5	6
Output of G1 (MW)	5	5	2	4	3.5	6
Output of G2 (MW)	0	4	4	0	4	4
Cost of production at the end of each hour	62	187	287	340	453	586

As can be seen, total cost of producing same amount of energy with case 1during same time horizon is increased to 586 $ from 557 $ in case 2. This is because minimum ON and minimum OFF durations are introduced to the problem. There are changes that draw attention in generation schedule. Unit 2 was not committed at hour 3in the first schedule. But now it is committed at hour 3 because minimum ON duration does not allow to unit 2 to be shut down which happens in case 1.Timers matrix which is used for min-ON and min-OFF checking of units is given table below.

Table 15: Timers of units in case 2-a

Hours	initials	1	2	3	4	5	6
Timer of Unit 1	3	4	5	6	7	8	9
Timer of Unit 2	3	-1	1	2	-1	1	2

Timer of unit 1 is increased at each hour starting from the initial status 3because it is committed during the whole planning horizon. On the other hand, timer of unit 2 is equaled to -1 at the first hour because it is not committed. It is equaled to -1 again in hour 4.

It can be also noted as a sub-output that number of iteration of the dynamic programming task is 3. It means that the algorithm calculates 3 different generation schedules, first 2 of which are eliminated because of the minimum-ON and minimum-OFF constraints.

4.3.3 Case 2 (b) – effect of different initial states to the problem in case 2 (a)

In this case initial status values are taken differently to show how they could be effective on the problem solution. Initial status unit 1 is taken as -2 and unit 2 is 1. Obtained results are given in the table below.

Table 16: Scheduling results of case 2-b

Hours	1	2	3	4	5	6
Output of G1 (MW)	1.5	5	6	4	3.5	6
Output of G2 (MW)	3.5	4	0	0	4	4
Cost of production at the end of each hour	91	216	287	341	453	588

It can be seen that even if total productions cost of whole planning horizon has not changed too much, cost of first hour is increased almost 1.5 times. The reason is that unit 2 cannot be shut down because of its minimum-ON time which is 2. Timer matrix of units is given table below.

Table 17: Timers of units in case 2-b

Hours	initials	1	2	3	4	5	6
Timer of Unit 1	-2	1	2	3	4	5	6
Timer of Unit 2	1	2	3	-1	-2	1	2

4.3.4 Case 3 (a) - problem including ramp limitation constraints

In the first case, ramp limitations were given as whole generation range of the generators. It means that ramp is not limited to a specific value. But in this case, ramp values will be introduced to problem. For unit1, ramp rates for both ramp-up and ramp-down taken as 1 MW which divides the generation range into 5 intervals. For unit one, ramp rates are taken as 2 MW which divides the generation range into 2 intervals. . When ramp limitations are considered, initial generation levels of the units become an important input because they can affect the solution by eliminating the possible commitment combinations in the first hour. In case 3-a, initial generation levels of units are taken as 5 MW and 3.5 MW for unit 1andunit 2 respectively. It means that units were generating 5 MW and 3.5 MW just before the first hour. In case 3-b, different initial status values will be employed to show their effects on the solution. Values of ramp limits and initial generation levels are given in Table 18. Rest of the inputs is taken as same with case 1.

Table 18: Ramp limitations and initial generating levels for case 3

	Generator 1	Generator 2
Ramp limitations (MW)	1	2
Initial generating levels (MW)	5	3.5

When the algorithm is conducted with new ramp limitations, results of generation schedule is expected to changes because it is seen on the result of case 2 that unit 1 has an output level of 6 MW at hour3 and 4 MW at hour 4. This 2 MWof difference in the generating level is not allowed by ramp limitation of unit 1 which is 1 MW. Unit 2 seems to change its generating level from 0 to 4 MW or from 4MW to 0. It should be noted that the in the transitions in which a unit is started-up or shut down, ramp limitation is not checked for that units.of Similarly, unit 2 has an output level of 1.5 MW at hour 5 and 4 MW at hour 6.In such situations, it is assumed that the ramp issue is tolerated by the start-up or shut down period. Even though the developed algorithm is not coded in that manner, transitions realized from zero level to any output level, or vice versa, could be easily involved in the ramp checker mechanism with slight changes in the algorithm. Results of case 3-a are given in the table below.

Table 19: Scheduling results of case 3-a

Hours	1	2	3	4	5	6
Output of G1 (MW)	5	5	6	0	5	6
Output of G2 (MW)	0	4	0	4	2.5	4
Cost of production at the end of each hour	62	187	258	320	433	567

As can be seen from the table, schedule is now different from the case 1. Differences show themselves at hours 4 and 5. Total cost of producing same amount of energy with case 1 during same time horizon is increased to 567 from 557. In the new schedule, no transition is allowed between generation levels whose difference is over than 1 except for the starting up and shot down cases for unit 1. Matrix of ramp states which is explained earlier is given in the table below.

Table 20: Ramp states of units in case 3-a

Hours	initials	1	2	3	4	5	6
Ramp states of unit 1	4	4	4	5	0	4	5
Ramp states of unit 2	1	0	1	0	1	1	1

Number of iteration in this case is 13. First 12 generation scheduling solution is eliminated by the ramp checker mechanism. It will be seen in following cases that number of iteration may increase enormously as the constraints are integrated in the problem.

4.3.5 Case 3 (b) - effect of different initial generation levels to the problem in case 2 (a)

In this case, effects of initial generation level will be observed when the ramp limitations are included in the solution. In case 3-b Initial generation levels are taken as 3 MW and 2 MW respectively. And all other inputs are same with case 3-a. Results of this case is given in the Table 21.

Table 21: Scheduling results of case 3-b

Hours	1	2	3	4	5	6
Output of G1 (MW)	4	5	6	0	5	6
Output of G2 (MW)	1	4	0	4	2.5	4
Cost of production at the end of each hour	92	218	288	351	463	597

As can be seen, total cost of production is increased to 597 from 567. This is because of the first hour scheduling. Initial generation level of unit 1 limits the first hour generation of it at 4 MW. Therefore second generator need to be committed at the same time. This causes an increase in the cost of first hour. Ramp states matrix of both generators is given below in table.

Table 22: Ramp states of case 3-b

Hours	initials	1	2	3	4	5	6
Ramp states of unit 1	2	3	4	5	0	4	5
Ramp states of unit 2	1	1	1	0	1	1	1

Ramp rates of unit 2 are always 1 if it is committed. It is because ramp limitation of this unit is equal to whole generation range.

4.3.6 Case 4 – problem with start-up cost of units

Objective of this case is to analyze the effects of start-up cost on generation scheduling. It is a common situation that a generator is continued to be committed in order to avoid its start-up cost. In case 4, start-up costs are added to the problem to observe such a situation and the increase in the total cost will also be realized. Start-up cost of the first unit 1 shout is taken as 30 $ which does not make any sense because unit 1 is never shut-down in case 1. On the other hand, it is seen that unit 2 is started-up two times in schedule of case 1. Start-up cost of unit 2 is taken as 80 $ and a change is expected in schedules of unit 2. Rest of the inputs are taken as same with case 1. Results of the algorithm with the start-up costs are given in Table 23.

Table 23: Scheduling results of case 4

hours	1	2	3	4	5	6
Output of G1 (MW)	1,5	5	2	1.5	3.5	6
Output of G2 (MW)	3.5	4	4	2.5	4	4
Cost of production at the end of each hour	62	217	287	341	513	646

Total cost of production becomes 646 $ in this case. An 89 $ increase with respect to cost of schedule of case 1 is not caused by the start-up costs but the change in the generation schedule. Even though the GENCO does not have to pay for starting up the units, a higher costly schedule have to be conducted because the most optimal generation schedule is gone away in order avoid start-up costs.

It also should be noted that the number of iteration of dynamic programming process is still 1 which is same with case 1 because the constraint of start-up costs are not handled with the checking mechanisms. They are involved in the operation of dynamic process. Therefore 1iteration will be enough if any other constraint is not given in the problem.

Until case 4, effects of different constraints on the total production cost, generation scheduling and unit commitment are observed one by one. In the next cases, more than one constraint will be employed together in generation scheduling problem which is the situation in real applications. The algorithm is going to be forced to deal with more units and challenging constraints.

4.3.7 Case 5 – enlarged unit commitment problem

In case 5, 4 units will be available to produce forecasted amount of power during 12 hours. Both the number of generating units and total hours to be scheduled are increased in this case. Although this will bring a larger computational workload to the algorithm, a GENCO might have 4 or even more units to be utilized in the day ahead markets. Therefore it is unavoidable to go around a case involving 4 units. 12 hours could be little bit long to schedule because most of participants in day ahead markets bids for the prime hours in which the consumption reach its highest values. But there might be GENCOs who bid for longer times even for the whole 24 hours period. In this case, a problem requiring a schedule of 12 hours will be involved to observe the performance of the algorithm. Inputs parameters of this case are given in the table below.

Table 24: Inputs of case 5

inputs	Unit 1	Unit 2	Unit 3	Unit 4
Cost coefficient a	20.6	31	18	43.2
Cost coefficient b	8.26	7.85	6.8	12
Cost coefficient c	0.0128	0.0098	0.037	0.015
Maximum generating capacity (MW)	6 MW	4	3.5	18
Minimum generating capacity (MW)	1.5 MW	1	2	10
Minimum ON duration (hours)	1	1	3	2
Minimum OFF duration (hours)	1	1	1	2
Ramp limitation (MW)	2	3	1.5	3
Start-up costs ($)	30	15	56	190

Table 24 (continued)

Initial status (hours)	3	1	-1	-2
Initial generating levels (MW)	4	2.5	0	0

As can be understood from the table, ramp limitations are introduced for two of the units which are unit 1 and unit 4 having higher generation ranges. For units 2 and 3, ramp limitation is given as the whole generation range of units meaning that ramp is not limited for these units. Minimum ON and minimum OFF durations are also given in a restricting manner for only units 3 and 4. Units 1 and will started up or shut down whenever desired in the schedule. Forecasted power demand during 12 hours is given in Table 25.

Table 25: Forecasted demand quantities in case 5

Hours	1	2	3	4	5	6	7	8	9	10	11	12
Forecasted demand (MW)	9	12	17	20	24.5	23.6	27	25	22	20.5	19.6	17

Forecasted demand is assumed to make peak during hours 5, 6 and 7 which corresponds to the peak hours of a day like 11:00, 12:00 and 13:00 AM. Graph of the forecasted demand is given in the figure below.

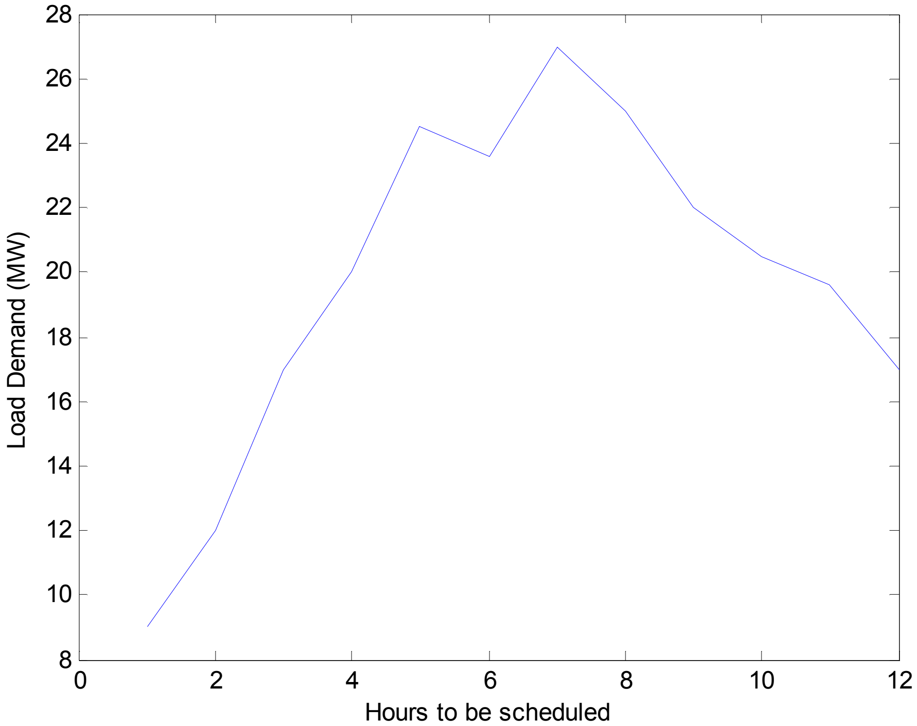

Figure 16: Graph of forecasted demand for case 5

Results of case 5 are given in the table below.

Table 26: Scheduling results of case 5

	Generation levels of units (MW)				
Hours	Unit 1	Unit 2	Unit 3	Unit 4	Cost of hour($)
1	5.5	0	3.5	0	125
2	4.5	4	3.5	0	343
3	3.5	0	3.5	10	756
4	4.5	0	3.5	12	1049
5	6	0	3.5	15	1417
6	5.6	0	3.5	14.5	1746
7	6	0	3.5	17.5	2119
8	6	0	3.5	15.5	2464
9	6	0	3.5	12.5	2772

Table 26 (continued)

10	6	0	3.5	11	3062
11	6	0	3.5	10.1	3341
12	6	0	0	11	3588

It can be seen on the table that unit 2 is committed seldom because of its high cost coefficients. Unit 1 and unit 3 look like the cheaper units because they are committed during almost whole period of scheduling. Fluctuations in the forecasted demand are tolerated by the ramping up or down the unit 4 whose cost curve is between that of unit 1 and unit 2. One could make a lot of comments on the schedule that the algorithm generates by looking at the output levels of the algorithm. But the best way to see the effects of the inputs on schedule is to run the algorithm with another input set. In case 6 different inputs will be given to algorithm which will utilize unit 2 more by lowering its cost coefficients.

The schedule given in the Table 26 is found by 12 iterations. First 11 of them are eliminated because of the min-ON, min-OFF or ramp constraints. This number of iteration may increase highly as number of units which has ramp or min-ON min-OFF constraints is increased. Such a schedule will be developed in case 8.

4.3.8 Case 6 – effect of modified unit parameters to the problem in case 5

In case 6, another input set in which the cost coefficients of unit 2 is lowered will be given to the algorithm and effects of this is going to be observed. Start-up cost of the unit 2 is also taken as zero to enhance the combinations which commit unit 2. The new input set for case 6 is given below.

Table 27: Inputs of case 6

inputs	Unit 1	Unit 2	Unit 3	Unit 4
Cost coefficient a	20.6	12	18	43.2
Cost coefficient b	8.26	4.54	6.8	12
Cost coefficient c	0.0128	0.0058	0.037	0.015
Maximum generating capacity (MW)	6 MW	4	3.5	18
Minimum generating capacity (MW)	1.5 MW	1	2	10
Minimum ON duration (hours)	1	1	3	2
Minimum OFF duration (hours)	1	1	1	2
Ramp limitation (MW)	2	3	1.5	3
Start-up costs ($)	30	0	56	190
Initial status (hours)	3	1	-1	-2
Initial generating levels (MW)	4	2.5	0	0

In the table above, parameters of unit 1, 3 and 4 is same with case 5. There are changes only at unit 2. Results of this case are given below.

Table 28: Scheduling results of case 6

	Generation levels of units (MW)				
Hours	Unit 1	Unit 2	Unit 3	Unit 4	Cost of hour($)
1	5	4	0	0	92
2	4.5	4	3.5	0	279
3	0	4	3	10	700
4	0	4	3.5	12.5	969
5	6	4	3.5	11	1295
6	5.5	4	3.5	10.6	1607
7	6	4	3.5	13.5	1982
8	6	4	3.5	11.5	2309
9	6	4	0	12	2599
10	6	4	0	10.5	2870

Table 28 (continued)

11	5.6	4	0	10	3133
12	0	4	0	13	3364

As can be seen in the table, unit 2 is committed at full power during the whole operation as it is the cheapest unit in the portfolio of the GENCO. Fluctuations are mainly tolerated by unit 4 or by shutting down the unit 3 which seems to be the most expensive unit.

Number of iterations in this case is about 346. It means that the obtained schedule is 346th cheapest schedule. First 345 of them are eliminated by the constraints. Lowering the cost coefficients of unit 2 brings cheaper solutions violating the ramp constraints.

4.3.9 Case 7 - effect of decreased number of ramp states in case 5

It has been explained earlier that increasing the number of generation range intervals yields more optimal schedules because generators have more flexibility. Until case 6, all cases are handled with the increased intervals. Each interval is taken as half of the ramp limit for a unit. In order to show its effect on cost and schedules, case 7 will be performed using decreased intervals. Same input set with case 5 is used in case 7. Obtained results are given below.

Table 29: Scheduling results of case 7

	Generation levels of units (MW)				
Hours	Unit 1	Unit 2	Unit 3	Unit 4	Cost of hour($)
1	5.5	0	3.5	0	125
2	4.5	4	3.5	0	343
3	3.5	0	3.5	10	756
4	3.5	0	3.5	13	1049

Table 29 (continued)

5	5.5	0	3.5	15.5	1417
6	5.5	0	3.5	14.6	1747
7	6	0	3.5	17.5	2125
8	6	0	3.5	15.5	2470
9	6	0	3.5	12.5	2779
10	6	0	3.5	11	3068
11	6	0	3.5	10.1	3347
12	6	0	0	11	3595

Differences show themselves at hours 4, 5, and 6. Even though the difference in cost is very small in this case, there might be huge cost differences in cases where ramp issue plays effective role.

4.3.10 Case 8 – problem including all constrains

In this last case, a challenging input set with four generators will be dealt with. It is assumed that all of the units have a ramp limitation and three of them have minimum-ON or minimum-OFF limitation. Objective of this case is to show the performance of algorithm and number of iterations in such a case. Input parameters given to the algorithm is given below.

Table 30: Input parameters of case 8

inputs	Unit 1	Unit 2	Unit 3	Unit 4
Cost coefficient a	20.6	31	18	43.2
Cost coefficient b	8.26	7.85	11.4	9.28
Cost coefficient c	0.0128	0.02	0.037	0.0098
Maximum generating capacity (MW)	6 MW	4	3.5	18
Minimum generating capacity (MW)	1.5 MW	1	2	10
Minimum ON duration (hours)	2	3	1	1

Table 30 (continued)

Minimum OFF duration (hours)	2	1	1	2
Ramp limitation (MW)	2.5	2	1	5
Start-up costs ($)	30	60	48	26
Initial status (hours)	3	1	-1	-2
Initial generating levels (MW)	4	2.5	0	0

As seen from Table 30 , ramp limitations and minimum ON and minimum OFF durations are introduced to almost all generators. Forecasted demand and planning horizon is taken as same with case 5. It should be noted that input set is not same with case 5. Obtained results are given in the table below.

Table 31: Scheduling results of case 8

	Generation levels of units (MW)				
Hours	Unit 1	Unit 2	Unit 3	Unit 4	Cost of hour($)
1	5	4	0	0	125
2	0	2	0	10	335
3	0	4	0	13	538
4	0	4	0	16	814
5	6	4	0	14.5	1163
6	6	4	0	13.6	1443
7	6	4	0	17	1805
8	6	4	0	15	2123
9	6	0	0	16	2387
10	6	0	0	14.5	2638
11	6	0	0	13.6	2880
12	0	0	0	17	3084

Above results are founded at the end of 1621 iterations. Most of the combinations are eliminated because of strict ramp and ON OFF limitations. But the algorithm has the ability to deal with such cases even if it takes a bit longer time like few hours.

The algorithm can also terminate with an error message when producing the forecasted demand with the given constraint is not possible.

4.3.11 Comparison of results of proposed algorithm and genetic algorithm

In this section, input set of case 5 and case 8 will be given to another unit commitment problem solver which employs genetic algorithm method. Main features of the genetic algorithm were explained in chapter 3.5. It is inspired from the genetic theory and law of evolutionary adaptation. The first task which is done in the genetic algorithm is generating the parent genotypes. Genotype matrices represent the possible schedules. Number of row of genotypes is equal to the hours to be scheduled and columns stand for generating units. All the constraints like min ON/OFF times, ramp limitations and generation capacities are considered when creating parents. In the genetic algorithm which is used to make a comparison, total number of 1000 parent genotypes is created. Resolution of the generation level is defined as 0.1 MW. Then costs of each parent genotypes are calculated secondly to initialize the crossover period. Although the crossovers process involves random variables, a technique which put cheaper schedules forward is used. Therefore the genotypes yielding better cost results are more likely to be chosen as parents. Two parents are crossed to create a new generation genotype. Based on a random variable, the new genotype takes some part of it from first parent and takes the rest from the second parent. When crossing the parent genotypes, probability of mutation is also considered. With a low probability which is about %1, just like in the nature, the new genotype may involve a totally different schedule from its parents. At the end of crossover stage, total number of new generation normal and mutant genotypes is 1000 again. And they are ready to be the parents of next generations. The whole process is repeated after this point.

Different termination criterions may be used in genetic algorithm. One could count the number of iterations to find the most feasible solution. Or a gap may be aimed. In this practice, stability of the cost value of solution is taken into consideration as termination criterion.

In order to make a comparison, results of case 5 obtained from genetic algorithm (GA) and proposed algorithm (PA) are given in Table 32.

Table 32: Scheduling results of case 5 when solved by genetic algorithm

	Generation levels of units (MW)									
Hours	Unit 1		Unit 2		Unit 3		Unit 4		Cost of hour($)	
	GA	PA	GA	PA	GA	PA	GA	PA	GA	PA
1	5.6	5.5	0	0	3.4	3.5	0	0	165	125
2	5.4	4.5	3.1	4	3.5	3.5	0	0	343	343
3	0	3.5	0	0	3.4	3.5	13.6	10	784	756
4	0	4.5	0	0	3.4	3.5	16.6	12	1072	1049
5	6	6	0	0	3.4	3.5	15.1	15	1442	1417
6	6	5.6	0	0	3.5	3.5	14.1	14.5	1770	1746
7	5.9	6	3.7	0	3.5	3.5	13.9	17.5	2170	2119
8	6	6	0	0	3.4	3.5	15.6	15.5	2516	2464
9	5.5	6	0	0	3	3.5	13.5	12.5	2830	2772
10	6	6	0	0	3.4	3.5	11.1	11	3120	3062
11	6	6	0	0	0	3.5	13.6	10.1	3400	3341
12	6	6	0	0	0	0	11	11	3647	3588

As can be seen above total cost of the schedule obtained from genetic algorithm is higher than the one obtained from the developed algorithm in this thesis. The total cost was 3588 $ in the developed algorithm. It is 59 $ more economical than the genetic algorithm.

Variation of the cost values with iterations is given in the figure below.

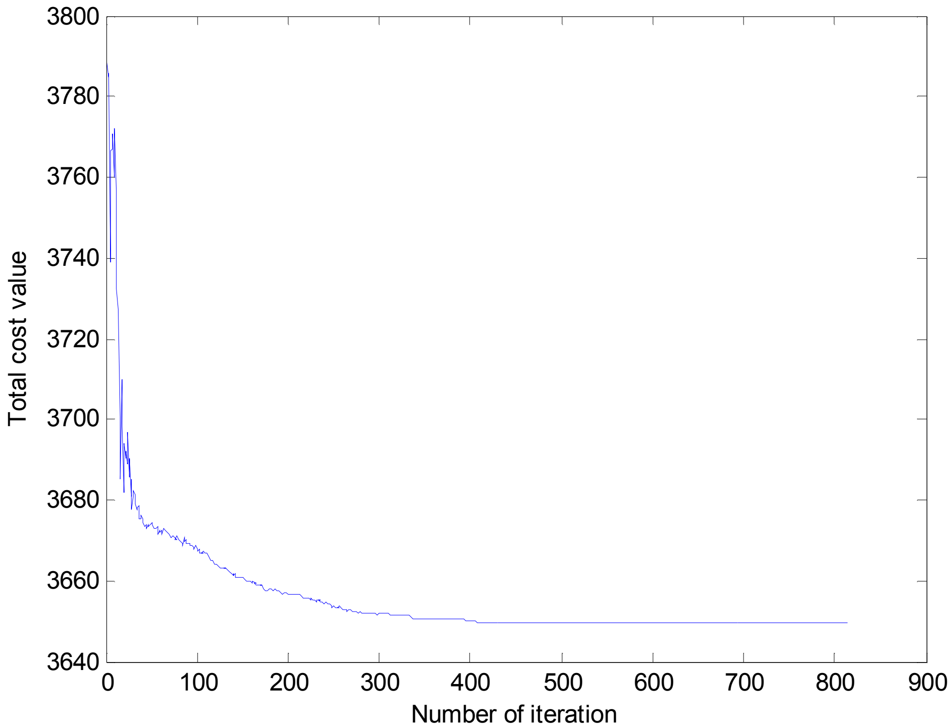

Figure 17 : Variation of total cost value with iterations at genetic algorithm

As another example, inputs of case 8 are also entered to the genetic algorithm. Results obtained from genetic algorithm (GA) and proposed algorithm (PA) are given in Table 33.

Table 33: Scheduling results of case 8 when solved by genetic algorithm

	Generation levels of units (MW)									
Hours	Unit 1		Unit 2		Unit 3		Unit 4		Cost of hour($)	
	GA	PA	GA	PA	GA	PA	GA	PA	GA	PA
1	5.4	5	3.6	4	0	0	0	0	125	125
2	0	0	1.7	2	0	0	10.3	10	335	335
3	0	0	3.6	4	0	0	13.4	13	564	538

Table 33 (continued)

4	0	0	3.8	4	0	0	16.2	16	821	814
5	6	6	4	4	0	0	14.5	14.5	1165	1163
6	3.5	6	3.3	4	0	0	16.8	13.6	1473	1443
7	6	6	4	4	2.1	0	14.9	17	1880	1805
8	6	6	3.9	4	0	0	15.1	15	2198	2123
9	4.3	6	0	0	0	0	17.7	16	2465	2387
10	6	6	0	0	0	0	14.5	14.5	2716	2638
11	6	6	0	0	0	0	13.6	13.6	2958	2880
12	0	0	0	0	0	0	17	17	3161	3084

As can be seen above total cost of the schedule obtained from genetic algorithm is higher than the one obtained from the developed algorithm in this thesis. The total cost was 3083 $ in the developed algorithm. It is 78 $ more economical than the genetic algorithm. Variation of the cost values with iterations is given in the figure below.

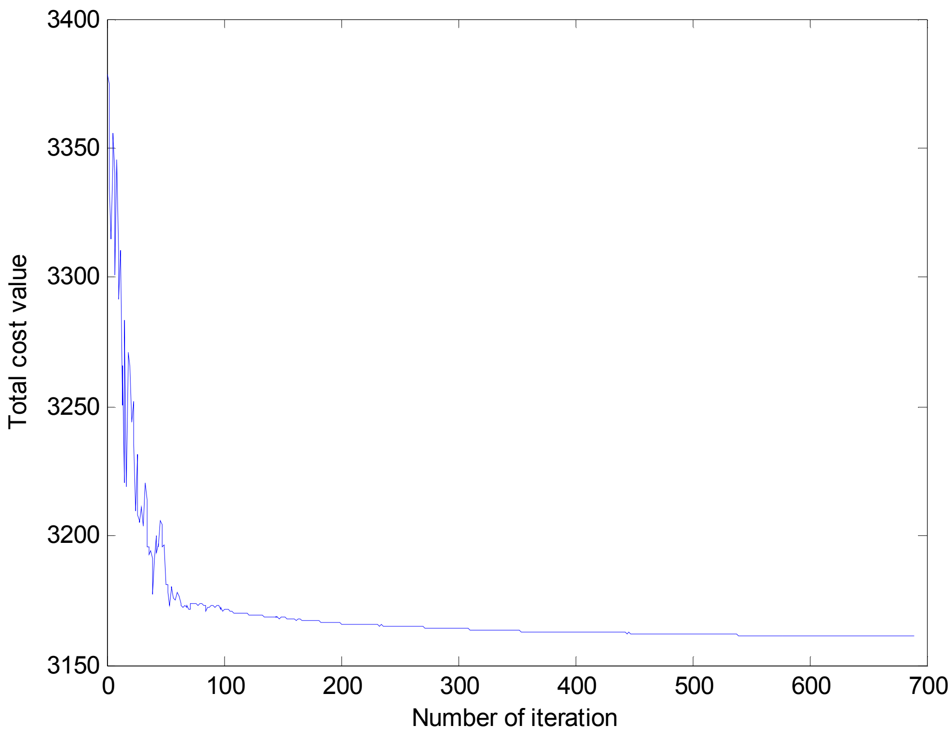

Figure 18 : Variation of total cost value with iterations at genetic algorithm

4.3.12 Comparison of results of proposed algorithm and mixed integer linear programming with branch and bound method

In the previous section, performance of the developed algorithm is compared with a unit commitment problem solver based on genetic algorithm. Now it is going to be compared with another solver which can find the global optimum. This new method uses the mixed integer programming approach.

For solving general MIP problems, two major methods are implemented: cutting planes method and branch and bound method. The cutting plane method handles the linear programming problem with its feasible region including all feasible solutions of the objective functions and constraints. The LP problem is generally called LP relaxation and it has the same objective with the initial MIP problem. If the optimal solution of LP relaxation satisfies all the constraints of MIP problem, it becomes the result of MIP problem. If not, a cutting plane, meaning a linear inequality constraint, is created to cuts of the fractional solution of current relaxed LP problem from the feasible region [29]. Only one inequality is considered at each exclusion. Now the new LP problem is solved using dual simplex method. To find an optimal or near-optimal solution, above procedure is repeated finite times. Efficiency of this algorithm depends on the cutting plane. There are several schemes to apply cutting plane. If it is good and deep enough, better results are obtained.

The branch and bound method is based on a different concept. If the binary variables of a MIP problem are determined, problem becomes an LP problem that is easy to solve. But when considering the binary variables, exhaustive enumeration is generally impossible because of huge number of possibilities. The key is organizing the LP problems as a tree and setting a lower bound for branches of this tree. If lower bound of a branch is worse than the best solution obtained so far in the tree, that branch is eliminated. With this way, small amount of LP problem is solved and global optimal solution is obtained.

Cutting plane method terminates very fast but it may not reach to global optimum solution. On the other hand, branch and bound method converge to the most optimal schedules but the computational time increase exponentially with increasing number of units. Integrating these two methods result with branch-and-cut algorithm which is successfully implemented in literature. The CPLEX mixed integer problem solver uses the branch-and-cut algorithm explained above. A software combination of MATLAB and CPLEX is used to show the optimality of the developed algorithm. MATLAB part takes the inputs and create the necessity '.lp' file to feed CPLEX. Then CPLEX read this file and solve mixed integer programming optimization problem. After that, MATLAB takes the output of the CPLEX and display results. When the inputs of case 5 are given to this combined algorithm (CA), obtained results together with proposed algorithm (PA) are shown in Table 34.

Table 34: Scheduling results of case 5 when solved by combined software

	Generation levels of units (MW)									
Hours	Unit 1		Unit 2		Unit 3		Unit 4		Cost of hour($)	
	CA	PA	CA	PA	CA	PA	CA	PA	CA	PA
1	5.5	5.5	0	0	3.5	3.5	0	0	125	125
2	4.5	4.5	4	4	3.5	3.5	0	0	343	343
3	3.5	3.5	0	0	3.5	3.5	10	10	756	756
4	4.5	4.5	0	0	3.5	3.5	12	12	1049	1049
5	6	6	0	0	3.5	3.5	15	15	1417	1417
6	5.6	5.6	0	0	3.5	3.5	14.5	14.5	1746	1746
7	6	6	0	0	3.5	3.5	17.5	17.5	2119	2119
8	6	6	0	0	3.5	3.5	15.5	15.5	2464	2464
9	6	6	0	0	3.5	3.5	12.5	12.5	2772	2772
10	6	6	0	0	3.5	3.5	11	11	3062	3062
11	6	6	0	0	3.5	3.5	10.1	10.1	3341	3341
12	6	6	0	0	0	0	11	11	3588	3588

As it is seen from the table, output of the combined software is exactly same with the one obtained from the developed algorithm. Therefore it can be concluded that the output of the developed algorithm which uses the Lagrange multipliers and dynamic programming approaches is comparable with the output of the MIP branch-and-cut algorithm which finds the global optimum. It does not mean that the developed algorithm in this thesis will always converges to most optimal solution, but results of cases 5 show us that it finds solutions which are close to or same with the most optimum one. This means that the developed algorithm finds rational results.

As another example, inputs of case 8 is also run with combined software in order to see the most optimal solution and compare it with the one obtained from the developed algorithm. Results are given in Table 35.

Table 35: Scheduling results of case 8 when solved by combined software

	Generation levels of units (MW)									
Hours	Unit 1		Unit 2		Unit 3		Unit 4		Cost of hour($)	
	CA	PA	CA	PA	CA	PA	CA	PA	CA	PA
1	5	5	4	4	0	0	0	0	125	125
2	0	0	2	2	0	0	10	10	335	335
3	0	0	4	4	0	0	13	13	538	538
4	0	0	4	4	0	0	16	16	814	814
5	6	6	4	4	0	0	14.5	14.5	1163	1163
6	6	6	4	4	0	0	13.6	13.6	1443	1443
7	6	6	4	4	0	0	17	17	1805	1805
8	6	6	4	4	0	0	15	15	2123	2123
9	6	6	0	0	0	0	16	16	2387	2387
10	6	6	0	0	0	0	14.5	14.5	2638	2638
11	6	6	0	0	0	0	13.6	13.6	2880	2880
12	0	0	0	0	0	0	17	17	3084	3084

As it is seen from table above, results are again same with the outputs of developed algorithm.

CHAPTER 5

CONCLUSION

In global world, there is no place for monopolistic and regulated market mechanisms for any kind of commodity. To increase the efficiency and to provide consumers with high quality and cheap products, all market structures should be deregulated in a constructive manner.

Electricity is a market that had been managed by authorized governmental entities till 2000's in Turkey. With the Electricity Market Law issued in 2001, four different entities were in charge having different responsibilities of generation, transmission, distribution and trading. Beside these, a regulation agency was also established to oversee the market participants. These steps were requisite but not enough to have a fully deregulated market structure. Therefore, to keep up with the liberalized world, electricity market is opened to individual investors by time. Making long bilateral agreements under the supervision of the system operator became possible. Bilateral agreements were an effective method to create a comparative market structure and to decrease the electricity prices. However, an additional balancing market mechanism called day ahead market was necessary because of the forecast error that participants could possible make. Beside the forecast error, suppliers called GENCOs find a second chance to utilize their portfolios in day ahead markets.

Day ahead market is a market mechanism that energy trading is completed one day ahead of the actual transfer day. Price for the electrical energy could be different at each hour of the day because participants submit hourly bids to make agreements. Buyers make their price forecasts and submit bids to meet their scarcity of energy. On the other side of the market, a GENCO has to submit efficient bids to make agreements and to make more profit by utilizing its portfolio remained from bilateral agreements more efficiently.

At this point, optimal generation scheduling emerges as a very important problem that is needed to be solved by the GENCOs. This thesis provides an algorithm for GENCOs to schedule their generations by handling the system and unit constraints. Optimal schedule which yields most economical way of generating required quantity of energy is tried to be achieved in the developed algorithm. GENCOs decrease their production cost with the help of this tool and get a chance to make more profit.

Scheduling the units to produce required amount of energy in an hour-based planning horizon is kind of an optimization problem involving unit commitment. In chapter 3, commonly used optimization techniques like priority list method, stochastic programming, exhaustive enumeration, sequential method, genetic algorithm, mixed integer programming, branch and bound, tabu search, artificial neural networks, Lagrange relaxation and dynamic programming are explained in detail. Last two of these techniques are employed in the developed algorithm, Lagrange relaxation and dynamic programming. Advantage of Lagrange relaxation is that it divides the problem into sub-problems and it relaxes the system constraint which couples all units to each other. Then, dynamic programming tries to reach the final hour by saving only the most economic sub paths. In another saying, dynamic programming makes commitment decisions by handling the transitions costs whereas the Lagrange relaxation finds the dispatches.

Developed algorithm is a MATLAB based program. It mainly consists of seven steps. The first step takes the inputs like generator parameters and constraints, and then creates necessary matrices to be used in rest of the implementation. Secondly possible combinations of committed units are found including ramp intervals. In the third step, Lagrange relaxation method is employed in order to find the most economical dispatch for each unit commitment combinations at every hour. Then production costs of each commitment combination and possible transition costs between successive hours are calculated in fourth part. Dynamic programming process is performed in the fifth step to find the most economical way of reaching last hour. A generation schedule is obtained at the end of this step. But, obtained schedule is not checked in terms of ramp and minimum ON/OFF constraints yet. In the sixth step, transitions which violating the minimum ON/OFF durations are eliminated from search space of the dynamic program. If all transitions provide enough time to unit for ON/OFF durations, ramp limitations are checked in the last step and the transitions violating ramp limits are eliminated in the next iteration of the dynamic programming process. The first schedule which can pass from both minimum ON/OFF duration and ramp limits checking mechanism is the output of the whole algorithm. Beside the schedule, cost of each hour, total production cost, timers of units are also among the outputs of the algorithm.

Effects of constrains on the schedule is explained with different case applications in chapter 4 by changing one of the constraint while keeping others constant. To show these effects, a simple case involving two generators and six hours is handled. Performance of the algorithm is also observed with different cases involving 4 generators and 12 hours to be scheduled. At cases 9 and 10, sample problems are solved using the genetic algorithm and mixed integer programming branch-and-cut algorithm respectively. Results show that the developed algorithm converges with a more optimal solution than the genetic algorithm which searches the solution in a sample space generated based on random variables. Beside, outputs of the developed algorithm for two sample cases are exactly same with the outputs of the branch-and-cut algorithm which generates the global optimum. Even though it does not mean that developed algorithm will always find the global optimum, it is proved that outputs of it are reasonably optimal.

In the developed algorithm, cost models of the generating units are taken as second order quadratic equations. In fact, cost models of units might vary according to the type of the generator. It is quite simple to adopt the developed algorithm to any type of cost model by making small changes in coding. Therefore any GENCO could modify the algorithm up to its type of generators as the main idea which is dynamic programming and constraint checker mechanisms remains same in all applications.

A GENCO could use the algorithm before submitting bids to day ahead market in order to calculate its possible production cost and makes an efficient bid. Beside this, any entity might utilize algorithm to decrease its production costs after it won the auction and made an agreement with the system operator.

As a future work, the algorithm can be developed by integrating more constraints like source managing. Current algorithm regards that there are enough amount of source for all types of generators. In real life, some type of units may have limited sources. For instance water reservoir of a hydro unit could be limited amount. Or forecasted wind may limit the output of a wind generator. In such a case, whole period might needed to be re-scheduled because it would be convenient to commit such limited units at peak hours even if they have lower cost curve than the other units in the portfolio of the GENCO.

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