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Dynamic Analysis of Capacity Payment Mechanism for Investment Planning in Iranian Electricity Market

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Thanks to my parents for their endless love and encouragement.

Abstract

In the last decade, many countries have experienced restructuring in their electric utilities. This restructuring has presented the power industries with new challenges, the most important of which is long-term investment planning under uncertain conditions. Rising feed-in from renewable energy sources decreases margins, load factors, and thereby profitability of conventional generation in several electricity markets around the world, while, conventional generation is still needed to ensure security of electricity supply. The Iran's restructured electricity market, conjugated with rapidly growing demand and RES penetration in generation mix, concern firms considering investments in generation capacity and make regulatory authorities interested in assuring the long-term supply adequacy and the stability of power markets.

Since it is aimed that the incurred capital and operating costs of generation technologies be recovered in Iranian electricity pool, the regulator of Iranian power system has introduced a noncompetitive capacity payment mechanism in order to encourage new investments in electric power generation. In the current mechanism, the capacity payments are designated to the generating units in the whole country electricity market. There is an annual base value of capacity payment which is based on recovering the capital cost of a benchmark generation technology and the regulator alters this value according to the operational reserve in the day-ahead electricity market.

In this research, after an extensive discussion about the rationale and functionality of Capacity Remuneration Mechanisms (CRM), it was shown that a technology neutral capacity payment which is equal to the amount of the missing money (incurred by the price cap), will correct the investment incentives. Furthermore, this thesis develops a system dynamics model to analyze the impacts of different decisions regarding the capacity payment as investment incentive mechanisms in Iranian electricity market. Indeed, this supporting policy is simulated and analyzed in the proposed dynamic framework in order to track the trend of new investments in the Iranian electricity market.

The simulations suggest that there might be serious problems to adjust early enough the generation capacity necessary to maintain stable reserve margins. An alternative design option, based on various base value for capacity payment according to generation technology, is introduced to guarantee at least a minimum capacity reserve margin. Moreover, aiming at improving the security of supply of the system and maintaining a healthy margin of generation over demand, the major drawbacks of the existing Iranian CRM are addressed by tendering a new regulatory scheme. Such a decision model enables both the generation companies and the regulators gaining perfect insights into the possible consequences of different decisions they make under different policies and market conditions.

Keywords: System Dynamics, Investment Incentives, Capacity Payment

Sommario

Nell’ultimo decennio, il settore elettrico ha subito importanti cambiamenti in molti paesi. Questi cambiamenti hanno introdotto nuove sfide per le compagnie che si occupano di generazione elettrica, tra le quali la più importante consiste nel programmare investimenti a lungo termine sottostando a condizioni al contorno variabili. Inoltre, l'aumento del contributo delle fonti energetiche rinnovabili alla produzione riduce i margini di profitto, diminuisce i fattori di carico, e quindi la redditività della generazione convenzionale in molti mercati elettrici nel mondo, mentre gli stessi impianti convenzionali sono ancora necessari per garantire la sicurezza dell'approvvigionamento elettrico.
La riforma del mercato elettrico Iraniano, insieme con la rapida crescita della domanda e della penetrazione delle RES nel mix di generazione, preoccupa le compagnie che pianificano investimenti in nuova capacità e veicola l’attenzione delle autorità di regolazione verso misure volte a garantire l'adeguatezza dell'offerta a lungo termine e la stabilità dei mercati elettrici.

Per permettere il recupero dei costi di capitale sostenuti e le spese operative degli impianti di generazione all’interno del mercato elettrico iraniano stesso, il regolatore ha introdotto un meccanismo di pagamento della capacità non competitivo al fine di incoraggiare nuovi investimenti in impianti di generazione di energia elettrica. Nell'attuale meccanismo, i pagamenti di capacità sono assegnati alle unità di generazione del mercato elettrico in tutto il paese; un valore base annuo di pagamento della capacità, che si basa sul recupero del costo di capitale riferito ad un benchmark, viene proposto e modificato in base alla riserva operativa nel mercato del giorno prima.

In questa tesi, dopo un'ampia discussione riguardo la logica ed il funzionamento dei meccanismi di remunerazione delle capacità (MRC), viene dimostrato che un pagamento della capacità technology-neutral pari ai flussi monetari mancanti (derivanti da un price cap), può correggere gli incentivi agli investimenti. Inoltre, la tesi sviluppa un modello dinamico per analizzare l’impatto di diverse politiche regolatorie relativamente al pagamento della capacità in quanto meccanismo di incentivazione degli investimenti nel mercato elettrico Iraniano. Infatti, tale sistema di incentivazione è simulato e analizzato all’interno del modello dinamico proposto al fine di studiare l'andamento dei nuovi investimenti nel mercato elettrico iraniano.

Le simulazioni suggeriscono che ci potrebbero essere seri problemi nell’adeguare in tempo utile la capacità di generazione necessaria per mantenere margini di riserva stabili. Viene introdotta un'opzione alternativa basata su un valore base per il pagamento della capacità diverso per ogni tecnologia di generazione, finalizzato a garantire almeno un margine di riserva minimo. Inoltre, nell’ottica di migliorare la sicurezza dell'approvvigionamento del sistema e mantenere un buon margine di generazione rispetto alla domanda, i principali inconvenienti dell'attuale CRM iraniano sono affrontati mediante la formulazione di un nuovo regime normativo. Tale modello decisionale consente, sia alle compagnie di generazione che alle autorità di regolazione, di comprendere perfettamente le possibili conseguenze delle diverse decisioni adottate nel contesto di diverse condizioni regolatorie e di mercato.

Parole chiave: Dinamiche del sistema, incentivi agli investimenti, pagamento della capacità

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Introduction

Before the liberalization of the electricity industry, investments in power plants were the result of an optimized capacity expansion planning at national or regional level. The aim of this planning was to determine the right level of generating capacity, the optimal mix of generating technologies and the timing of investments and retirements of capacity to ensure that future demand in a certain region would be served at minimum cost with an adequate level of reliability. In order to decide when and which power plants should be constructed, the minimization of the discounted, cumulated operating and investment cost over the considered planning horizon was the classical approach. In the centrally planned power industry, generation expansion planning was conducted with vast quantities of reliable data. Consequently, uncertainties were narrowly limited to a few variables. In fact, the future demand and the future fuel prices were the only significant source of uncertainty in the decision-making process. The expected profits were not generally subjected to uncertainty, since utilities were allowed to charge customers in order to recover the total costs and gain a fair rate of return on the incurred investments.

After the liberalization of the electricity generation sector, investments and decommissioning of generation capacity are a consequence of decentralized, commercial decisions made by multiple self-oriented firms and no longer the result of a centrally optimized expansion planning. The process of restructuring in Iran happened in 2003 in order to introduce commercial incentives in the expansion of electric power supply chain including generation, transmission, and distribution. At the same time, unbundling of generation, transmission, and distribution has been decided in addition to deregulation and privatization of power systems. The main objectives of these reforms are to increase the competition and thereby, the economic efficiency in the electric power system operation and planning. The strategies of utilities are also shifted from cost minimization to profit maximization since the decentralized decisions have been made for both the power system operation and the capacity investment. Besides, the energy and environmental policies have added complexity to this framework.

In this new environment, the decision of investing in new power plants faces new uncertainties. Unlike the regulated environment, decision-making of market participants is now guided by price signal feedbacks and by an imperfect foresight of the future market conditions. Future revenue streams are no longer guarantee through regulated tariffs since generators are rewarded an uncertain price for the energy sold. Furthermore, the ability of generators to sell energy depends now upon their cost competitiveness relative to their competitors. In this situation, financial uncertainties, beside the technical ones, play more prominent roles in investment decisions in contrast to the regulated systems where they have lower effects on the regulated tariffs. Some electricity markets running under competitive rules have experienced periods of excess of investments, and therefore over-capacity, such is the case of UK with a large entry of private investors relying on gas-fired power plants. Others have already experienced long periods without new capacity additions that have ultimately led the market to under-capacity conditions. Such was the case of California during the electricity crisis in the summers 2000 and 2001[1].

[1] Olsina, F., Garces, F., Haubrich, H.J., 2006. Modeling long-term dynamics of electricity markets. Energy Policy 34 (12), 1411–1433.

This has raised concerns about security of supply and has re-ignited interest in capacity remuneration mechanisms (CRMs) across the European Union (EU) and beyond. CRMs come in many different forms, and are generally designed to offer payments to electricity market operators for their capacity to produce electricity or to reduce or shift electricity demand. By providing a stable stream of revenue, independently of actual electricity produced and sold, capacity remuneration mechanisms aim to prevent the shutdown of existing generation capacity or to incentivize investment in new resources, with the primary objective of ensuring security of electricity supply.

Real economic systems, and particularly the power generation industry, do not meet the requirements to assume that the system remains on the long-run optimal trajectory at every time. As in other capital-intensive industries, power markets cannot immediately adjust the production capacity after perturbations, such as a rapid increase in the demand growth rate. The reasons that prevent immediate response are that expectations need time to be updated to the new market conditions, investments are delayed under uncertainty, and power plants need usually a long time to be constructed and to be brought online. Under these conditions, it is to be expected that power markets experience business cycles (boom-and-bust cycles), i.e. periods of high investment rates followed by other periods with no investment activity. This might result in severe fluctuations of the reserve margin, and therefore of power prices. Classical industry models based on long-run equilibrium assumptions fail to explain these cycles since they are not capable of capturing the dynamic nature of the problem. Indeed, characteristics of power markets not considered in these models, such as delays in adjusting timely the production capacity and the fact that aggregated long-term forecasts often behave like simple extrapolation of recent past trends, cause to alternatively over- and undershoot the long-run market equilibrium[2].

In this work, a long-term system dynamics model with the appropriate mathematical framework is proposed to illustrate the dynamics of different capacity mechanisms. The regulatory policies and the market player behaviors in accordance with the Iranian electricity market framework have been included in the presented model. First the present state of Iran electricity market is modeled, then two scenarios concerning the possible regulatory changes are examined in order to analyze the market performance related to the capacity investment and also to provide insights into the possible consequences of different decisions made either by the market players or by the regulatory commission. The first alternative is to simulate the energy-only market, the second is to introduce an improved capacity payment mechanism. Despite the RES support policies of Iranian Authorities, the penetration factor of renewable energies in Iranian electricity market is not high yet and the related effects may be trivial. Nonetheless, in order to keep the generality of the model in considering the parameters affecting the electricity market price, the renewable energy was included in the proposed model of Iranian electricity market. The structure of the thesis is as follows. In chapter 1, a description of Iranian electric power system and electricity market is presented. Chapter 2 covers the conceptual framework of the work and carries an extensive description of the generation mix. The drawbacks of the existing CRM in Iran have been identified and addressed by some regulatory measures. The mathematical formulation of the model is elaborated in chapter 3. In chapter 4, a simulation of Iranian electricity market with different regulating scenarios using the proposed model will be carried out and the results is analyzed. The conclusions are outlined in this chapter.

[2] Sterman, J., 2000. Business Dynamics: System Thinking and Modeling for a Complex World. McGraw-Hill/Irwin, Boston.

1. IRANIAN ELECTRICITY MARKET AND POWER SYSTEM

Overview

The Islamic Republic of Iran with an area of 1,648,196 sq. km is located in South-West Asia. With an estimated Gross Domestic Product (GDP) of US$406.3 billion, Iran is the second largest economy in the Middle East and North Africa (MENA) region after Saudi Arabia. The country, which is the second populous country in the region after Egypt, had an estimated population of 78.5 million in 2014 and is characterized by its high youth population with about 60% of people estimated to be under the age of 30 [1].

Iran's economy is characterized by its large hydrocarbon sector, Medium scale agriculture and service sector, as well as a noticeable state presence in manufacturing and financial services. The country ranks second in the world in natural gas reserves and fourth in proven crude oil reserves. Additionally, Iran has the world's largest zinc and the second-largest copper reserves, with also important reserves of iron. Despite this, economic activities and government revenues still depend to a large extent on oil revenues [1].

After two years of recession, the economy expanded by 3% in 2014. The GDP growth in 2016 and 2017 was rate 5.8% and 6.7%, respectively, as oil production reaches 3.6 and 4.2 million barrels per day [2].

The state continues playing a key role in the economy with public banks controlling the financial sector and large public and parastatal enterprises dominating the manufacturing and commercial sector (e.g. 60% of the manufacturing sector belongs to the government). [1]

The country faces a fast growing demand for electricity and the average rate of electricity generation growth was 5% per year in the last 10 years. The country should add 5 GW of generation capacity each year to supply the demand for the coming years. Since the beginning of the subsidy reform, the prices of electricity and water were increased and they will continue to rise gradually only to cover full cost price. The reform was a major change and opened a new era for both energy conservation and the use of renewable energy technologies to generate electricity in Iran, which has a long history of heavily subsidizing its energy. [3]

Although Iran has great potential for solar power generation, there has been a little development in the solar field so far. The main reason is the plentiful oil and gas reserves in the country which led to the low price of fossil fuel for electricity generation. In order to stimulate private sectors, some new incentives have been determined to make solar energy a competitive energy resource for nonrenewable power plants. Nevertheless, the government needs to develop reforms to promote competition, rationalize licensing and authorization requirements, reduce the imprint of Military-Owned Enterprises in the economy, and improve the financial and banking sector.

1.1. Electricity Industry Profile in Iran

1.1.1 Decentralization and Power System Restructuring

It was in 1992 that the first activities were observed in Iran toward the decentralization of electricity industry. In this regard, independent generation management companies were established. New generation facilities were going to develop based on two major contract types "Building, Operation and Ownership" and "Building, Operation and Transfer" the BOO and BOT respectively. In BOO contract as its name says, the building, operation and ownership of generation facilities belongs to a certain party from beginning to the end. Conversely in BOT, the building and operation of the generation facilities were done by a party and finally the ownership was transferred to the governments. Distribution companies were also separated in 1994 and began their official activities. Similar to other countries convinced to proceed the power system restructuring revolution, there were several motivations for the power system restructuring in Iran. They are as follows (Fig. 1.1)

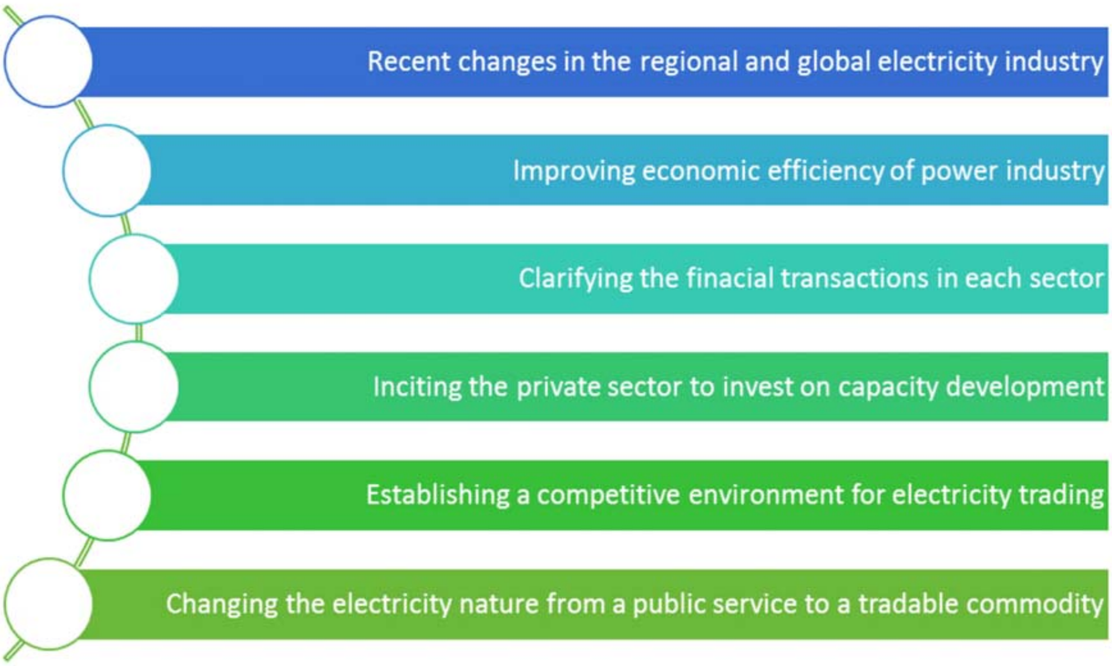

Fig. 1.1. Motivations of power system restructuring in Iran

It was in late 2001 that Iran Electricity Regulatory Board (IERB) was established. The main activities of this committee were to study the existing electricity markets of the other countries. The goal of those studies was to exploit the past experiences in the world. After all, the model of (Iran Electricity Market) IEM was proposed and based on this model, the "buying and selling electricity regulations" was legislated by the council of ministers in September 2003. Finally, it was in 23th November 2003 that the IEM officially begins to work, the market providing a competitive environment for selling trading electric power. Following to this newly born electricity market, Iran Grid Management Company (IGMC) was established in fall 2004. In fact, this is the turning point of power system restructuring in Iran. This company functions as the power system operator and the market operator. Fig. 1.2. illustrates what has been reported so far.

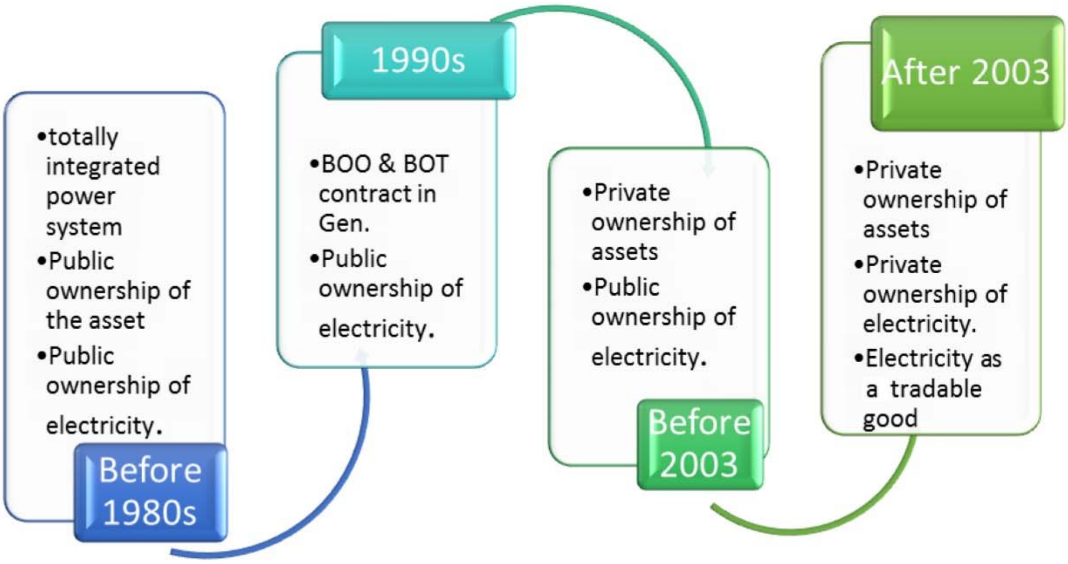

Fig. 1.2. Process of power system restructuring in Iran

1.1.2. Primitive Organizational Principle of Iran Electricity Industry

Generation and Transmission Company of Iran "TAVANIR" was established in 1970. The main activity of this company was to implement the major transmission and generation plants, operate generation facilities, substations and high voltage (230 and 400 kV) transmission network efficiently and technically. Major planning and coordination of all energy related activities were assigned to the ministry of "Water and Electricity". It was in late 1975 that the name of "Ministry of Water and Electricity" was modified to "Ministry of Energy". After this modification, the statute of TAVANIR was revised and finally in 1976 "Iran Generation and Transmission Management of Electric Power Company" was born. It is remarkable that it was called with the same old name, the "TAVANIR". Apparently, TAVANIR handled the electricity related issues as a part of ministry of energy.

As is seen, at the beginning, the electric industry that was completely nongovernmental becomes a thoroughly governmental industry and the electric power was considered as a public service. By advancing the power system restructuring and electricity markets, there are obviously some motivations to perform this revolution in Iran.

Currently the company is responsible for the management of 16 Regional Electric Companies, 28 Generation Management Companies, 39 Distribution Companies, Iran Power Development Co. (IPDC), Renewable Energy Organization of Iran (SUNA), Iran Energy Efficiency Organization (SABA), Iran Power Plant Project Management (MAPNA) and Iran Power Plant Repairs Co54. Based on this arrangement all shares of aforesaid companies have been transferred to TAVANIR. The General Assembly of TAVANIR is composed of: The Minister of Energy (Chairman the Assembly), The Minister of Assets and Economy, The Head of Management & Planning Organization of the country, The Minister of Oil and The Minister of Mine and Industries. The organizational chart of TAVANIR is shown in Fig 1.3. The organizations which are involved in the procedure of renewable energy are highlighted in blue.

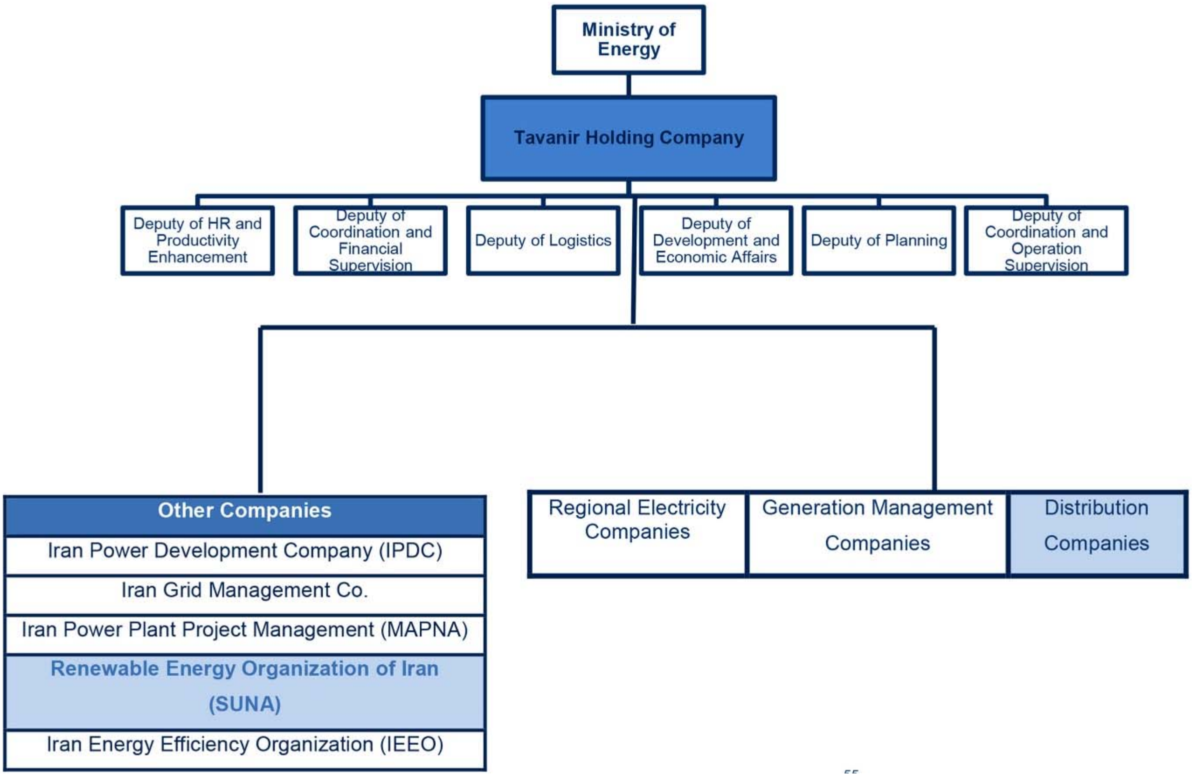

Fig. 1.3. Organizational Chart of the TAVANIR Holding Company [3]

1.1.3. Featured Companies in TAVANIR Holding Co

- **Regional Electricity Companies**

  The regional electricity companies belong to the Holding Company of TAVANIR, which is responsible for the coordination of their affiliated companies of generation, transmission and distribution, as well as for the sell and supply of electricity to all consumers in their region. The total share of all these companies is public and is administrated by TAVANIR. The generation, transmission and distribution facilities in each region are under the ownership of the relevant Regional Electricity Company.

- **Generation Management Companies**

  The Generation Management Companies are non-governmental companies responsible for the operation of the power plants in the related region. Currently each of these companies acts as a contractor for the operation of power plants with the agreement of the corresponding Regional Electric Company. These companies offer their services in the fields of optimization, information systems, operation, and recruitment of staff, as well as commissioning and operation of new power plants. For the implementation of policies related to the privatization of electrical engineering capabilities in the country, the TAVANIR Expert Holding Company has established several companies within the managerial territory of regional electric company as non-governmental or private companies. Since 2012, a few generation companies have been released to the private sector. Today, 28 Generation companies are still the subsidiary of TAVANIR.

➢ **Distribution Companies**

Currently 39 Distribution Companies (DSOs) are working in the country. These companies could be in charge of a province, a city, and in some cases several companies could be responsible for the distribution of electricity in one province. For example, there are two distribution companies in Mazandaran province. In Figure 1.3, the departments colored in blue emphasize their role in the permission procedure of renewable power plants in Iran. The distribution companies belong to TAVANIR and are under supervision of regional electricity companies. Some activities of the distribution companies such as upgrading and renovation services of the distribution network, development of rural electrification of agricultural irrigation systems, sales, meter recording, administration and transportation services have been released to the private sector.

1.2. Electricity Mix and Share of Renewable Energy

Iran holds the fourth-largest oil reserves in the world and the second-largest gas reserves. The abundant oil and natural gas caused renewable energies (except hydro power plants) to not have a significant role in Iran's electricity generation. The capacity of installed conventional power plants increased about 70% from 2005 to 2013[3], reaching 70 GW in the last year (see Table 1.1.). In 2013, the gas turbines constituted 35.2% of the installed capacity and the combined cycle and steam power plants had 25.4% and 22.5% respectively. Conventional hydro power plants operating on the large dams had 14.5% and diesel plants constituted less than 1% of the total capacity of the network in 2013. The 1020 MW nuclear power plant in south of Iran was installed in 2011 which left the remaining share to other renewable technologies to 0.2% in 2013 (Fig. 1.4.).

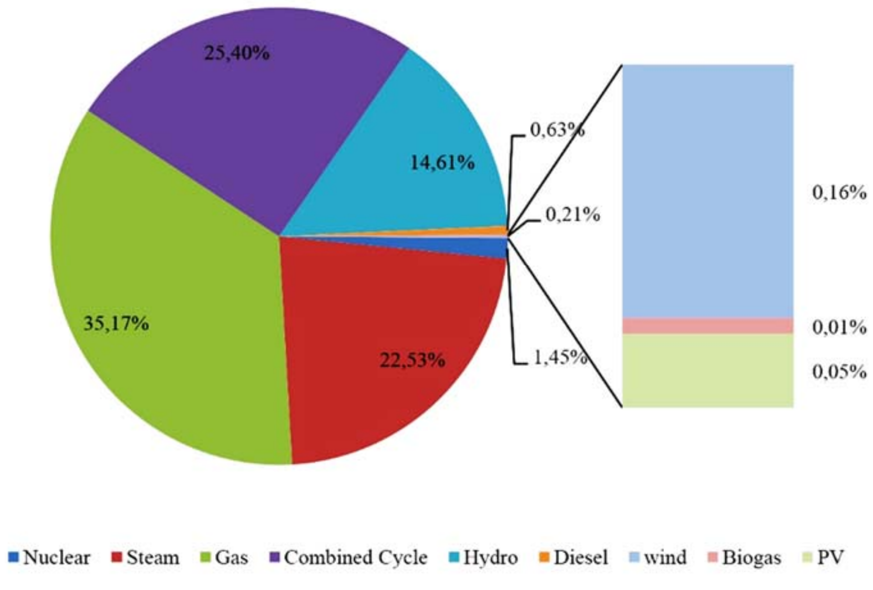

Fig. 1.4. Electricity generation capacity mix [4]

[3] Due to an at least three-year-delay in publication of the Detailed statistics of Iran Electricity Industry and Energy Balance Sheet, all data provided here pertain to the year 2013.

Table 1.1. Iran's installed capacities and annual generation amounts of different generation technologies in 2013 [4]

Generation technologies	Installed capacities		Annual generation	
	MW	(%)	($\times 10^6$) kWh	(%)
Steam Turbine	15,830	22.5	95,771	43.2
Gas Turbine	24,715	35.2	53,846	24.3
Combined Cycle Gas Turbine	17,850	25.4	64,142	29.0
Hydro	10,265	14.6	7207	3.2
Diesel	397	0.5	280	0.2
Nuclear	1020	1.5		
Wind and other RES	250	0.3	72	0.1
Total	70,327	100	221,318	100

Investment planning in nuclear power plants is ultimately complicated in Iran. It took 37 years for Iran to install its first and only nuclear power plant. The Islamic revolution and political crisis hindered the normal construction procedure of this generation unit. Even now, after lifting the nuclear sanctions, the investment planning on nuclear generation technology is vague. Last year, the government announced that it is going to invest more almost 11 billion dollars for the construction of 2 new nuclear power plants, in collaboration with Russians. This announcement raised crucial controversies in Iran. Some believed that this money could be a good supporter for RES instead of nuclear plant that is being mothballed all around the world. Some others criticized the ambiguity in the contracts with Russians and accused them to sell 2nd generation technology to Iran instead of 3rd generation. Due to these conflicts, after 10 months of the expected beginning date of new projects, nothing is clear in this regard. Besides, the nuclear fuel price is indecisive; for example, last year Iran acquired most of the required yellowcake (U_3O_8) by swapping it with part of its heavy water. It was due to a provision in nuclear accord and Iran paid no money for this fuel.

1.3. Iranian Electric Power Grid

Iran has a highly developed integrated power grid, including generating plants, bulk power transmission network with 400 kV and 230 kV transmission lines with the length of more than 18,000 miles and 132 and 63 kV sub-transmission networks. The 400 kV transmission lines in Iranian bulk power transmission network are depicted in Fig. 2.1. As shown in this figure, the electric power system in the whole country is partitioned into five regions. The regional partitioning of Iranian electric power grid is the result of comprehensive studies made by SIEMENS Company (SIEMENS, 2006) in which the whole electric power grid has been divided into five regions with the related tie-lines depicted in Fig. 1.5. The regions were selected based on the dynamic stability analysis in the transmission system of Iran. Important tie-lines of 400 kV are shown in Fig. 1.5.

Three regions in this figure are north region (Region 1 including six electric companies), west region (Region 2 including four electric companies), south-east region (Region 3 including three electric companies), north-east region (Region 4 including one electric company), and south region (Region 5 including two electric companies).

This mass transmission network covers 100% of all urban areas and almost 99% of rural residents. Moreover, several interconnections exist to transit electricity with all neighboring countries including Iraq, Turkey, Armenia, Azerbaijan, Turkmenistan, Afghanistan, and Pakistan. Iran has the largest installed capacity amongst the systems in the Middle East.

1.3.1. Dispatching Order in Iran

- Level 1: National Dispatching (System Control Center - SCC)
  Frequency control is done with regulating the production of large size plants.
- Level 2: Area Operating System – AOC
  By now the transmission system is divided to 6 regions: NEAOC, NWAOC, SEAOC, SWAOC, CENTRAL AND TEHRAN. 3 more regional dispatching center is under construction
- Level 3: Regional Dispatching Center – RDS (upper-distribution dispatching center)
  Control and exploitations of 63 kV and 132 kV grid and 63 kV/20 kV and 132 kV/20 kV posts.
- Level 4: Distribution Control center – DCC
  Control and exploitations of 11 kV, 20 kV and 32 kV grid and 11 kV/4 kV, 20 kV/4kV, 32 kV/4 kV posts (accident centers)
- Level 5: Low Voltage Dispatching
  On 400 kV grid, could be more than 20 in a city.

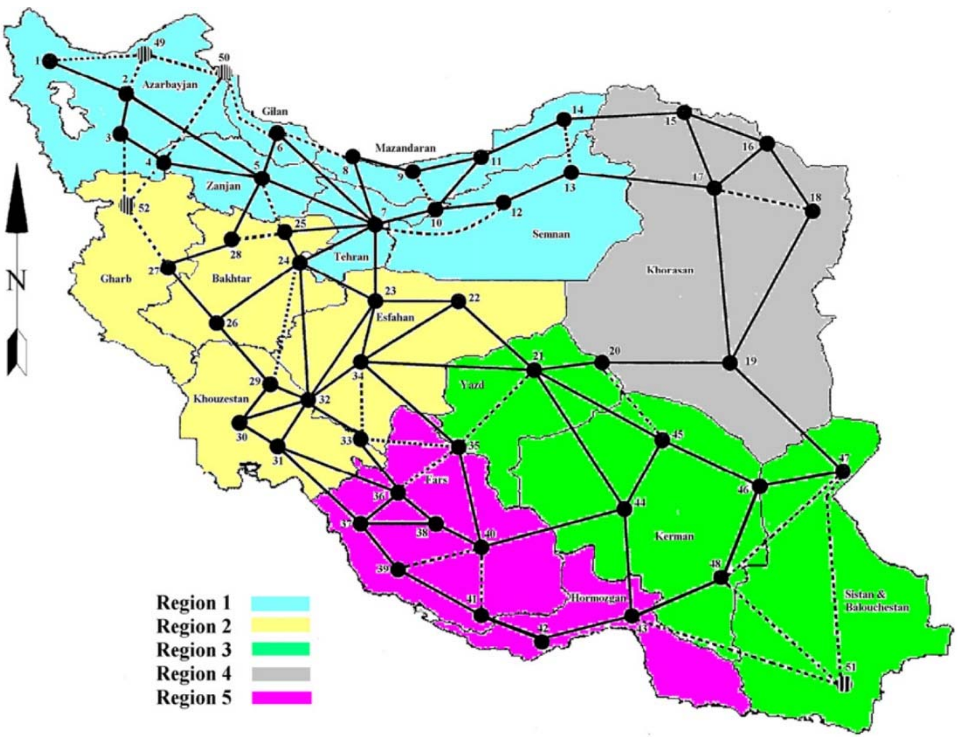

Fig. 1.5. Iran bulk power transmission network with only 400 kV transmission lines [5]

1.4. Load Profile

Prior to introducing the Iran Electricity market, it is necessary to take a look into Iran's peculiar daily demand profile (Fig. 1.6.)

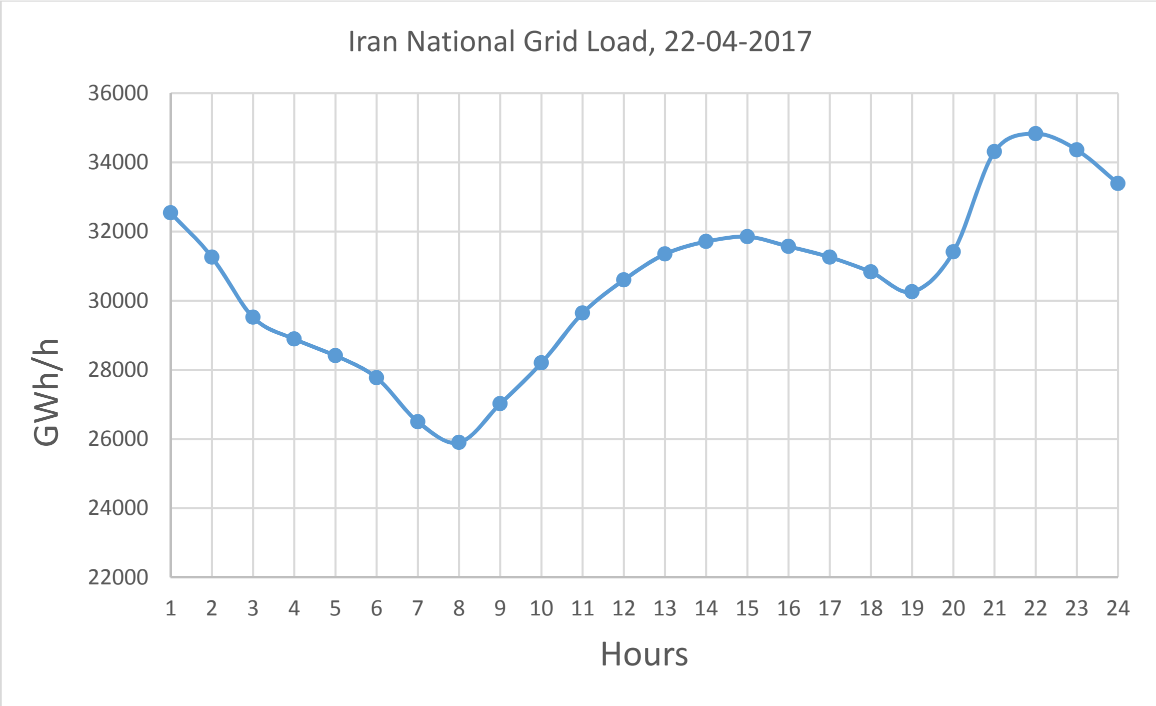

Fig. 1.6. A typical daily load curve of Iran Network

As it is clear in Fig. 1.6. the min load happens at 7:00 while people are neither at home nor at work, but getting to work places or schools. Banks' opening hour is 08:00, while the market and shops start from 10:00. The commuting in the evening back to home is the reason to the second load drop. The electricity consumption in transportation sector is dedicated to subway lines in some Iran's metropolises that couldn't be a parameter to be took into account. The peak load happens at 22:00, when people are at home. Iran is a country of night life and shops are open at least until 22:00 and people don't go to bed until 01:00. That's why we observe a pretty high consumption even in late night.

Moreover, no significant drop could be seen in nights that is risen by following reasons:
1- The ventilation systems are almost always on in Iran. Taking a look to the southern zonal demand gives us a good view. Southern part consumption (mainly regions 5 and 2) comprises of giant petrochemical companies and inhabitants that do not turn off the ventilation for almost 10 months per year to deal with scorching climate. Since none of the aforesaid loads are interrupted during a day, the load is almost the same all day long. This can be seen in Fig. 1.7.

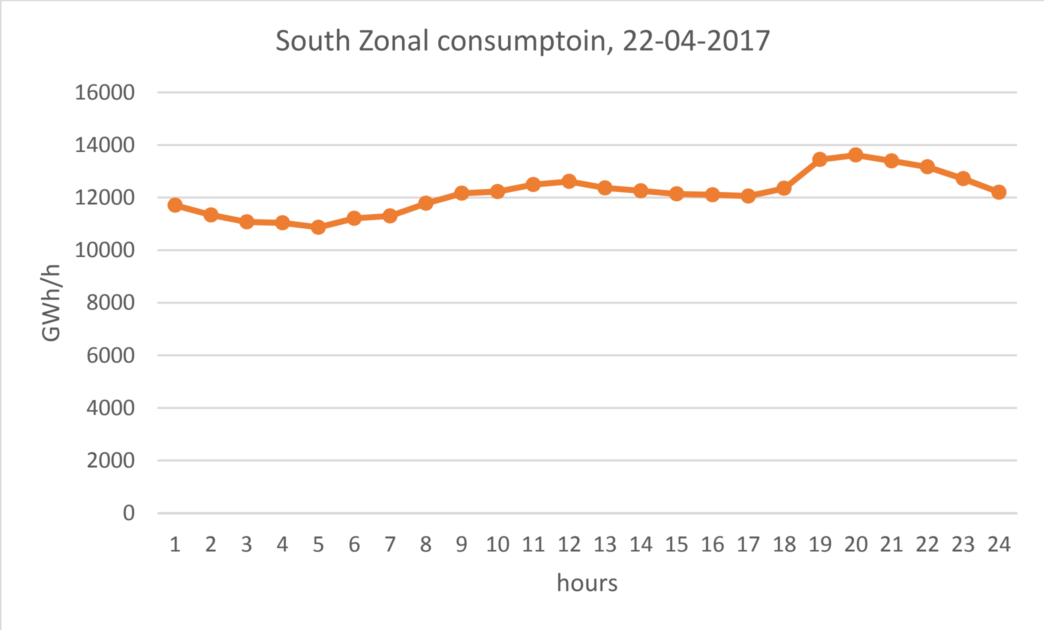

Fig. 1.7. Monotonic load profile of industrial region with warm climate in Iran

2- The major contribution of the industrial, public and lighting consumption (45%), justifies why the load never goes beneath a pretty high minimum. The distribution of consumption in different sectors could be found in the following figure [4].

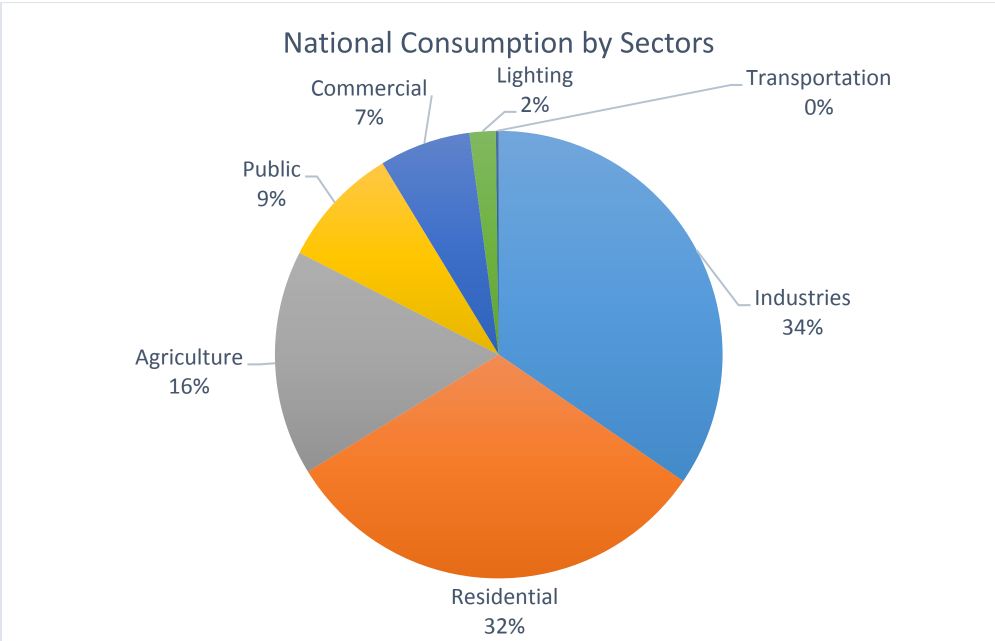

Fig. 1.8. Share of electricity consumption per sector

The Iranian specific life style, conjugated to low electricity price, lead to high national consumption that makes Iran residential consumption 3 times the world average. While per capita residential consumption is 900 kWh/year in world, this number is 2740 kWh/year in Iran [6]. In the part 1.8. we'll talk about Iran Subsidies Reform Act, upon which government are rectifying the energy carrier policies to prevent spoiling the national resources.

1.5. Structure of Electricity Trades

In Iran, the electricity trades are performed in three major environments, the day-ahead market, the power exchange, and bilateral contract. Fig 1.7. illustrates main building blocks of IEM. Regarding the ancillary service, there is no united Ancillary Service Market in Iran; nonetheless, there are two markets operational from Jun 2007: Frequency Control Market and Reactive Power Market. In latter, the capacity of absorbing or injecting reactive power is remunerated by 6% of the equivalent active capacity.

- **Day Ahead Market**

In the day ahead market an auction is established for the generation companies (GENCOs) with pay as bid mechanism. GENCOs submit their bids the day before delivery of power. The sellers' bids consist of the prices and the quantities. The customers only submit their quantity of demand. As a matter of fact, this mechanism is a single sided auction for the sellers. Market operator clears the market based on the submitted bids of GENCOs and buyers' demand. For inciting the players to develop the generation system capacity, the capacity payment mechanism is included to the IEM. These payments are made to the generation units regardless of being a winner in the auction for selling the energy or not. A price cap is also determined by the regulatory committee limiting the sellers' maximum bidding price.

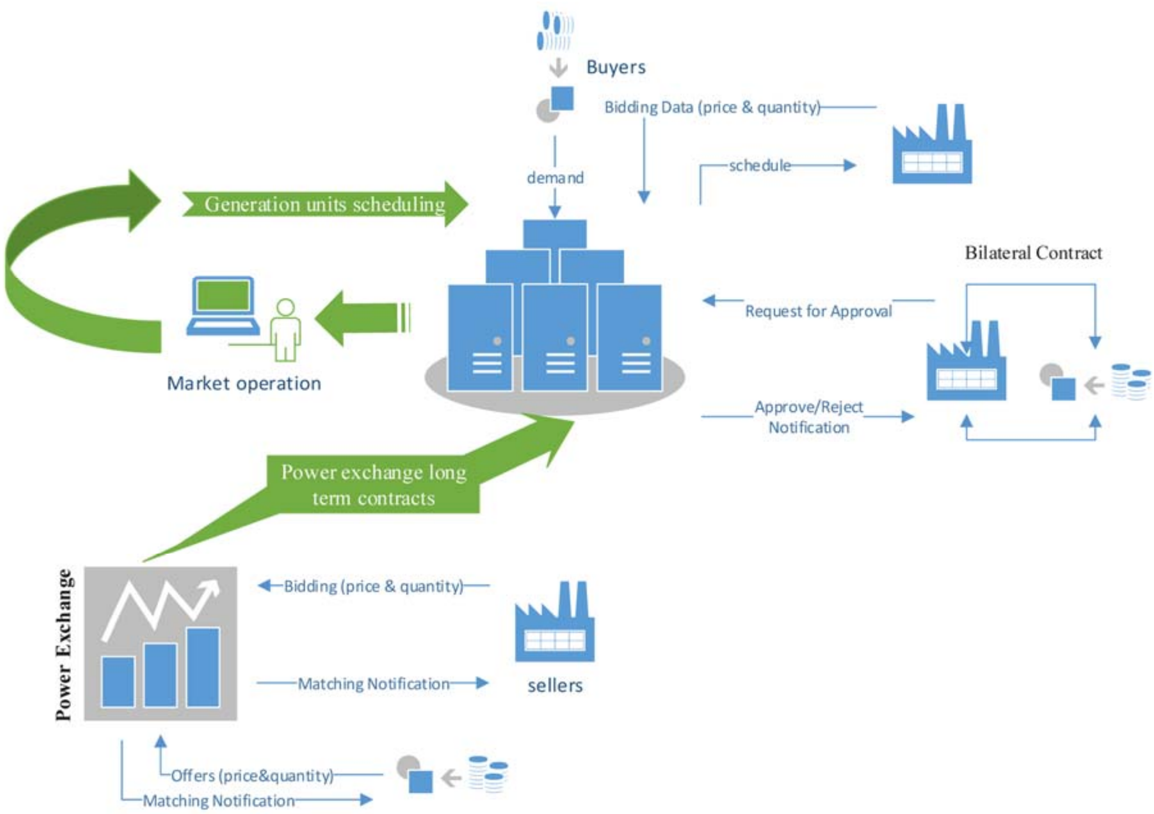

Fig. 1.9. Iran electricity trades overview [7]

- **Power Exchange**

In the Iran Energy Exchange (IRENEX), the trades are categorized as the future contracts leading to power delivery. The buyer and sellers match their bids and offers for a certain quantity of power and the delivery of power will be in the time to come. They are free to make decisions about the prices and there will not be an intervention on their decisions. It should be noted that only the private GENCOs have the authority to participate in the power exchange and sell their power. There is also a limit on the maximum authorized power that could be sold in the power exchange for each generation unit. The quantity of power which is sold in the power exchange will be omitted from the sellers' bidding curves in the day ahead market clearing process. The buyers also will not be imposed to pay any additional cost after the day ahead market settlement, for the power that they purchased in the power exchange itself.

- **Bilateral Contracts**

Another possibility in the power market is that both, the producer and the consumer, negotiate for specific capacity of electricity in a bilateral contract. Therefore, the price is defined during the negotiation without any regulation. However, the transaction has to be approved by the system operator (IGMC). Bilateral contracts are in their infant stages in which subsidized tariff for final consumers give a limited motivation to secure their needs by bilateral negotiation.

1.6. Iran Electricity Market

Despite the various structures of trades, it is assumed that the Iran Electricity Market is the sole medium through which all the energy trades are done. The detailed mathematical model of the market is discussed in chapter 3.

1.6.1. Market operator

The Iran Grid Management Company (IGMC) was funded as a state-owned company to handle the power market and operate the electricity network in 2004. The main objectives and the scope of activities of IGMC are: conducting and monitoring the production and transmission of the national network, developing competitive electricity market in generation and distribution, as well as adopting policy-induced participation of private sector into the market [7]. The market regulation is administrated by the Electricity Market Regulatory Board, which is a group of experts assigned by the Minister of Energy to monitor market performance and to revise the market operation rules and procedures.

Market operation bureau functions in the IGMC as an important part of the market operator. This bureau has two main responsibilities: first, to clear the electricity market; second, to issue the market players' bills.

As the day ahead electricity market requires, power suppliers should submit their bid 10AM in the day prior to delivery. The bids contain both the prices and the quantities. GENCOs submit their bids via Electricity Market Information System (EMIS) which is an online platform. The system operator provides the scheduled outages data until 14:00, this schedule determines the power plants who are not ready to bear the system load. Fuel data is also submitted to the EMIS at this hour. Market operator derives the unit commitment schedule for the system operator based on the auction hold considering the security constrains of the power system. In fact, using the information provided in the EMIS, market operator solves the Security Constrained Unit Commitment (SCUC) to determine the market results. Then, settled market output are uploaded to the EMIS and the market players access to the results based on the predefined authority. The results should be uploaded until 21:00. Figure 1.10. illustrates the time arrangement which is mentioned here.

Issuing the market players' bill is also the responsibility of the bureau of market operation. Based on the power market settlement results and what is physically occurred in the day of power delivery, the market players' bills are issued. Real data of generation and consumption are measured and fed to the electricity market information system via telemetering infrastructures. These data are compared with the market settlement results. Briefly, the revenue of GENCOs depends on their bidding strategy and the ability to follow their schedule which is derived based on the market settlement mechanism. The market players' roll can be seen in Fig 1.11.

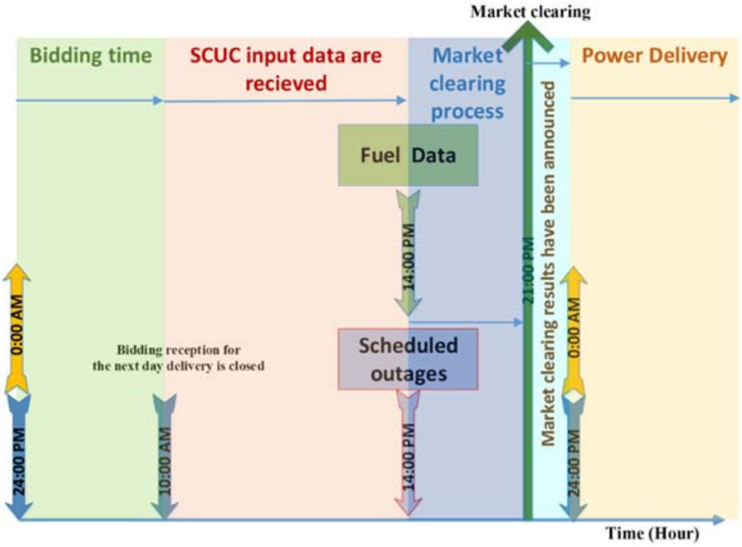

Fig. 1.10. Market operation timing [7]

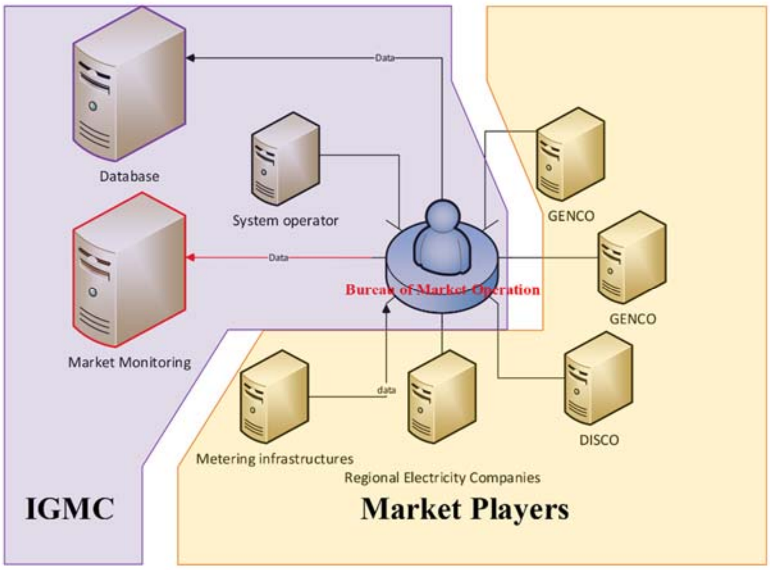

Fig. 1.11. The composition of market players [7]

1.6.2. Market Players

- **Sellers**

In Iran, it is possible for a privately owned power plant to make an energy conversion agreement (ECA) with TAVANIR. TAVANIR buys the output power of this power plant with a predetermined tariff (regulated by the ministry of energy) for a certain period of time (namely five years). TAVANIR is authorized to sell the power of ECA plants in the wholesale electricity market. At the end of the agreement the power plant should participate in the electricity market. Privately owned power plants could also freely participate in the electricity market and sell the energy.

Renewable energy resources such as, incineration plants, wind power plants that are connected to the distribution system, small-scale solar power plants, and biomass plants make agreements with Renewable Energy Organization of Iran (SUNA) and the generated power will be purchased based on the regulated tariffs that is discussed in part 1.9.
Small scale gas turbines (58 power plants with the total capacity of 472 MW) bilaterally sell the energy to the regional electricity companies. As a conclusion, there are 3 types of sellers in IEM that half of the them are state-owned and half of them are private entities [7]:

1. Government owned power plants participate in the wholesale electricity market
2. Privately owned power plants that directly participate in the wholesale electricity market
3. Privately owned power plants that indirectly participate in the wholesale electricity market

- **Buyers**

Iran electricity market (IEM) (wholesale market) is a single sided auction in which Iran Grid Management Company (IGMC) purchases the electricity on behalf of the consumers. Large consumers (distribution companies and regional electricity companies) forecast their demand and inform IGMC. Then the market will be created based on the adjusted load forecast data.

Distribution companies and regional electricity companies constitute the buyers sector in IEM. TAVANIR can also take the role of a consumer purchasing electric power for export. It buys the power and sells it to the foreign parties. In short, we have three types of buyers act in IEM:

1. 39 distribution companies
2. 16 regional electricity companies
3. TAVANIR

1.6.4. Remuneration Mechanisms

The revenue of producers consists of two components: Energy remuneration and capacity payment.

- **Energy Remuneration**

The price cap in IEM is 330 IRR/kWh (1 €cent/kWh). This is less than the energy conversion and the fuel price that the benchmark power plant pays. There is a price cap for the bids in IEM. If there was no price cap and the market was open, some power plants were left out of the market for almost all the year and their generation was necessary just in peak hours, so they had to bid high numbers to compensate their yearly expenses. The purpose of price cap is to prevent such a problem and all power plants are being paid according to their installed capacity.

Price cap optimization is under intense discussion. If the cap is so high, it is in contradiction with the reason of putting a cap in first hand; on the other hand, if it is too low, the competition in electricity market would be meaningless. In addition, some studies show that capacity price and energy price cap are not optimized.

- **Capacity Payment**

Power plants are paid according to their expressed generation capacity, regardless of whether they are admitted to the market or how much of their generation is sold in the market. The capacity payment is to fully remunerate the admitted PPs in IEM, to guarantee the grid reserve, to compensate the personnel cost of the PPs that left out of market (avoid boom & bust) and to reduce the investment risk.

The base rate for capacity payment is announced by IGMC every year, then some correcting coefficients according to daily reserve margin corresponding to available capacity are used. The base rate is 185 IRR/kWh in 2017 that experienced a great jump from 2011 and we assume it in our modeling.

The capacity payment is a challenging topic for the government, because it is paid to some power plant which are not in charge almost all the year. To overcome this problem IGMC decided to stop capacity remuneration to plants that are dispatched less than 300 hours per year, nonetheless still some power plants are being paid that are shabby and low efficient. Figure 1.12 below shows the contribution of energy and capacity payment in the monthly cost of electricity. Please note that in it capacity component also includes ancillary services payments.

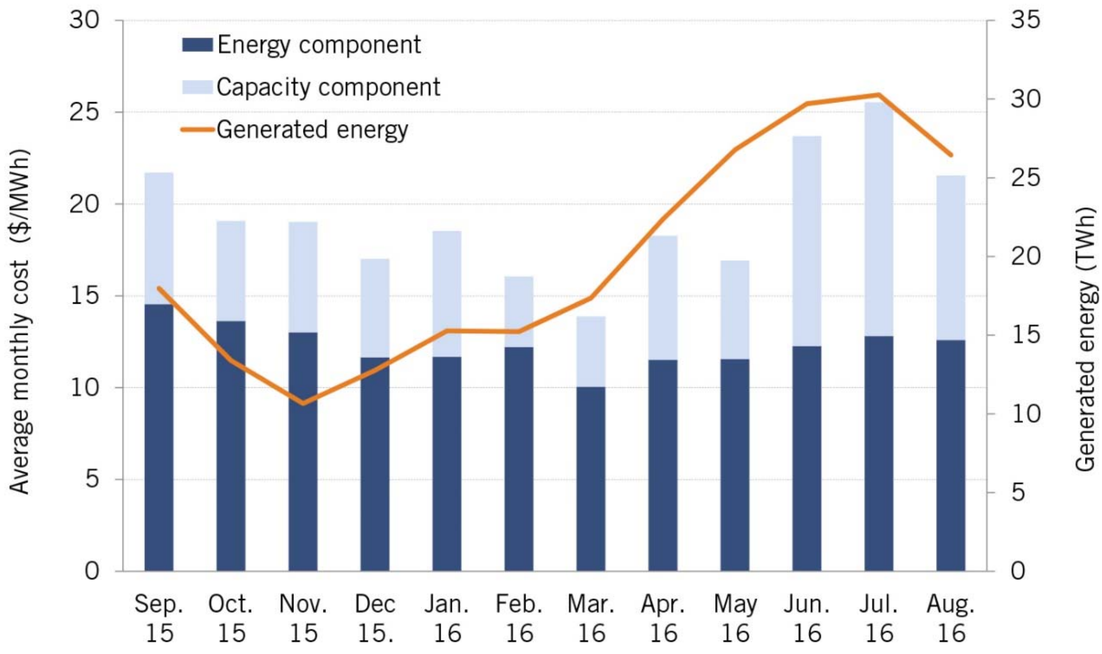

Fig. 1.12. Recent price trend and remuneration mechanism share [8]

1.7. Generation Costs[4] and Subsidies

Generation, transmission and distribution of electricity cost 3000 IRR/kWh (=8.5 €cent/kWh) to reach to the final user [9]. This price consists of following components: [10]
Fuel price: 2000 IRR/kWh (=5.6 €cent/kWh) [5]
Energy conversion in Power Plant: 600 IRR/kWh (=1.7 €cent/kWh)
Transmission cost: 200 IRR/kWh (=0.56 €cent/kWh)
Distribution cost: 200 IRR/kWh (=0.56 €cent/kWh)

The final users pay 600 IRR/kWh in average [9]; it means that government pays almost 2400 IRR of subsidies per kWh. It is a considerable number that shows the potential of RES compared to subsidized fossil fuel burning PPs, and makes it reasonable to redirect the subsides from fossil fuel to sustainable energies.

1.7.1 Electricity Bills

Household consumers are being charged according to an intricate mechanism with following components:

- There are three different rates corresponding to different hours of day, 19:00 – 23:00 (Peak Load), 07:00 – 19:00 (mid-load), 23:00 – 07:00 (low-load).
- The country is divided to different segments according to climate, where the rates are different.
- A step-by-step mechanism is improvised to charge more the high usage users.

[4] Due to Iran's high inflation rate, numbers are so unstable over time and this makes it so difficult to find consistency among reports, thus the numbers reported in this part is subject to compromise.
[5] Due to contradictory reports, this number would be validated

These steps for Tehran are tabulated in Table 1.2. In contrast to this mechanism, since electricity is quite cheap, no demand response is being observed in current situation in Iran.

Table 1.2. Tehran domestic users' bill issuance price steps

kWh/30 days	IRR/kWh	€cent/kWh
0 – 100	450	1.2
100 – 200	525	1.5
200 - 300	1125	3.2
300 – 400	2025	5.7
400 – 500	2325	6.6
500 – 600	2926	8.3
>600	3226	9.1

1.7.2. Fuel Subsidy

The fuel composition of Iran Power Plants is as follows [4]: Gas: 56.6%, Diesel Fuel: 18.5%, oil: 24.9%. Since 61% of generation is relied on gas in the form of gas or CC power plant, we follow the subsidy calculation for NG. Compared to EU, natural gas is so cheap in Iran, however its price is different in various month of the year, in different regions and in different sectors such as household, agriculture, etc. For instance, the household gas price ranges between 800 IRR/m3NG (2.3 €cent/m3NG) to 1300 IRR/m3NG (3.7 €cent/m3NG), the gas price for power plants is 800 IRR/m3NG (2.3€cent/m3NG) [4]. The government is subsidizing gas for Power Plants with an incredible rate of 21 €cent/m3NG, [11] which means 91% of the fuel price.

According to composition of Iran NG, 1 m3NG is equal to 10.55kWh [12] and knowing the overall efficiency of total thermal power units in Iran is 37% [10] we have:

$$\text{Gas Price paid by Power Plants} = \frac{2^{\text{€}cent}/_{m^3NG}}{10.55^{KWh}/_{m^3NG} \times 37\%} = 0.51\ ^{\text{€}cent}/_{kWh} \quad (1.1)$$

and the power plants are receiving the following subsidies on the gas:

$$\text{Gas subsidies for Power Plants} = \frac{21^{\text{€}cent}/_{m^3NG}}{10.55^{KWh}/_{m^3NG} \times 37\%} = 5.38\ ^{\text{€}cent}/_{kWh} \quad (1.2)$$

The regulatory authority sets a defined level of efficiency for the units of each generation technology in order to give the subsidy. Therefore, the generators will be motivated to improve their efficiency in order to acquire the governmental subsidy. A subsidized tariff of fuel prices is allocated only for a quantity of fuel that guarantees the benchmark efficiency of generating units while the extra consumption of fuels is settled based on the liberalized tariffs of fuel prices [13]. For the sake of simplicity, in the calculation of marginal cost in our model in chapter 3, we assume the subsidized tariff as the only fuel price.

1.7.3. Targeted Subsidies Reform Act

Electricity price is different in regions and in different sectors, however, according to Chitchian the minister of Energy, 600 IRR/kWh (1.4 cent/kWh) is a reasonable average for the electricity paid by the consumers on their bills [14]. Out of this number 102 IRR/kWh used to go National Treasury according to Iran Targeted Subsidy plan, however, now the government decided to waive TAVANIR from this payment to foster the power industries [15]. 30 IRR/kWh is the share of RES support. Therefore, 46 IRR/kWh is the revenue of the selling the electricity to users. As it is evident this number doesn't even cover the electricity conversion costs and it calls a comprehensive subsidy mechanism.

Creating excessive and inefficient energy use, contributing to price volatility, discouraging much-needed investment in the energy sector and incentivizing fuel smuggling are just some of the negative impacts of direct and indirect electricity subsidies. Therefore, the recent Government policies are based on elimination of electricity subsidies, followed by commissioning complete electricity market to attract investors in the power industry.

In March 2010, the Iranian parliament ratified the Targeted Subsidies Reform Act (henceforth the Reform Act) to phase out subsidies to energy products and replace them with nationwide cash transfers as compensation for rising energy prices within a five-year period (2010–2015). In its first phase, the indirect subsidies which were estimated to be equivalent to 27% of GDP in 2007/2008 (approx. US$ 77.2 billion), have been replaced by a direct cash transfer program to Iranian households [16]. The program focuses on essential products and services such as petroleum products, water and electricity which resulted in a moderate improvement in the efficiency of expenditures and economic activities. The second phase is still under review and it would involve a more gradual fuel price adjustment and the improvement targeting the cash transfers to low- income households. One of the implementations resulting from this reform plan will be the development of renewable energy plants for electricity generation.

Some features of Reform Act are [16]:

- The retail prices of petrol, diesel, fuel oil, kerosene and liquefied petroleum gas (LPG) are required to increase to no less than 90% of Persian Gulf free on board (FOB) prices. Natural gas retail prices are also envisaged to increase to at least 75% of average export prices after deducting transmission costs and export taxes. For electricity and water, the prices are set to increase to cover full cost price.
- The Reform Act also stipulates gradual subsidies elimination for wheat, rice, cooking oil, milk, sugar, as well as postal, air and rail services within the same five-year period.
- In order to manage future fuel price volatility, the Reform Act has authorized the government to absorb up to 25% of the FOB Persian Gulf price increases (relative to FOB Persian Gulf prices of 2010 when the Reform Act came into force) through further subsidization without changing the consumer price.

1.8. RES Support

In 1996 the Renewable Energy Organization of Iran (SUNA) was established to evaluate the renewable energy potential, to implement projects (solar, wind, geothermal, hydrogen and biomass) and to guarantee the purchase of the electricity generated to attract private sector's participation in this field. Additionally, the organization had the function to study the research policies in order to prepare plans for the development of renewable energies in the country and to provide knowledge and training in this field.

Based on the 5th Five-year Development Plan (2010–2015), the National Development Fund was established to transform oil and gas revenues to productive investment for future generation. The Fund is based on the annual petrochemical sales income determined in annual budget law and is independent from the government budget. It provides debt financing in foreign and local currencies and the payment is in the same currency.

1.8.1. Feed in Tariff Regime

According to Iranian laws and Regulations, the Ministry of Energy is obliged to purchase electricity from RES power plants established by the private sector with specific tariffs & conditions. The Ministry of Energy accepted SUNA's suggestion to have technology-specific feed in tariffs based on the LCOE of each technology [3]. Ministry of Energy announces the tariffs once a year conforming principles appointed by Economy Council of board of Ministers. The size of the power plants is considered as another factor in defining the price of electricity. The tariffs for the year 2017 is tabulated on Table 1.3. The average rate on the basis of the formula is calculated 4873 IRR per kWh and then by taking the equal rate of return on investment and the capacity of development of each type, different prices are determined. There is up to 15% extra bonus added to the feed in tariff, if the power plant uses domestic products (manufactured in Iran).

The feed in tariff is being paid for 20 years. The announced rates will be valid for the first 10 years of guaranteed purchase contract, and in the second 10-year-period, the rate will be decreased to 0.7 (excluding wind power plants). In order to adjust the feed in tariffs to inflation and the change in the exchange rate, the adjustment formula (1.3) was developed. This formula will be used for the 20 years of contract.

$$k = \left(\frac{CPI_{X_1}}{CPI_{O_1}}\right)^{\propto} \times \left(\frac{€rate_{X_2}}{€rate_{O_2}}\right)^{1-\propto} \tag{1.3}$$

k: Index factor
CPI: Retail Price Index announced monthly by the central bank of Iran (CBI)
$€rate$: Annual average of the exchange rate of Euro with IRR, as announced by the CBI
α: Power coefficient between 0.15~0.3 set by investors
X1: Refers to the first month of payment year
X2: Refers to the year before payment date
O1: Refers to the first month of contract year
O2: Refers to the year before contract date

Table 1.3. Guaranteed electricity purchase tariff for types of renewable and clean energy [17]

Technology type			Guaranteed purchase tariff (IRRs/kWh)	Guaranteed purchase tariff (€cent/kWh)
1	Biomass	Landfill	2700	7.6
		The anaerobic digestion of manure, sewage and agriculture	3500	9.85
		Incineration and waste gas storage	3700	10.41
2	Wind farm	≥ 50 MW	3400	9.56
		≤50 MW	4200	11.81
3	Solar farm	≥above 30 MW	3200	9.00
		≤30 MW	4000	11.25
		≤10 MW	4900	13.78
4	Geothermal (including excavation and equipment)		4900	13.78
5	Waste Recycling in industrial processes		2900	8.16
6	Small hydropower	Installation on the rivers	2100	5.91
7	Fuel cell systems		4948	13.78
8	Turbo expanders		1600	4.50
Allocated to the consumers and limited to the connection capacity				
10	Wind with the capacity of 1 MW and less		5700	16.03
11	Solar	≤100 kW	7000	19.70
12		≤20 kW	8000	22.50

1.8.2. Budget for Purchasing Renewable Energy

Government decided to increase the RES installation up to 5 GW in next 4 years [17]. Since there is a gigantic gap between MCP or even IEM price cap, a large subsidy is required to cover the ambitious FIT that SUNA pays. To provide the financial resources for this plan, users are charged by a rate of 30 IRR/kWh (=0.08 €cent/kWh) on their bills, from which SUNA earned 7000 billion IRR (200 million €/kWh) [18].

Mohammad Sadegh-zade, CEO of SUNA said: 5870 IRR/kWh (=16.5 €cent/kWh) is the average number that SUNA is paying to RES plants [19], that is almost 10 times of the price that the consumers pay on their bills. Now let's suppose that each RES unit is generating 8 hours per day for all days of the year (in depth studies is necessary), and suppose that all 5 GW is installed and operational, in this case the government need 85000 billion IRR/y to pay FIT. If SUNA wants to continue to on-bill-charge mechanism to pay this enormous number, it has to increase the charge 12 times bigger that 30 IRR/kWh!! This is the heart of the problem, SUNA is signing PPA every day, but there is no clear provision to how to pay back the investors!

1.9. Iran Electricity Market at One Glance

The overview of Iran Power Industries can be seen in Fig. 1.13. This figure illustrates the process and flow of energy and monetary payments including all governmental and private entities. All generation companies, including public regional electricity companies, deliver their electricity to the market and compete for the price and quantity of the sale. It should be noticed that TAVANIR works as off-taker in power purchase agreements (PPA) in the power industry and usually participates in the competitive market on behalf of other private power plants that have PPA contract. Currently, independent thermal power plants benefit of a 5-year PPA. After the PPA period, they directly sell the electricity to the wholesale electricity market, energy exchange or to the potential customers. Likewise, for renewable resources the Iran Renewable Energy Organization (SUNA) has the role of 'planning, policy making, providing solutions and publicizing of information. SUNA is assigned to facilitate private investment in this sector and works as electricity off-taker from the renewable generators. SUNA proposes and develops the legal and financial settings in annual Budget Acts and Five Year Development Plans (FYDPs).

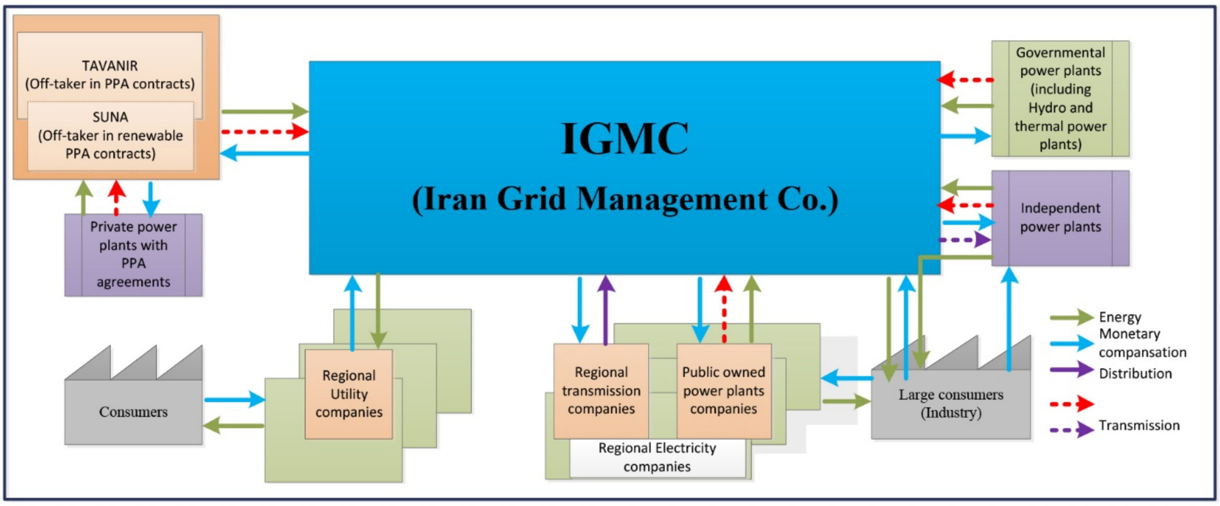

Fig. 1.13. Overview of energy and monetary flows in power industry [3]

Iran electricity market is a single sided market and, on the side of purchase, IGMC buys almost all the national demand and sells them to final users through the Regional Electricity Companies and Distribution Companies. TAVANIR (as the main holding which IGMC is a part of it) has to pay for Energy remuneration and capacity payment. IGMC, as a public company, afford these payments via: electricity bills and government support. It means that the government subsidizes the electrical industries in three ways:

1- Indirectly: by gas and petroleum products
2- Directly: by capacity payment.
3- Indirectly: by payment to network operators and ancillary service providers

As it seems apparent, it is a sick mechanism and TAVANIR has a debt of 700 million Euro to banks, producers and power system operators. [20]

List of figures

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2. GENERATION MIX & CAPACITY REMUNERATION MECHANISMS

There is a growing concern in many countries that electricity markets, with increasing shares of (intermittent) renewable electricity generation, will not be able to deliver sufficient capacity to meet electricity demand at all times (including peak times) in the future. The political sensitivity to blackouts, as well as practical and theoretical uncertainties as to if and when investors will build new generation capacity, has compelled a number of countries to intervene by introducing Capacity Remuneration Mechanisms ("CRMs") in order to provide additional stimulus to investors and ensure that a sufficient amount of capacity will be available.

In this chapter after defining some technical terms and categorizing the CRMs, the functionality of energy-only markets and optimal generation mix would be elucidated. By identifying the deviation of systems from long-run equilibrium, CRMs come on the scene, aiming at providing market participants with a more effective stimulus than what is delivered by energy-only markets. Consequent to detecting the flaws in the present CRM mechanism in Iran, a regulatory framework for rectifying the drawbacks is presented.

2.1. Definitions

It is necessary to define some terms and identify some characteristics of the investment in the electricity generation sector.

- **Value of Lost Load (VOLL)**

Given that electricity cannot be stored, total production needs to be equal to total consumption at each moment in time. This is achieved (1) by constructing a sufficiently large amount of generation capacity such that production output can follow demand most of the time, and (2) by rationing demand when production capacity is insufficient.

Some production units will only be used in a small number of hours every year when demand is large, while being idle the rest of the year, *i.e.* they have a low *load factor*. For those production units it is optimal to use power plants with low capital costs (so called peak-load power plants). Other production units will be used for a large number of hours every year and almost never run idle, *i.e.* they have a high load factor. For those production units, power plants that convert primary energy (gas, coal) very efficiently into electrical energy are used (so called base-load power plants). They have higher capital costs than peakload power plants, but their production efficiency gains outweigh those capital cost disadvantages for the high load factors they are used for. For a very small fraction of the year even the capital cost of the peak power plants is too high to justify building additional capacity to meet demand. Instead it is more efficient to ration a small fraction of total demand and to pay consumers that are rationed to forego electricity consumption entirely. Typically, those compensation payments are relatively high, reflecting the importance of electrical energy, but only have to be paid out during a small number of hours to a small subset of consumers. The price for not receiving electricity is often called the *Value of Lost Load* or VOLL.

- **Long-run Uncertainties**

Capacity investments are vulnerable to unanticipated scenarios that can take place in the long-term future. Future demand, fuel costs and long-term electricity prices are the most important uncertain variables, which in a competitive setting are uncontrollable for generating firms. A possible entry of more efficient generating technologies, i.e. technological innovation risk, represents another relevant threat for the firm's market positioning against potential competitors. In addition, as Iranian power market is not yet mature, the probability of periodical policy adjustments and regulatory intervention, i.e. regulatory risk, is another relevant source of uncertainty.

- **Investment Irreversibility**

Because of the low grade of flexibility, investments in generation capacity are considered sunk costs. Indeed, it is very unlikely that a power plant can serve other purposes if market conditions turn it unprofitable for electricity production. Moreover, under these circumstances the power plant could not be sold off without assuming significant losses on its nominal value.

- **Firm Capacity**

Regulators must define a methodology to evaluate and provide consideration for each generating unit's actual contribution to system reliability. This definition is usually based on a measure of the availability of units during critical periods, when the likelihood of scarcity is highest. In more general terms, such a measure might be referred to as "firm supply" which depends on system requirements and the specific details of the incentive. It is termed "firm capacity" in Spain, "firm energy" in Brazil and "adequacy capacity" in Chile [1]. Defining the measure is much trickier than it might seem at first glance. The regulator must first establish, ex ante, an objective rule for determining when a period (a given hourly interval, for instance) is critical, while at the same time assessing the real availability of the generating units should such situations arise. The latter is particularly complicated, since not all units will necessarily be producing at that specific time (that is why the spot market price would ultimately appear to be the best indicator of the existence of critical situations [1]).

- **Reliability**

The National Electric Reliability Council in the USA defines reliability as 'the degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired' [1]. Therefore, the ultimate measure of the reliability of the generation activity is the level of quality of supply provided to the load by generation at the wholesale level. Although the quality of supply only materializes in real time, its provision encompasses a number of deregulated activities that have to be performed in different time ranges, from several years to seconds, such as investment in new facilities, scheduled plant maintenance, fuel acquisition and management (particularly of hydro resources) and provision of operation reserves of different types (tertiary, secondary and primary reserves). It is necessary to distinguish between the three dimensions of the reliability problem: *security*, *firmness* and *adequacy*:

1. ***By security***, we understand the readiness of existing generation capacity to respond, when it is needed in operation, to meet the actual load (a short-term issue). Security typically depends on the operating reserves that are prescribed by the System Operator.
2. ***By firmness***, we name the short-term generation availability that partly results from operation planning activities of the already installed capacity (a short to mid-term issue). Firmness depends on short and medium-term management of generator maintenance, fuel supply contracts, reservoir management, start-up schedules, etc.
3. ***By adequacy***, we mean the existence of enough available capacity, both installed and/or expected, to meet demand (a long-term issue). A measure of expectation that system demand will exceed capacity during a given period is LOLP (loss of load probability), often expressed as the expected number of days per year (e.g., one day in ten years).

Capacity remuneration mechanisms are in place in many competitive electric power industries indicate that sheer generation capacity provides value even in the absence of generation. The value of uncalled reserve capacity is basically enhanced reliability [2]. Available capacity in a power system adds to system-wide reliability since excess capacity on reserve lowers the probability and impact of an outage event. Actual prices set for these payments directly impact generator behavior in both the short and long run. Long run capital investment decisions in turn influence generation supply reliability (in terms of adequacy) [2]. Hence prices offered for capacity in competitive markets ultimately affect resulting system reliability.

2.2. Introduction to CRM

2.2.1. Taxonomy of CRMs

A variety of CRMs have been proposed in the world. They can be classified according to whether they are quantity-based or price-based. Quantity-based CRMs can be further grouped in targeted and market-wide categories. As a result, five different types of CRMs can be defined, as presented in Figure 2.1.

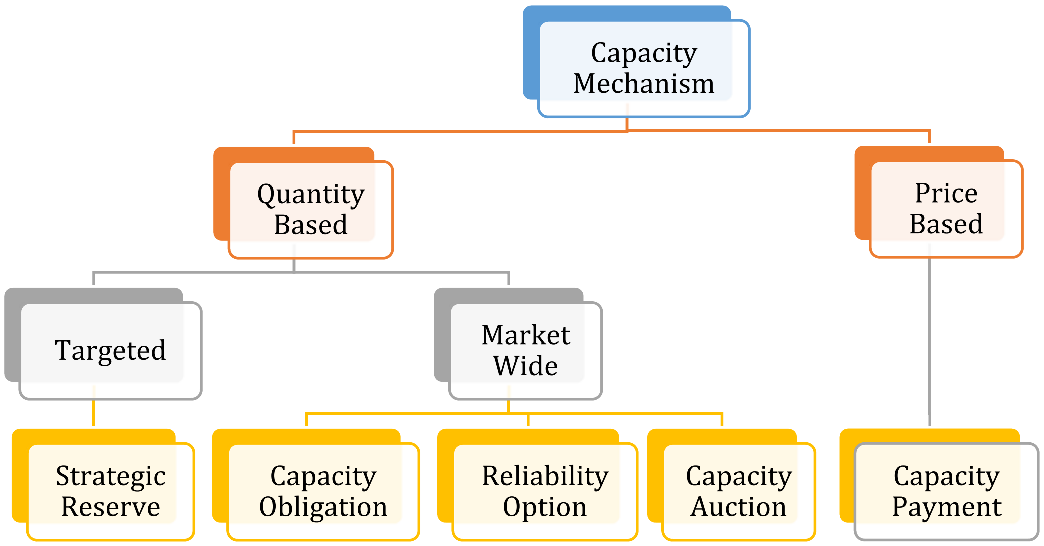

Fig. 2.1. Types of capacity mechanism

➢ *Strategic Reserve*

In a Strategic Reserve scheme, some generation capacity is set aside to ensure security of supply in exceptional circumstances, which can be signalled by prices in the day-ahead, intra-day or balancing markets increasing above a certain threshold level. An independent body, for example the Transmission System Operator ("TSO"), determines the amount of capacity to be set aside to achieve the desired degree of adequacy and dispatches it whenever due. The capacity to be set-aside is procured and the payments to this capacity determined through a (typically year-ahead) tender and the costs are borne by the network users.

The Strategic Reserve is intended to operate only when the market does not provide sufficient capacity and should therefore be dispatched at a price above a reference level signalling scarcity. In theory, the reserve should only be dispatched at a price close to VoLL in order not to interfere with the market even in tight conditions. In this case the natural price formation on the market is not affected and generators receive the same investment incentive as if there was no strategic reserve.

➢ *Capacity Obligations*

A Capacity Obligation mechanism is a decentralized scheme where obligations are imposed on large consumers and on load serving entities ("LSE", further referred to as "suppliers"), to contract a certain level of capacity linked to their self-assessed future (e.g. three years ahead) consumption or supply obligations, respectively. The capacity to be contracted is typically higher, by a reserve margin determined by an independent body, than the level of expected future consumption or supply obligations. The obligated parties can fulfil their obligation through ownership of plants, contracting with generators/consumers and/or buying tradable capacity certificates (issued to capacity providers). Contracted generators/consumers are required to make the contracted capacity available to the market in periods of shortages, defined administratively or by market prices rising above a threshold level. Failure to do so may result in penalties. A (secondary) market for capacity certificates may be established, to promote the efficient exchange of these certificates between generators/consumers providing capacity and the obligated parties or between obligated parties. Capacity providers are paid for the capacity certificates (or bilateral contract) issued; the suppliers pass on the costs of these certificates to their consumers.

➢ *Capacity Auctions*

A Capacity Auction scheme is a centralized scheme in which the total required capacity is set (several years) in advance of supply and procured through an auction by an independent body. The price is set by the forward auction and paid to all participants who are successful in the auction. The costs are charged to the suppliers who charge end consumers. Contracted capacity should be available according to the terms of the contract.

Capacity Auctions are similar to a Capacity Obligation scheme, though the capacity procurement process is centralized and an independent body acts on behalf of total demand. It calculates how much generation (interruptible load) capacity consumers/suppliers require based on the expected total peak demand. The calculations require reliability assessments, i.e estimates of the total need for capacity including forecasts of peak demand and reserve margins. Generators may sell capacity contracts up to the volume of generation capacity that they have reliably available, which is determined by an independent body. Capacity certificates can be traded.

- ***Reliability Options***

Reliability Options (ROs) are instruments, whereby contracted capacity providers (typically generators) are required to pay the difference between the wholesale market price (e.g. the spot price) and a pre-set reference price (i.e. the "strike price"), whenever this difference is positive, i.e. the option is exercised. In exchange, they receive a fixed fee, thus benefitting from a more stable and predictable income stream.

A scheme based on ROs usually rests on an obligation imposed on large consumers and on suppliers to acquire a certain amount of ROs, linked to their (self-assessed) future consumption or supply obligations, respectively. Under a RO scheme, the incentive for the contracted generator to be available (at times of scarcity) arises from the high market price and from the fact that, if not available and therefore not dispatched, it will have to meet the payments under the RO without receiving any revenue from the market. The holders of ROs effectively cap their electricity purchase price at the level of the strike price, since whenever the market price increases above this level, the excess will be "reimbursed" through the payment made under the ROs.

Different RO variants can be designed, depending on whether the scheme is purely financial or also involves an obligation to have and make capacity available when the option is exercised (or otherwise face a penalty). In this latter case, the RO scheme becomes similar to a scheme based on Capacity Obligations.

- ***Capacity Payments***

Capacity Payments represent a fixed price paid to generators (consumers) for available capacity. The amount is determined by an independent body. The quantity supplied is then independently determined by the actions of market participants. The simplest type of capacity mechanism is to provide direct Capacity Payments. A direct Capacity Payment scheme encourages generators to invest in new or maintain old capacity by complementing the revenues that generators receive from the sale of electricity on the wholesale energy market.

There are different methods of calculating the level of payments and how to target them. For example, the Capacity Payment may apply to all capacity or to existing generation plants only, to new plants, or to specific plant types. Alternatively, it can be differentiated between types of capacity, e.g. between base-load and peak capacity, existing and new capacity, etc.. Demand side resources are typically not eligible to capacity payments.

Generators who receive Capacity Payments for their plants sell their electricity on the wholesale market (i.e. electricity exchanges or bilateral contracts). Capacity Payments may refer only to the present, but may also apply (exclusively) to new capacity. In the latter case, the payment is explicitly aimed at amplifying the investment incentives for new capacity such as the case in Iran.

2.2.2. Current Developments in the European Union

At present, a large number of EU member states pursue a national generation adequacy policy. Figure 2.2 shows the current approach to generation capacity adequacy in Europe. It shows that Finland, Greece, Ireland and Northern Ireland, Italy, Portugal, Spain and Sweden have already implemented a CRM, with a number of other MSs including Belgium, Denmark, France, Germany and Great Britain considering doing so. Figure 2.2 also illustrates the diversity of approaches from one MS to another (Strategic Reserve, Capacity Payment and market wide schemes).

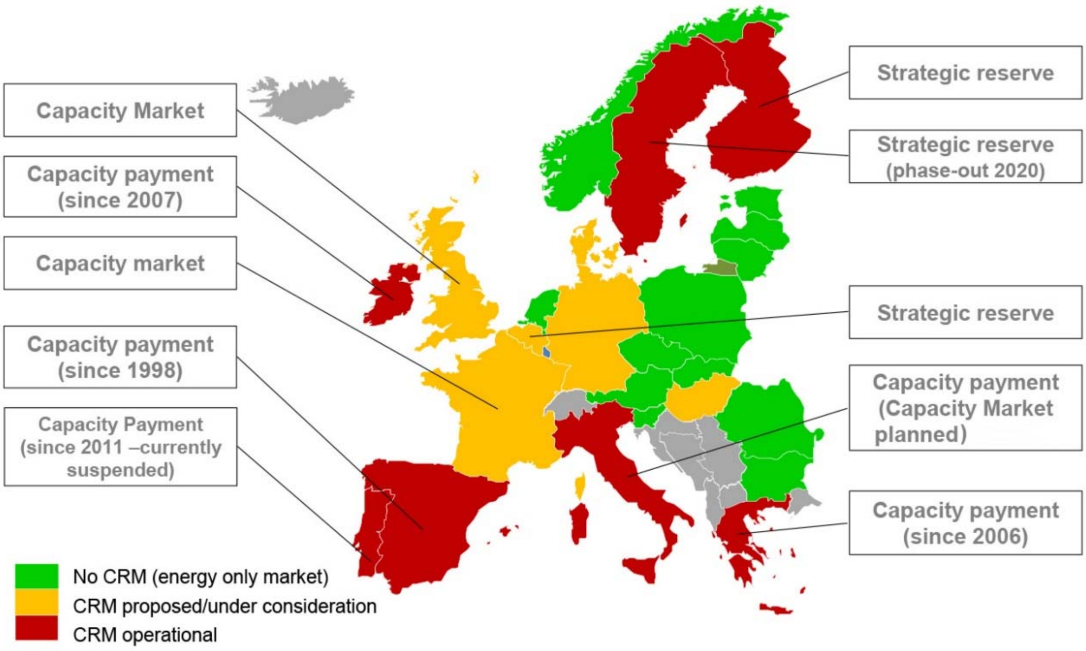

Fig. 2.2. Status of capacity remuneration mechanisms in Europe 2013 [2]

2.2.3. Problems Experienced with CRM

It is always advantageous to investigate the failures and malfunctions of a system to shed some light on the its aspects. Provision of CRMs is to serve to hedge risks inherent in energy production and plant investment by providing valuable price signals and incentives, nonetheless, in some cases they led system to sever problem.

- **British Experience**

Concerns expressed prior to the onset of the deregulated British system included uncertainties as to whether generating units could recover their investment costs via receiving only energy payments from the energy pool [3]. As a result, a capacity revenue component was devised which was to be paid to all units supplying available capacity in the pool. The capacity element was set up to be partly determined by generation system availability through a loss of load probability (LOLP) measure, and partly determined by regulators through a decree on the value of loss load (VOLL).

In a perfectly competitive environment, arguments for capacity payments to augment energy payments may be well founded. However, excessive market power comprised the actual British generation industry to begin with, and abuses of capacity payments resulted. Generators found early on that capacity payments were particularly sensitive to the amount of spare capacity declared in the pool [3]. The method used to compute LOLP exaggerated the probability that plants would not be available, and led to magnified capacity payments. Before the problematic LOLP computation scheme was revised, generators could mis-report unavailability and collect capacity payments based on an invalid predication of scarce capacity.

Even after revision, rules for computing LOLP led to other perverse affects, such as encouraging generators under certain circumstances to delay redeclaring availability after experiencing a fault. Such problems resulted in magnified capacity payments to generators. During the 1994-95 financial year alone, capacity payments were 20% of total payments for generation in the British pool [3]. The payments from that one year would have paid for construction of 6% of total existing capacity. Therefore, the possibility of gaming by generators to influence capacity payments was very significant in the British pool.

- **California Experience**

Unlike the British pool, California auction markets for energy contain no capacity component to compensate generators. Scheduling coordinators like the Power Exchange (PX) only pay generators for scheduled energy. Capacity payments, on the other hand, are awarded by the Independent System Operator (ISO) to units that supply reserves in one of four ancillary service markets. Separate markets exist for regulation, spinning, non-spinning, and replacement reserves, respectively. These auction markets pay scheduled reserves according to market-clearing capacity prices, regardless of whether energy is produced or not from the reserves. So, in contrast to the British pool, capacity payments in California are primarily determined through competitive auction mechanisms. Nevertheless, California markets for reserves have not always functioned competitively [4].

The markets have exhibited extreme price volatility even under long periods of unchanged demand. Prices for lower quality reserves like replacement reserve have at times surpassed that of higher quality reserves such as regulation. Moreover, capacity prices in reserve markets have frequently exceeded energy prices in the Power Exchange. Problems with generator gaming on capacity bids have also been experienced. For example, clearing prices for replacement reserves reached $9999/MWh, the maximum price bid acceptable by computer software, during certain hours of the first summer of ISO operation. The ISO is rumored to have spent millions for purchasing these reserves, compared to $1500 if they had been procured under original utility bid cap rates [4]. At the time of writing, the ISO was imposing a $250/MWh price cap on all ancillary services. Clearly, the evidence indicates that capacity reserve markets have not functioned competitively in California.

2.4. The Contribution of Energy-Only Markets to Adequacy

In a pure energy-only market, in theory and in the absence of market failures[6], the operating (e.g. fuel, start-up costs) and capital costs of a plant should be recovered exclusively through market prices for electricity and for the associated ancillary services. In energy-only markets, there are no payments for capacity and no distortions to the functioning of the IEM. [2]

In most hours of the year and under most circumstances, there will be more available generating capacity than needed to meet demand. During these hours, assuming workably competitive market conditions, the energy market price, if allowed to vary unhindered, will tend to reflect the marginal operating cost of the most expensive unit dispatched or the opportunity cost of any energy-limited hydro resources when at the margin. In these hours, base-load and intermediate-load generators with operating costs lower than the market price can recover their variable operating costs and obtain an “infra-marginal rent” which can be used towards covering fixed costs.

In some hours, however, the margin between available capacity and (peak) demand may tighten and electricity prices will rise above marginal operating costs to include a “scarcity premium”. During these (rare) occasions of capacity shortage, the system experiences extremely high prices, potentially up to the “value of lost load” (VoLL). During these hours, all plants in the merit-order (e.g. base-load, intermediate and peaking plants) receive a price which also contributes to recover their fixed costs.

In an energy-only market, scarcity prices should be sufficiently frequent to attract investment in new capacity and prevent existing capacity from leaving the market. In the absence of such price spikes and without any other revenues (e.g. from the provisions of ancillary services), existing peak plants might exit the market without being replaced. This would reduce the available generation capacity and increase the frequency of scarcity conditions and scarcity prices.

In any case, as long as demand is sufficiently price responsive, and falls to zero at VoLL[7], an energy-only market will always deliver an equilibrium. The interaction between available capacity and demand determines the economically optimal level of installed capacity through the prices established in the market. The level of adequacy is therefore determined by the market. [2]

The “political” acceptability of the adequacy provided by energy-only markets depends on the frequency with which prices reach very-high levels, possibly VoLL, and the “political” implications of such high prices. It is the “political” unacceptability of extreme prices in energy-only markets which pushes authorities to intervene, e.g. by introducing CRMs, in order to reduce the frequency and level of price spikes. Most CRMs interact with the energy-only markets and, if not properly designed, may add on the difficulty of creating a sound wholesale market producing reliable and efficient price signals. In any case, the objective of removing any barrier to the well-functioning of energy-only markets needs to remain a priority. [2]

[6] For instance, the absence of smart metering or, more generally, the absence of mechanisms/tools to develop Demand Side Response

[7] Since, given the definition of VOLL, no consumer is willing to pay a price for energy higher than VOLL

2.5. Optimal Generation mix

Any handbook on electricity markets starts from three fundamental characteristics of electricity markets: (1) demand varies over time and is very inelastic, (2) storing electrical energy is expensive, and (3) production capacity is fixed in the short run and capital intensive in the long run. Based on those characteristics it is then explained how electricity markets rely on a form of peak-load pricing to organize the spot market for electrical energy and how a mixture of base-load and peak-load power plants is optimal.

2.5.1. Long-Run Equilibrium

The total production cost of a generation plant i consists of a fixed capital cost (FC), which is incurred even when the power plant is not used, and a variable cost (VC) which is proportional to the number of hours the power plant is actually producing electricity. Those variable costs consist mainly of operating and fuel costs. Therefore, the total cost (C_T) of using a unit of capacity for serving a load of duration D is expressed as:

$$C_{T_i} = FC_i + VC_i = FC_i + MC_i \cdot D \tag{2.1}$$

In which MC_i is the marginal cost of generation unit i. Fig. 2.3. shows the linear screening curves for the three generating technologies. Screening curves plot the average cost of using a capacity unit of each technology as a function of the capacity factor.[8] To these curves, a high-sloped curve is added to represent the costs of load curtailments of increasing duration. Fixed costs of load curtailment are assumed negligible. The slope of this curve is the average value of lost load ($VOLL$). The technologies serving loads of different durations at a minimum cost can be determined by simple inspection of the diagram and the profile for the optimal technology usage is represented with the bold line envelope.

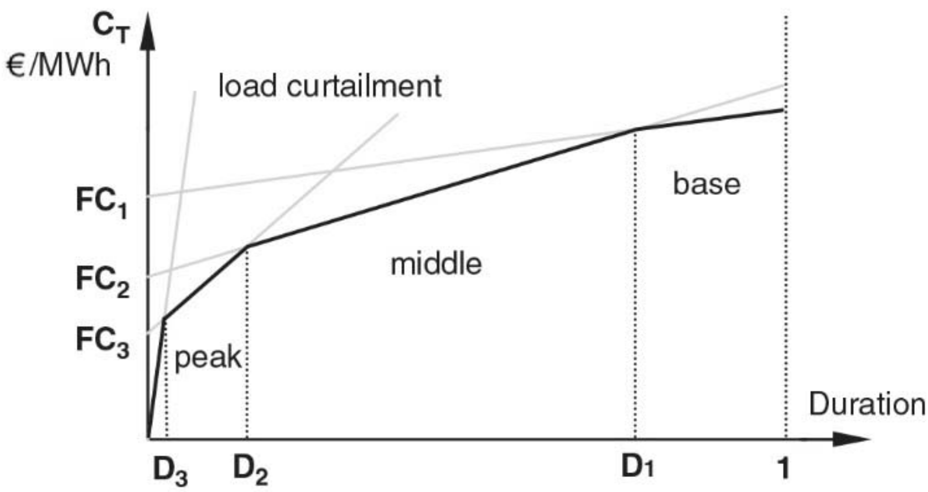

Fig. 2.3. Screening curves for three generating technologies and cost curve for the load shedding

[8] Note the reader that *linear screening curves* plot the average cost of using a unit of plant capacity to produce energy. However, this cost is NOT the average cost of energy produced by the plant, the so-called "levelized energy costs". Levelized energy costs are a very different kind of average cost, which are represented by *hyperbolic screening curves* and are best suited for technologies with non-market dependent capacity factors, such as solar and wind.

The duration at which the cost of using two technologies turns equal can be directly read from the figure. They are indicated by D1, D2 and D3 for base-, middle- and peak-load power plants, respectively. It should be noted that the cost of serving loads of a shorter duration than D3 is higher than the value given by consumers. Therefore, no more peak-load capacity is worth to be added to the system and the most economical choice would be not to serve this demand. The usage durations that should be exceeded for each one of the technologies to make an optimal use of the generating resources can be analytically solved as

$$
\begin{aligned}
D_1 &= \frac{FC_1 - FC_2}{MC_2 - MC_1} \\
D_2 &= \frac{FC_2 - FC_3}{MC_3 - MC_2} \\
D_1 &= \frac{FC_3}{VOLL - MC_3}
\end{aligned}
\tag{2.2}
$$

The system marginal cost (SMC) is set each time by the running, most expensive technology, i.e. the marginal technology. For the three-technology system and neglecting the unavailability of generating units, the distribution of the SMC duration over the considered period is shown in Fig. 2.4. If we assume again a perfectly competitive market (the SMC equals the market price at each time), the revenues per capacity unit, R_i, perceived for each one of the generating technologies can be calculated from Fig. 2.4. as follows:

$$
\begin{aligned}
R_1 &= VOLL \cdot D_3 + MC_3 \cdot (D_2 - D_3) + MC_2 \cdot (D_1 - D_2) + MC_1 \cdot (1 - D_1) \\
R_2 &= VOLL \cdot D_3 + MC_3 \cdot (D_2 - D_3) + MC_2 \cdot (D_1 - D_2) \\
R_3 &= VOLL \cdot D_3 + MC_3 \cdot (D_2 - D_3) + MC_2 \cdot (D_1 - D_2)
\end{aligned}
\tag{2.3}
$$

By inserting Eq. (2.2) into Eq. (2.3), the resulting revenue per capacity unit for each generating technology is

$$
\begin{aligned}
R_1 &= FC_1 + MC_1 \cdot 1 \\
R_2 &= FC_2 + MC_2 \cdot D_1 \\
R_3 &= FC_3 + MC_3 \cdot D_2
\end{aligned}
\tag{2.4}
$$

By comparing Eq. (2.4) with Eq. (2.1), we can see that in a market with an optimal plant mix, the revenues will compensate exactly the total incurred costs. In this breakeven situation, the market is said to be on the *long-run equilibrium*. As long as the market remains in equilibrium, there are no incentives to either invest in additional capacity (since the market does not offer the possibility to gain supernormal profits) or exit from the business (since all costs are recovered).

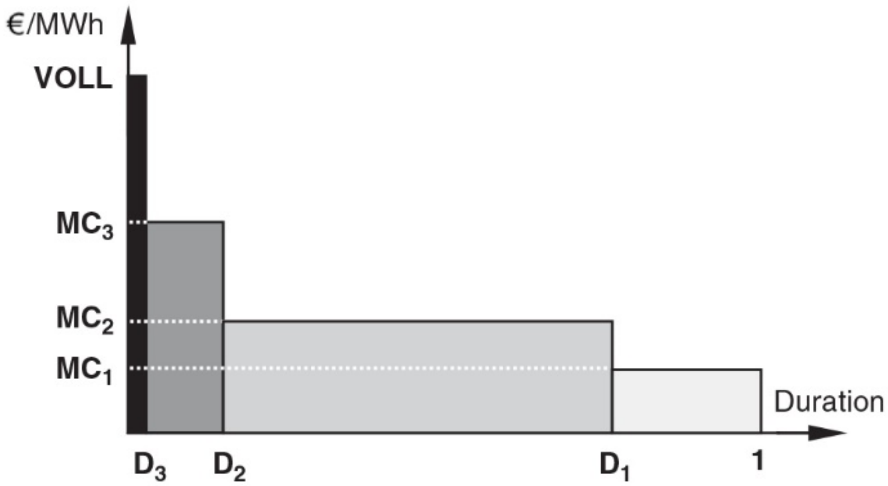

Fig. 2.4. Duration of the system marginal cost for an optimal generating mix.

Note that peak-load plants will recover their fixed costs only from the very rare times when there is not enough capacity available to fully satisfy the demand and the price is set at *VOLL*. Under equilibrium conditions, middle-load and base-load power plants need also from deficit conditions to recover fully their fixed costs. Nevertheless, as it can be observed in Fig. 2.4, these technologies do not depend strongly on these rare events, as price-spike revenues represent only a small fraction of their total revenues.

In an actual power market, new, more efficient base-load power plants can even recover their fixed costs without the necessity of waiting for any deficit supply condition. Indeed, if the thermal efficiency of the proposed plant is much higher than the efficiency of the average base-load plant in the system, the entire fixed costs can be recovered from the *scarcity rent* or *infra-marginal rent* derived from its generation cost advantage. The same argument is also valid for peak- and middle-load technologies. Strictly, the equilibrium described above is dynamic in nature. It is altered each time the optimal technology mix changes, for example, due to changes in the load pattern or relative changes in the fixed costs, fuel prices, thermal efficiencies of the generating technologies, or simply, changes in the regulatory environment. [5]

2.5.2. Formation of the Electricity Prices

Since we are not interested in predicting short-term movements of electricity prices, such as those caused by weather, we can accept some loss of chronological information gaining in model simplicity. For this reason, the load is characterized by a load duration curve (LDC), which results of sorting the chronological load from higher to lower. Furthermore, possible structural changes in the load pattern are neglected; henceforth, the LDC conserves its linear pattern for the entire simulation period.

In addition, the economical demand for power is considered price-irresponsive in the short term, which represents the observed inability of customers to adjust their electricity consumption at short notice. Although the load is modeled as price inelastic, it is assumed that consumers will not be willing to purchase any power if the market price rises above the cost of being curtailed (VoLL).

The electricity market is assumed perfectly competitive. This implies that firms cannot strategically influence the price, behaving solely as price-takers. In such a market setting, the price at each time equals the marginal cost of the most expensive running generator. By sorting the marginal costs from the lowest to the highest, the *dispatching merit order* for the available generating capacity is determined. If now the ordered marginal costs are plotted against the total cumulated generating capacity, the industry *supply curve* is obtained for each time. Jointly with the LDC, the supply curve allows one to determine the simulated market price duration curve (PDC).

In a given period, the PDC function will specify the number of hours, during which a certain market price is equaled or exceeded. The methodology to simulate the market price formation is depicted schematically in Fig. 2.5. This price formation model, which accounts for the annual price distribution, allows us to derive the *short-term inframarginal rent* being perceived at each time by each generating technology and thereby, the market signals for the investment decision-making. As a practical example, we will see in next chapter how Iranian Regulator utilizes this signal to improve the system reserve margin.

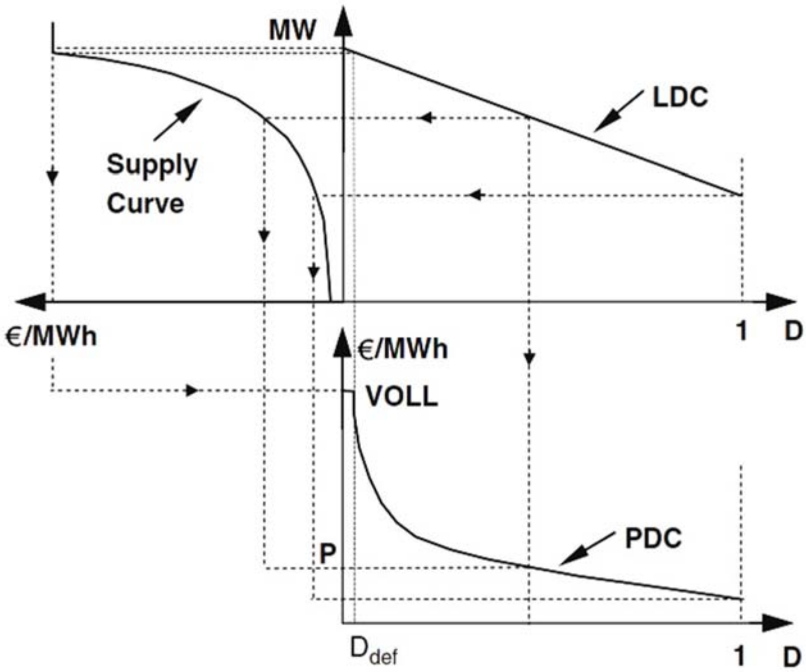

Fig. 2.5. Price formation in a competitive power market by means of a supply curve and the LDC [5]

2.5.3. Deficit Duration

Price spikes cover a substantial part of the plant fixed costs, therefore they play a crucial role in inducing investments (especially in peak-load power plants). Investors will hence evaluate the probability of occurrence and duration of these events. Therefore, the price duration curve (PDC) must take into account the high prices paid during the infrequent price jumps. The sudden price spikes occur because of the response to tight supply conditions, such as unplanned outages of significant generating capacity during peak-load hours. In this case, if the reserve capacity is enough, peak load will be served by more expensive units, which will set the price at a higher level. In case of insufficient reserve and absence of demand bidding activity, the load cannot be satisfied completely and the market cannot be cleared. Fig. 2.6 depicts the procedure for determining the deficit duration for a certain capacity outage level , given a reserve margin and a determined load duration curve, LDC, of the load model.

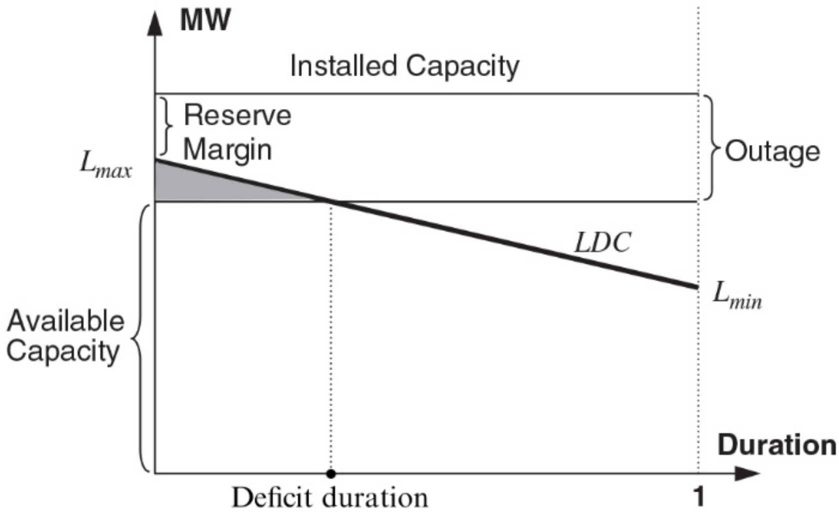

Fig. 2.6. Deficit duration for a given reserve margin and LDC, when an outage happens

Expected deficit duration is negligible for high reserve levels and rises abruptly when capacity becomes tight. It is noticeable that the average size of generating units plays an important role in the loss of load expectation [5].

2.6. Investor Behavior in Power Markets

Because power plants need a long time to be constructed and they will be amortized over several years, investment decisions must be based upon expectations on future profits. Unfortunately, the forecasting of these profits is an extremely difficult task, since they are highly uncertain and volatile.

Tight supply conditions and the consequent price spikes are expected to cover some significant portion of the fixed cost for peak-load plants. Nevertheless, they occur for only a few hours in the year and their probability of occurrence changes dramatically from year to year. The expectation on price-spike revenues is affected by significant uncertainties, mainly as a consequence of uncertainties on demand growth, on the maintenance schedules, on timing and size of the retirements of old, inefficient power plants and size and timing of new capacity additions. Consequently, these uncertainties have a major impact on decisions to invest in peak-load technologies.

The duration of deficit conditions is very sensitive to the addition of any single unit of capacity. As the own market entry and subsequent entries of other firms would substantially reduce the deficit probability and consequently the expected profits, investors have not any first-mover advantage. Hence, it is likely that investors behave extremely cautious upon price spikes and, thus, the response to high prices by adjusting the supply capacity might turn somewhat insensitive [6].

Even though base- and middle-load power plants do not rely strongly on price spikes to cover their plant fixed costs, the expected infra-marginal rents for these technologies are also affected by significant uncertainties. Indeed, they depend upon the own expected fuel costs as well as of the fuel costs of other generating technologies, the progress in the thermal efficiencies of the future plants and the uncertain entries and exits of other competitors.

These characteristics configure a very uncertain environment for investments. The above-mentioned irreversibility of capacity investments causes that they are not to be immediately committed when the expected economic profit turns positive. On the contrary, irreversible investments facing uncertainties turn valuable to maintain alive the option “wait-and-see” to invest until more information, though always incomplete, about the future is revealed [6].

Indeed, investors will remain reluctant to invest until they observe clear and consistent evidence of positive profitability. This causes an important delay in investment decision-making and increases the threshold at which investors are willing to commit huge financial resources. The uncertainties that characterize the generation sector might prevent from inducing timely investments in power plants, and therefore might cause power markets to deviate significantly from the long-run equilibrium. In next part we will try to tackle the spikes with price cap. Due to prominent distortion of such policy on optimal mix, the capacity payments as the ultimate solution would be introduced.

2.7. Addressing the Price Spikes by Price Cap, Missing Money Problem

Since the LDC of Iran is quite flat, to illustrate the topic, a fictitious composition of base-, and peak-load is considered in this part. The bottom half of Figure 2.7 presents the screening-curves of a base-load plant and a peakload plant each capable of producing 1 MW, as a function of the number of operating hours in a year, in the optimal condition of energy only market.

When the power plants do not operate, they incur only their capital costs, but no operating or fuel costs. Capital costs for the peak-load power plant are 30kEUR, while they are 100kEUR for the base-load power plant. Their peak-load and base-load marginal costs are 25 EUR/MWh and 35 EUR/MWh, respectively. Total production costs will increase with the number of hours that plants operate, but they will increase faster for peak-load than for baseload power plants. At the intersection of those two costs lines (which occurs at 7,000 hours per year) their total costs are equal. The bottom graph shows that a peak-load power plant is cheaper than a base-load power plant whenever it has to run less than 7,000 hours per year. Above this number, the base-load power plant is less expensive.

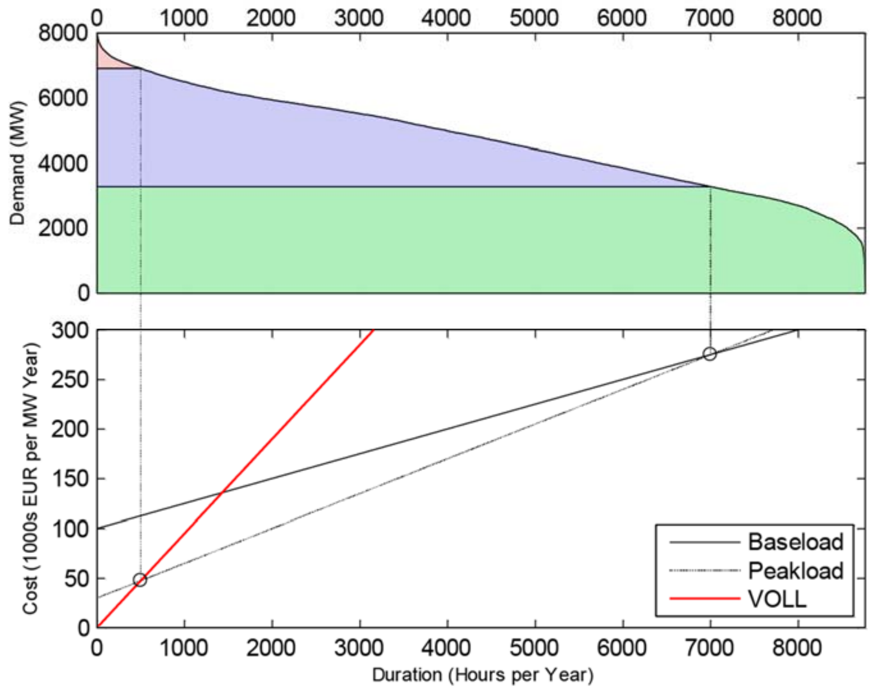

Fig. 2.7. Optimal generation mix for a fictitious generation park

To mitigate the investment uncertainties clarified in 2.6, we assume a price cap of 45 EUR/MWh to obviate the price spikes. In the short run, investment capacities remain constant and are not affected by the price cap. However, the introduction of the price cap will lower electricity prices during peak hours from 95 EUR/MWh to 45 EUR/MWh. This price reduction will benefit consumers at the expense of producers. The price cap will reduce revenue for all generation plants with 50 EUR/MWh during 500 hours per year. This creates a yearly shortfall of 25,000 EUR per MW installed capacity, both for peak-load and base-load generation plants. This short-fall is called the *missing money* problem. [7]

Short run supply is perfectly inelastic at the price cap and also demand is assumed to be perfectly inelastic. Hence there are no short-term negative welfare effects of introducing price cap. Myopic policy makers (or network operators) might be tempted to impose such a price cap to transfer revenue from generators to consumers without any obvious negative effects on market outcomes. In the long run, supply is perfectly elastic, as we assume free market entry, and the price cap will therefore distort the market equilibrium and create dead weight losses. Given the missing money problem, generators are unable to cover their capital costs and installed capacities will decrease until the resulting higher prices are sufficient to pay for the capital costs. In the long run, the market will reach new equilibrium in which all generators break-even.

We can determine the long run equilibrium capacities graphically by lowering the value of VOLL to level of the price cap as illustrated in Figure 2.8. The Figure shows that peak-load capacity is reduced to the point where consumers are rationed about 3,000 hours per year. At this level, prices are sufficiently high to pay for the total cost of the peak-load capacity. The lower price during hours with demand rationing (45 EUR/MWh instead of 95 EUR/MWh) is off-set by an increase of the duration of demand rationing hours (from 500 to 3,000 hours per year). The markup of 10 EUR/MWh that the peakload power plant earns on top of its marginal cost during those 3,000 hours are sufficient to pay for its yearly capital cost (10 EUR/MWh times 3,000 hours per year, or 30,000 EUR per year). The total amount of base-load capacity remains, maybe somewhat surprisingly, unchanged. As the peak power plants break-even at a duration of 7,000 hours per year and as total production cost for base-load is identical to peak-load at this load factor, also the base-load power plants will break even.

Hence, although in the short-run, both the peak and the base-load power plants face the missing money problem, in the long run, investment levels will decrease only in peak-load capacity. As long run supply is elastic, the price cap distorts investment decisions, and creates a dead weight loss. Hence, from a social viewpoint total welfare is reduced, and demand is rationed too often.[7]

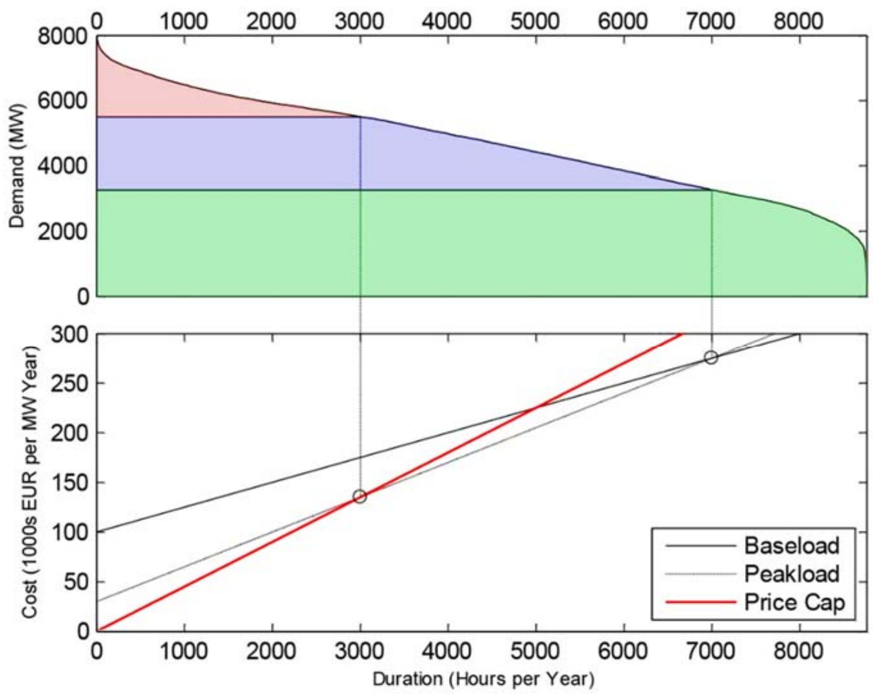

Fig. 2.8. Long-term effect of price cap

2.8. Capacity Payments Restore Efficiency

The previous section has shown that a price cap will lower peak-load capacity, increase demand rationing, and lower overall welfare. We now discuss how a capacity payment can restore market efficiency.

The introduction of the price cap lowered the red VOLL-line in Figure 2.7 to the red price cap line in Figure 2.8. As a result, the intersection of this line with the total cost line for peak capacity moved to the right, and the number of hours with rationing increased from 500 to 3,000 hours per year. By subsidizing investments in peak-load capacity using a capacity payment, the total cost line for base-load capacity will shift downwards, and the intersection with the price cap line will move to the left. If we give a capacity payment of 25,000 EUR per year to peak-load generators, then the intersection with the price cap line will be at 500 hours per year and the number of hours with rationing reaches the optimal level again. (Fig. 2.9)

However a subsidy to the peak-load generators will also affect the trade-off between base-load and peak-load generation. Peak-load generation becomes relatively cheaper than base-load generation and will be operating more than 7,000 hours per year as the intersection between the total cost line of peak-load and base-load has shifted to the right. Therefore, in order to obtain the optimal mixture of peak and base-load generation, also base-load generation should receive the same capacity payment of 25,000 EUR per year. This will shift the total cost line of base-load capacity downwards with the same amount as the peak-load plant, such that it intersects at the optimal level of 7,000 hours per year.

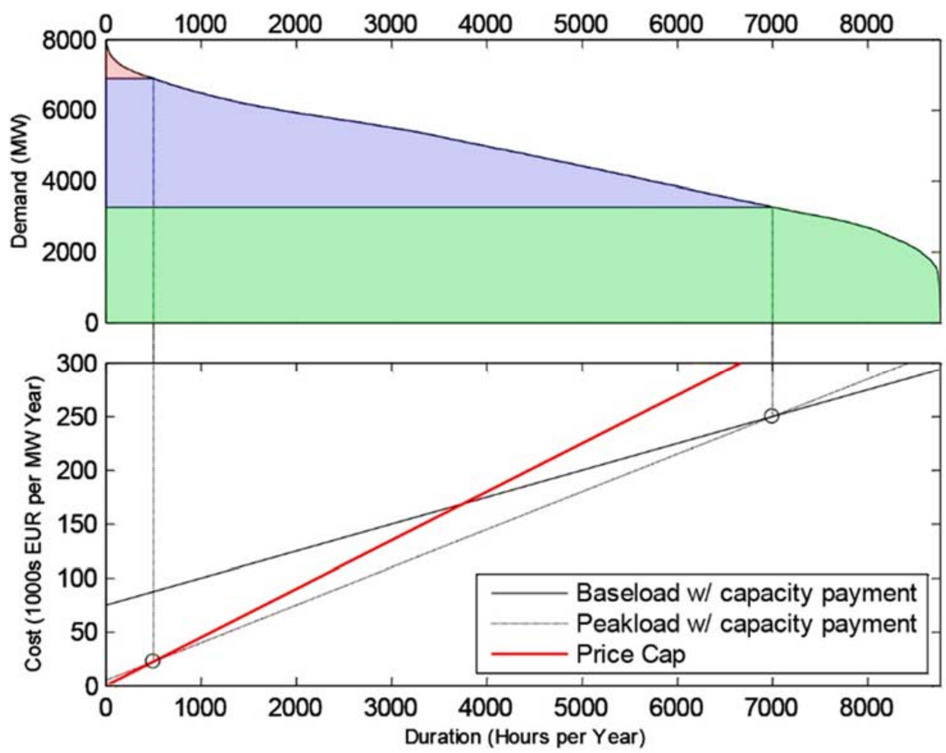

Fig. 2.9. Generation mix with price cap and capacity payment.

2.9. Key Weaknesses of Iranian Capacity Mechanism

We have shown that a technology neutral capacity payment which is equal to the amount of the missing money will correct investment incentives. If the capacity payment would only be given to peakload power plants, then too few base-load power plants would be built. Motivated by this idea, the current mechanism of capacity payments in Iran consist in awarding generating units a daily capacity payment (only when they are available) that is computed by multiplying the firm capacity of each generating unit times a per unit capacity payment (€/MW) that is regulatorily determined. This payment involves certain obligations, as generating of at least 300 h per year to prove their availability or having certain strategic fuel stocks at their disposal. This mechanism is expensive and has significant weaknesses that can be summarized in two:

- It does not provide generators with an incentive to make a special effort to be available and producing electricity when there is a real need for it
- It does not guarantee that there will be a reasonable volume of installed capacity to meet demand at all times.

2.9.1. Absence of a Well-Defined Product

The mechanism implies that generating units receive a payment in exchange for almost nothing. If a generating unit happens to be unavailable in a day when there is not enough supply to satisfy the system demand, it just loses the capacity payment corresponding to this particular day, what represents an extremely small proportion of the total amount to be earned for the whole year. It can be therefore stated that the mechanism does not represent a special incentive for generators to really provide reliability for the system.

Therefore, there is no product from the generators' side, no commitment to provide the assigned firm capacity when the system is close to scarcity. Besides, this scheme forces the regulator to supervise the availability status of each power plant very closely, since there is an economic incentive for the generator to declare as available a non-dispatched power plant, regardless whether it is available or not.

Moreover, the firm capacity to be taken into account for this payment is calculated following an extremely crude and arguable procedure: multiplying an average availability rate times a capacity value that, schematically, is the installed capacity for thermal units and the energy produced in an average year for hydro plants. However, there is not yet a consensus in the literature about an adequate model to calculate the actual firm capacity of the different (and diverse) power generating plants technologies.

On the other hand, the current criteria that are followed to make sure that the plant is able to contribute to the reliability of the system are very questionable. In particular, the requirement to produce at least 300 h per year to have the right to receive the payment interferes with the market functioning, forcing a set of expensive plants to generate when they are not needed. Moreover, the fact that a generator will lose the payment if it declares its unavailability creates an incentive not to be truthful in its declarations; regarding that, bidding high enough to be excluded from the dispatch results more profitable.

The strategic fuel reserves condition can also be subject to conflict. The experience shows that the requirement to have at the generator's disposal an alternative fuel and a prescribed stored volume to prevent scarcities is difficult to supervise. In a broader sense, from the point of view of reliability, the way the gas procurement is managed in the case of GT and CCGT can pose some problems. For example, a generator might decide not to operate so that it can sell the gas in the International Liquefied Natural Gas market (due to the price difference between the liberalized and subsidized price in Iran). Another case could be that it might decide to tighten its reserve margin, in such a way that if for instance a boat is delayed (e.g. due to a storm) the generator would be subject to an energy limitation that might lead to “critical scarcity situation” when the production obligation would be held from it.

2.9.2. No Adequate Reserve Margin Guarantee

The second regulatory flaw that has to be faced is that, although in a limited extent the capacity payment backs new investments by introducing an additional remuneration, it is not possible to ensure that it will be sufficiently appealing for the amount of them required to hold the desired capacity margin.

The security of supply mechanism in force in the Iranian market has been effective to prevent certain old installations from retiring. These plants were expected to be into operation very rarely, although their contribution to the system reliability in emergency periods was (and in certain moments has indeed been) crucial. Nevertheless, it does not look like that this mechanism has been behind the rather numerous new plants that have decided to get installed in these recent years. The regulatory uncertainty related to the capacity payments has reduced significantly the efficacy of the mechanism as an attractor for new investments. Although the initial value was notably high, the perception that the Government can often and unexpectedly modify it has overshadowed the desired long-term investment signal.

As a result, if the regulator's purpose is to assure a certain level of investment margin, a new methodology has to be put in place. These weaknesses are tackled by the proposal of an alternative mechanism, which is described in the next section.

2.10. Choosing the Right Mechanism for Iran

One may wonder due to all the mentioned flaws a more advanced mechanism could replace the existing capacity payment, such as capacity market that is implemented in most progressive electricity markets such as Italy, but assigning a new CRM to a market calls for quite intricate considerations.

Due to the capacity shortage, it is not possible to run capacity market (of any kind) in Iranian electricity market. As in any other market-driven mechanism, there are many advantages in letting players express their valuations and preferences, but there is also a risk for manipulation if the players are few. The workability of the mechanism depends critically on the ability of the auction to attract several potential new entrants. In contrast, it is not the case in Iran: almost every day in July, 2017, Iran demand is reaching a new record. In the very same days, the available national reserve margin is less than 5GW! Thus, there is not enough capacity installed that an auction can choose between them. In contrast, the idea behind the CRM in Iran is just to develop the infrastructure.

One should be aware of abrupt changes in remuneration of the generation units that will affect what is supposed to be a long-term economical signal. So any transition in CRM calls a very meticulous pathway design. On the other hand, the Achilles' heel of the auction based CR schemes is the potential for market power that can appear in the capacity auction. Recalling the almost 50% share of state owned generation units in Iran generation mix, this couldn't be an ignorable parameter.

Another concern is the capacity of transmission lines that jeopardize the essence of a centralized capacity market. However, TAVANIR is developing all transmission, sub-transmission and distribution lines, but congestion is a problem even now. Besides, the appropriate regulatory frameworks do not exist for capacity contracts even for centralized scheme, so the decentralized capacity market is a very long shot.

Iranian capacity payment mechanism is categorized in cost-based scheme, since annual base value of capacity payment (BVCP) is proposed based on recovering the capital cost of a benchmark generation technology. The alternative is LOLP-based capacity payment, which is again, not the case for Iran, because developing the generation capacity is the foremost aim of the Iranian government, despite (for example) Ireland that to impede over-capacity in its capacity payment system, characterizes the reserve margin with LOLP. Besides, the great consumer price fluctuations in LOLP-based capacity payment cannot be accepted by the consumers right now.

Summing up, given the solidity of the CRM scheme in Iran, amendments on the existing mechanism is in order. These amendments that will appear in the coefficients of BVCP, are mathematically modeled in next chapter and discussed in chapter 4. The regulatory framework to foster these changes is proposed here.

2.11. Proposed Regulatory Framework

Spanish power market benefits from a liberalized market, assisted by a capacity mechanism to improve investment signals. The defects similar to the mentioned weaknesses in Iran, are recently pointed out in Spain [8]. They are planning to overcome the problems by migrating to a hybrid CRM, compounded of reliability options and capacity payment. The idea behind the proposed regulatory framework here comes from the "Spanish white paper for regulatory reform" [9].

The basic recommendation is to maintain the existing capacity payment format, consisting in a regulated remuneration to the generating units according to their firm capacity. However, we propose to add a new element: the commitment of each generating unit to provide its assigned firm capacity whenever the system is close to rationing, in such a way that a heavy penalty must apply to dissuade non-compliance. In other word, the main regulatory proposal is to complete the current mechanism in such a way that it allows to measure to which extent the awarded capacity is available when needed, as well as establishing high penalties associated to its unavailability. This enables to make agents responsible for the intermediate measures necessary to comply with their obligations, like fuel acquisition and hydro reservoirs management. As a result, it would not be necessary to monitor availability explicitly and inefficient rules as the obligation to produce at least 300 h per year would become unnecessary. Nevertheless, the regulator should not assign capacity payments to a plant that does not have an Access to the Network contract or that is affected by a local NOx emissions limit that does not permit it to generate energy under every circumstances.

The obligation for generating units under near-rationing conditions involve that they should compulsory present a program to the System Operator in which they will be producing at least their firm capacity during the critical hours. They can comply with this obligation both through bids to the spot market and bilateral contracts. The generating units that were not dispatched become exempt of their firm capacity responsibility, which is helpful for generating units with excessively low reaction times. In addition, all energy purchased in shorter-term markets (intraday or ancillary services markets) should pay also the penalty associated to capacity payments. This rule impedes undesirable behaviors as having some generators selling their energy to the daily market and buying it back in the subsequent markets to avoid the penalty. In addition, it enables to detect problems in the daily time horizon and not afterwards.

The penalty is intended to dissuade agents from not complying with their firm capacity obligation. Thus, it should be high enough to have economic consequences. Moreover, it should be potentially higher than the original total capacity payment as, if it was not, generating units would be willing to be assigned a large firm capacity because, in the worst case, the payment would still compensate the penalty. On the other hand, the penalty must not imply excessive risks for a peaking unit with a reasonable failure rate.

- **In a nutshell the proposed procedure is structured as follows:**

1. A firm capacity value is administratively assigned to each generating unit, which can choose to reduce it in case it estimates that the risk of not meeting the commitment and being penalized is too high.
2. A regulated payment per megawatt is established. This payment should be updated in such a way to support more capital intensive power plants (as it is discussed in details in chapter 4).
3. When system experiences near-rationing condition the generating units that are awarded a capacity payment are committed to produce at least their firm capacity. In case they do not fulfill this requirement, they will be penalized for each non-supplied megawatt.
4. Utilizing stochastic modeling of the investment signals (presented in chapter 3), the reserve margin in long-run system dynamics is observed. In the case that the system reliability doesn't sustain in long-run, regulating the control variables of the system will retrieve the reliability. These control variables are: price cap, base value for capacity payment and coefficients of BVCP.

The obligation for generating units under near-rationing conditions involve that they should compulsory present a program to the System Operator in which they will be producing at least their firm capacity during the critical hours. They can comply with this obligation both through bids to the spot market and bilateral contracts. The generating units that were not dispatched become exempt of their firm capacity responsibility, which is helpful for generating units with excessively low reaction times. In addition, all energy purchased in shorter-term markets (intraday or ancillary services markets) should pay also the penalty associated to capacity payments. This rule impedes undesirable behaviors as having some generators selling their energy to the daily market and buying it back in the subsequent markets to avoid the penalty. In addition, it enables to detect problems in the daily time horizon and not afterwards.

It should be noted that the proposed approach is considered as an amendment on the defects of the existing framework and do not intervene with TAVANIR or SUNA's policies in development of thermal or RES power plants, respectively. If government takes some more substantial measures such as facilitation in the implementation of "targeted subsidy reform act", privatization of remaining state-owned power plants, electricity market liberalizing and activating the demand side response, the investment planning would be drastically subject to change.

List of Figures

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3. MODEL DESCRIPTION

3.1. General Characteristics

As shown in Table 1.1, six generation technologies including steam turbine (ST), gas turbine (GT), combined cycle gas turbine (CCGT), hydro (H), diesel (D), renewable, dominated by the wind power (W) and nuclear are used in Iranian power system. Considering all the uncertainty in situation of nuclear generation in Iran, we will not consider this technology as a generation category in our model. The investment planning is involved in many parameters that most of them reflects the historical data of each generation technology. We consider the installed nuclear capacity as a base value that is not going to be increased over the time. This simplification helps to decrease the number of generation technologies from 7 to 6 and overcome the uncertainty of nuclear generation.

In this study, a system dynamics-based simulation model is developed to analyze the Iranian electricity market and capacity payment. The fundamental model is described in detail in [1], in which the competitive and liberalized electricity market dynamics has been developed; many details and formulation have been added from [2] where different capacity mechanisms have been developed. Elaboration of formulae is referred to [3] that is the cardinal reference of market dynamics investigations toward the investment planning.

In this framework, it is assumed that no market power exists, i.e., the generation companies cannot strategically influence the market price as they are price takers and bid their marginal costs. Besides, it is assumed that the long-run equilibrium exists at the initial time of simulation, i.e., the optimal mix of generation technologies will be obtained while different generation technologies earn the exact amount to cover their fixed and operational costs [3] and the market clearing price (MCP) equals the marginal cost of the most expensive running generation technology.

The electricity price which is dynamically cleared in the electricity market in our model is paid to all conventional generation firms without considering their offered prices for electricity generation. But it should be noted that this is not the case which really occurs in the actual electricity market in Iran. After market clearing in the Iranian electricity market, the generation technologies are paid according to their offered prices since the electricity market in Iran has the discriminatory auction design (pay-as-bid). Since the auction design and the price offering are not included in our model, the type of auction design is not important in this modeling framework and this model has no dependency on the type of the auction design. The default price cap is considered 330 IRR/kWh which is ratified in 2011 in IGMC.

3.2. Conceptual Model

The conceptual framework for the generalized system dynamics model of an electricity market is depicted in Fig. 3.1. The model contains nine different modules and some input and output signals which are connected to each module. The input signals are regarded as the exogenous parameters of system dynamics model which may have uncertainty.

As depicted in this figure, five feedback loops can be observed illustrating the feedback structure of the system. Since in these loops the changes in variables are finite, they are called balancing loops. The first feedback loop connects the electricity market implementation module to the electricity demand modeling module and shows that the consumers may respond to the electricity price with some price elasticity factor. The second feedback loop illustrates the price elasticity of electricity generation in the conventional generation technologies. The electricity price is cleared from the intersection of the electricity demand and the electricity supply curves.

The third and fourth feedback loop characterize the capacity investments of new generating units (one loop for the conventional generation technologies and the other loop for renewable generation technologies). As it can be seen, most of the modules are involved with these feedback loops. The electricity price is predicted in expectation and forecast modeling module. Then, the profitability assessment and investment decision will be performed based on the expectation of future electricity price and the capacity payment which is dedicated to the generating units. Next, the process of capacity development is fulfilled including application processing, permission acquiring, construction processing, and capacity installation. The new installed capacity is utilized in order to perform the new dispatch and electricity price clearing. Therefore, the third and fourth feedback loops deal with some long time delays and are relevant with the long-term assessment of electricity market.

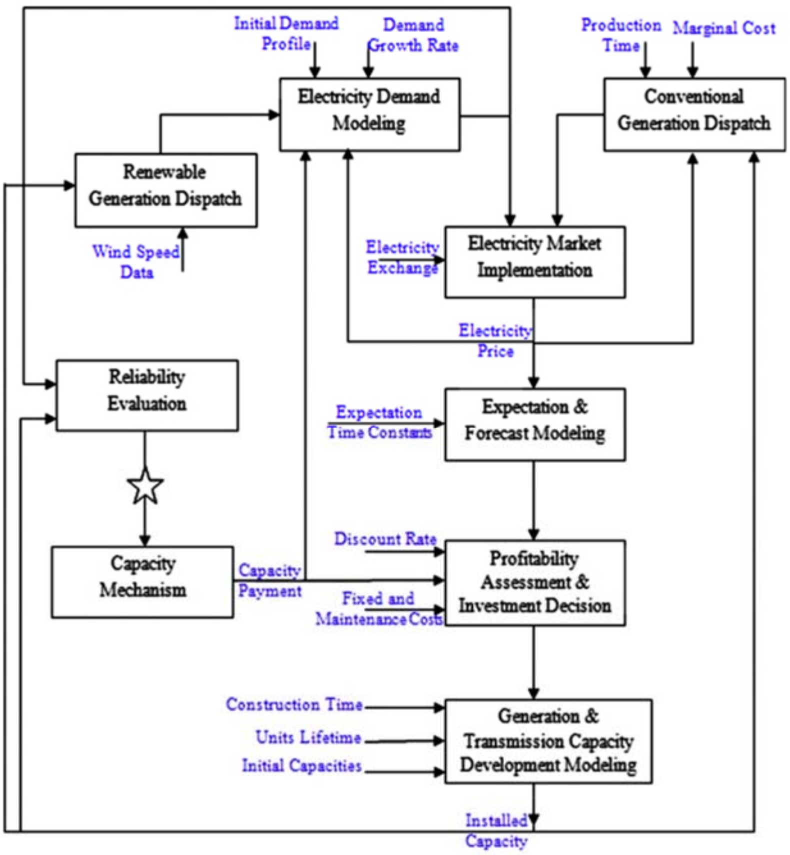

Fig. 3.1. The conceptual framework for the generalized system dynamics model. [4]

The decision making for investment is based on assessment of profitability gained from both the electricity market price and the capacity payment. The fifth feedback loop connects the profitability assessment and investment decision, the capacity development modeling, and the capacity mechanism modules together, i.e., the capacity payment should be remunerated regarding the current available capacity. The demand and installed capacities are used for the reliability evaluation and the capacity payment in this way is rewarded considering the current reserve margin and the probabilistic evaluation of the system adequacy. This procedure is the basis of the reliability-based capacity payment method and the capacity market mechanism described in [1].

Since the cost-based capacity payment is employed currently in the Iranian electricity market, this loop will be ignored and the related connectivity (the star-marked arrow shown in Fig 3.1) will be deleted. Furthermore, in the presented model some features have been ignored compared to this generalized reference model including demand response module, or stochastic behavior of RES. Utilizing this model, the reserve margin in next 30 years would be elucidated through 3 different scenarios in next chapter: first, the current situation in Iran electricity market; second, the market without CRM and higher price cap; third, the present market with different base value for capacity payment corresponding to different technologies to optimize the investment signals.

3.3. Supply Curve

Market price equals the marginal cost of the most expensive running generation technology. We assume all MWhs of energy supplied by a particular generating technology to the market are characterized by one price, which equals to the marginal cost assigned to that technology, so that the competition is reflected among several technologies (with different marginal costs). Thus, we will have six generation companies which are representative of the six existing generation technologies in Iranian power system. This can help to analyze the investment trend of different generation technologies in the electricity market.

For each generation technology, the operating costs is a function of fuel price (*FP*) and gas emission price (*EP*). It has been demonstrated that the total marginal cost (*MC*) of operation for each company *i* can be expressed as[9]:

$$MC_i = \frac{FP_i}{\eta_i} + e_i.EP \tag{3.1}$$

In which, η_i and e_i are thermal efficiency of power plant representing the part of input energy converted to electrical energy and Emission rate respectively. Sorting these marginal costs from the lowest to the highest, the dispatching merit order for the available generating capacity is determined. The supply curve can be obtained by plotting the ordered marginal costs against the total cumulated generating capacity (Fig. 3.2). For simplicity we show the figures for three generating technologies that serve in base, middle and peak load conditions.

[9] However, in Iranian case we ignore the gas emission term.

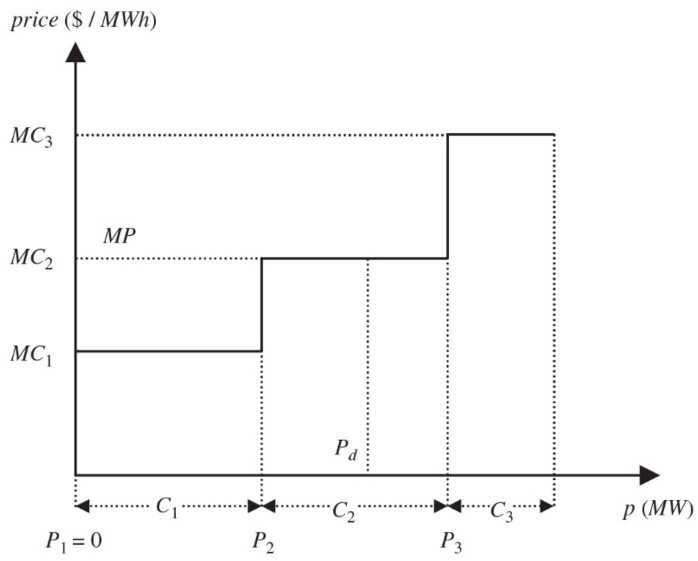

Fig. 3.2. Supply curve for three different technologies

In this figure, MC_i and C_i stand for marginal cost and the capacity of generating technology *i*. Using the supply curve, the market price (MP) can be determined for any value of the total demand (P_d). It is obvious that, for market prices lower than the marginal cost of a particular generating technology, the energy offered by that technology will not be admitted in the market. Therefore, the technology *i* participates in the market only in periods that

$$MP \geq MC_i \tag{3.2}$$

Or

$$P_d \geq P_i \tag{3.3}$$

where, P_i stands for the lowest demand at which technology *i* will be accepted in the market.

3.4. Probability Density Function of Load

Accumulating the time intervals for which load has a certain value during a period T (normally a year) and plotting the ordered values of the load versus time will produce load duration curve (LDC). Then, normalizing the values on time axis (dividing the values on time axis by T) and reversing the axes, the resulting curve can be used for probability purposes (function *F(p)* in Fig. 3.3). In fact, this curve presents the probability that the average hourly demand takes on values greater than or equal to *p* megawatt in an hour of period *T*. Using function *F(p)* as described, the probability that an average value of load may occur in an hour of period T is calculated by using the probability density function *f(p)* described by

$$f(p) = \frac{d}{dp}\left(1 - F(p)\right) \tag{3.4}$$

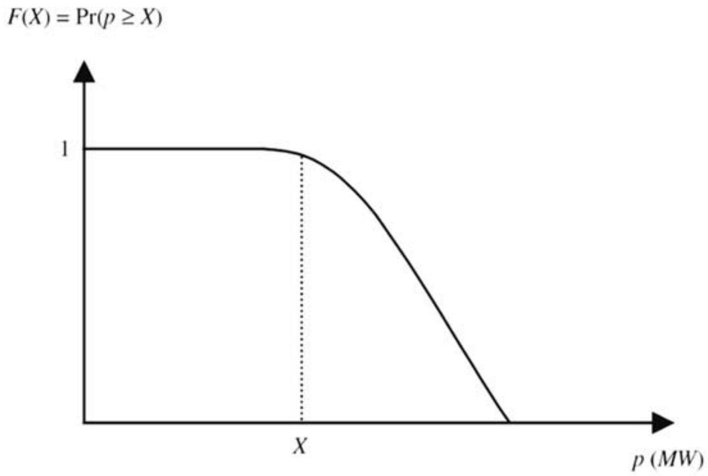

Fig. 3.3. Reversed LDC curve for probabilistic applications

3.5. Average Market Price and Technology Price Calculation

Fig 3.4. illustrates the probability distribution function of load $(f(p))$ and supply curve *(price(p))* together. *Price(p)* is the function of the *MC* of different technologies in the system. Expected average price during the period T can be computed as follows:

$$\overline{price} = \int_0^{P_{max}} price(p) f(p) dp \tag{3.5}$$

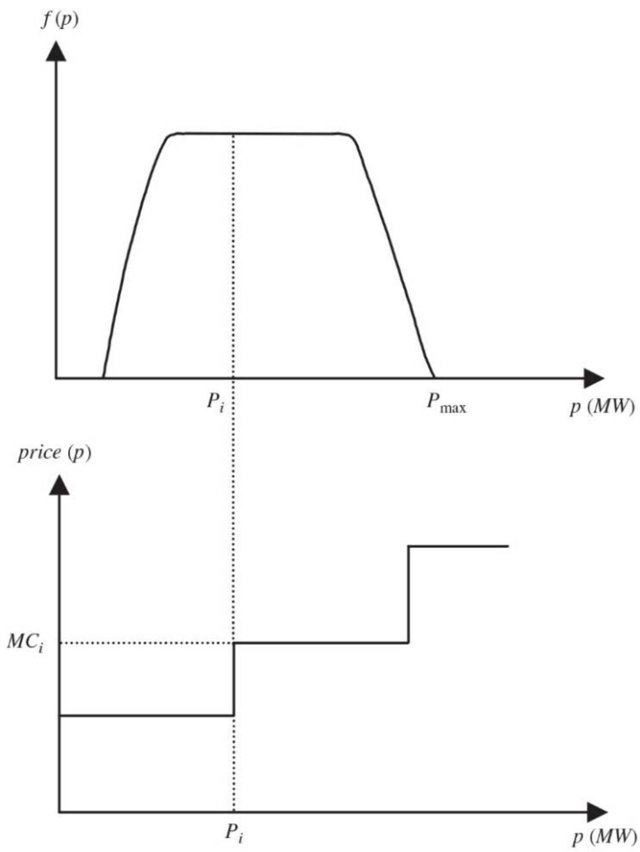

Fig. 3.4. Typical PDF of load and supply curve

Now, the average price paid for a MW in an hour for a certain technology can be calculated. As expressed before, technology *i* will participate in the market only if Eq. (3.3) is satisfied. As a result, the period that technology *i* participates in the market can be computed as:

$$T_i = T\int_{P_i}^{P_{max}} f(p)dp \tag{3.6}$$

Therefore, the average price paid to any MW of capacity for technology *i* during this period is calculated as:

$$\overline{price_i} = \frac{T\int_{P_i}^{P_{max}} price(p)f(p)dp}{T\int_{P_i}^{P_{max}} f(p)dp} = \frac{\int_{P_i}^{P_{max}} price(p)f(p)dp}{\int_{P_i}^{P_{max}} f(p)dp} \tag{3.7}$$

In our modeling, we consider a linear pattern for LDC. Now we assume that the total demand is large enough to ensure participation of C'_i MW of the capacity of technology *i* (which is greater than zero and less than the total available capacity of this technology (C_i)). Then, considering the fact that the marginal cost for each megawatt of this technology is the same, we may conclude that the probability of any megawatt of technology *i* to be admitted in the market equals C'_i/C_i (Fig. 3.5.).

Fig. 3.6 shows the probability for participation of a megawatt capacity of technology *i* at any time versus different amounts of total market demand. Therefore, the probability for participation of any megawatt capacity of technology *i* in the market during a period T can be calculated as

$$\overline{D}_i = \int_{P_i}^{P_{max}} r_i(p)f(p)dp \tag{3.8}$$

The expected duration in a year (T=8760 h) for which 1 MW capacity of this technology will share the market is equal to

$$D_i = T\int_{P_i}^{P_{max}} r_i(p)f(p)dp \tag{3.9}$$

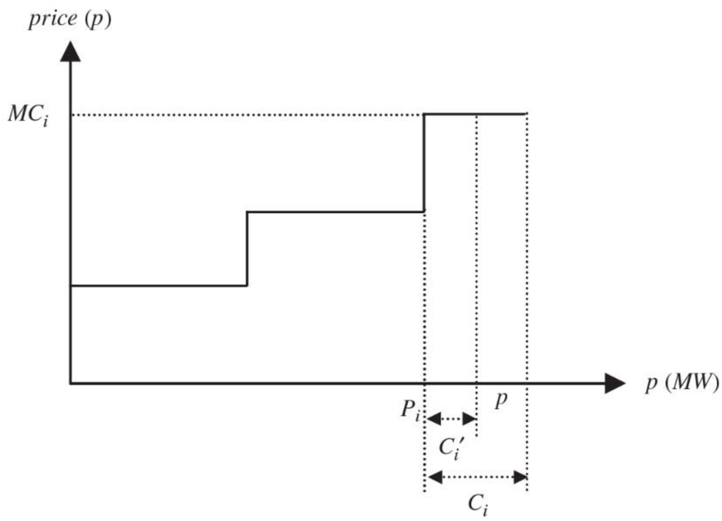

Fig. 3.5. Participation possibility of each megawatt for technology i in the market

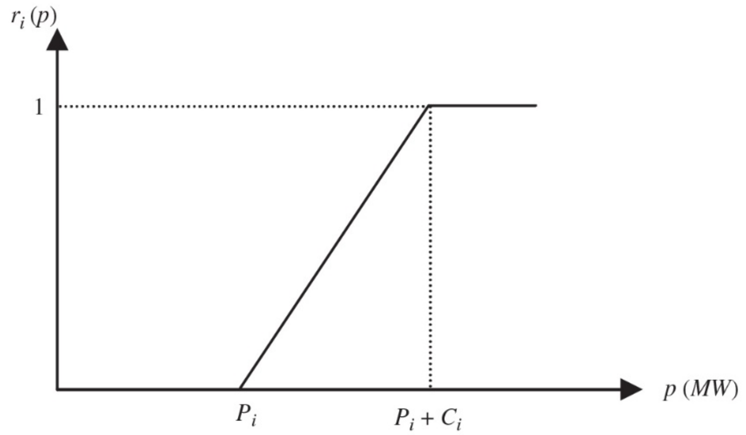

Fig. 3.6. Probability function for participating of 1 MW capacity of technology i versus load (demand) values

3.6. Capacity Mechanism Module

In Iranian electricity market, a fixed cost-based capacity payment mechanism has been introduced since 2003 when the Iranian electricity market was originated. The base value of capacity payment (BVCP) has been updated occasionally in recent years. The value which is set in our analysis, 185 (IRR/kW), pertains to year 2016. The rational assumption behind this payment is to recover the capital cost of a benchmark generation technology which is not frequently employed in the electricity market, e.g., the peaking load generation technology. The base value of capacity payment is considered as a regulatory policy to encourage the new investments in Iranian electric power system.

In the Iranian electricity market, the electricity demand, available capacity, and electricity reserve of each operating hour in the year are forecasted in the early time of the year. When getting closer to the operating hour, these parameters are forecasted again more precisely. But the capacity payment of each operating hour is calculated in the day-ahead market (1 day prior to the operating day) based on the last forecasted parameters.

We consider all the installed capacity as the available capacity by the time being. To calculate the system reserve, we need to subtract the available capacity ($AvCap_t$) of each year, as a constant value, from load profile (LDC); the result would be the *Reserve%* as a function of duration (D). In this way the duration in which the reserve is more or less than a critical value could be computed.

$$Reserve_D\% = \frac{AvCap_t - Load(D)}{Load(D)} \times 100 \tag{3.10}$$

Since the operational reserve market has not been established yet, the regulatory commission decided to encourage the generating units in order to provide the operational reserve. For this purpose, the base value of capacity payment is altered inversely proportional to the operational reserve, i.e., if the operational reserve decreases in a period, the capacity payment of that period will increase in order to make an encouragement for generating units to be available for providing the reserve margin. Since the generating units can receive more profit in the time of deficiency when the reserve margin is expected to be low, they provide most of their available capacities in order to supply the electricity reserve beside the electrical energy. Inversely, if the operational reserve increases in a period, the capacity payment will decrease. So, the weighting factor which depends on the value of operational reserve is defined as follows [5]

$$W_D = \begin{cases} \dfrac{1}{Reserve_D} & if\ Reserve_D > 3\% \\ {}^{1}\!/_{3} & if\ Reserve_D \leq\ 3\% \end{cases} \tag{3.11}$$

In calculation of the operational reserve it should be noted that the operational capacity is averagely 12% less that the installed capacity (*C(t)*) of that year. Utilizing an auxiliary factor, the framework perceived by market regulator in the Iranian electricity market is amended in order to fit the peculiarities of our model.

$$K = \frac{T \cdot AvCap_t}{\left[\frac{1}{Reserve_D} \cdot \overline{D}_I + \frac{1}{3} \cdot \overline{D}_{II}\right] T \cdot AvCap_t} = \frac{1}{\left[\frac{1}{Reserve_D} \cdot \overline{D}_I + \frac{1}{3} \cdot \overline{D}_{II}\right]} \tag{3.12}$$

In it, K is the auxiliary factor, $AvCap_t$ is the available capacity in year *t*. $\overline{D}_I, \overline{D}_{II}$ are respectively the durations in which the $Reserve_D$is more or less than 3% and T=8760 h. So, the capacity payment factor will be calculated as follows:

$$CPF_D = W_D \cdot K \tag{3.13}$$

The market regulator in the Iranian electricity market decided to make the sum of weighted average of all capacity payment factors become unity, so that the regulator can be ensured that the total capacity payment in the whole year will be the same as the sum of all available capacities in the year multiplied by the base value of capacity payment. In this way national yearly capacity payment will be:

$$CP_{tot} = (T \cdot CPF_D) \cdot (T \cdot AvCap_t) \cdot BVCP = (T \cdot AvCap_t) \cdot BVCP \tag{3.14}$$

Eq. (3.14) demonstrates that the total capacity payment in a year equals the sum of all available capacities in that year multiplied by the base value of capacity payment. In fact, it implies two points:

- The incentive for new capacity investment and availability of capacity in the long-term (which is reflected in the base value of capacity payment)
- The incentive for utilizing the current capacity and availability of capacity in the short-term to provide both energy and operational reserve (which is reflected in the weighting factor W_t)

For simplicity we assume that all the generators respond to reserve in the same way, thus the annual capacity payment to each megawatt of each generation technology pertaining to 1st scenario is:

$$CP_i = \frac{CP_{tot}}{AvCap_t} \tag{3.15}$$

For the 3rd scenario in which we have different base value for capacity payment (BVCP)

$$CP_i = \frac{BVCP_i \cdot T}{AvCap_t} \tag{3.16}$$

The capacity payment mechanism that has been discussed above is devoted to the conventional generating units (i.e., thermal and hydroelectric units). The payment for renewable generating units conforms to another mechanism that is already discussed in chapter 1.

3.7. Economic Assessment of Investment

One of the most conventional methods for economic assessment of a project is the Net Present Value (NPV) method. NPV for any project is equal to the difference between the present value of the total income and the total cost of the project within its operational lifetime. However, for comparing projects with different lifetimes, this may not be easily used. On the other hand, using Internal Rate of Return (IRR) and Annual Equivalent Value (AEV) methods may be considered as better measures for comparison among different projects. The AEV method converts the income and cost during the operational lifetime to its equivalent annual value.

Each generating technology *i* has two periods in its lifetime; construction period (T_{ci}) and operation period (T_{oi}). For simplification, we have assumed that all investment costs (IC_i) have been paid at the beginning of the construction period. Then subtracting the operation cost from the income, the annual profit for each year can be calculated. Fig. 3.7. illustrates the related cash flow diagram. In it, *t* is the time reference indicator.

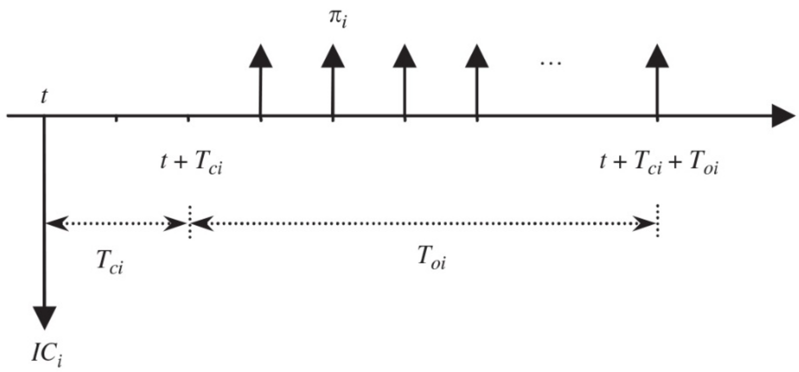

Fig. 3.7. Cash flow diagram considered for economic assessment

The annual profit for a MW capacity of technology *i* (π_i) can be calculated as follows:

$$\pi_i = \left(\overline{price_i} - MC_i - OMC_i\right) \cdot D_i + CP_i \tag{3.17}$$

where $\overline{price_i}$ is the annual expected average electricity price (€/MWh), MC_i is the annual expected average marginal cost (€/MWh), OMC_i is the operation and maintenance cost (€/MWh) and D_i is the expected average time duration that each MW of technology *i* is utilized in a year (hours).

To investigate profitability of investment, according to AEV method, annual equivalent value of profit during the period T_{ci}+T_{oi} (represented by $\bar{\pi}_i$) should be compared with annual equivalent value of investment during the period T_{ci}+T_{oi} (represented by $\overline{IC_i}$).

The annual equivalent values of investment and profit during the period T_{ci}+T_{oi} can be formulated as

$$\bar{\pi}_i = \pi_i(P/A, r, T_{oi})(P/F, r, T_{ci})(A/P, r, T_{ci} + T_{oi}) \tag{3.18}$$

$$\overline{IC_i} = IC_i(A/P, r, T_{ci} + T_{oi}) \tag{3.19}$$

where

$$(P/F, r, \theta) = (1 + r)^{-\theta} \tag{3.20}$$

$$(P/A, r, \theta) = \frac{(1 + r)^{\theta} - 1}{r(1 + r)^{\theta}} \tag{3.21}$$

$$(A/P, r, \theta) = \frac{r(1 + r)^{\theta}}{(1 + r)^{\theta} - 1} \tag{3.22}$$

Eqs. (3.20-22) are transformation functions as multiplier coefficients, which convert the future value in year θ to its present equivalent value, the annual equivalent value during period θ to its present value and the present value to its annual equivalent value during period θ, respectively [6]. In these formulas, r stands for the required rate of return at the industry level. Using Eqs. (3.20-22), the annual equivalent value of profit during the period $T_{ci}+T_{oi}(\bar{\pi}_i)$ for an investment in technology i at year t, with a construction duration of T_{ci} and an operation period of T_{oi} (Fig. 3.7.), can be calculated. To do this, first of all π_i during the years $t+T_{ci}$ to $t+T_{ci}+T_{oi}$ is converted to its equivalent value in year $t+T_{ci}$, then this value is converted to its equivalent value in year t. Finally, this latter equivalent value is converted to its equivalent distributed value during period $T_{ci}+T_{oi}$. Eq (3.18) stands for the integration of these three transformations.

3.8. Profitability Index

We may define a profitability index for each generating technology as

$$PI_i = \frac{\bar{\pi}_i(r, T_{ci}, T_{oi})}{\overline{IC_i}(r, T_{ci}, T_{oi})} \tag{3.23}$$

At the long-term equilibrium point for an ideal competitive market, the profitability index for each technology will be equal to one. This is because of the fact that the profit equals the average investment costs. Under such circumstances the market does not offer any incentive for new entries or exits. However, old power plants being decommissioned will be replaced by new ones covering the retired capacity and the long-term perceived demand growth [3]. We have considered this condition as the reference level of investment rate in our investigation.

When aggregated perceived profitability rises and $PI>1$, then more projects will be profitable and more firms will invest in new capacities. On the contrary, when $PI<1$, fewer projects will be profitable and only firms with lower capital costs may invest. In this case, the aggregated investment rate will be less than the reference level. Due to these explanations, Olsina et al. [3] have used a logistic function m_i (a type of S-curve functions) to describe the aggregated investment responsiveness to the profitability index for each technology i

$$m_i(PI_i) = \frac{m_i^{max}}{1 + e^{-(\lambda_i PI_i + \gamma_i)}} \tag{3.24}$$

Where m_i is the logistic function for technology i, PI_i is the profitability index of technology i, m_i^{max} is the upper limit of the logistic function (maximum value of m_i), and λ_i and γ_i are the parameters of the logistic function. The above equation must satisfy the condition

$$m_i(PI_i) = 1 \tag{3.25}$$

where

$$\lambda_i = ln\left(\frac{1}{m_i^{max} - 1}\right) - \gamma_i \tag{3.26}$$

and

$$\gamma_i = ln\left(\frac{m_i^0}{m_i^{max} - m_i^0}\right) \tag{3.27}$$

For a high profitability level, it seems logical that investment responsiveness shows a saturation level since participants are aware of the high attractiveness for investing and the potential danger of a wave of massive entries; so we have assumed different saturation levels (m_i^{max}) for different generation technologies. The saturation level for base power plants is set relatively low, as it is unlikely that a severe investment over-reaction in this type of plants happens; on the contrary, the saturation level for CCGT and renewable power plants is set relatively high, since a high degree of responsiveness of the investments in this technology upon the profitability level has been observed in actual markets. To describe the investment rate at time t for generation technology *i*, the following equation has been adopted

$$\dot{I}_i = m_i(PI_i)\left(\dot{R}_i + \dot{L}_i\right) \tag{3.28}$$

where $\dot{I}_i$ is the investment rate of technology *i* at time t (MW/year), $\dot{R}_i$ is the capacity retirement rate of technology *i* at time t (MW/year) and $\dot{L}_i$ is the capacity addition rate necessary to cover the expected growth of the maximum load served by technology *i* (MW/year).

The maximal and minimum load (demand) for year $t + \Delta t$ can be formulated in 3.29 and 3.30, where $P_{max}(t)$ and $P_{min}(t)$ are respectively the maximum and minimum demand for year *t*, and g is the average load growth:

$$P_{max}(t + \Delta t) = P_{max}(t)(1 + g)^{\Delta t}, \tag{3.29}$$

$$P_{min}(t + \Delta t) = P_{min}(t)(1 + g)^{\Delta t} \tag{3.30}$$

Under long-run equilibrium market conditions, the maximal load economically served by technology *i* at time t can simply be derived from the linear screening curves and the LDC prevailing at that time. The optimal capacities for each technology, denoted by K_i^*, can be determined by assuming that the LDC conserves its linear pattern over the simulation horizon

$$K_i^* = [P_{min}(t + \Delta t) - P_{max}(t + \Delta t)]\overline{D}_1 + P_{max}(t + \Delta t) \quad , i = 1 \tag{3.31}$$

$$K_i^* = [P_{min}(t + \Delta t) - P_{max}(t + \Delta t)](\overline{D}_{i+1} - \overline{D}_i) \quad , i = 2,3, \dots ,6 \tag{3.32}$$

By introducing Eqs. (3.29, 3.30) into Eqs. (3.31, 3.32), and by differentiating the latter with respect to time, the addition rate of capacity for each technology, required to optimally cover the growing demand can be obtained to be substituted in Eq. (3.28).

$$\dot{L}_i = \partial K_i^* / \partial t \tag{3.33}$$

3.9. Capacity Development

For a more thorough analysis, assume that the regulator decides to promote the available capacity to meet a certain amount of reserve by motivating the CCGT technology. Then, if we assume that the time delay between investment decision and capacity realization for CCGT technology is almost equal to the construction time of such units, it will be obvious that the impact of incentives on investment at the time being (year t), will emerge in year $t + \Delta t$. Therefore, the regulator may set the incentive signal according to his plan such that the available capacity in year $t + \Delta t$ will satisfy the extra required capacity (ERC).

The capacity for year $t + \Delta t$ can be expressed with the following equation:

$$C(t + \Delta t) = C(t) + \Delta C_{inp}(t, \Delta t) - \Delta R(t, \Delta t) \tag{3.34}$$

where $\Delta C_{inp}(t, \Delta t)$ is the volume of new commissioned capacity during the period starting in year t and ending in year t+Δt and $\Delta R(t, \Delta t)$ is the volume of retired capacity during the period from year t to year t+Δt.

Having the information about the investment for the capacity during the period from year t−Δt to year t, the capacities supposed to be commissioned during the period from t to t+Δt can be computed accurately. Therefore, we may write

$$\Delta C_{inp}(t, \Delta t) = \int_{t}^{t+\Delta t} \dot{C}_{inp}(\tau) d\tau = \int_{t-\Delta t}^{t} \dot{I}(\tau) d\tau \tag{3.35}$$

Where $\dot{C}_{inp}$ and $\dot{I}$ are, respectively, the rate of entered capacity and the rate of investment on new capacities. For the retired capacity we may write

$$\Delta R(t, \Delta t) = \int_{t}^{t+\Delta t} \dot{R}(\tau) d\tau \tag{3.36}$$

Where $\dot{R}$ is the rate of retried capacity that is calculated according to the lifetime of each generation technology.

Finally, the reserve margin (RM) for each year is computed using the total installed capacity and the maximum demand as follows:

$$RM(t) = C(t) - P_{max}(t) \tag{3.37}$$

3.10. Input Data

The characteristics of the demand and different generation technologies as well as the fuel prices are given in Table 3.1.

Considering the constant variation of the Euro-IRR exchange rate and frequent changes in the administrative parameters and three years delay in publication of the annual Energy Balance Sheet, utilizing the most recent data in the model is not possible. Therefore, the model is fed with the data provided by TAVANIR in 2013, when each Euro is 32300 IRR.

Table 3.1. Electricity demand characteristics, fuel prices, and generation technologies characteristics [7]

Electricity Demand Characteristics	
Initial peak demand of duration curve (MW)	45,659
Initial minimum demand of duration curve (MW)	25,212
Expected annual growth rate (%/yr)	7

Fuel Prices	
Gas subsidized tariff (IRR/m3)	700
Mazut and fuel oil tariff (IRR/Liter)	2000
Diesel tariff (IRR/Liter)	3500

Generation Technologies Characteristics

	ST	GT	CCGT	H	D	W
Average construction time (yrs)	5	2	4	2	3	0.5
Lifetime (yrs)	45	40	40	60	50	20
Investment cost (IRR/MW)	8320	3740	7480	18,000	9700	9700
Maintenance cost (IRR/MW/yr)	330	150	300	720	390	390
Thermal eff. (mid–age vintage) (%)	39	29	42	–	–	–
Internal rate of return	0.08	0.08	0.08	0.08	0.08	0.08
m^{max}	1.5	2	3	1.5	0.5	4
m^0	0.15	0.15	0.15	0.15	0.15	0.15

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Reference

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4. RESULTS AND DISCUSSION

The proposed model for the Iranian electricity market is implemented in MATLAB©, to investigate the impact of using different regulated policies for capacity payment and electricity price cap. We assume that the system is initially at the long-run equilibrium. Using this assumption means that we will avoid any exogenous sources of dynamics that might happen in the past and may affect the system operation in the future. Thus, our simulation results reflect only the consequences of dynamic behaviors, policies, and time delays which happen after the start of the simulation time horizon. The Iranian electricity market will be analyzed under three scenarios: First, present state of Iranian electricity market; Second, energy-only market; Third, different base capacity payments for different generation technologies.

4.1. 1st Scenario: Present State of Iranian Electricity Market

The first scenario involves with the current situation of the Iranian electricity market, i.e., the current electricity market price cap (330 IRR/kWh) and the current base value of capacity payment introduced in the previous sections are applied (185 IRR/kWh). The simulation results for the electricity peak demand, total installed capacity, reserve margin, and installed capacities of different generation technologies are depicted in Fig. 4.1. A. As it can be observed, the capacity shortage is likely to happen in year 2040 as the result of applying the current regulatory settings of electricity price cap and capacity payment.

As one can see in Fig. 4.1 B, unlike the ST and CCGT technologies, the installed capacities of GT technology is increasing over time. Since the capital cost of GT technology is lower than the capital costs of ST and CCGT technologies, the capital cost of GT can be easily recovered and consequently, the GT capacity investment will be more than the capacity investments of other generation technologies. Besides, due to low capacity investments in ST and CCGT technologies, the investment rates in these technologies are lower than the retirement rates of them. So, the installed capacities of ST and CCGT technologies are decreasing over time.

Due to higher fuel cost and lower thermal efficiency, the GT technology's marginal cost of generation is higher than the marginal cost of other technologies. So, the GT technology is frequently utilized during the peak load periods. Although the installed capacity of this technology is high, its capacity factor[10] is low. Therefore, due to imbalances between the electricity generation and consumption, the electricity market price finally reaches the price cap and remains in this condition. As a result, higher price caps are required in order to balance the electricity generation and consumption. When the price cap is set to a higher level, incentive will be more for investment in generation capacity and the generation capacity will be expanded to balance the electricity consumption. Eventually, the capacity shortage and energy imbalances will be less likely to happen.

[10] The net capacity factor is the unitless ratio of an actual electrical energy output over a given period of time to the maximum possible electrical energy output over the same amount of time

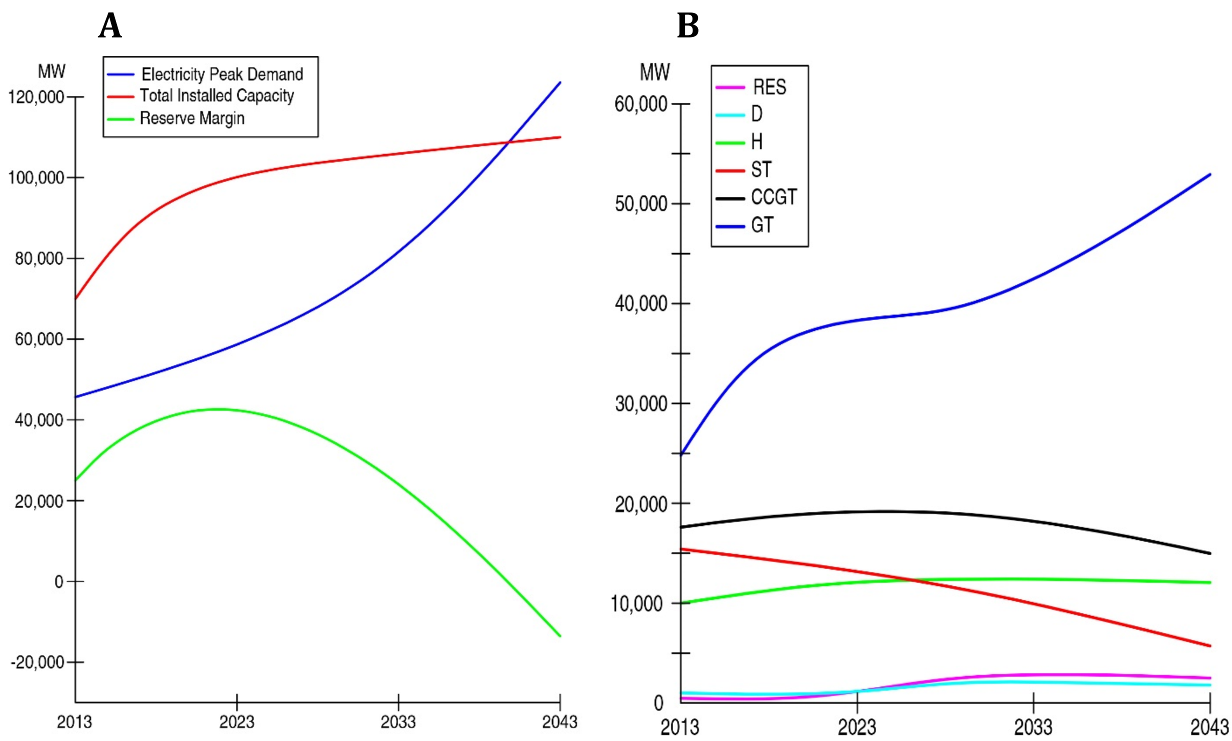

Fig. 4.1. First scenario simulation result (Present State of Iranian Electricity Market): A) electricity peak demand, total installed capacity and reserve margin, B) installed capacities of different generation technologies

4.2. 2nd Scenario, Energy-Only Market

As the second scenario, it is assumed that the capacity payment is totally ignored while the electricity market price cap is set to 660 IRR/kWh. Compared with the first scenario, the capacity payment was omitted and the electricity price cap was doubled. In other words, by applying the second scenario, the market regulator wants to recover the omission of capacity payment incentives by setting the electricity price cap at a higher level. As the simulation results of this scenario show in Fig. 4.2, the capacity shortage will happen in the absence of any other payments such as capacity payment since the investment rates in all generation technologies are not sufficient.

Simulation results of the first and second scenarios (in Figs. 4.1 and 4.2 A) show that the same condition happened in both of them. It is observed that the capacity shortage is likely to happen while the electricity price will reach to its cap value and the imbalances between electricity generation and consumption will happen in the simulation time horizon. The market regulator wanted to recover the lack of capacity payment incentives in the second scenario by setting the electricity price cap twice the value which had been set in the first scenario. But it was seen that the electricity price cap was not high enough to make enough incentives. Therefore, the comparison of these scenarios shows that the market regulator cannot neglect completely the capacity payment by adding the same value to the electricity price cap. Since the price cap is low in this energy-only mechanism, sufficient incentives do not exist in order to encourage the investors to invest in the generation capacity since lack of enough investment has been discovered.

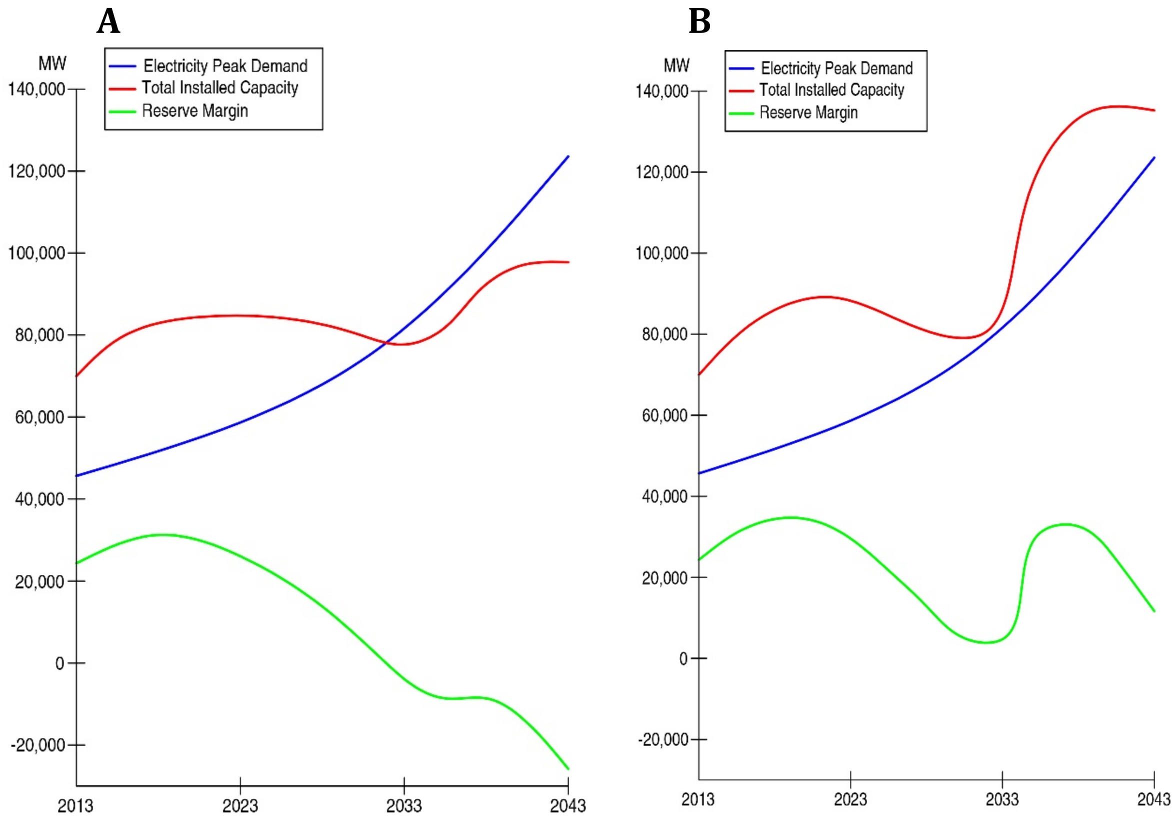

Fig. 4.2. Second scenario simulation result, energy-only market with A) doubled price cap, B) price cap set to VOLL

Now consider another case under the energy-only market scenario, in which the price cap is removed, i.e. is set to VOLL. (computing VOLL is not a straightforward task, especially for Iran electricity market that always had a price cap. In this case we consider it 10 times than the price cap.) As one can see in Fig. 4.2.B, the capacity shortage happening in 20 years after the simulation start time causes the energy price to increase abruptly to values more than 3000 IRR/kWh. the reserve margin is approximately 6% at this time. So this energy price "virtual motivation" is the only incentive signal for future investments. The new wave of investment and installation of capacity results in 20% of reserve margin in a few years later. As a result of this over investment, about 137 GW of capacity is installed in year 2041. This will subsequently depresses the average prices and makes a great investment bust. These long time and intensive boom and bust cycles in investment wave, established from price volatilities, are not normal conditions for investors to recover efficiently their fixed costs. The situation can be mitigated by employing some regulatory policies such as application of lower energy price cap; in contrast, it was shown that however simulations with lower price cap makes the investment wave amplitude smaller, but it doesn't lead to the system reliability. When the higher price cap is imposed, severe price spikes are likely to happen in the durations of capacity shortages. This can solve the problem of missing money, but cannot contribute to investment planning. Moreover, due to political considerations, such high prices are not welcome. This is a crucial point where the nature of CRM would be challenged: intervening in market dynamics for a greater good, or trust the market signals. Our choice is the first option. Figure 4.3 outlines the points of view of two sides of argument.

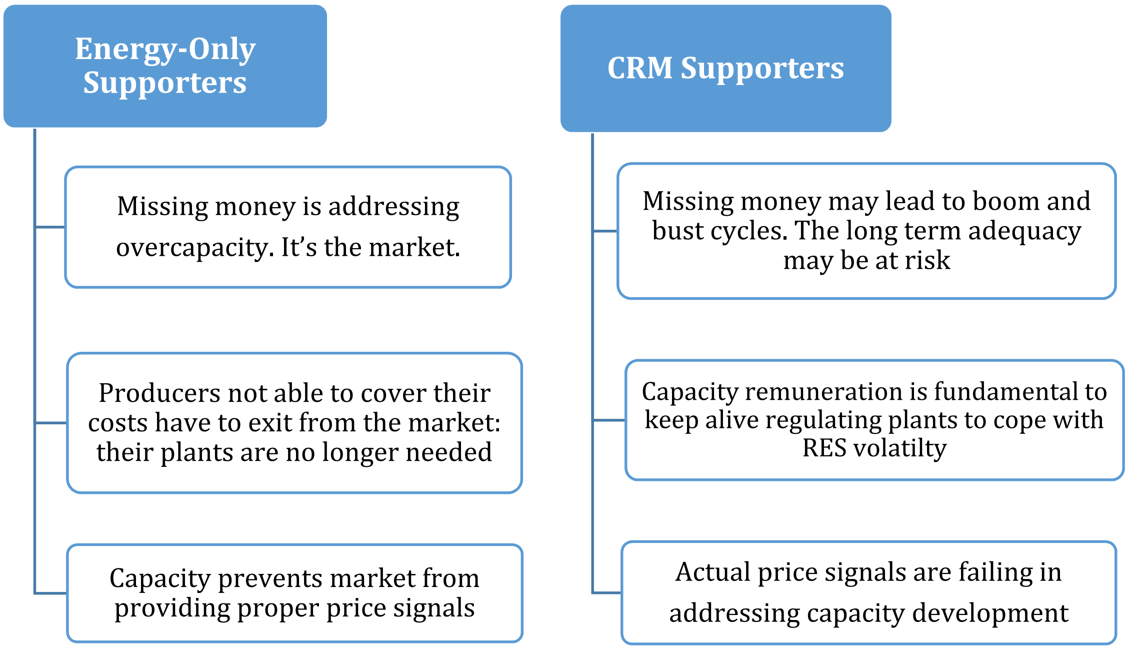

Fig. 4.3. Pros and cons of CRMs from investment planning point of view

4.3. 3rd scenario, Toward the System Reliability

In the third scenario, different base capacity payments for different generation technologies are assumed. In this case, three-tariff capacity payments are applied. The base load capacity payment of 220 IRR/kW was assigned to recover the capital and the fixed operating and maintenance costs of a most recently planned steam unit as the base load supplier, whereas the middle load capacity payment of 130 IRR/kW and the peak load capacity payment of 89 IRR/kW reflect the capital, operating, and maintenance costs of standard CCGT and GT technologies, respectively. Fig. 4.4 depicts the simulation results of this scenario. The investment rates of all thermal units are smoothly increasing in this condition and, consequently, the total installed capacity increases moderately with the electricity demand without happening any boom and bust cycling of investment. Since appropriate incentives are set for capital-intensive generation technologies, both the capacity investment and capacity factor are high enough that no capacity shortage and severe imbalances between supply and demand happen in the electricity market.

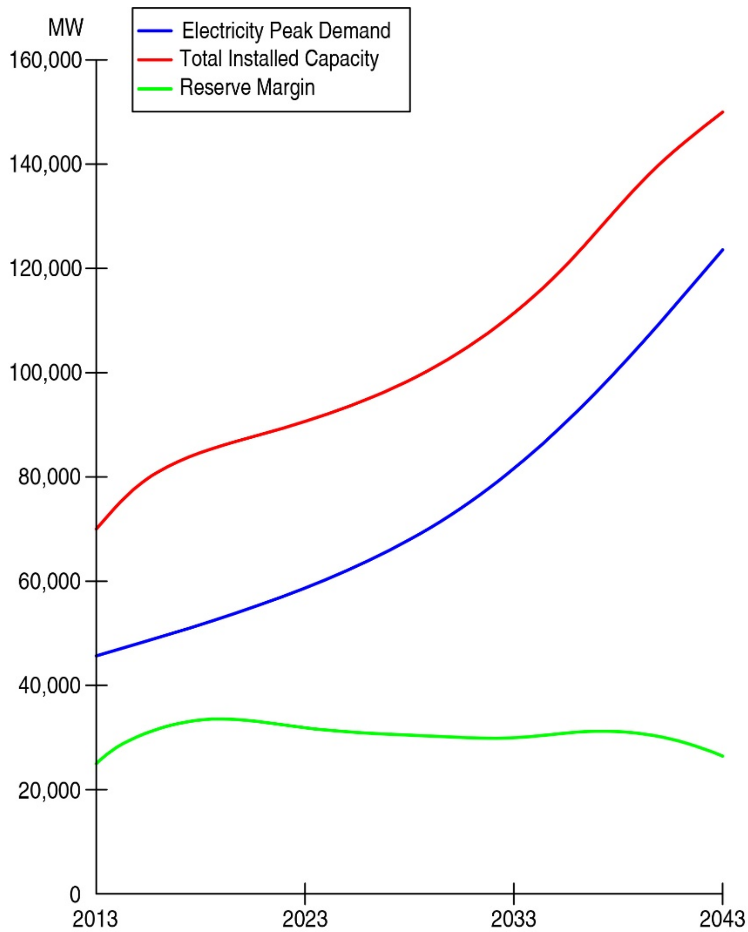

Fig. 4.4. Third scenario, stable reserve margin due to disparity in assigning the base value for capacity payment

In fact, this policy helps to keep alive and improve the base, mid and peak load power plants corresponding to their importance and contribution in generation mix: while base load power plants cover the most dominant part of the demand, it is not convenient to design the market in such a way that peaking units address the demand growth. Instead of leading the electricity market to the point that stochastic price spikes play a significant role in investment planning, the electricity market should be able to absorb the investors in capital intensive generation units. This point must be referred to the reasons of CRM in Iran at first hand, however the future RES penetration can be considered as a treat to system security, but by now, the coverage of growing demand is the most prominent target.

Tables 4.1 provides a comprehensive view to the all three scenarios. The data from every five years is reported. In this table the “reserve margin” reflects the green lines in figures 4.1.A, 4.2.A, 4.2.B and 4.4. To have a better comparison tool, the percentage of reserve margin is tabulated. Equation 4.1 defines this variable.

$$RM\% = \frac{Reserve\ Margin}{Peak\ Demand} \times 100 \tag{4.1}$$

Table. 4.1. Comparison of three scenarios in term of reserve margin

		1st scenario		2nd scenario A		2nd scenario B		3rd scenario	
year	Demand	RM(MW)	RM%	RM(MW)	RM%	RM(MW)	RM%	RM(MW)	RM%
2013	46294	25089	54	24974	54	25058	54	25281	55
2018	52256	39840	76	31863	61	34981	67	33348	64
2023	59145	42463	72	26785	45	30409	51	31912	54
2028	68393	36603	54	14546	21	13787	20	30477	45
2033	81939	24128	29	-3172	-4	5424	7	29975	37
2038	100960	6818	7	-7828	-8	33211	33	31170	31
2043	123610	-13715	-11	-24955	-20	12460	10	26426	21

This table highlights the importance of long term view on security of supply. If the current situation of the Iran sustains, the reserve margin will be 72% in year 2023 that can mislead the myopic decision makers with this idea that the current mechanism is perfectly functional, while in subsequent 20 years RM is less than zero. Another important point that can be understood from table 4.1 is that even under 3rd scenario, however the reserve margin is stable, the RM% is decreasing. This means that however 25 GW of system reserve seems totally appealing, by level of demand growth is that much high that undermines it over time. This calls for more serious demand response measures. In fact, the Iranian authorities should note that leaning the regulatory policies solely on the shoulders of generation side and neglecting the demand contribution to system reliability is wrong. It can be easily perceived from French or Italian policies in their capacity market design.

4.4. Limitations of the Model and Future Research

Even though we included a wide range of important features of electricity markets and peculiarities of Iranian market in our case, one should keep in mind, that we also have left out a number of complexities that can be highlighted below.

- To encourage new investors, TAVANIR grants a power purchase agreement (PPA) to each power plant for the first 5 years of their operation. After the PPA period, they directly sell the electricity to the wholesale electricity market; nevertheless, in presented model we did not consider this matter directly.
- We assumed that all the energy is offered in main electricity market, while a part of the demand is covered with bilateral contracts and ENEX trades (Energy Exchange).
- We presumed perfectly inelastic behavior for demand; nonetheless, due to stepwise billing policies demand side is responding to price signals.
- Beside the generation capacity the transmission lines and congestion is among the serious concerns of TAVANIR that is not included in the model.
- No interaction with neighboring countries is conceived in the model. The government plans to develop the international power lines for some political reasons, thus international tie-lines would be an important parameter in modeling the electricity market.

Actualizing the investment model by considering the first three points is the foremost target of future investigations. Moreover, an advanced study on regional electricity market with territorial capacity allocation seems strategic in investment planning. In the scenario of regional assignments of capacity in electric power systems, the electricity market will be run regionally and the electricity price is cleared considering the tie-line capacities, and the supply and the demand curves in each region. The investors are encouraged to invest in the generation capacity of each region based on the incentives provided in that region. As referred to previously (Fig 1.5), the whole electric power grid has been divided into five regions with the related tie-lines. The characteristics of electricity demand and the generation technologies related to each region should be inserted in system dynamics model. To do so, the electricity exchanges with neighboring regions will be considered in the electricity market implementation of each region. The electricity price is cleared considering the electricity imports and exports beside the demand and supply of electrical energy in each region. The capacity payments will be assigned depending on the capacity requirements in the regions. Toward this aim, the experience of some advanced power systems in regional capacity assignments will be desirable. The utmost example in this case is Italy that benefits from 6 zonal capacity markets. Moreover, the Italian experience in designing a regulatory framework for central coordination of decentralized markets could be useful in designing such a framework for Iran.

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Conclusion

Relying on a healthy reserve margin is a key element for the correct development of a market, which should lead to turn it into the appropriate tool to provide the required incentives for generation and demand to maximize the overall system efficiency (and therefore the net social benefit). The credibility of the market price, i.e., the success of the price as the efficiency signal, free market barriers and uncompetitive behaviors, will be a critical factor in facilitating the entry of new investors and this, in turn, will help in maintaining this desired margin of the installed and available generation capacity over demand at all times. One of the defects in the current capacity payments mechanism in Iran is that although it introduces an additional remuneration that supports new investments to some extent, there is no guarantee that it will be enough to attract the required amount of generating units. These payments are more likely to persuade obsolete generating units to stay in the system, but not to stimulate new investments. Therefore, it is necessary to introduce an additional procedure that allows the regulator to achieve its installed capacity goal.

In this thesis, a system dynamics-based simulation model is proposed that helps to get insights into how different regulatory policies in capacity payment mechanism and electricity market price cap can be employed in Iranian electricity market to create investment incentives. While most capacity payment methods reflect only short-term signals of the reserve margin and may be manipulated by generators, the proposed method is advantageous because it is determined based on long-term expected reserve margin. In this model, the probability density function of load has been used for average market price calculations. To analyze Iranian electricity market where several technologies participate in the market, two concepts in market calculations have been applied to this model: average price paid to 1 MW of a technology and the expected duration for which 1 MW capacity of a certain technology participates in the market. Delays in unit constructions, estimation of demand and market capacity growth during construction periods have been included and considered in the proposed algorithm as parameters which effect the decision.

The model has been used for investigating the effect of variable capacity payment in market investment. Three scenarios were assessed in the electricity market. It was observed that the current regulatory policy cannot be appropriate since the problems of capacity shortages and energy imbalances were observed in the simulation time horizon. Our simulations indicate that energy only market is unable to motivate investor with stable signals to cover the arising demand in long-run and business cycles strongly threaten the system reliability, while with a fixed capacity payment the amplitude of these cycles is reduced. Adoption of different capacity payments according to the generation technology shows favorite results. The results reflect lower total capacity expansion cost for this scenario compared to the other scenarios. The results also show that in a market with a variable capacity payment, the reserve and available capacity can efficiently be controlled.

The ideology behind the optimal energy-only markets and system behavior in sub-optimal conditions were elaborated. The necessity of capacity remuneration mechanism to retrieve the healthy investment signals, in order to guarantee the system reliability has been clarified. Looking at the experiences of pioneer countries in CRM, a number of amendments in Iranian regulatory framework have been proposed to improve the utilization of already-installed power plants.

Iranian electricity market design is relatively new and is quickly developing due to the fast growth of electricity demand and new wave of investment in renewable power plants. The decision model developed in this paper can help both the generation companies and the regulators to comprehend the possible outcomes of different decisions, regulatory policies, and market conditions in the electricity sector.