PONTIFICIA UNIVERSIDAD CATOLICA DE CHILE
SCHOOL OF ENGINEERING

IMPROVED MARKET REPRESENTATION OF AGENT PREFERENCES IN A RENEWABLE ENVIRONMENT

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Thesis submitted to the Office of Graduate Studies in
partial fulfillment of the requirements for the degree of
Doctor in Engineering Sciences

Advisor:
HUGH RUDNICK

Santiago de Chile, August 2017

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To María José, Gabriel and Amaya,

for their love and support

throughout this journey...

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ABSTRACT

The context given by the growing inclusion of variable renewable energies in power systems worldwide, presents both operational and regulatory challenges. The large-scale entry of these technologies changes the dynamics of the market, so existing market mechanisms and regulatory schemes lose effectiveness in this new paradigm. In this sense, some dimensions of the involved agents are not being fully represented by existing mechanisms, whose effect is accentuated as the inclusion of these technologies advances.

This raises the need to design and evaluate new market mechanisms that allow advancing towards an ideal market under these new conditions imposed by this renewable environment.

The objective of the research is to design mechanisms for the generation sector, that allow to improve conditions in the areas of energy, capacity and security, through a better representation of agents' preferences participating in this new renewable scenario. In the area of energy, a long-term energy auction design is proposed, which considers a representation of the short-term profile of the participants at the time of allocation of the auction. In the area of capacity, a capacity market is proposed, where the construction of the demand curve considers both the statistics of renewable power plants and the demand preferences. In the area of security, a mechanism is proposed to determine the optimum systemic volume of Liquefied Natural Gas to be imported on the basis of a risk hedging market, in order to have the necessary volume of such fuel.

The document presents an analysis of the problem that each mechanism tries to solve, the design of each one of them and the development of case studies to evaluate their effectiveness.

The contribution of the doctoral research is to: i) identify areas of the Chilean electricity market where an insufficient representation of the agents' preferences is being carried out and the problems that are present due to that insufficiency, ii) the design of three market

mechanisms that improve the preferences' representation of the involved agents, in relation to what actually exists in the Chilean market, iii) the characterization of the considered agents through a modeling of their preferences, iv) an evaluation of the effectiveness of the proposed mechanisms. The developed mechanisms bring elements to the regulator that could serve as a starting point for the design of new mechanisms in a renewable environment.

It is concluded that through market mechanisms that improve the representation of agents' preferences in this new context, given by the inclusion of variable technologies, it is possible to reduce risk and improve the allocation of resources. In all the proposed mechanisms, a benefit is obtained in comparison with existing mechanisms in the Chilean electricity market.

RESUMEN

El contexto dado por la creciente inclusión de energías renovables intermitentes e inciertas en los sistemas eléctricos del mundo, presenta tanto desafíos operacionales como regulatorios. La entrada a gran escala de estas tecnologías cambia la dinámica del mercado, por lo que los mecanismos de mercado y esquemas regulatorios existentes pierden eficacia en este nuevo paradigma. En este sentido, algunas dimensiones de los agentes involucrados no estn siendo plenamente representadas por mecanismos existentes, cuyo efecto se acentúa a medida que avanza la inclusión de estas tecnologías.

Esto plantea la necesidad de diseñar y evaluar nuevos mecanismos de mercado, que permitan avanzar hacia un mercado ideal bajo estas nuevas condiciones impuestas por este entorno renovable.

El objetivo de la investigación es diseñar mecanismos para el sector generación, que permitan mejorar condiciones en las áreas de energía, capacidad y seguridad, a través de una mejor representación de las preferencias de los agentes que participan en este nuevo escenario renovable. En el área de energía, se propone un diseño de subasta de energía de largo plazo, el cual considera una representación del perfil de corto plazo de los participantes a la hora de adjudicar la subasta. En el área de capacidad, se propone un mercado de capacidad, donde la construcción de la curva de demanda considera tanto las estadísticas de las centrales renovables como las preferencias de la demanda. En el ámbito de la seguridad, se propone un mecanismo para determinar el volumen sistémico óptimo de Gas Natural Licuado a importar sobre la base de un mercado de cobertura de riesgo, con el fin de disponer del volumen necesario de dicho combustible.

El documento presenta un análisis del problema que cada mecanismo intenta resolver, el diseño de cada uno de ellos y el desarrollo de casos de estudio para evaluar su efectividad.

La contribución de la investigación doctoral es: i) identificar áreas del mercado eléctrico Chileno donde se está realizando una representación insuficiente de las preferencias de los

agentes y los problemas que se presentan debido a dicha insuficiencia, ii) el diseño de tres mecanismos de mercado que mejoren la representación de las preferencias de los agentes involucrados, en relación con lo que actualmente existe en el mercado Chileno, iii) la caracterización de los agentes considerados a través de una modelación de sus preferencias, iv) una evaluación de la efectividad de los mecanismos propuestos. Los mecanismos desarrollados aportan elementos al regulador que podrían servir como punto de partida para el diseño de nuevos mecanismos en un entorno renovable.

Se concluye que a través de mecanismos de mercado que mejoran la representación de las preferencias de los agentes en este nuevo contexto, dado por la inclusión de tecnologías intermitentes e inciertas, es posible reducir el riesgo y mejorar la asignación de recursos. En todos los mecanismos propuestos, se obtiene un beneficio en comparación con los mecanismos existentes en el mercado eléctrico Chileno.

1. INTRODUCTION

The energy sector, and in particular the electricity sector, is an essential pillar for the socio-economic development of the countries, so progress towards a more efficient and harmonious sector has been a priority at the global level. The advance to a deregulation of the electricity sector, which began in the 1980s, aims precisely at increasing efficiency through the implementation of market schemes in the segments of the system that would benefit from it. On the other hand, a perfect market is still an ideal, even more so if the system on which the market is built is a complex system such as the electric one, which obeys different restrictions such as those given by the technical characteristics of the power plants and physical laws for the transmission of electricity through power lines, among others. However, this does not imply that we cannot move forward in the direction of this ideal, which has been carried out through the continuous implementation of new market mechanisms and regulatory measures that provide both new levels of efficiency and mitigation of negative externalities. In this sense, a characteristic of a perfect market is free access on equal terms, which results in a perfect representation of the agents involved. This often cannot be achieved by information asymmetries and technological limitations, but to generate progress in this regard is an actual concern that is currently present in different power systems. This work intends to propose market mechanisms that present an improvement in that direction, that is to say, they better represent some dimension of the agents that are not currently being fully considered, and thus obtain a better representation of their preferences. The development is particularly focused on developing countries, where such mechanisms are vital to reduce the perceived risk of agents.

1.1. Generation sector

The generation sector comprises companies that have a portfolio of power plants with which to produce and commercialize electricity. It is part of the wholesale electricity market, where electricity purchase and sale transactions take place among these generation companies, large consumers and resellers such as distribution companies and traders. In this way, companies belonging to this sector interact on two levels.

At a commercial level they interact in a competitive market structure in a framework defined by the regulatory entity which designs and implements incentive mechanisms and norms that are in line with the country's energy policy. In general, this structure is composed of a short-term market ("spot" market), where each generation company offers both the quantity and the price at which it is willing to sell the electricity commodity produced by its plant, so that a system market operator (MO), giving priority to the lowest offers, determines the transactions and clearing prices following a marginal pricing scheme.

On the other hand, there is a physical level that is strongly linked to the commercial level. One particularity of the electric market is the difficulty of storing electrical energy at a large scale, so it has to be produced the instant it is consumed. This implies that the system's power plants operations must be coordinated by an Independent System Operator (ISO). At each moment, the ISO will make the operational decisions that present the greatest benefit to the system, for which it considers both the transactions determined by the MO and the technical and security constraints of the system. In several systems such as the ones in the United States and Chile, the ISO fulfils both the ISO and MO functions, so in the rest of the work we are assuming that this is the case.

Finally, the commercial level considers other instruments such as bilateral long-term contracts, forwards contracts and remuneration for additional services, among others, either informally or through formal mechanisms. In this sense, it is worth noting that in some power systems there are also physical bilateral contracts, where the physical dispatch is a consequence of the agreement between the parties.

Another peculiarity of the generation sector in a competitive market, is that its evolution over time does not respond to a centralized planning process carried out by the regulator, but depends exclusively on the investment decisions of the participants, which are based on their expectations of the future.

In theory, the result of this interaction in a perfect market where the cost of failure is correctly valued would be equivalent to that obtained through centralized planning (Stoft, 2002). However the market is not perfect and each generation company has its own expectations and risk aversion, therefore the regulator has an important role through the implementation of mechanisms and norms that deliver the appropriate signals for an harmonic and safe development, consistent with the guidelines of the country's energy policy, such as what technologies are required and where to locate them.

On the other hand, investing in a power plant is a long-term decision, where the required investment cost is usually significant. This, along with the fact that most agents are risk averse (Porrua et al., 2005), implies that the perceived risk must be limited when it comes to obtain financing. In this sense, besides clear rules in the market, mechanisms and regulations must exist in order to allow the generation companies to mitigate to some degree their perceived risk, allowing in this way a safe, reliable and low cost supply.

There are 3 areas in the market that allow generation companies to earn income, being them energy, capacity and security (ancillary services).

1.1.1. Energy

Energy is the main product transacted in the electricity market and corresponds to power delivered in a time interval, which is valued in the spot market. The price of transaction and the way it is calculated will depend on the specific implementation of the market, for example a market with nodal prices such as the PJM (Tong, 2004) or a single market price such as the Spanish case (Ciarreta & Espinosa, 2012). Independent if the price is nodal or system wide, it will be given by the intersection between supply and demand curves (in the case of nodal prices, the differences among them will account for losses in the transmission system and congestion costs), being the demand curve elastic or inelastic according to the particular power system. This product constitutes the main income received by so called "baseload" power plants, which correspond to plants with a high cost of investment and a low variable cost of operation such as nuclear and renewables, and others with high capacity factor such as the coal plants

Finally, additional elements to the spot market such as long-term contracts allow generation companies to stabilize their revenues by selling energy over time, thus reducing the faced risk.

1.1.2. Capacity

The capacity product refers to a specified amount of capacity available in a specific zone when called on within the obligation time span (Zhao & Litvinov, 2010). In theory, with a correct valuation of the value of lost load (VOLL), the price of energy would be sufficient to remunerate this product (Stoft, 2002) and there are even markets known as "energy only" that do not explicitly remunerate it, such as ERCOT (Hogan et al., 2012) and the NEM in Australia (Nelson et al., 2015). However, in other markets explicit mechanisms for capacity remuneration are considered, such as capacity markets as in PJM (PJM, 2016) and NYISO (NYISO, 2016) or capacity payments as in Spain, Portugal and Ireland (Linklaters, 2014). The plants whose income is most dependent of this concept are the so-called "peaker" power plants, corresponding to those with a low investment cost and a high variable cost of operation. In general, because they are the plants with the highest operating cost of the system, they only receive profits from the sale of energy when the spot price is higher than such cost, that is, the VOLL. An erroneous estimation of the VOLL results in the "missing money"[1] problem (Joskow, 2013), which leads to the implementation of the aforementioned capacity remuneration mechanisms.

1.1.3. Security

To this area belong the elements grouped under the name "ancillary services", considering products such as frequency control and operating reserves that allow the system to have a certain level of security and flexibility to respond to failures and variations in demand. Although there are specific markets for the transaction of some of these services such as operating reserves, there are others such as voltage support that still maintains side payments schemes (Chen, 2016). Different levels of sophistication can be observed in the

[1]Money that is needed in order to keep the optimal generation mix, but is missing due to a low set VOLL.

implementation of these markets, for example in some US power systems such as PJM and NYISO, services are assigned almost at the time of operation in the real time market, while in others such as MISO and CAISO, it takes place the day before in the day ahead market (Zhou et al., 2016). The main plants that receive revenues for this concept are those whose technical characteristics allow a quick operational response on their part (for example in startup time and ramp rate) such as natural gas turbines, diesel engines or storage units such as reservoir plants.

The entry of variable renewable energies at a large scale is significantly changing the dynamics of the electricity market, both at its physical and commercial levels. There are regulatory challenges at both levels in the concepts of energy, capacity and flexibility, where new mechanisms and adjustments to existing ones need to be implemented, in order to obtain the greatest benefit for the system under this new paradigm.

1.2. Renewable energy

Large-scale entry of renewable energies is going on in the power systems around the world, and everything indicates that the growing trend will continue. At the global level, the International Energy Agency (IEA) projects in its main scenario that 60% of the new generation capacity will come from renewable sources by 2040 (IEA, 2016).

To a large extent, its development has been the result of policies implemented by pioneer countries such as Germany, Spain, USA and Denmark, which, recognizing the importance of energy in national and economic security, have created markets for this type of technology in order to decrease their dependence on fossil fuels. In addition, the impact of these fuels in relation to climate change and other negative externalities, have resulted in agreements at a global level to reduce their use, further boosting energy projects based on renewable sources (REN21, 2014).

In its beginnings, these technologies were not profitable under a market scheme due to their high investment costs; however, currently the levelized cost of energy[2] of some of these technologies is competitive with conventional baseload plants, due to the significant decrease in their investment costs. The main mechanisms used to promote this type of technology correspond to feed in tariffs (FIT) and renewable portfolio standards (RPS). In the case of FITs, they correspond to award long-term fixed tariffs, to be paid for the generated energy by certain renewable sources, in order to ensure that they can cover their investment costs. On the other hand, the RPS corresponds to require that part of the energy supplied by the electricity companies come from renewable sources. This gives rise to a renewable energy market, where different renewable power plants compete to offer their energy for that purpose. The result of the use of these instruments will depend heavily on the specific implementation carried out by the regulator, because decisions on price (in the case of FIT) or quantity (in both cases) will determine the level of penetration of these technologies.

These technologies drastically change the dynamics of the electricity market due to its intermittent and uncertain characteristics, presenting operational and regulatory challenges.

1.2.1. Operational challenges

At the operational level, the inherent variability of these technologies makes it difficult to coordinate with the rest of the generating park, due to technical constraints such as technical operating minima, startup time and ramp rate, among others. If on the one hand, all generators could startup and change their generated power as quickly as renewable resources can vary, and on the other hand operators could reliably predict those resources, then accommodating any amount of renewable energy would not be a problem. In this sense, the operational inflexibility of conventional baseload plants is a major obstacle for the coordination with renewable power plants. In order to obtain the actual levels of stability and security in a mostly renewable system, additional generation to renewable resources

[2]The levelized cost of energy of a power plant corresponds to its expected lifetime costs (including construction, financing, fuel, maintenance, taxes, insurance and incentives), divided by its expected lifetime produced energy.

should come from more flexible plants such as gas turbines or reservoir hydro plants in order to cover the peak load hours, and demand would have to be handled more efficiently and intelligently.

On the other hand the storage technologies are the perfect complement to maintain those standards considering this type of variability. Like renewable technologies, there is huge diversity in the characteristics of such technologies, such as size and speed of response. To this category belong the water reservoirs power plants, with a strong presence in hydrothermal systems of both Nordic and Latin American countries, which depend on "non electrical" elements for filling up, such as the running waters of their affluent rivers. Moreover, great relevance are acquiring new storage technologies that require electricity for their filling, such as flywheels and batteries, which additionally present great potential within the concept of "smart grids".

1.2.2. Regulatory challenges

The inclusion of these technologies also presents challenges at the regulatory level. The most obvious case comes from the price of energy or spot price, since one of the main characteristics of this type of technologies is to present a practically null variable cost. Because of this, the spot price tends to fall when renewable power plants are generating energy, especially when there is a high level of renewable penetration, a situation known as the merit order effect (Sensfuss et al., 2008). This characteristic drastically modifies the price signals when they enter massively in the electrical systems, mainly affecting the baseload thermal power plants such as the coal-fired power plants that cannot enter or leave the system with the speed that this new scenario requires. In this way, these last plants begin to stop being profitable in systems with these characteristics.

In theory this low profitability is a signal in the right direction for a system with a considerable proportion of renewable energies, since it translates into an incentive to the investment in plants that complement the operational characteristics of the renewable ones. Nevertheless, it must be considered that an existing generator park with sunk costs already exists, so a radical transition to a mostly renewable system is a major challenge from the operational and market point of view.

Storage units also play an important role in this new scenario, since buying energy when the spot price is low (when the renewables are generating) and selling it when it is high, result in a more stable price through the day, allowing a less risky system in terms of prices.

In the same direction of the energy concept, it is necessary to rethink other mechanisms such as long-term contracts and auctions, since these technologies face a greater risk when entering into an energy contract. This is due to the fact that they don't have their own energy production when prices are higher. In terms of capacity, it is necessary to define the extent to which these technologies contribute to this concept, and consider an according remuneration. Finally, the appropriate signals must be sent in order to allow the necessary flexibility to accommodate these technologies in the power system, so that this new context does not imply a decrease in security of supply.

In the proposals developed in this work we only consider variable technologies such as solar and wind. Although hydroelectricity is considered within the renewable technologies, this technology has been present since the beginnings of the power systems, so that its operational characteristics do not modify the current state of the market. On the other hand, renewable technologies such as geothermal and biomass present a fairly stable energy production (coupled with the fact that there are non trivial variables at stake, such as location and construction) so they do not add more complexity than the hydro plants to the system.

1.3. Chilean context

As in the rest of the world, in the particular case of Chile an increasing trend has been observed in new renewable technologies such as solar and wind. A distinction used in Chile is the category of Non Conventional Renewable Energy (NCRE), which includes solar, wind, biomass, geothermal, tidal and mini hydro technologies. This is in contrast to conventional renewable technologies, mainly large hydroelectric plants whose large scale presence in the system has been observed since its inception.

A mechanism of the RPS type was established with the objective of having 20% of the total demanded energy produced by NCRE technologies by the year 2025. This mechanism responds to the strategic direction of following a more sustainable development and decreasing dependence on foreign fuels (Chilean Senate, 2010). In this sense, according to the National Energy Commission (CNE), 40% of the generated energy could come from these sources by 2035 (CNE, 2016), which raises a new scenario in terms of renewable energy in the country.

As mentioned above, the existing regulatory and market elements will be affected by this new scenario, so in this work we are proposing improvements in mechanisms that affect the three areas described in point 1.1, in order to take advantage of the dynamics that this new scene presents.

1.3.1. Energy: Long term energy auctions

The first of these mechanisms responds to securing the energy supply in the long term, more specifically the long-term energy auctions. This mechanism is present mainly in South American countries, however in some countries in Europe and Southeast Asia can also be found. This type of mechanism is of particular importance for the baseload plants, which need long term contracts to finance their high investment costs. Since renewable technologies are part of this group, the mechanism is especially impacted by their inclusion on a large scale.

The energy supply auctions for regulated customers in the Chilean system were implemented to solve the lack of investment in the generation sector that was observed in the electric market. This lack of investment originated in the late 1990s. Specifically, in 1998 there was the greatest drought in 30 years, for which the system was not ready (in fact, 1997 had been rainy, and 1998 was expected to maintain this condition). This situation resulted in rationing episodes, which in turn brought economic implications in the country.

At the regulatory level, this episode involved a modification of the electric law, specifically article “99 bis”, and droughts were no longer considered a “force majeure condition” and therefore exempt from the compensation of supply deficits. This new regulatory scenario, coupled with low spot prices projected by the regulator (as a consequence of the low price of Argentine natural gas, which was being imported progressively since 1997 through pipelines from the neighbor country) brought with it an increase of the perceived risk by the generation companies. This resulted in a decrease in the generation investments made in the system, favoring a progressive increase of distribution companies that were left without supply contracts to supply their demand, whose prices were the consequence of a regulatory determination instead of bilateral negotiations.

In other words, after this regulatory change, the price calculated by the regulator for this type of contract, called “the nodal price”, failed to reflect the faced risk by generation companies when maintaining a contract of that nature. This scenario pave the way to the implementation of a new mechanism to replace the nodal price as the electricity price for regulated customers, choosing to implement an auction scheme, which had already been implemented with good results in Brazil, whose implementation was due to similar problems to those faced by Chile.

Additionally, this type of auction presents challenges for renewable technologies in the short term, since the inability to follow load given its variable and non-dispatchable nature makes it difficult for them to deliver the committed energy on an hourly basis. In the Chilean case, most of the auctions have treated these technologies in a similar way to the conventional ones, having to fulfill their obligation to provide energy at an hourly level according to the load profile. Nevertheless, a percentage of the energy in the last conducted process has been auctioned in three time windows within the day, moving forward in this work’s proposed direction.

1.3.2. Capacity: Capacity remuneration

The second mechanism is related to the capacity remuneration, that is, the mechanism that tries to ensure the right amount of the capacity product in the system and to remunerate it. Even though electricity markets try to shift demand away from peak demand hours, pricing the electricity in them at a higher price according to the peak load pricing theory (Boiteux, 1960), having an adequate installed capacity to face those hours is still a concern in several systems. The consideration of a capacity component dates back to the beginning of the deregulation process of the Chilean market in 1982, but it was not until 1985 that the concept of "peak power transfers" was formally defined by Supreme Decree N°6 (SD).

Broadly speaking, every year the generators must ensure the demand for their customers at the annual peak hours of the system, which is carried out by means of a power balance in those hours, calculated ex ante to the period in question. This balance is simply the determination of the power, both provided by each generator and consumed by its customers in those hours. And based on that calculate the commercial transfers that must be made between them. These transfers are valued at a regulated price calculated by the system regulator.

Although the spirit of the power balance was aligned with the installed capacity remuneration, in 1998 the norm was changed by means of the SD N°327, introducing the concept of "firm power". This new concept not only included elements of adequacy, but also of "security", considering characteristics of the plants such as startup time and ramp rate.

Given the price at which to value the power transfers, it is the responsibility of the system operator to determine how much firm power to allocate to each generation unit, which is carried out through procedures that consider its unavailability given both operational issues and systemic hydrological conditions.

Through SD N°62 of 2006, the norm which rules power balances is modified again, where the so-called "sufficiency power" replaces the firm power concept, considering only the elements related to adequacy. Everything that has to do with security is treated independently under the concept of "ancillary services", which are ruled by the SD N°130.

In addition, DS N°62 deals more explicitly with non-conventional renewable power plants, assigning a sufficiency power given the worst average annual availability presented by the plant in the last 5 years.

1.3.3. Security: Liquefied natural gas imports

In the Chilean context, the installed capacity of natural gas power plants is approximately 4,750 MW (38% of the thermal capacity), whose access to fuel is indispensable to have an acceptable level of flexibility and security under a significant inclusion of renewable energies. Due to this, the third mechanism is related to take or pay schemes for the importation of liquefied natural gas (LNG) in the Chilean market. These schemes can present storage characteristics, since after taking a position of purchase under take or pay, the LNG plant will dispose a boat with storage capacity in the regasification terminal, being able to take advantage of the regulation capacity that the configuration presents for a limited time. That is, the gas supply is delivered over time in a way that optimizes its use in the system.

The use of LNG in the Chilean electricity market arises from a problem that Chile had with Argentina. Starting in 1997, a cooperation agreement between the two countries began in relation to natural gas. Specifically, through the construction of the gas pipelines Del Pacfico, Gas Andes, Nor Andino and Atacama that united the two countries, an import of such fuel into Chile started. Low fuel prices compared to those used by other thermal technologies on the market led to a fast expansion of natural gas plants in the Chilean power system. It was not until 2004 that due to internal problems, Argentina began to restrict natural gas exports to Chile, a situation that became critical for the year 2008 when in conjunction with periods of drought left the Chilean system with high spot prices given by diesel and an unused natural gas generator park.

This is why the government, through its companies Codelco and ENAP, together with the private sector, promoted the construction of two regasification terminals, Quinteros and Mejillones. Through them, for the years 2009 and 2010 respectively, the possibility was opened again of supplying that fuel to the installed capacity that requires. Because this

LNG scenario is relatively new in the Chilean electricity market, a norm and mechanisms to regulate its use are currently being developed.

1.4. Objectives of the work

The objective of this research is to propose mechanisms to be used in the Chilean electricity market to deal with the management of the variable generation that a renewable environment brings, so that the interests of the involved agents are represented more reliably.

In particular, this work will develop and propose:

- A modification to the current mechanism of long-term energy auctions, so that the short-term profile of the participants is represented in some way when allocating the auctioned energy.
- An implementation of a capacity market, where the elaboration of the power demand curve considers both the renewable power plants statistics and the demand preferences.
- A mechanism in which the optimal amount of liquefied natural gas to be imported is determined by risk hedging contracts between different electricity market agents.

The implementations of the proposals will be simulated in the Chilean power system with different levels of simplification.

1.5. Hypothesis

The development of this work's hypothesis considers the following elements:

- The short term variability given by the inclusion of variable technologies increases the risk perceived by the agents of the system.
- The short term variability is a factor considered by the agents of the generation sector when making medium and long term decisions.

- Although an agent in the generation sector could search for risk in order to obtain a higher profit, this work considers that they are risk averse and therefore they minimize their exposure to risk.
- From the perspective of a generator the market cannot be influenced unilaterally, therefore it is assumed that the generators behave competitively.

Considering these elements, we formulate the main hypothesis of the investigation:

Through the implementation of market mechanisms that better represent the preferences of agents in this new context given by the inclusion of variable technologies, it is possible to reduce risk and improve the allocation of resources.

1.6. Methodology

For each of the problems addressed in this work, four stages are followed.

(i) In the first stage, the specific problem and the mechanism or mechanisms that currently address the problem are reviewed.
(ii) In the second stage, a mechanism is proposed that in some dimension presents a better representation of the involved agents.
(iii) In the third stage the preferences of the involved agents are modeled.
(iv) Finally, the fourth stage evaluates the proposed mechanism through simulations in the Chilean market with different levels of simplification. For this, the results obtained using the proposed mechanism are compared with those obtained using an existent mechanism that has the same purpose.

In the following points there is a summary of the four aforementioned stages applied to each area under analysis.

1.6.1. Energy:

- The *First stage* will address the specific problem in this area, which is is to have and adequate energy supply in the long term, in order to prevent high prices and undesired loss of load scenarios.

- In the *Second stage* an energy auction mechanism is proposed, where a modification in the offer structure used in actual mechanisms, allowing the participants to express their supply preferences in the short term.
- Within the *Third stage*, the participants whose preferences are modelled in this chapter are the generator companies that participate in the auction, and the medium by which them expose their preferences is the shape of their offers. In this sense, different levels of risk aversion are considered in order to obtain different offer shapes.
- In the *Fourth stage*, the results of using the mechanism are compared with a traditional energy auction, where the short term is not represented in the auction.

1.6.2. Capacity:

- The *First stage* will address the problem of having an adequate installed capacity in the system, in order to respond to peak demand scenarios.
- In the *Second stage* a capacity market mechanism is proposed, where a modification in the demand curve used in actual mechanisms allows a better representation of the demand willingness to pay.
- Within the *Third stage*, in this chapter the preferences of the demand are modelled, where a parametric function is derived that values the willingness to pay for capacity that the consumers have, based in the expectation of loss load and its value.
- In the *Fourth stage*, the results of using the mechanism are compared with a capacity market that follows the design principles used in some North American power systems.

1.6.3. Security:

- The *First stage* will address the problem of having an adequate amount of natural gas in the system, in order for the gas plants to be available both for generation and to provide the require fast response that they are capable of.

- In the *Second stage* an insurance market based on natural gas imports is proposed, where an explicit value is defined and traded in a market setting.
- Related to the *Third stage*, in this chapter there are modelings for both the LNG importers and the generators of the system. The import price of the importers is represented through a random variable. On the other hand, the generators (or insurance buyers) calculate their offer prices based on an expected spot price value, considering for that a random risk aversion.
- Finally, in the *Fourth stage*, as there isn't an implemented mechanism in this sense, the results are compared with a centralised approach suggested in the literature.

1.7. Work overview

The thesis has been organized in four chapters. The objective of each chapter is the development and evaluation of a particular market mechanism, associated to a specific area of the electricity market. Due to this, although the thesis encompasses the topic of implementing market mechanisms that improve the representation of agents' preferences in a context of renewable energies inclusion, each chapter is complete and self-contained, including an introduction and its own conclusions.

In this first chapter, the need to develop market mechanisms and regulatory measures in order to move in the direction of an ideal electric market, in a future with an increasing level of variable renewable energy is stated. The context of the research is introduced, considering only the energy generation sector. There is a description of 3 areas of the electric market where generators can earn income and the difficulties that the incorporation of renewable energies poses to the system. Then the Chilean context is described in each one of the 3 areas mentioned above and the mechanisms currently implemented in them are mentioned. Finally, the research objectives are proposed, a working hypothesis is formulated and a study methodology is proposed and evaluated.

Chapter 2 discusses the topic of long-term energy auctions. The types of auction that can be found in the electric sector are listed and the use of auctions as an object to support the development of renewable energies described. Then, alternatives for the short-term allocation at the hourly level in the long-term auction processes are described and a mechanism is proposed to include a representation of this short-term in the long-term allocation. Both the system and the generators participating in the auction are modeled, with which 3 case studies are implemented considering different levels of risk aversion for the participants. The first and second only differ in the amount of energy auctioned, while the third considers a supporting scheme for solar technology by the auctioneer. Finally, a discussion section and the conclusions of the chapter are presented.

Chapter 3 develops the topic of capacity remuneration. It describes the problem that results in the remuneration of capacity and the types of mechanisms that have been used to do so. Additionally, the effects that renewable energies have in this area are described. Then a methodology is proposed to implement a capacity market, where the variability of renewable energies and load are considered explicitly. Additionally, the definition of an arbitrary capacity target defined by the regulator is avoided, considering the modeling of the capacity demand curve through a parametric function that only depends on the VOLL and technical characteristics of the system. A case study is implemented in order to compare the proposal with a capacity market similar to the one found in NYISO, with sensitivities in the value of VOLL, renewable technological mix and level of inclusion of renewable energies. Finally the conclusions of the chapter are presented.

Chapter 4 develops the issue of importing LNG. It describes the LNG characteristics and its relationship with the electric sector, as well as its state in South America and the dynamics of take or pay contracts for its importation. Then the insurer characteristic that can be assumed by the power plants that import and use such fuel is described. Based on this, a mechanism is proposed to decide in a decentralized way the optimal level of LNG to be imported into the system, using a market scheme where there are insurance trades between importers and generators with energy supply contracts. Both the system and the generators participating in the market are modeled considering 3 systemic trends of risk aversion, with 2 case studies being implemented with them. The first one applies and evaluates the benefit of the proposed mechanism, while the second is a simplified use of the mechanism to support renewable energy plants. Finally, a discussion section and the conclusions of the chapter are presented.

2. A NOVEL INCLUSION OF INTERMITTENT GENERATION RESOURCES IN LONG TERM ENERGY AUCTIONS

2.1. Background

2.1.1. Auctions

As mentioned in (Maurer & Barroso, 2011), an auction is a selection process designed to distribute goods and services competitively; and in most of the cases in the electricity market, generation companies offer their products because they are interested in selling power contracts to large clients or distribution companies with a design that is focused on obtaining the best price (this is the so-called reverse auction).

Within the auctions oriented to attract new capacity, we can find ones that (i) include all types of technologies or technology neutral (direct competition among all technologies), (ii) only renewable energies, (iii) specific renewable technologies, (iv) specific projects (for example, to award a concession in a specific site) and (v) for demand resources.

Another distinction is the product that is auctioned as capacity per se (as in (Hobbs et al., 2005), (Hobbs et al., 2007), (Cramton, 2006), (Cramton & Stoft, 2005)), which normally correspond to short term auctions (annual, monthly) whose target is to keep the system reliability within certain margins in peak hours, or if the auctioned product is energy to be delivered within a certain period, which generally are long term contracts (up to 20 years) as in (Moreno et al., 2009), (Moreno et al., 2010) and (Chacon, 2013), among others. These last types of auctions (where long term contracts for delivering energy are the products) are the ones that we are going to be referring for the rest of the work.

2.1.2. Renewable technologies in auctions

In the context of renewable energy, several countries have decided to foster the development of renewable technologies through exclusive auctions for one or more of those technologies, which necessarily implies a regulatory decision about the quantity of the demand intended for those kind of technologies. According to (Maurer & Barroso, 2011), these types of auctions have proven to be a viable alternative to the more traditional approaches like feed-in-tariff to attract renewable energy into the system. As the traditional auctions to attract new capacity, there are different combinations of target participants in these renewable auctions, being some of them: a) all types of renewable technologies, b) technology-specific or c) technology and site specific. In this context, (del Río & Linares, 2014) declare that there are mixed results in the implementations of such auctions, being one positive aspect the low level of subsidies in general. On the contrary, some of the negative elements include the low effectiveness to attract the expected renewable capacity, the low technological diversity, low innovation and high transaction costs. On the other hand, technology neutral auctions are those where there aren't restrictions on the types of technologies that can participate, being them renewables or conventionals.

2.1.3. Short term issue of hourly power obligation

Clearly the long term is the main focus of the energy auctions, but also there are short terms issues involved, even at the hourly level. One of those issues is that the group of auction winners has to supply the actual aggregated load of the demanding entity, independent of the dispatch made by the ISO. The hourly power obligation will determine a short term risk that every auction participant will have to face in the case of winning. This issue becomes especially relevant as more renewable technologies enter the system, because unlike conventional base load technologies it is common for some renewable technologies to present several hours without generation, which raises the question of who has the obligation to supply the power on those hours.

2.1.3.1. Existing hourly assignments between auction winners

In most long term energy auctions, what has been done until now is to let the renewables fulfill their awarded energy supply according to a production logic (whenever they generate, their energy is recognized by the LSE until the awarded energy for the period is reached). This clearly imposes different conditions on conventional and renewables technologies, transferring risk among them. On the other hand, the Chilean energy market has been pioneer in implementing auctions where both kinds of technologies are treated equally. However, the implementation does not acknowledge that the dynamics of the generation technologies are different.

Until 2014, the Chilean electric market supply auctions considered that each generation company *i* that is awarded a supply contract must provide the awarded energy with a power profile that is equal to the demand in question[1]. In other words, in every hour *h* of the day it must provide P_i^h power equivalent to the Load Serving Entity demand at that time D_{LSE}^h multiplied by the percentage that represents its E_i awarded energy with respect to the total awarded E_{LSE}, as seen in the following equation.

$$P_i^h = D_{LSE}^h \cdot \frac{E_i}{E_{LSE}} \tag{2.1}$$

Moreover, the power system's economic dispatch is cost based (responds to the real audited costs associated to the units' generation, considering restrictions such as technical minimums and reserves). As mentioned, such economic dispatch is carried out by the ISO, independent from the commercial obligations that each generation company has acquired beforehand. This implies the full separation of the system's physical operation from the contractual obligations between the generation companies and demand. Due to this, there might be the case where a generation company has a contractual obligation to supply X power at a specific hour of the day during which its generation units are not dispatched by the ISO, in which case that company will have to buy that energy in the spot market. On the other hand, if we assume that the same company has no surpluses or deficit (that is, through its supply contracts it sells the total exact amount of energy it produces), it will necessarily generate that X energy at another time of the day, which will have to be sold in the spot market. This situation makes the generation company face a risk that involves the spot market, with the need to cover with its own money the supply and generation time differences ($\widetilde{spot}_{supply} - \widetilde{spot}_{gen}$).

[1]The auction scheme was modified in 2014, allowing a small percentage of the energy to be auctioned at different time windows during the day.

In the case of Chile, the situation described had not been a major issue with conventional base load generation, because when spot prices are high, the base power plants (coal and hydro in Chile) are usually running, mitigating in this way the spot price risk associated with their contracts. On the other hand, the NCRE power plants do not necessarily have that characteristic, so their entry in the system starts questioning the logic behind such hourly assignment.

2.1.3.2. Alternative hourly assignments between auction winners

In relation to the described hourly assignment scheme, two major features presented by some NCRE which have an important impact when being considered in supply auctions are the non-manageable intermittency and uncertainty of their generation. However, the mechanism design will only consider the non-manageable intermittency issue in an explicit way.

To illustrate this issue, we will use a simplified example in order to understand its essence. Although demand in a distribution company is not usually flat, in this example we will consider what could correspond to an industrial consumption, which is a flat demand. On the other hand, we will assume that there are two participants in the auction, a coal and a solar generation company, and both are necessary to satisfy the daily demand.

Figure 2.1 shows the two possibles assignments mentioned in the previous point. Due to the solar generation characteristics there would be an area (hatched area) that, independent from who is awarded, would have to be necessarily marketed (that is, supplied without having own backup generation at that time). The figures show the two extremes in the award, they are:

(i) The energy to be marketed is in charge of the NCRE (like in the Chilean scheme).
(ii) The energy to be marketed is in charge of the conventional generator (like in a feed-in-tariff-like scheme).

In addition, there is a continuum of possible assignments between these two extremes, where each one will imply a different distribution of the total risk faced by the generators.

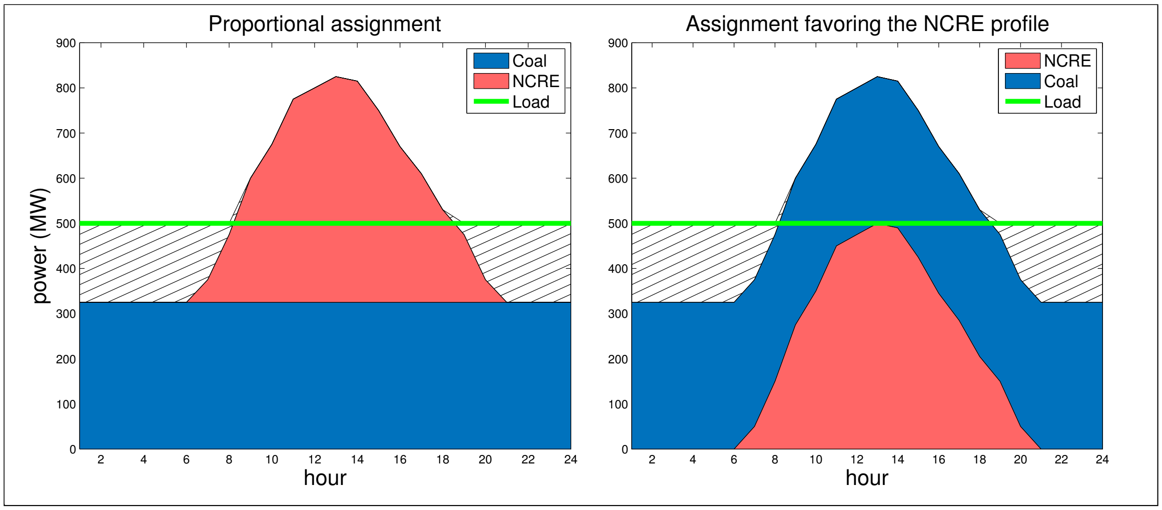

FIGURE 2.1. Extreme assignment schemes

With this range of possible hourly assignments, probably a proportional assignment such as equation (2.1) is not optimal in all the cases and it is also not clear how much that assignment will affect the prices for the end consumers due to the resulting offers by the bidders. Although it is clear that if the solar and coal generators are risk averse, both would prefer the hourly assignment that is more similar to their power generation profile in order not to be exposed to the spot price risk.

In this work we use the term *"backed"* energy in reference to a participant's awarded energy that fits within its power generation profile; therefore that participant will have a power plant backing up that energy requirement. On the contrary, we use the term *"marketed"* energy for the participant's awarded energy that does not fit within its generation profile, and will have to be acquired in the spot market in order to fulfil the supply contract requirements.

2.1.4. Chile case

As we will use the Chilean power market as a background, a brief description of its two auction schemes where renewables can bid is presented. As mentioned in (Rudnick & Mocarquer, 2006), through short law II (Law 20.018), Chile decided to award long-term energy contracts to supply distribution companies through non-discriminatory, technologically-neutral auctions where the winners correspond to those agents that offer the most economic alternatives. Such auctions must be carried out at least three years in advance in order to give time to the investors to obtain funding and building a project.

Another auction scheme was created in 2013, when the law on renewables incentive was amended. This amendment authorised the government to carry out annual auctions only for non-conventional renewable energy projects in case it is estimated that the renewable quota[2] required by law will not be reached with the installed capacity. To participate, the bidders must: (i) have an Environmental Qualification Resolution accepted for the project, (ii) have a capital equal or higher than 20% of the total required for the project, (iii) give proof of the land ownership, (iv) provide a bid performance bond and (v) provide a collateral for the project implementation. This auction considers a cap price for energy equal to the mean cost for the long-term development of an efficient generation project in the relevant system. This second scheme is oriented to attract new renewable technologies in a technology-specific manner (that can be oriented to attract more than one type of renewable energy simultaneously). The winners of the auction are awarded a feed-in-tariff-like product, essentially becoming a production contract. This scheme has not been used, as the renewable quota has been reached without need for support. Thus, the following analysis and proposals consider only the first scheme, technologically-neutral auctions.

Given the fact that the Chilean system is presenting new dynamics due to the growing NCRE incorporation (partly due to the incentives mechanisms such as the RPS implemented by the authority), there is the challenge to find new mechanisms that adapt to such characteristics. The need is to obtain the best of each world, namely, allowing to obtain the low prices and environmental benefits that the NCRE can provide, but without disregarding the risk transfers toward conventional power stations that such incorporation could trigger, effect that would finally cause an impact on the price paid by end consumers.

[2]Renewable Portfolio Standard (RPS) mechanism is actually implemented in the Chilean system, where in a progressive way, 20% of the withdrawals have to come from NCRE sources by the year 2025.

2.2. Mechanism design

We believe that a methodology for optimal assignment should consider the hourly assignment issue when deciding the energy awarding among auction participants, to allow the LSE (or distribution company in the Chilean case) to make a better decision, considering the different variables at stake. In this sense, we are proposing a framework for energy auctions that considers the short term power profiles from the participants in order for the LSE to obtain a lower purchase total cost through a contract allocation that is more suitable to each generating technology. Like the existing long term energy auctions schemes, the proposal follows the logic of a centralized clearing mechanism for the long term contract market and is not a reliability auction per se. Moreover, it does not deal with the problem of capacity adequacy and rather assumes that sufficient generation capacity is always available in the electricity system via capacity mechanisms. To find the optimal assignment considering the short term supply issue, we must consider both the generation profiles of the participants and their risk management capability. The latter skill is required when acting as a marketer. With this information, the LSE can make awarding decisions for the energy to be bought and the hourly assignment for each participant, which includes both elements through the co-optimization of both dimensions. The core of the proposed mechanism is the bid structure of the generators' offers, which are comprised by an offered energy, a generation profile and a price indifference curve. The following nomenclature will be used in the rest of the chapter.

<u>Nomenclature</u>

q_{it}^{B}	backed energy awarded to generator i in hour t
q_{it}^{B}	marketed energy awarded to generator i in hour t
x_i	binary variable representing if there is energy awarded to generator i
$pback_i$	price offer for backed energy by generator i
$pmark_i$	price offer for marketed energy by generator i
k_{it}	percentage of the energy produced by generator i in hour t of the day
D_t	LSE total load in hour t of the day

E_i^O	annual energy offered by generator i
var_cost_i	variable production cost for generator i
AIC_i	annualized investment cost for generator i
$green\_taxes_i$	cost or benefit for generator i related to environmental taxes
max_energy_i	annual maximum energy produced by generator i
cf_{ih}	capacity factor of generator i in hydrologic scenario h
$\widetilde{spot}_{supply}$	cost of buying 1 MWh in the spot market at a certain hour
$\widetilde{spot}_{gen}$	income of selling 1 MWh in the spot market at a certain hour

2.2.1. Bidders offered energy

First, for a generator *i* the bid must include the energy available for awarding E_i^O. This can be a monthly or annual quantity or the quantity for the entire horizon, among others, but in this case we shall consider an annual resolution.

2.2.2. Bidders generation profile

In addition to the bid, there must be an hourly generation profile for an average day. The idea of this profile is that it assumes that what has been assigned within it will have dispatched generation backing up such assignment, hence eliminating the spot market exposure risk.

In this work we consider an hourly resolution for a typical day of the year in the assignment; therefore the profile submitted must be a 24-hour vector with the percentage of the daily generation that will be produced on each hour of a regular day. The symbol k_{it} is used to represent the elements of this 24-hour profile vector presented in the auction by generator *i*.

Figure 2.2 presents a sample profile for a solar generator in a graphical form.

It can be seen that in this particular case the solar generation company is providing information that says that its generation is mostly between 8:00 and 17:00 hours, therefore

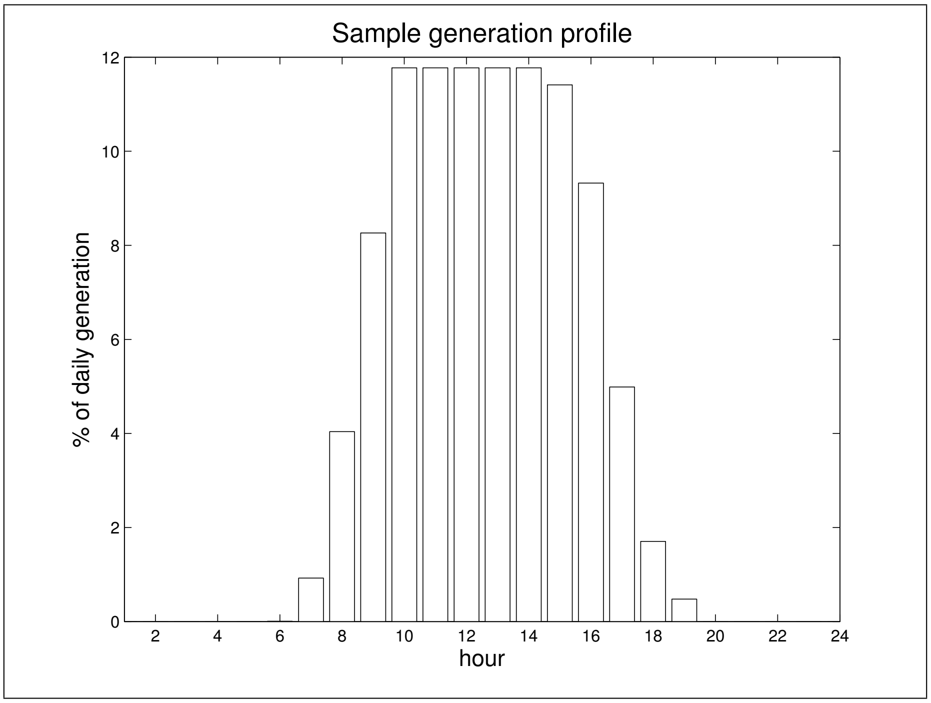

FIGURE 2.2. Sample generation profile

in case it supplies energy to the LSE, during such interval it will be backed up by its own generation.

It is worth mentioning, that although we are considering one typical day as the bidders provided profile, the implementation could equally consider several types of typical days at once, like winter and summer days, which would further improve the mechanism performance.

2.2.3. Bidders price indifference curve

For a generator, we are using the concept of price indifference curve as the function that maps the possible combinations of awarded backed and marketed energies with an offer price that varies in order to make the awarded combination indifferent for the generator. In other words, if a quantity is awarded to a generator, it will be indifferent if all of its energy is within or outside its generation profile, because the offer price function will reflect that in the form of a risk premium.

Therefore, each participant must provide a price indifference curve with the detail of the price offered in function of the total awarded energy that is assigned beyond the generation profile. It must be mentioned that although this curve can be complex for the generators to calculate, it is an exercise that at least the NCRE plants are already implicitly doing, given that the current hourly assignment mechanism (equation 2.1) implies that a certain amount of its awarded energy will have to be marketed. The proposed mechanism makes explicit this process to all participants to allow the LSE to consider this additional information at the moment of the award, hence resulting in a better solution. The price indifference curves could be quadratic in order to reflect a cost that increases quadratically because of higher exposition to spot prices. They can also be linear, similar to the indifference curves used in the different duration contract auctions made by Electricité de France (Ausubel & Cramton, 2010).

We will use the variables q_{it}^{B} and q_{it}^{M} to represent the backed and marketed energy that is awarded to generator i in hour *t* of the day (*ie.* the assigned energy within and outside its generation profile). Additionally, in order to obtain general conclusions without overcomplicating the model, in this work we will limit our analysis to the linear case only. Therefore the price function will be defined by only two values, joined by a straight line, with the parameters $pback_i$ and $pmark_i$ representing the price offers made by generator *i* for a MWh of *backed* and *marketed* energy respectively.

The linear case serves well the purpose of this work, but it is worth noting that for a more detailed implementation of a price indifference curve one can search in fields like decision making in economic theory and finances (Glimcher & Fehr, 2013), where creating profiles that trade off risk and return is a central issue.

2.2.4. Awarding

On the other hand, the LSE must award the following among the generation companies that participate in the auction:

(i) The total amount of energy that will be purchased from each company.

(ii) The hourly assignment profile for the company, which will result on the purchase price depending on the amount of energy assigned within and outside of the generation profile provided by the company (backed and marketed energies, respectively).

In this manner, the problem to be solved by the LSE will be the following:

$$
\begin{aligned}
\underset{q_{it}^B, q_{it}^M, x_i}{\text{minimize}} \quad & \sum_i \sum_t (pback_i \cdot q_{it}^B + pmark_i \cdot q_{it}^M) & \\
\text{subject to} \quad & \sum_i (q_{it}^B + q_{it}^M) = D_t & ; \forall t \\
& \sum_t (q_{it}^B + q_{it}^M) = x_i \cdot E_i^O & ; \forall i \\
& q_{it}^B \leq k_{it} E_i^O & ; \forall i, t \\
& q_{it}^B, q_{it}^M \geq 0 & ; \forall i, t \\
& x_i \in 0, 1 & ; \forall i
\end{aligned}
\tag{2.2}
$$

It can be seen that the presented equations solve the problem in the case where a linear objective function is considered, ensuring that the total demand is supplied at the least cost for the LSE, caring not to assign to a participant more energy than what it is offering. It is worth noting that the model works in our case because we will consider combinations of offers that exactly match the demand in order to fulfil equation **??**. The problem presented here must be adjusted based on the particular characteristics of the price indifference curves (*eg.*, quadratic, exponential, linear, etc.) and the considered typical days (summer day, winter day, etc.).

2.3. Modeling

We try to obtain an estimate of the impact of the supply cost of this new mechanism in an auction process, and for this three participant technologies are considered; coal, solar and win. These are technologies that can be competitive in the Levelized Cost of Energy, but they have different production profiles. On the other hand, we consider two cases in relation to the total amount of energy offered (including backed and marketed energy, namely within and outside the generation profiles of the generation companies):

(i) The energy of three generation companies is required to satisfy the auctioned demand.

(ii) The total energy auctioned can be satisfied by two of the generation companies (namely, one is excluded).

Independent from the case, we assume that each generation company makes a competitive bid, trying to offer the minimum price considering the expected return and their risk aversion.

2.3.1. System modeling

The actual auction will be a process that occurs within the context of a physical power system, with more generation units and demand that the ones present in the auction itself (we will assume that the system is large enough so that not being able to buy energy in the spot market will not be a concern for the participants).

Clearly, the participants' perception about the spot market risk will depend on this system configuration, both on the generation mix and the demand. Although we considered a deterministic annual demand level, we considered 3 possible NCRE inclusion levels equivalent to 20, 30 and 40% of the system's total energy generated by generation units that fulfil such characteristic, where for each level there is a corresponding complementary thermal generation pool.

Using a demanded energy projection for the year 2030 by the Chilean National Energy Commission, we present a brief summary of the methodology used for the installed capacities calculation and the resulting spot prices.

First, the three NCRE inclusion levels were considered. In each level, approximately 10% of that energy comes from mini hydros, geothermal and biomass sources, while 47 and 43% come from solar and wind sources, respectively, keeping the projected percentages of the Chilean National Energy Commission.

Considering these NCRE inclusion levels as a fact, we calculated the optimal thermal mix in order to complement each level in particular. This is equivalent to assume that each NCRE inclusion level results from the country's energy policy decisions, while the rest of the system adjusts itself accordingly (assuming a perfect competition, absence of congestions in the transmission system and omitting technical constraints such as start-up times and technical minima).

The calculation of the optimal installed capacity in each inclusion level was made through the screening curves methodology seen in (Phillips et al., 1969) and (Baldick et al., 2011). This methodology represents each generation technology through a linear function based on its fixed and variable costs (including the annualised investment cost). With these functions, the total cost of using each technology for a number of hours in the year can be easily obtained. Using this information and the load duration curve, the methodology calculates the optimal mix to serve the load on each hour of the year in order to have the least total cost (fixed plus variable costs) in the whole year.

Through such methodology an optimal thermal mix is obtained in terms of investment and operating costs, considering both the generation uncertainty given by the NCRE and the hydrological uncertainty that highly impacts the hydraulic power stations' generations. Figure 2.3 presents the resulting installed capacity by technology for each NCRE level considered.

As we need an estimate of the hourly spot price for the year in question, we simulated the system's daily operation in each case. In this manner, for each NCRE inclusion level, the resulting installed capacity, the hydrological statistics available for the Chilean system (56 annual hydrological scenarios) and the hourly statistics of solar and wind plants from 2013 were used. This allowed obtaining different dispatch scenarios for a typical day for such year, and the hourly spot prices in each one of those scenarios were calculated. Figure 2.4 presents the average spot price for each hour and level of NCRE inclusion.

It can be observed that in all the cases there is a clear influence of the solar plants on the system, resulting in lower spot prices between 8:00 and 17:00 hours due to the abundance

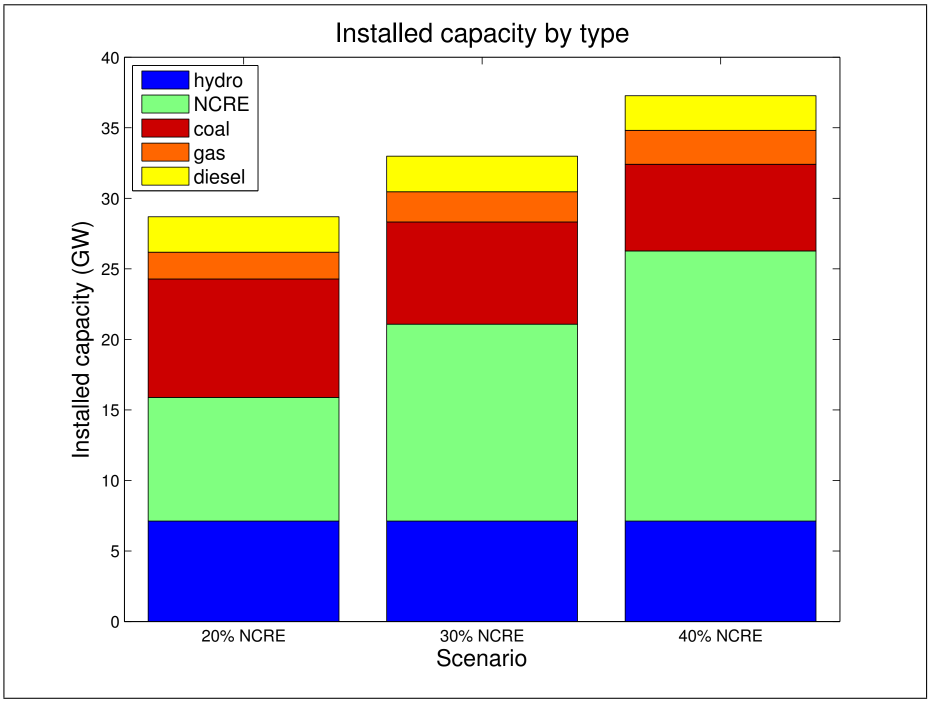

FIGURE 2.3. Installed capacity by type

of economic generation at that time of the day. In addition, it must be taken into account that although the figure shows an average, there is a variance associated to each hour of the day, which will be different in each one of the NCRE inclusion cases.

On the other hand, the hourly distribution of the demand considered corresponds to figure 2.5 that is the total demand profile of the Central Interconnected System (SIC) (main Chilean system), where 64% of its demand is regulated or residential.

It can be observed that although the curve is not flat, most of its energy could be circumscribed in a rectangle, approximately matching the situation with the example presented in figure 2.1.

2.3.2. Generators modeling

We consider that each participant can have a low, medium or high-risk aversion level, which will be reflected in its bids. So in each simulated case we will try different combinations of these risk aversions in order to obtain a broader view.

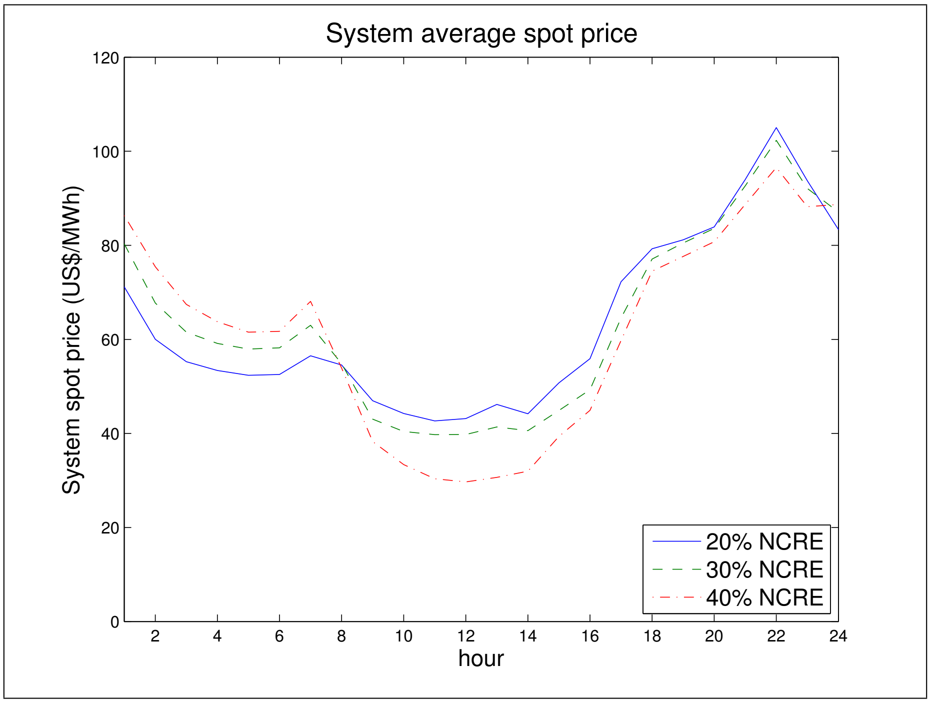

FIGURE 2.4. System average spot price for each hour and NCRE scenario

Additionally, as mentioned in section 2.2.3, there are several possibilities to represent the bid or indifference curves. However, in our modelling we used linear functions for such representation in order to prevent complicating the problem and centre ourselves in its essence. With this, the bid is defined with the offered energy, the generation profile and a price indifference function.

2.3.2.1. Generation profile

We assume the daily generation profile as the average profile for each technology, calculated from the statistics used. Figure 2.6 shows the generation profile for each technology participating in the auction.

It can be observed that the coal profile is modified as additional NCRE percentage is considered in the system. This happens because the nil marginal cost of such technologies displaces the generation of more expensive technologies such as coal. On the other hand, the solar and wind technologies do not show any modification in their generation in the different scenarios, because as they have nil generation prices, there is no technology that

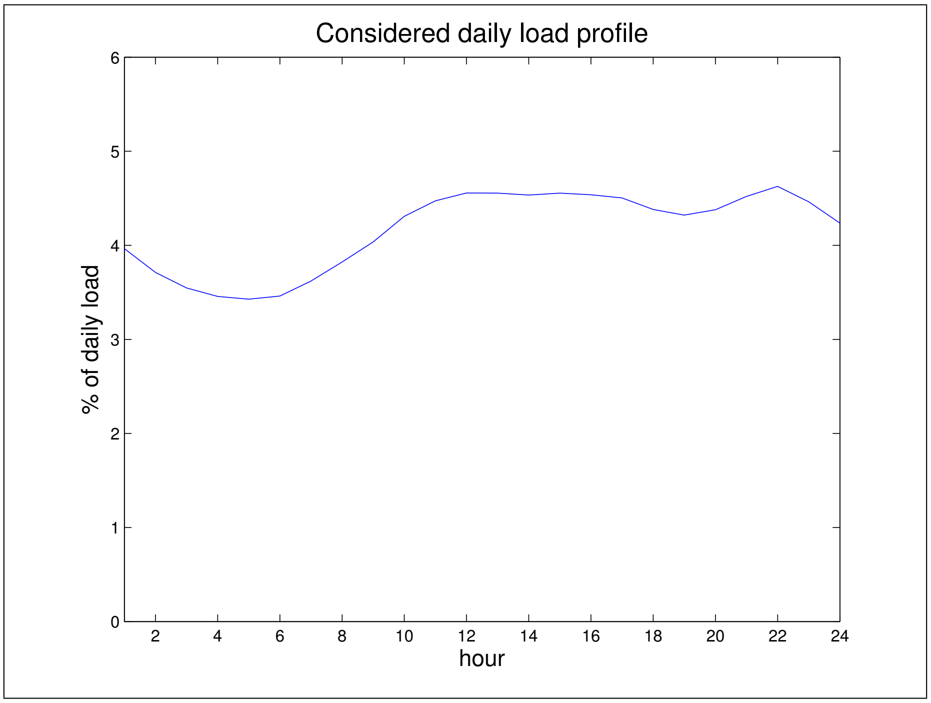

FIGURE 2.5. SIC daily average load profile

displaces them (this would happen if at any hour there is more nil-price NCRE generation than demand, something that does not happen in our scenarios).

It is necessary to take into account that we are not considering operational aspects such as technical minima or start-up costs, which, albeit it is a simplification, it is not the essence of the problem we are analysing.

2.3.2.2. Backed price

The backed price corresponds to the bid price that a generator is ready to offer provided the hourly assignment of its energy matches with the generation profile included in the bid, which we assume is known by the generator with a certain level of certainty.

We assume that the backed price will correspond to the minimum price to charge for one MWh that guarantees the generator a predetermined profitability, considering both the investment and operating costs and taxes or subsidies associated to environmental issues. The revenues and costs values that influence the calculation of the backed price of the participant technologies are shown in table 2.2.

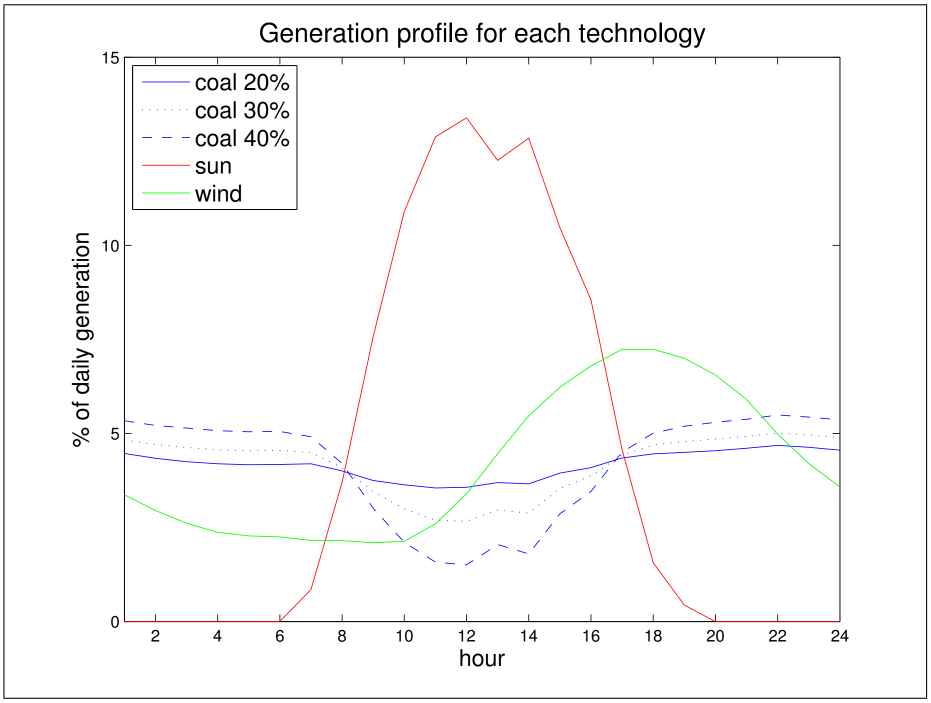

FIGURE 2.6. Generation profile by technology

TABLE 2.2. Backed price calculation factors

Cost	Coal	Solar	Wind
Annualized investment cost 10% (US$/MW)	278,249	222,600	200,340
Operation cost (US$/MWh)	40	0	0
NCRE attribute (US$/MWh)	12 (%NCRE)	-12	-12
CO_2 tax (US$/MWh)	4.7	0	0

Note that the NCRE attribute item corresponds to a cost for the coal generator (that depends on the NCRE quota fixed by the authority) but it is considered as revenues for the NCRE generators. The value considered for this attribute corresponds to an approximation of the attribute's average price for 2013. On the other hand, for the CO_2 emissions tax of US$ 5 per ton of CO_2 emitted, an emission factor of 0.94 ton CO_2/MWh was considered for coal. Additionally we are considering a 10% rate of return for calculating the annualized investment cost.

In addition, each generator will need an estimation of the amount of energy to be generated in the year in question. This estimate will depend on the generator's risk aversion.

TABLE 2.3. Backed Price by risk aversion (US$/MWh)

Technology	Low	Medium	High
Coal (20% NCRE)	84.57	86.14	88.42
Coal (30% NCRE)	89.02	91.13	94.17
Coal (40% NCRE)	95.61	98.64	103.02
Solar	89.64	89.64	89.64
Wind	64.23	64.23	64.23

As we are assuming that the annual NCRE production must correspond to an annual fixed value (as percentage of the demand), such generation will not be displaced by large hydro electric power stations, therefore we assume that both the solar and wind participant have certainty about how much they will generate in the year independent of the present hydrological scenario. However, this cannot be assumed for coal, because its annual generation will indeed be displaced by hydraulic generation. Table 2.3 shows the backed prices for the different participant technologies in function of their level of hydrological risk aversion (note that offer prices for coal technology are higher as there are more NCRE in the system, cause its capacity factor will be lower).

For a generator *i*, these prices were calculated as in the following equation:

$$pback_i = var\_cost_i + \frac{AIC_i}{max\_energy_i \cdot CVaR(cf_{ih})} + green\_taxes_i \tag{2.3}$$

where *CVaR(cf)* corresponds to the Conditional Value at Risk (CVaR) (Uryasev, 2000) of the plant factor considering the 56 statistical hydrological scenarios, where the Low, Medium and High aversions are equivalent to the production confidence levels of 5, 50 and 95%, respectively. On the other hand, green taxes correspond to the revenues or costs for the generator given by the NCRE attribute and the CO_2 tax.

2.3.2.3. Marketed price

As mentioned in section 2.1.3.1, the excess cost paid by a generation company when supplying 1 MWh at an hour of the day different from the generation time is $(\widetilde{spot}_{supply} - \widetilde{spot}_{gen})$. Therefore, the random variable that represents the price that a generator *i* will

TABLE 2.4. Marketed Price by risk aversion (US$/MWh)

Technology	Low	Medium	High
Coal (20% NCRE)	90.75	106.81	222.51
Coal (30% NCRE)	93.90	111.31	226.25
Coal (40% NCRE)	97.18	117.60	226.32
Solar (20% NCRE)	107.79	124.13	265.00
Solar (30% NCRE)	111.37	130.92	282.77
Solar (40% NCRE)	117.29	142.18	290.60
Wind (20% NCRE)	68.70	83.17	190.63
Wind (30% NCRE)	69.89	85.44	196.51
Wind (40% NCRE)	70.47	89.07	199.28

charge to sell 1 MWh at a time different from the generation time (during the same day) shall correspond to the following equation:

$$\widetilde{pmark}_i = pback_i + (\widetilde{spot}_{supply} - \widetilde{spot}_{gen}) \tag{2.4}$$

As an approximation to the probability distribution given by $(\widetilde{spot}_{supply} - \widetilde{spot}_{gen})$, we considered many daily scenarios based on the statistics generated before in section 2.3.1. We assumed that for a specific day, a generator considers that the LSE can request the MWh to be supplied in an equiprobable manner during each one of its 24 hours. However, that same MWh will not be generated at any hour with the same probability (for example, as seen in figure 2.2; for the solar generator such MWh will be generated in hour 4 with 0% probability, while there will be a 11.4% probability to generate it at hour 15). With this information and the amount of days in the statistics, it is possible to obtain a discrete estimation of the random variable $(\widetilde{spot}_{supply} - \widetilde{spot}_{gen})$, which in turn allows us to calculate an estimate of the $\widetilde{pmark}$ variable.

Table 2.4 shows the marketed prices for the different participating technologies in function of their risk aversion level.

As it happens with the backed prices, the marketed prices correspond to the CVaR of the estimated distribution of $\widetilde{pmark}$, where the Low, Medium and High levels correspond to the confidence levels of the cost excess of 5, 50 and 95%, respectively.

From the table it can be concluded that for a high-risk aversion level, solar technology is the least adequate technology for the marketing task, because its energy production is mainly done at the hours of the day of the lowest spot prices, especially when there is a high NCRE inclusion.

It is worth noting that in both backed and marketed price calculations the Low risk aversion case (5% confidence level of the CVaR) is almost identical to a risk neutral case, given that it is an average considering 95% of the worst-case scenarios for the generator.

2.4. Results of the chapter

As mentioned before, for each NCRE inclusion scenario, both the case in which the 3 generation companies are required to supply the auctioned energy and the case where 2 generation companies can supply all the auctioned energy were considered. In addition, a third case was considered. It is similar to the second case, but assuming that there is an arbitrary support from the LSE to assign the backed energy to solar technology. In this manner, for each one of these "cases", 81 auction simulations are obtained (given by [3 NCRE scenarios] x [27 risk aversion combinations]).

2.4.1. Case 1: The three companies are required to supply the auctioned energy

In this first case, we consider that each one of the three technologies mentioned before offers 876 GWh for 2030 (equivalent to 100 MW of mean power), and in turn, the demand is 2628 GWh with the daily profile shown in figure 2.5. As in this case all the energy offered is required to fulfil the auctioned demand, the total awarded energy to each generation company will be the energy that each one offers. In this case, the aim is to estimate the benefit that the proposed mechanism could bring to the LSE in a case where there is no excess of bids.

The resulting hourly assignment under the current mechanism is presented in figure 2.7. It can be observed that in this case, in each hour, each technology is in charge of supplying the same amount of energy.

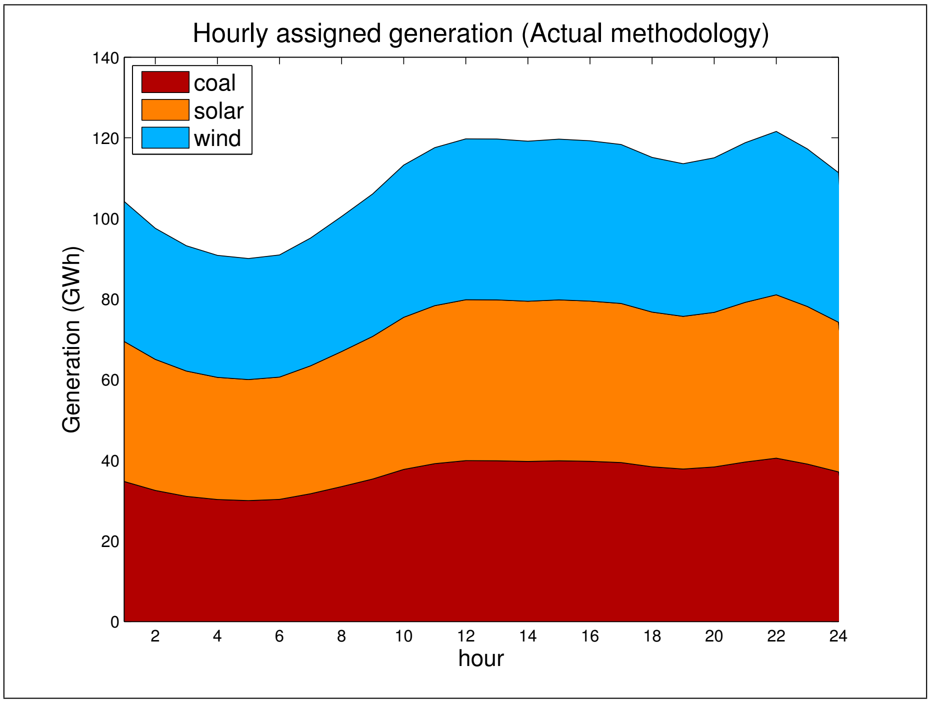

FIGURE 2.7. Case 1 hourly assignment (actual methodology)

On the contrary, figures 2.8 and 2.9 show the hourly assignment for two coal/solar/wind risk aversion combinations. In general, it can be observed that as more risk-adverse is a participant compared to its competitors, its energy assignment is increasingly similar to its generation profile.

In order to quantify the benefit or damage of the proposed mechanism, we will compare the result with the outcome of the current assignment mechanism, namely, where the hourly power assignment is made proportional to the energy awarded (as in equation 2.1). For this, the chart in figure 2.10 presents the purchase cost savings for the LSE provided by the proposed mechanism compared to the current one, in function of the various risk aversion combinations of the participants and for the three NCRE inclusion levels. In this case, the purchase cost savings obtained by the LSE oscillates approximately between 4.7 and 107.3 million US$ compared to the current mechanism.

It can be observed that the savings are quite notorious in those cases where solar technology has a high risk-aversion, because the actual mechanism “obliges” such technology

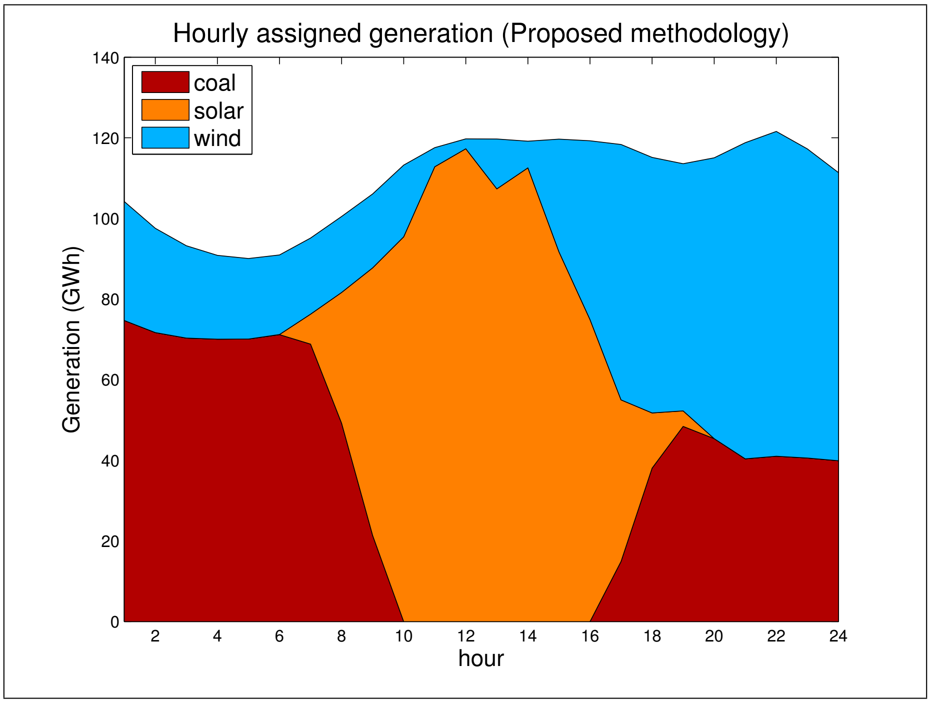

FIGURE 2.8. Case 1 hourly assignment (coal/solar/wind) = (low/high/medium) risk aversions

to market a large portion of its energy. Also due to its characteristics, it will generate during the hours of the day in which the spot price is lower, resulting in a back up that is not the most adequate one for the marketing task. It is worth noting that on each NCRE inclusion level there is a wide range of possible cost saving values, caused by a combination of two characteristics. In the first place, the considered power system has a large hydro share, which results in extreme opposite spot prices depending on hydrologic conditions. On the other hand, regarding the auction participants, all the combinations of risk aversion levels are being considered, giving place to extreme conditions such as where all the participants present high-risk aversion (or low-risk aversion). These two characteristics coupled together result in the mentioned wide ranges.

2.4.2. Case 2: Two companies can supply all the auctioned energy

This case considers that each company (represented by the coal, solar or wind technology) offers 1314 GWh for 2030; equivalent to a mean power of 150 MW, while the

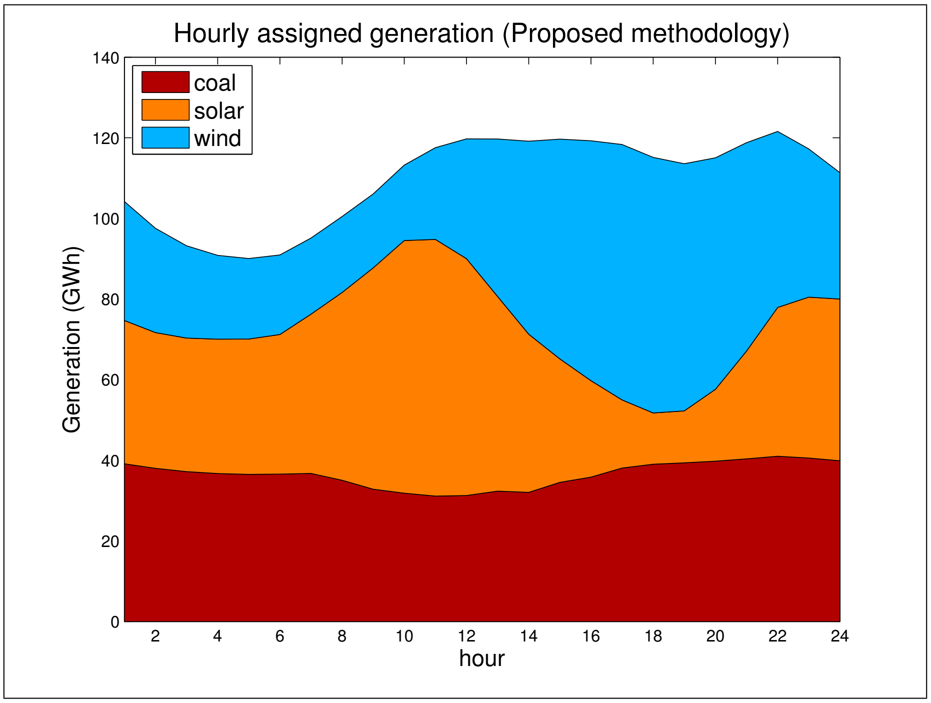

FIGURE 2.9. Case 1 hourly assignment (coal/solar/wind) = (high/low/medium) risk aversions

auctioned demand that same year is 2628 GWh. In this manner, two generation companies could supply all the auctioned energy, considering that if a company is chosen for the awarding, all its energy must be bought. The aim of this constraint is to create a more realistic case, because if a generation company foresees that only part of its energy will be auctioned, this would be expressed in its bid prices.

With the mentioned assumptions, there are only three possible award combinations in terms of technology mix, being Coal/Solar, Coal/Wind and Solar/Wind. So, for each one of the 27 possible risk aversion combinations (given by the 3 risk aversions of the 3 technologies) on each inclusion level of NCRE, the resulting awarded technology combination will be one of the 3 mentioned before. Table 2.5 shows how many times each of the 3 technology combinations is awarded in the different scenarios, both for the actual and proposed mechanism.

The table shows that while there are no significant differences between the two mechanisms in terms of technologies chosen (mainly being coal and wind the two awarded

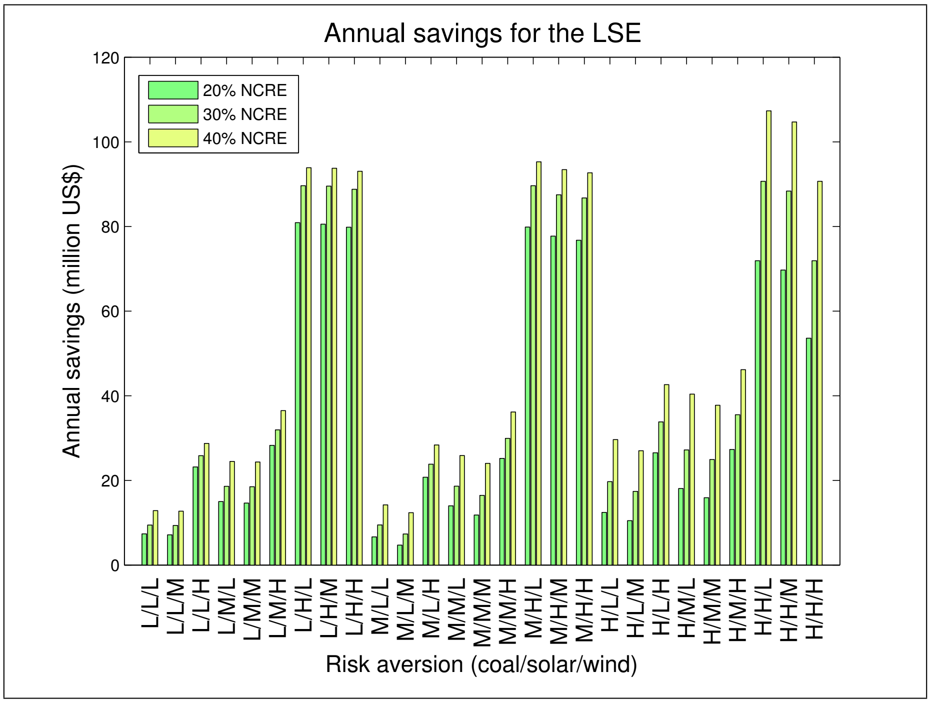

FIGURE 2.10. Annual savings for the LSE (compared to actual mechanism), Case 1

TABLE 2.5. Awarded combinations out of the total number of risk scenarios

	Actual mechanism			Proposed mechanism		
Technologies	20%	30%	40%	20%	30%	40%
Coal / Solar	0	0	0	0	0	0
Coal / Wind	27	24	21	26	25	20
Solar / Wind	0	3	6	1	2	7
# of scenarios	27	27	27	27	27	27

technologies), the slighter higher assignment that the solar generator has with the proposed mechanism is exclusively due to the greater freedom the LSE has when distributing the energies offered.

On the other hand, as there is more NCRE in the system, the coal generation dispatch is considerably reduced. Anticipating this condition, the coal generator would bid higher prices in the auction so that it can recover its investment costs, which in turn implies an increase of competeviness for the solar generator and greater assignment to its offers under both mechanisms.

Figure 2.11 shows for each risk aversion combination the savings in annual energy purchase costs for the LSE involved in using the proposed mechanism instead of the current mechanism.

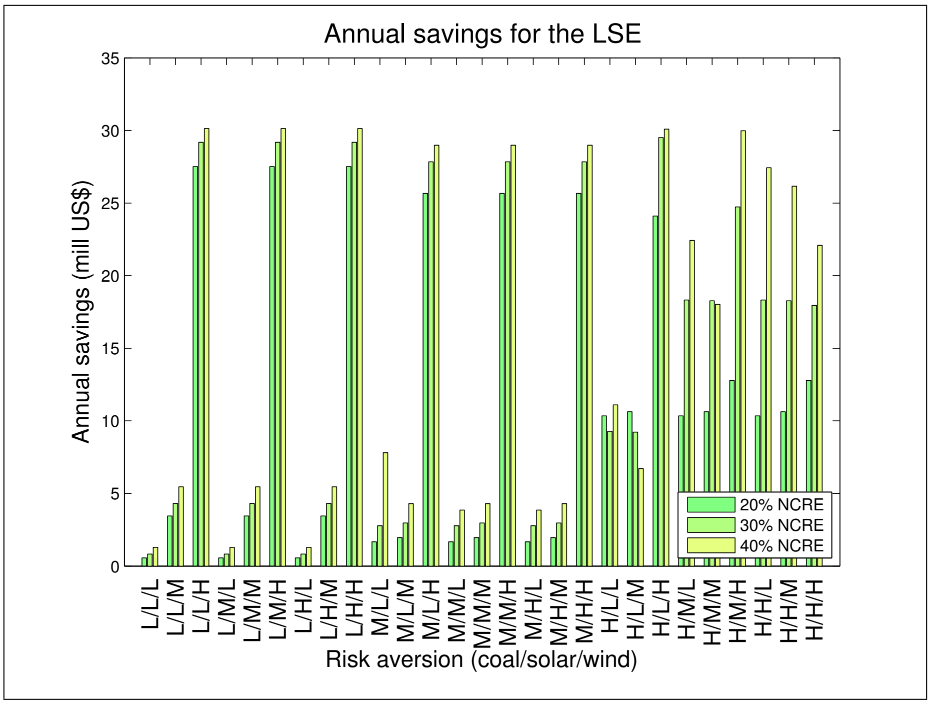

FIGURE 2.11. Annual savings for the LSE (compared to actual mechanism), Case 2

It can be observed that the annual cost savings when using the proposed mechanism is about 0.6 and 30.1 million US$ depending on the NCRE inclusion scenario and on the risk aversion combination.

Additionally, considerable savings are obtained when the wind generator has a high-risk aversion. This happens because the backed energy offered by such technology is very economic compared to the marketing cost, therefore the freedom the LSE has of being offered an assignment according to its generation profiles is of great benefit in this case.

2.4.3. Case 3: Two companies can supply the auctioned energy and the solar technology has preference in the backed energy awarding

To be exact, this case is a sensitivity analysis of Case 2, because we assume that only two generation companies are required to supply the entire auctioned demand. However, we consider that there is a benefit given to solar technology, giving it priority in the awarding of its backed energy with respect to remaining participants. In addition, the assumption that the companies do not know their competitors is relieved. However, we still consider that each company attempts to make the most competitive bid under this new scheme. In this manner, the companies calculate their bid prices without knowing the competitors' bid prices, but they are aware of the benefit for the solar generator when it is awarded the backed energy.

This could be similar to dedicate a special auction at the hours in which the solar generator is generating, because in this manner such generator could offer all its energy without marketing risks. Consequently, this would make the solar generator prices highly competitive in those hours, making the rest of the technologies to somehow give up winning in those hours, reflecting it in their prices.

To calculate the new bid prices we continue with the methodology described in 2.3.2.3. However, instead of considering that the LSE can request for an equiprobable supply in the 24 hours, we adjust such probability to allow a very low or nil probability of assignment during the hours in which the solar generator is producing, as applicable. These two probabilistic profiles for the hourly assignment of supply for the 40% NCRE inclusion scenario are presented in figure 2.12.

When observing this figure and comparing it with the generation profiles in figure 2.6, it can be observed that when increasing the NCRE inclusion level, the coal generation profile is more similar to the probability of assignment for Case 3, hence allowing to have a larger proportion of the assignment of that technology being covered by its own generation.

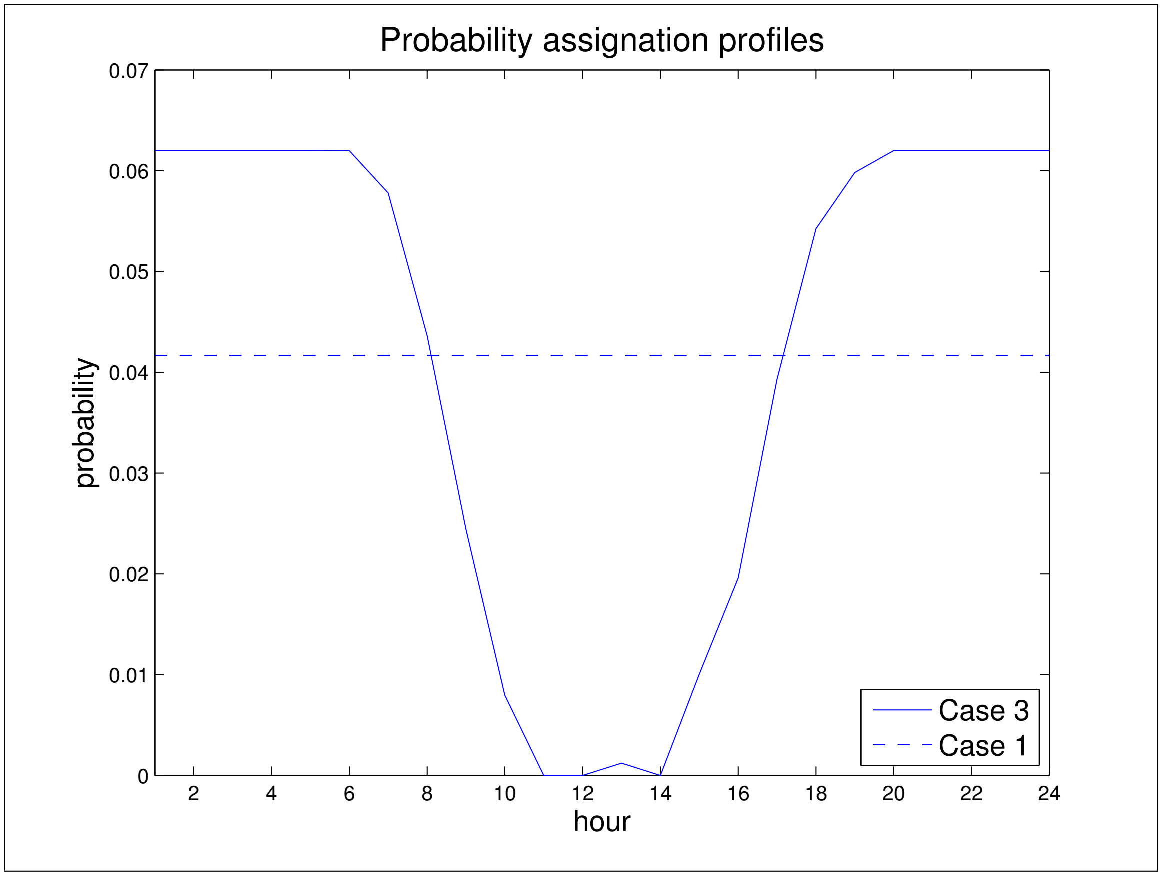

FIGURE 2.12. Hourly assignment probability, Cases 2 and 3

TABLE 2.6. Marketed price by risk aversion (US$/MWh), Case 3

Technology	Low	Medium	High
Coal (20% NCRE)	97.34	114.78	257.84
Coal (30% NCRE)	102.08	119.85	263.15
Coal (40% NCRE)	107.58	125.68	260.00
Solar	89.64	89.64	89.64
Wind (20% NCRE)	75.09	90.56	223.07
Wind (30% NCRE)	78.00	94.37	233.59
Wind (40% NCRE)	81.08	99.37	238.35

In this manner, the bid prices for this case in particular are the ones presented in table 2.6, where solar energy can present its most competitive bid in all the cases, namely, its backed price.

It can be observed that there is an important increase in the bid prices both from the coal and wind technologies, while the solar technology maintains the same bid price independent of its risk aversion.

Figures 2.13 and 2.14 show the annual over cost that the solar technology support has for the LSE under the actual and proposed mechanisms respectively.

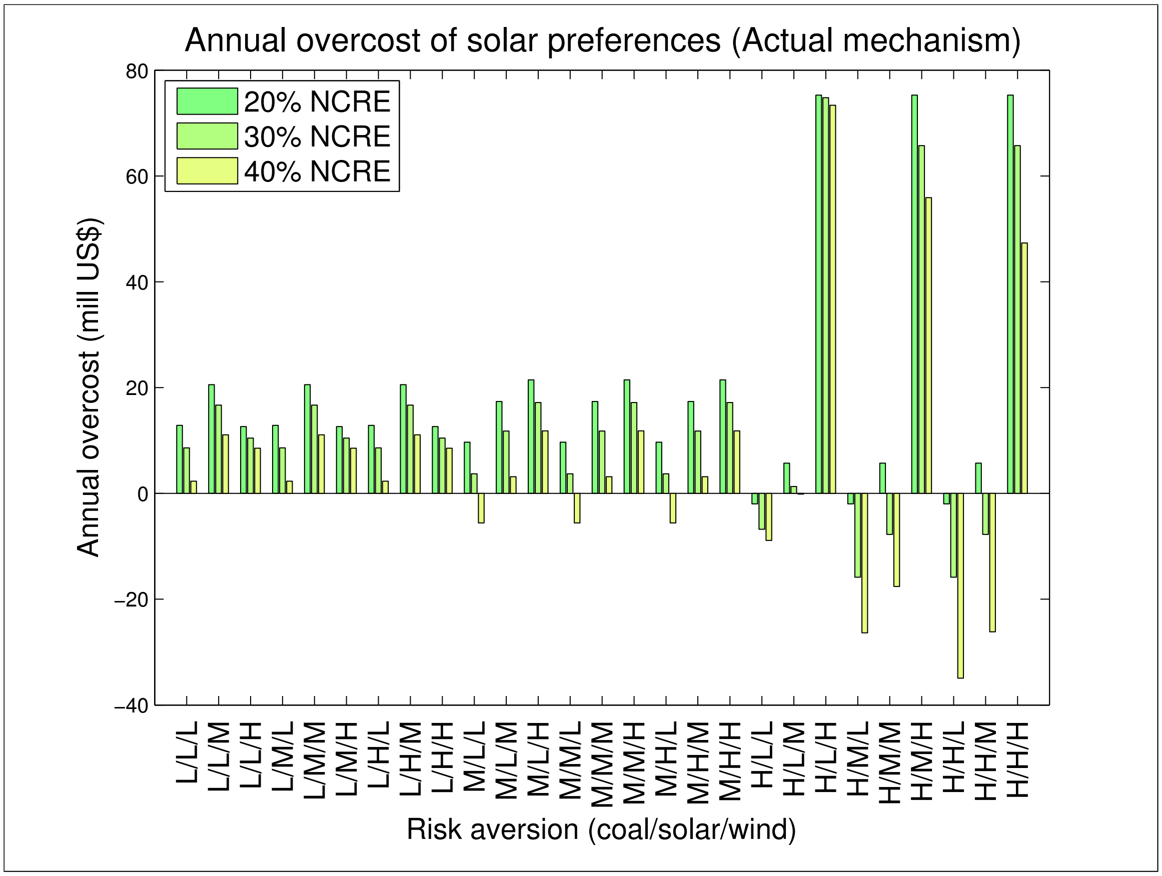

FIGURE 2.13. Annual over cost of the solar supporting scheme for the LSE (Actual mechanism)

In the case of the actual mechanism, it can be observed that there are some scenarios where the solar technology preference brings savings for the LSE, although mainly there are over costs. In general these savings are present in scenarios where the wind generator has low risk aversion and the coal generator has high risk aversion, so coupled with a low bidding price for the solar generator (which does not have marketing risk) allows the LSE

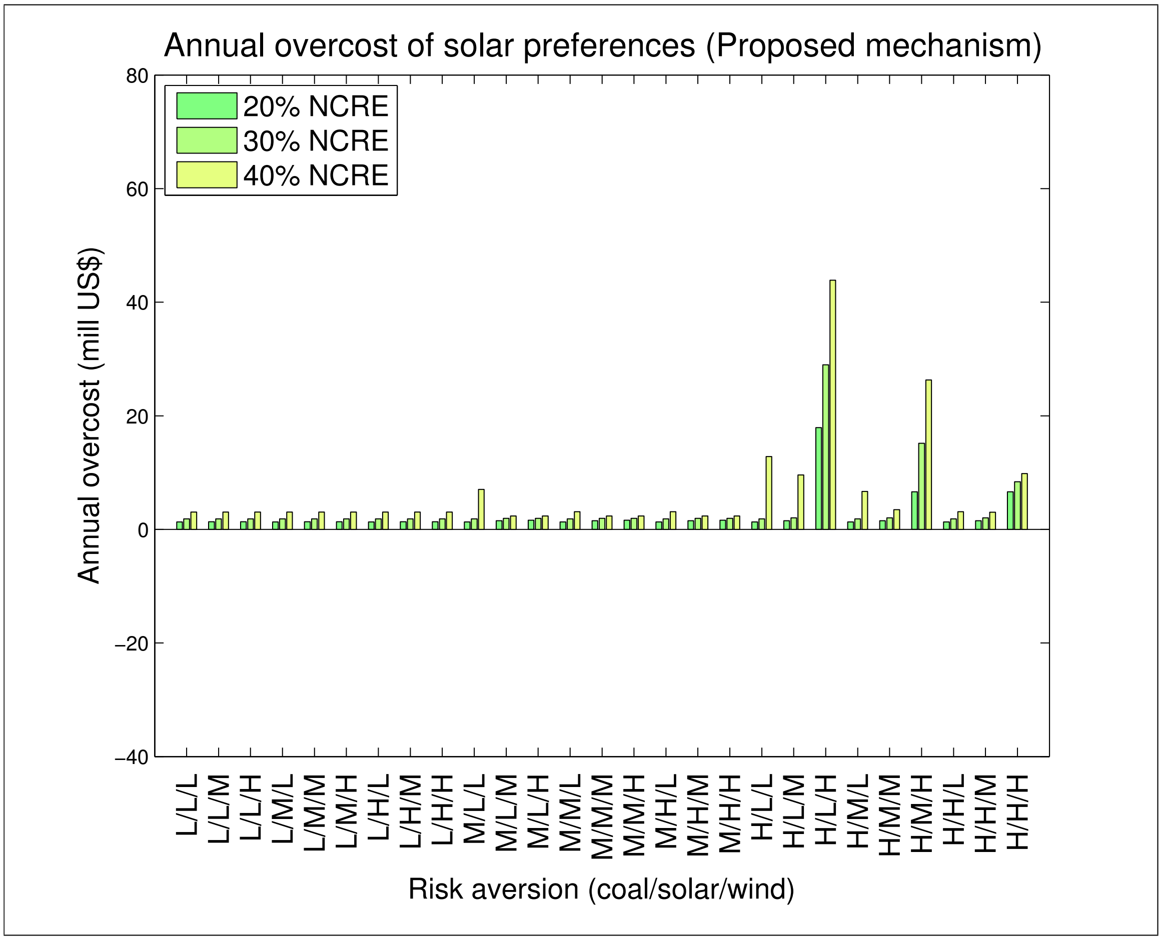

FIGURE 2.14. Annual over cost of the solar supporting scheme for the LSE (Proposed mechanism)

to award the auction to the solar and wind generators at a low clearing price. In the case of favouring the solar technology while using the proposed mechanism, there are only over costs, but in average they are lower than in the case of the actual mechanism. These over costs are due to the solar technology preference removing flexibility from the proposed mechanism, thus limiting its ability to find the best award. From the same figure we can deduce that the over costs variance is greater in the actual mechanism scenario than in the proposed one, making more difficult to predict the real effect that a transition to a solar support scheme of this kind will have. Also, it is worth noting that in this case the over costs or savings that resulted are independent from the solar generator risk aversion, as from that generator's perspective there is no marketing risk.

2.5. Discussion

At this point, it is worth mentioning that the developed work in this chapter gave rise to the article (Marambio & Rudnick, 2017), where the information can be found in a more concise way. In terms of discussion, this section review two important topics in relation with the proposed auction.

2.5.1. Arbitrary technology support

In both the first and second simulated cases, the results show a decrease in purchasing costs for the LSE when the risk aversion of the auction participants is explicitly considered in the awarding mechanism, which puts in evidence the necessity to consider such variable in the bidding rules definition for future auctions.

How to include this information in the auction mechanism may vary, but one must be careful at the time of the design and implementation. For example, in recent energy auctions conducted in the Chilean system, a portion (15%) of the total energy auctioned was offered in 3 independent time blocks (hours 23:00 to 07:59, hours 08:00 to 17:59 and hours 18:00 to 22:59), thus allowing technologies whose production profile fit with any of those blocks to only bid for the particular block, without acquiring the supply risk of the other blocks. While this is an advance in the sense of giving more flexibility to the bidders, in reality the situation is not very different from Case 3 of the simulations presented, where certain technology is supported with a specific profile without worrying about the increased risk that this decision brings to the rest of the bidders. As we have seen, this is not necessarily a good decision, whose outcome will depend on the risk aversion of the participants In this direction, an important policy implication from our work is the importance to carefully consider all the participants of the auction when designing the mechanism, because otherwise you can move one step forward and two steps back, getting suboptimal results for the end consumers.

2.5.2. Strategic behavior of the generators

The exercise of market power or strategic behavior from the auction participants would condition the application of the proposed methodology, and thus we make an analysis of this issue. In the first place, it is important to notice that the bid structure of the proposed mechanism allows us to obtain a single offer price for a generator i, as in the following equation:

$$poffer_i = \frac{\sum_t pback_i \cdot q_{it}^B + pmark_i \cdot q_{it}^M}{q_i^{Total}} \tag{2.5}$$

This price is a function of the *backed* and *marketed* price ($pback_i$ and $pmark_i$, offered by the generator) and the *backed* and *marketed* quantities (q_{it}^B and q_{it}^M, assigned by the auctioneer). With this in mind, a generator could try to exercise market power exaggerating either its costs (represented by $pback_i$) or its risk aversion (represented by $pmark_i$), both of which would imply offering a greater offer price than its true value. The issue of strategic behavior by generators has to be analyzed understanding that the proposed mechanism is a long-term energy auction, where generators offer a quantity and a single price, thus homologating it with existing long term energy auctions (moreover, being a simplification of the auctions already present in Brazil and Chile, which are multi-product).

Different references indicate conditions that limit market power exercise in such auctions and suggest approaches to tackle it. A good analysis is presented in the reference (Arellano & Serra, 2010), where they use a simple model composed of two generation firms with two available technologies, inserted in a 3 stages game. They tackle the problem of market power exercised by distorting the choice of the generating technology, assuming that the dispatch is cost based. The main conclusion from their work is that the larger the proportion of the total demand is auctioned in advance, then the lower are both the contract prices and the average spot price of energy. The reason for this is that the generator that wins the auction has an incentive to reduce its energy cost, therefore invest in baseload capacity, reducing the average spot price. On the other hand, the lower average spot price leads generators to bid lower prices in the forward auction. Their findings goes with the recommendation to pay attention to the design of the specific auction in order to mitigate market power and obtain good results, preferring a centralized process (simultaneous auctions for all consumers), offering long standing contracts and auction with enough anticipation to allow for new investors to bid, therefore increasing competition.

Reference (Villar & Rudnick, 2003) makes an assessment of market power in a hydrothermal system, and concludes that market power exercise mitigates considerably when there is an increase in the level of contracting. Further on, they argue that the need of competing firms to develop long term contracts has an important mitigation effect on their market power.

Related recommendations are given in (Moreno et al., 2009) where they remark the importance of designing the auction process in order to lower the entry barriers, increasing in this way the number of competitors. On the other hand, the awarding mechanism can play an important role in order to avoid collusion and inefficient allocation. For example the Brazilian process is a very interesting one, being a hybrid mechanism where a uniform price first stage is followed by a pay-as-bid negotiation. Finally, from a concrete implementation, observations of both (Moreno et al., 2009) and (de Souza & Legey, 2010) show that the auction processes in Brazil have increased competition and lowered prices.

2.6. Conclusions of the chapter

- The increase of economic and variable energy technologies in modern power systems modifies the electric market dynamics, increasing the level of uncertainty for all the participants in it. Due to this, the decisions that support the incorporation of such technologies must necessarily include changes in the auction methodologies used until today, because on the contrary, the costs benefits from such technologies will not be fully transferred to the end consumers simply due to a poor assignment process.
- In the case of the short term assigned hourly supply profile, it is necessary to recognize the capacity of the participants to manage risk, which must be remunerated in an efficient manner.

- A new auction mechanism is proposed to represent the short term hourly assignment issue in long-term energy auctions. It tries to clearly set out the short term risk management that the participants must necessarily have to make, and include that information in a market mechanism. In this sense, the mechanism requires auction participants to take responsibility for their own profile. Thus, risk transfers from the renewables to the conventional generators are avoided, assuming that there is not an intention to subsidize renewables by this mean.
- In the first example for the Chilean system, where all the energy offered is required to fulfil the LSE requirements, the proposed mechanism could result in cost savings in the ranges 4.7 80.9, 7.3 90.6 and 12.4 107.3 million US$ for NCRE inclusion levels of 20, 30 and 40% respectively, compared to the base mechanism. Likewise, in the case where not all the offered energy is required, the mechanism could result in cost savings in the ranges 0.6 27.5, 0.8 29.5 and 1.3 30.1 million US$ for the same NCRE inclusion levels. On each one of these ranges the only thing that varies is the risk aversion of the auction participants, which highlights the importance of considering it explicitly as the proposed mechanism does.
- As we mentioned in the Discussion section, in recent auctions of the Chilean system, a portion of the energy has been auctioned in three different intraday time windows, adding a level of flexibility to the process. For this reason, the calculated benefits from the proposed mechanism will probably be less when compared to this newly implemented method. Nevertheless, the detailed profile and indifference curves in the proposed mechanism give more flexibility to the LSE in order to optimize the total allocation.
- In the presented examples, explicitly supporting the solar technology, by favouring its backed energy awarding, brings as a consequence an important increase in the bid prices of the other technologies, although this does not necessarily imply an over cost for the LSE. In the context of the actual award mechanism, there are

some risk scenarios with cost savings benefits for the LSE given by the solar supporting scheme, but in average they are mainly over costs. On the other hand, in the context of the proposed mechanism the solar supporting scheme brings only over costs, although in average they are lower than in the actual mechanism context.

- The auction cost effects of a transition to a solar technology supporting scheme like the one considered in Case 3 are more predictable with the proposed award mechanism, so it could be useful when defining that kind of support policies.
- Regarding the short term risk due to the hourly assignment problem, at the light of the results it is convenient to explicitly consider the risk aversion of the participants in the auction mechanism design without missing the global perspective, that is to say, to carefully analyse the implications of favouring one technology over the others.

3. NEW CAPACITY MECHANISM DESIGN TO INCLUDE RENEWABLE TECHNOLOGIES

3.1. Background

3.1.1. Adequacy

Inducing an appropriate level of installed capacity in power systems has been a major issue in order to maintain reliability, specifically corresponding to the concept of "adequacy," which represents the ability of the system to meet the aggregate power and energy requirement of all consumers at (essentially) all times (NERC, 2007). In theory, pricing the energy at the marginal surplus (uniform price) results in investment incentives aligned with the optimum installed capacity according to centralized planning. This also implies to pay the VOLL (Value of Lost Load) at times when the load is greater than the installed capacity, because this will be the only income perceived by the most expensive generators (even though this "scarcity rents" will also be important to the others generators as well). The equilibrium in this market design will imply that the net income for all generators must be zero (considering the annualized investment cost at a certain rate of return), cause if there were a positive or negative net income in one or more technology, then there would be an incentive for generators of that technology to enter or leave the market, respectively.

Of course in reality there will be more uncertainty involved in the decision, for example the uncertain nature of the demand, but the design assumes that on average the signals sent by spot pricing will generate the desired output. Even though in theory the market can rely only on this mechanism to encourage an adequate amount of installed capacity (*ie.* energy only markets), in practice in many markets it is insufficient, mainly due to poor demand response and because concerns about market power induce the regulator to cap the scarcity price (*ie.* the missing money problem). In order to overcome the problem, a capacity complement has been implemented (moreover, additional mechanisms such as *energy auctions* have been implemented in developing economies that present a higher perceived risk, where even the above hasn't worked as expected (Maurer & Barroso, 2011)). The main mechanisms used as capacity complements roughly fit into two groups, capacity payments (mainly used in Latin America and some European markets) and capacity markets (mainly used in United States and some European markets). In both groups a reserve margin target for installed capacity have been traditionally set by the regulator defining an acceptable numbers of hours of load shedding, without considering the actual value of lost load (Stoft, 2002). The difference between them is that in the first group a price (payment) is defined by the regulator in order to encourage a target margin, while in the latter the Load Serving Entities (LSE) are required to secure the target margin, leaving the price determination to a market process. Among the two options, the capacity market is the preferred way in order to achieve the desired target margin (Oren, 2000).

3.1.2. Renewables in adequacy

Another aspect is the increasing level of non-dispatchable technologies such as renewables, that present variability as one of their characteristics. In this sense, traditionally the concept of adequacy has been associated with the peak load hours of the system, that is to say where the greatest load is presented. The reason for this is that if load in those hours can be satisfied with a certain level of confidence, then there would be sufficient capacity to meet the load for the rest of the hours, since by definition the demanded amount in these times will be less than in peak hours. While this thought process works in a pure thermal system, problems begin to arise in systems with high penetration of the aforementioned technologies.

In this context, is important to reconsider the way that the capacity contribution of each power plant is measured in relation to the adequacy of the power system. For example, a power plant might not contribute capacity in peak hours, but that does not necessarily imply that it will have a null contribution of capacity in the rest of the hours. On the other hand, the plant could provide capacity in peak hours but not in the remaining hours. In this latter case, if several plants are in this situation then the hour with the higher risk of load lost could be different than the one that presents the peak load.

In this work we are proposing a capacity market design that considers the renewable generation dynamics and a valuation of the expected unserved energy (EUE) in the calculation of the demand curve. The methodology is based on a reserve curve approach such as the ones presented in (Hogan, 2013) and (MISO, 2005) but used *ex ante*, before the relevant period (generally a year). It also considers an analytical derivation of the willingness to pay, which present similarities with (Zhao et al., 2016), where they propose a framework based on optimization to be used in a multi zonal analysis.

3.2. Mechanism design

We propose a methodology to implement a capacity market to be considered along the spot price scheme, but unlike actual designs, the goal is to determine a capacity demand curve that doesn't rely on an arbitrary capacity requirement made by the regulator, but instead on a correct valuation of the VOLL. On the other, the design considers the inclusion of renewable generation at the time of building the curve, in order to intrinsically represent the dynamics of those technologies in the willingness to pay valuation. The methodology requires to aggregate the hours of the year in groups, in order to derive a demand bid curve for each one of them. In this work we are considering 24 groups, representing each one of them an hour of a representative day of the year (but this also can be done considering more desagregations such as typical winter days, summer days, etc.). With the demand curve on each hour of the typical day, a capacity clearing price can be determined as the intersection of the offer and demand curves, which can be used to value the capacity contribution of each generator in every hour. With this, the payment to a generator will be based both on the capacity benefit that the generator contribute to the power system, and the price that the demand is willing to pay for that contribution. The general methodology for a particular year is presented in figure 3.1.

After defining the groups of hours, the next step in the methodology is a Monte Carlo simulation, where a number of random daily scenarios are obtained for the particular year. With that information we derive an expected capacity demand curve for each hour of the

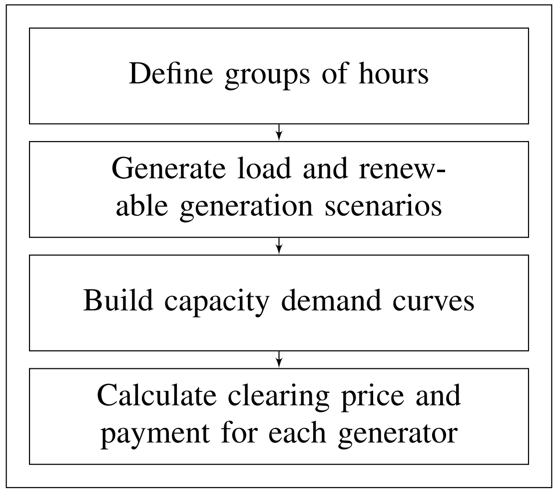

FIGURE 3.1. Methodology block diagram

representative day, meaning the aggregate willingness to pay that the demand would present for capacity.

3.3. Modeling

3.3.1. System modeling

A key element in the implementation of the methodology refers to a successful modeling of the probability distribution of both the system load and the generation of non-dispatchable plants in order to obtain the net load, which is the load of the system minus the production by the non-dispatchable plants.

The fact that renewable power plants are non-dispatchable makes it difficult to know ex ante if they will be providing useful capacity at times when the system will need them, however this does not mean that they do not contribute to the reliability of the system. This issue brings a new challenge, which is to develop new techniques to better predict their behavior, so that we can have higher levels of certainty as far as power output is concerned. In order to consider such plants in the proposed methodology, we not only need an estimate of the probability distribution function of the power plants in consideration, but a joint probability distribution between that generation and the load. In our case we carry out that task using copulas (Bouyé et al., 2007), which correspond to multivariate probability distributions that allow us to model the probability of the stochastic variable pair (renewable generation, load) being consistent with historical data.

With this we can obtain a copula for each hour of the day, that describes the joint probability of load and renewable generation. Then an arbitrary number of scenarios can be generated, in order to capture the regular scenarios as well as the extreme ones. Figure 3.2 shows a scatter plot between unitary load and renewable generation for historical and simulated data, both in hour 10 of the day. It can be seen that the simulated data replicated the behaviour of the input series, presenting the denser area approximately at (0.9 , 0.45).

A similar approach have been used in (Muñoz & Mills, 2015) and (Park & Baldick, 2013), where they derive an "empirical copula" through a clustering algorithm, in order to obtain (wind, load) points to feed a generation and transmission expansion planning problem respectively.

In order to obtain the different scenarios we are using some data from the Chilean power system, and only solar and wind technologies are considered as renewables. That system is extended through several geographic regions, but in our analysis we are considering that the wind and solar projects are concentrated in two places (SING and north segment of SIC subsystems). Moreover, even though each wind and solar power plants have their own hourly profile, for simplicity we will assume that they behave in a similar way, given the aforementioned geographic concentration. So we'll use a unique unitary profile for each technology and scale it according to the renewable scenario. The considered solar generator is "Maria Elena" while the wind generator is "Valle de los Vientos", presenting a capacity factor of 31% and 30% respectively.

On the other hand, for the demand we are using the SIC and SING hourly power profile for the year 2013, scaled up to represent an annual energy demand of 125,558 GWh, which is a projected demand by the National Energy Comission (CNE) for the year 2030.

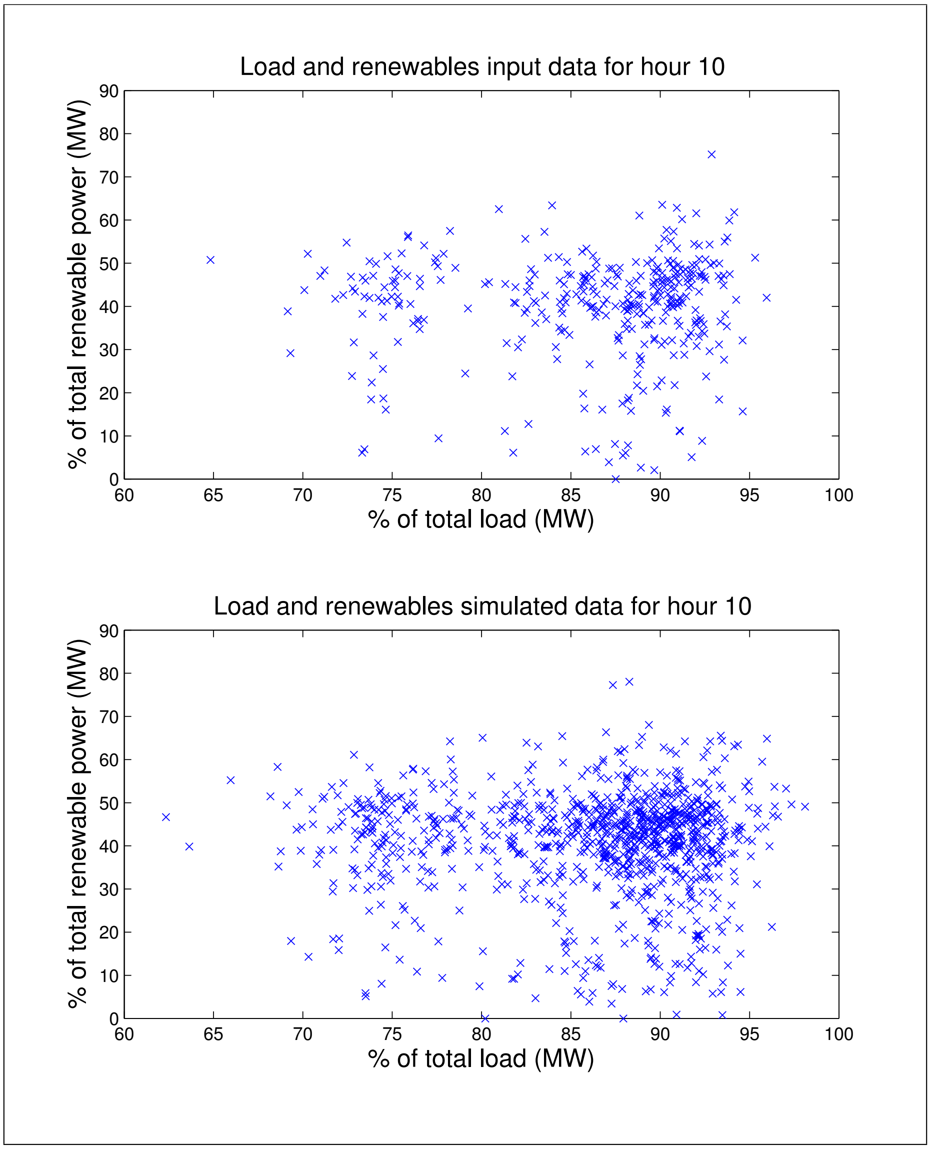

FIGURE 3.2. Net load histogram and distribution function

Considering that the load and renewable technologies are the elements in the methodology that provide the power profile to the system, table 3.1 presents their installed capacity used in the simulation.

Figure 3.3 shows the daily average profile for both the renewable generators and the load.

TABLE 3.1. Installed capacity by non dispatchable element

Element	Installed capacity (MW)
Load	17,092
Wind	2,000
Solar	2,000

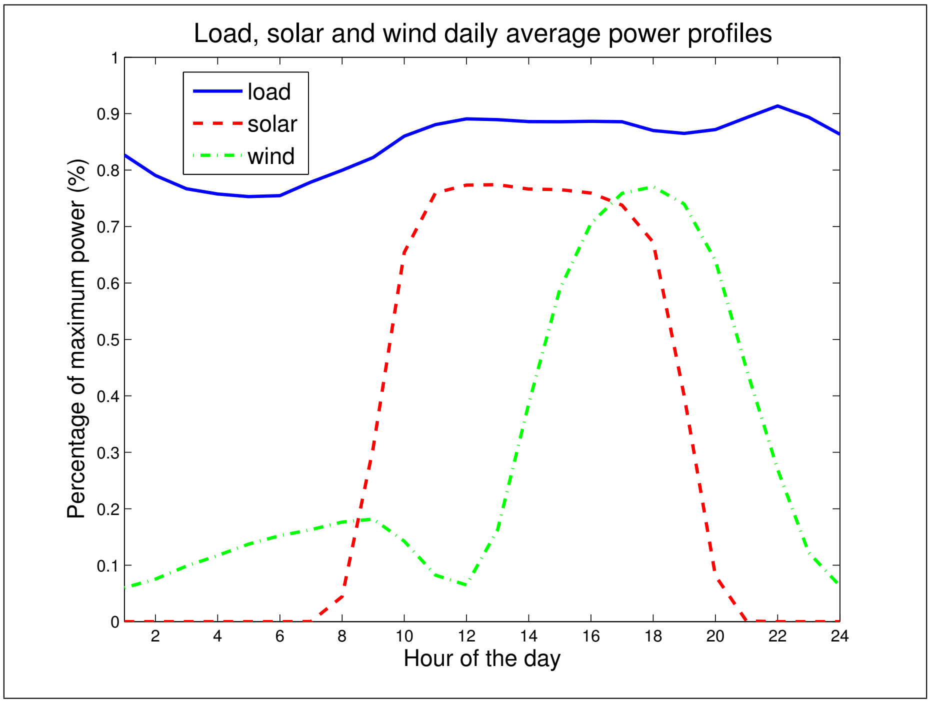

FIGURE 3.3. Load, solar and wind daily profiles

It can be seen that the peak demands tend to concentrate towards the hour 22, while the average peak generation of both renewable technologies presents earlier in the day.

With these time series one can proceed to find the distribution functions on each hour, as required by the methodology. Even though a parametric function can be used (*eg.* Weibull distribution), for this work we chose to fit the distributions with a non parametric technique, specifically by a *Kernel density estimation* (Hwang et al., 1994). This kind of techniques tries to find a distribution only based on the observed data, unlike the parametric techniques which tries to estimate parameters for an assumed distribution. In this work we are fitting a distribution function for the aggregated solar and wind generation, obtaining a distribution representing the total renewable generation. The histograms and resulting distributions for a specific hour are shown in figure 3.4.

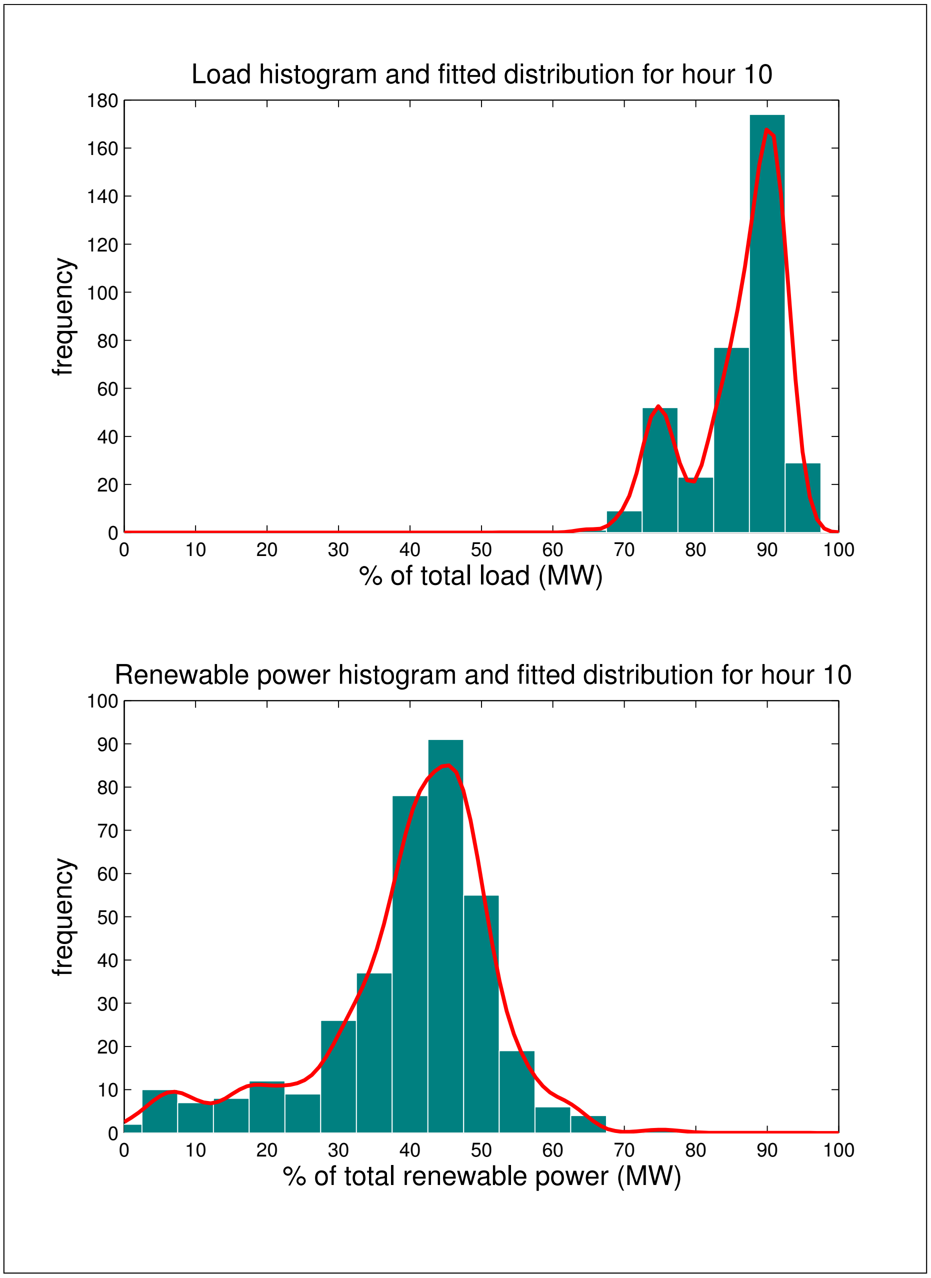

FIGURE 3.4. Fitted distributions for hour 10

It can be seen that the most probable value for the load and renewable generation is approximately 0.9 and 0.45 respectively for this specific hour, which is consistent with figure 3.2 shown before. In this way, for every hour of the day, 1000 simulated points are obtained through its fitted bivariate copula.

3.3.2. Demand modeling

The proposed approach tries to explicitly value the benefit that results from the existence of extra capacity in order to maintain a level of reliability in the system, but unlike actual capacity market and payments designs, try to make no assumptions about the desires of the consumers (like the reserve margin promulgated by the regulator). Instead, what it tries to do is to reflect the benefit that the extra capacity induces in the consumer, so it can take a decision aligned with the consumer desires. Nevertheless, for this to happen there has to exist a good valuation of the demand's VOLL, which in practice does make the approach somewhat dependent on administrative decisions if the value of VOLL is specified by the regulator.

In the classic paper (Garver, 1966), a graphical way to get the Effective Load Carrying Capability (ELCC) of a power plant is presented, which allows the calculation of the load magnitude that can be added to the power system maintaining the same reliability level. However, to achieve that, the author derives a number of very interesting mathematical relationships, one of them being the system loss of load probability as a function of the reserve capacity. The mentioned function is an exponential equation defined mainly by a parameter *M*, which is specific to the analyzed power system.

Specifically, the article proposes the following equation, where P^{out} is the outage capacity, a_0 is the historic outages per hour and y is the amount of reserves that the system has:

$$P(P^{out} \geq y) = a_0 e^{-y/M}, y > 0 \tag{3.1}$$

Following this line, we present the development of a formula derived in (Baldick, 2015), and adjusted to be used in the present work. We are considering an hourly resolution, and assuming that if a loss of load event is present, then it will be present in a fraction τ of the whole hour, representing the time for the Independent System Operator (ISO) to bring the load online again, assuming that sufficient generation is available. Additionally, the load loss expectation cannot be smaller than 0 or greater than the load *D* in the hour, and will only occur if the outage exceeds the reserve capacity *F* in the system. With this and acknowledging that the probability density function of P^{out} is $(a_0/M)\, e^{(-y/M)}$, the load loss expectation in a a specific hour will be:

$$
\begin{aligned}
&\mathbb{E}\left[\min(D, \max(0, P^{out} - F))\right] \\
&= 0 \times P(P^{out} \leq F) + \int_F^{D+F} (y - F)\,(a_0/M)\, e^{(-y/M)} \mathrm{d}y \\
&+ D \times P(P^{out} \geq D + F), \\
&= \left[-\,(y - F)\, a_0 e^{(-y/M)}\right]_F^{D+F} + \int_F^{D+F} a_0 e^{(-y/M)} \mathrm{d}y \\
&+ \left[D a_0 e^{((-D-F)/M)}\right], \\
&= \left[-a_0 M e^{((-D-F)/M)} + a_0 M e^{(-F/M)}\right] \\
&= M(1 - e^{(-D/M)}) a_0 e^{(-F/M)}
\end{aligned}
\tag{3.2}
$$

where integration by parts was used in order to solve the integral. Considering this along the VOLL we can deduce that the expected cost of curtailment on a given hour will be:

$$E\left[Cost\right] = VOLL \times \tau M(1 - e^{(-D/M)}) a_0 e^{(-F/M)} \tag{3.3}$$

which is dependent on the amount of reserve capacity. We can interpret this expected cost as minus the expected benefit function of the demand, from where we can obtain an equivalent *demand bid*. This demand bid will be equal to the derivative of this benefit function with respect to *F*, giving the following result:

$$demand\, bid(F) = VOLL \times \tau(1 - e^{(-D/M)}) a_0 e^{(-F/M)} \tag{3.4}$$

which is also dependent of the reserve capacity level *F*. The simulated scenarios will provide the netload which in conjunction with the assumed conventional installed capacity allow us to obtain the willingness to pay for an extra MW of available capacity on each of those scenarios.

We are defining the annual reserve margin as the one that is present in the hour of the year where reserves' conditions are tightest (*ie.* the maximum netload hour), and the reserve curves will be build as a function of this annual reserve margin. Note that for each assumed annual reserve margin, which is a unique value, there will be an associated profile of reserve margins corresponding to every other hour of the year (different to that of the maximum netload), which will be given exclusively by the load and renewable generation profiles of the power system under analysis. Another aspect is that the formula has to reflect the issue that load will have to be disconnected from the system in the case that operating reserves go below a certain threshold (minimum level of operating reserves in order to maintain security). So anytime the reserves fall below that threshold, the curve has to take a value equal to the VOLL, which results in the following willingness to pay function:

$$wtp(F) = \begin{cases} VOLL & F \leq F^{min} \\ demand\,bid(F) & F^{min} \leq F \end{cases} \tag{3.5}$$

The fixed parameter a_0 correspond to the probability of ocurrence of an outage in the hour, which may be obtained from statistical data and will depend on the power system under analysis. The last value needed to make the calculation is the parameter *M*, which is of great importance because it gives the shape to the function used for the valuation. The parameter *M* is a specific feature of the analyzed power system, which in practice may be determined by statistical or simulation data, the latter can be seen in (D'Annunzio & Santoso, 2008) where to calculate the value of a slightly different *M* they used a series of simulations to generate points in order to fit a curve with exponential relationship. In this paper we use a rough approximation presented in the original paper (Garver, 1966), which corresponds to the following equation:

$$M = \sum_{g} P_g^{max} \cdot r_g^{out} \tag{3.6}$$

where P_g^{max} and r_g^{out} are the maximum power and forced outage rate (FOR) for the power plants of the system. At this point it is important to clarify that for the calculation of *M* we consider only the thermal power plants, since we assume that renewable power plants have a negligible rate of unavailability due to mechanical failures, and we consider instead that their main unavailability source is the weather uncertainty. Moreover, as we consider the generation from these plants as a negative load, the weather variability is directly represented in the generated scenarios.

If we define the netload in the maximum netload hour to be $\hat{D}$, the annual reserve margin as $\hat{F}$ and the netload in hour h of scenario $s \in \mathbb{S}$ as D_h^s, then we can obtain the reserve margin on any hour and scenario F_h^s as a function of the annual reserve margin with equation (3.7) using F_h^s as the independent variable..

$$F_h^s = \hat{F} + (\hat{D} - D_h^s). \tag{3.7}$$

Then we can use equation (3.5) to value the demand willingness to pay on every point generated on the scenario simulation phase. Moreover, we can build a price curve for every hour of the representative day through varying the annual reserve margin between 0 and an arbitrary value. So, if each scenario *s* of the set $\mathbb{S}$ is equiprobable and the set corresponding to the hour i of the representative day is $\mathbb{H}_i$, then the curve to be used in the hour i of the representative day as a function of $\hat{F}$ is:

$$bid_i(\hat{F}) = \sum_{h \in \mathbb{H}_i} \sum_{s \in \mathbb{S}} \frac{wtp(F_h^s)}{|\mathbb{S}|} \tag{3.8}$$

which in essence is the aggregated average willingness to pay of the hours in the group considering all the scenarios. This will result in a price in [USD/MW-year] to pay for a MW of available capacity in that hour of the representative day.

With the simulated points of load and renewables, we can obtain the capacity demand curves for every hour using (3.8). The parameters for the curve are also taken from the chilean system, having the VOLL and a_0 values of 13,230 USD/MWh and 0.285 respectively. As equation 3.6 suggest, the value of *M* will depend on both the installed capacity and technology mix of the conventional generators present in the system, where the installed capacity will be equal to the peak net load plus the evaluated reserve margin (*ie.* the x axis of the curve). On the other hand, in order to simplify the calculations, we are assuming that all the conventional generators will have a FOR equal to 5%, sparing us the need to estimate the technology mix. Additionally, we are assuming that if a lost of load event occurs, the ISO (Independent System Operator) can bring the load back online in 30 minutes, so the value of τ will be 0.5. Finally, we are considering a value of 500 MW as the minimum level of operating reserves in order to maintain security. Figure 3.5 shows the average $\pm$ 1 standard deviation of the obtained hourly prices for two reserve margins.

It can be seen that although the profile of both plots are similar, both the average values and standard deviations are considerable higher when the reserve margin is tighter, specially around the peak load hours. Applying equation 3.8 to the prices, results in the curves presented in figure 3.6, where it can be seen that there are considerable differences in the demand willingness to pay for capacity according to the specific hour of the day.

Also note that the left part of the curves present a non smooth behaviour, which is exclusively due to the discontinuity introduced by considering a minimum security level for operating reserves.

3.3.3. Generators modeling

The next step is to determine the capacity that a power plant can contribute to the system on every hour of the day. For a conventional power plant, the most straightforward way to do this is to consider the maximum power adjusted by its FOR, to account for the times when the plant is unavailable to provide power. On the other hand, the capacity contribution for a renewable plant in an hour could be the maximum power adjusted by its corresponding capacity factor on that specific hour.

In order to obtain a clearing price on every hour, an offer price at which each generator is willing to sell its capacity is needed, along the demand curve and the capacity that each generator can contribute. In this work we are considering that a generator is fully price

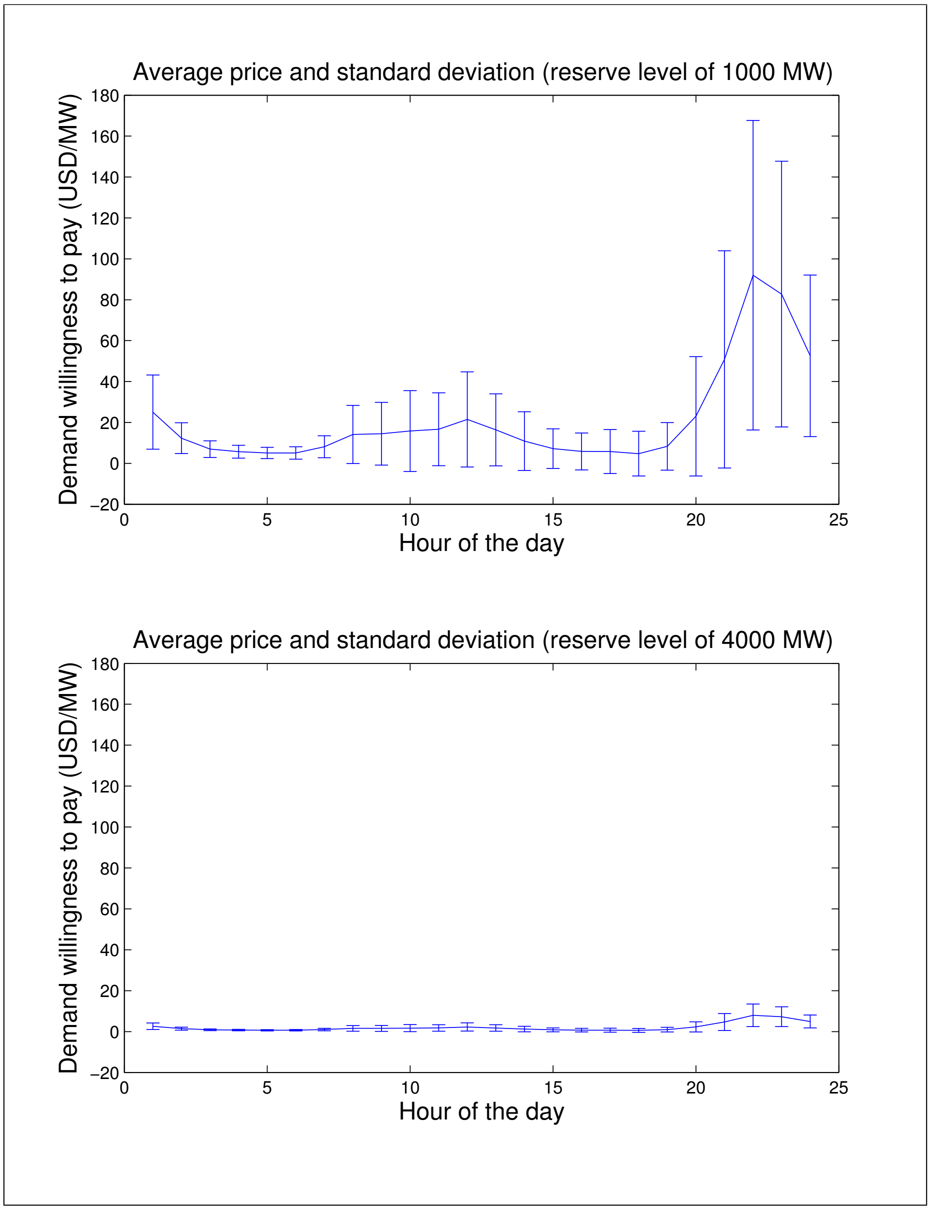

FIGURE 3.5. Hourly average price

taker, so its offer price will be zero, implying that the market clearing price will only be determined by the available capacity in the system.

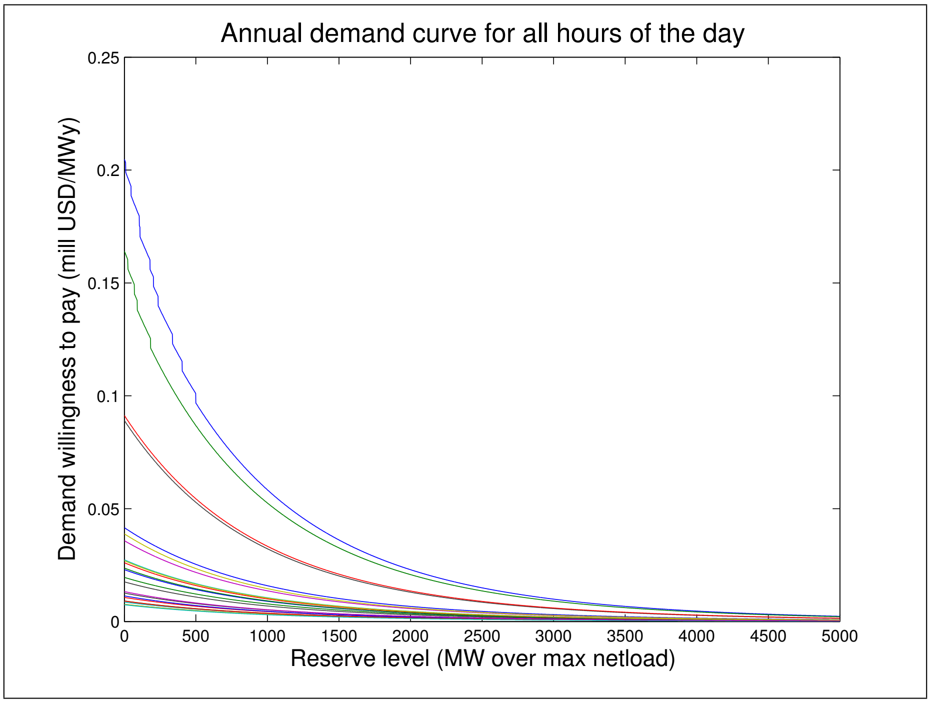

FIGURE 3.6. Capacity price curve for every hour of the day

3.4. Results of the chapter

3.4.1. Capacity valuation comparison

The contributed capacity of a conventional generator won't be subjected to variability through the hours, so its capacity offer will be equal in all the hours.

In order to compare the results of the proposed methodology with an existing design, we defined the simple capacity demand curve shown in figure 3.7 which has been built according to (FERC, 2013), following the design implemented in NYISO (within its New York City zone).

In essence this curve has two sections, the first one is a constant value which serves as a cap to the demand bid equal to 1.5 times the *Cost of New Entry* (CONE), which is the annuity of a peaker plant. The second section is a decreasing line defined by its slope and an arbitrary value at which it cross the x axis. One important issue is that the value of the function at the target reserve margin (marked with the dotted line) must be equal to the

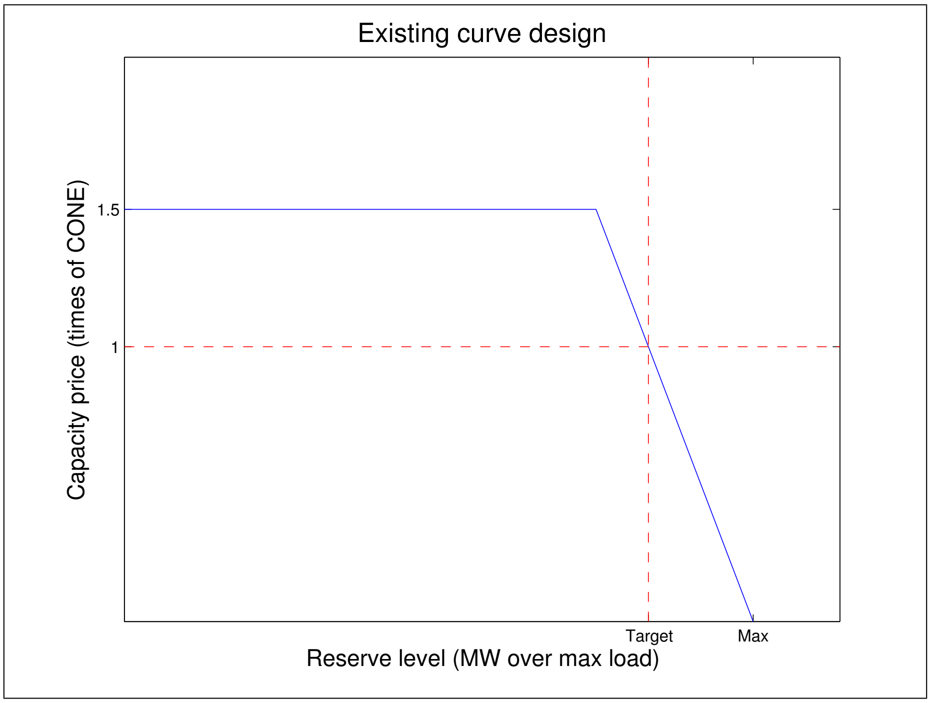

FIGURE 3.7. Existing curve design

CONE, in order to encourage that reserve margin in the equilibrium. For the comparison we are assuming that both mechanisms work as intended, that is:

- The traditional curve successfully induces the target reserve margin.
- The proposed curves successfully estimate the demand willingness to pay.

With these assumptions, we will compare the differences in economic surplus of using one mechanism instead of the other. This is done for different values of both the target margin and the CONE in the traditional curve, in order to have an idea of the influence of these parameters. We are considering a CONE of 0.078 million USD/MW, which corresponds to a diesel turbine in the Chilean system (annualised with a 10% rate of return), along with the curves derived in the previous sections. For the considered CONE, figure 3.8 shows the difference in both the producer and consumer surplus when using the traditional curve instead of the proposed one.

It can be seen that there is a point where the difference in both surpluses is zero. This point is where the induced target margin equals the consumers desired margin due to the

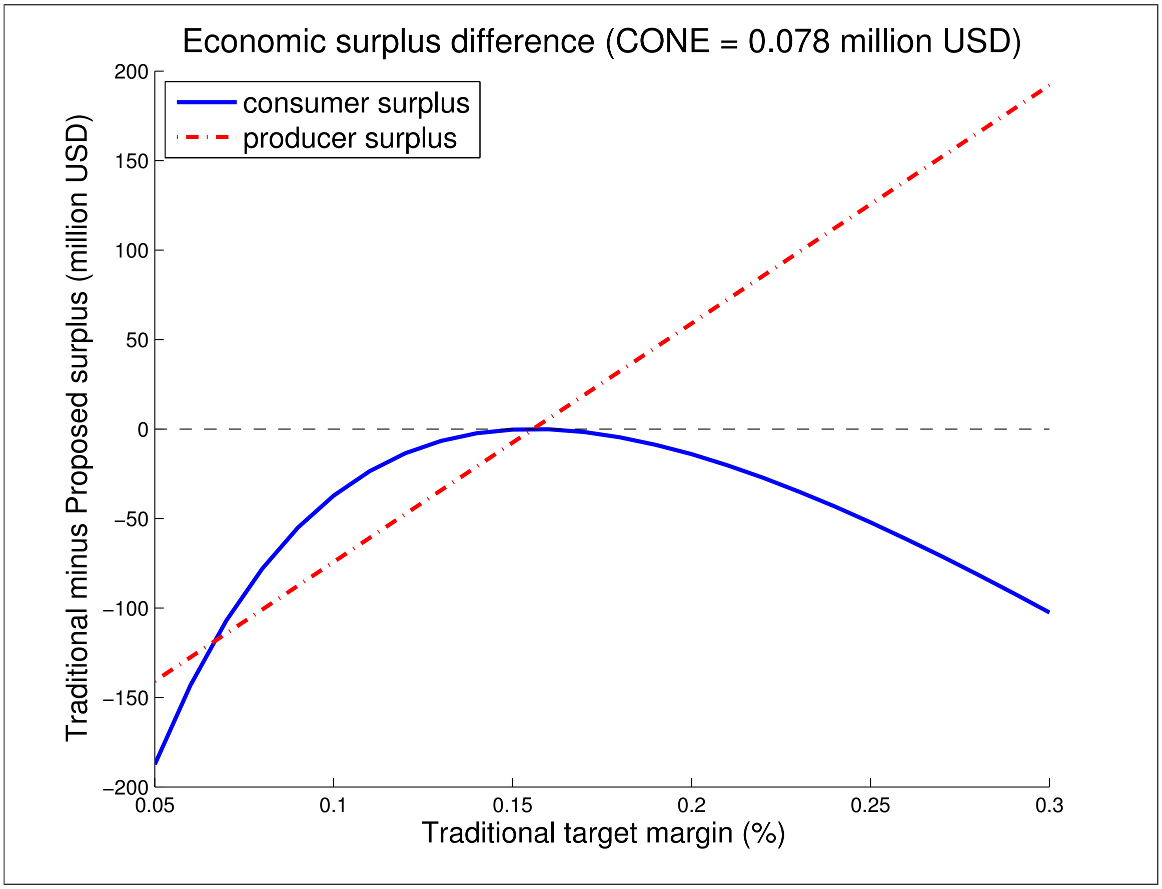

FIGURE 3.8. Economic surplus of traditional curve minus proposed

particular CONE. At lower reserve margins, both the producer and consumer surpluses are less than what they could have been (*ie.* less total surplus than the optimum), while after that point there is an increase in producer surplus at expense of the consumer surplus. Neither one of these situations is desirable from an economic viewpoint.

Figure 3.9 shows the same difference in consumer surplus for three different values of CONE (0.5, 1 and 2 times the original value).

Besides that the consumers desired margin is different for the three values, it can be seen that the greater the CONE value, the greater the surplus loss rate for consumers after the desired margin, so a traditional curve with a high CONE coupled with a high target

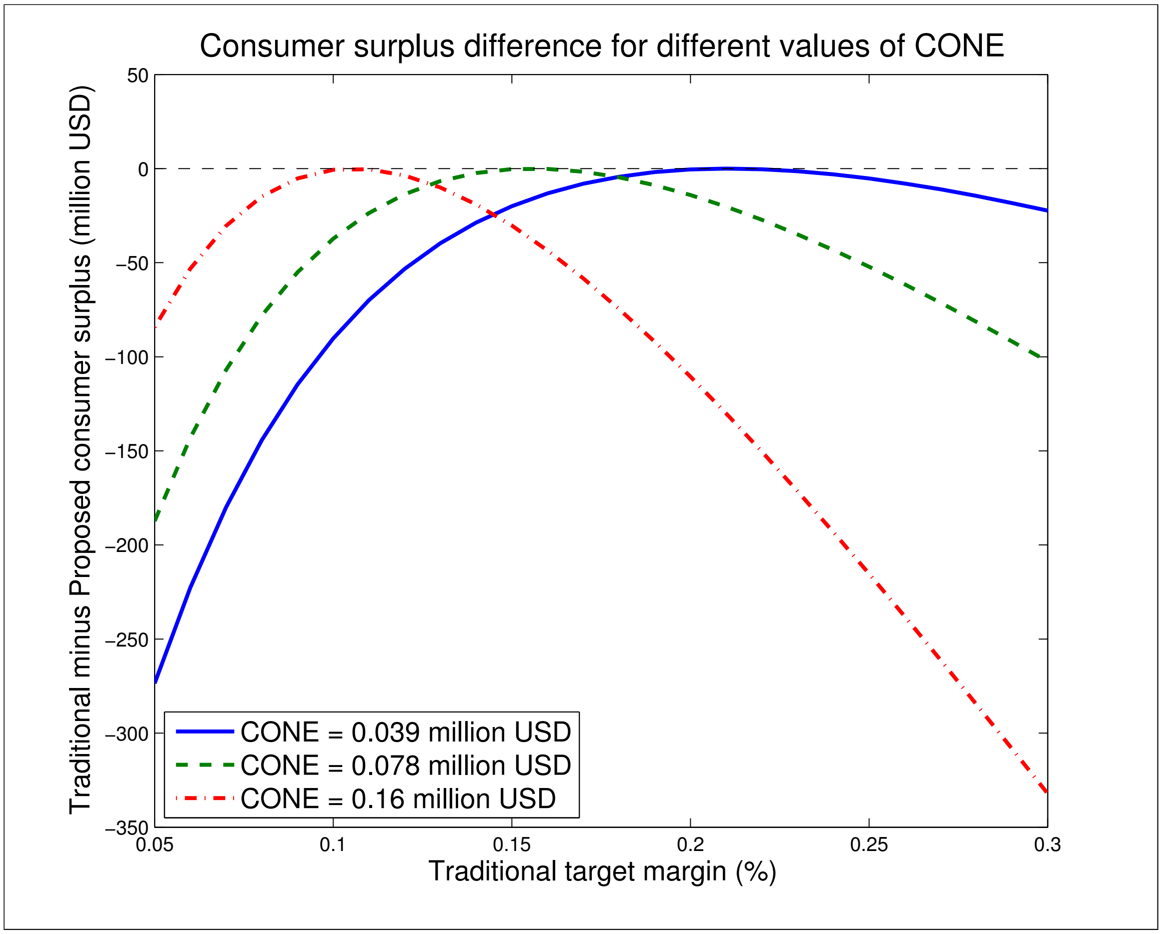

FIGURE 3.9. Consumer surplus of traditional curve minus proposed

margin is a bad combination for consumers. The next subsections will present some sensitivities in different inputs of the curve.

3.4.2. VOLL sensitivity

As we mentioned before, a correct valuation of the VOLL is essential to the correct functioning of the proposed mechanism. In order to measure how much influence this parameter has, figure 3.10 presents the annual revenue of 1 MW of capacity for three different values of the VOLL.

The parameter has a considerable effect as expected, with the differences between the curves decreasing as the reserve margin increases.

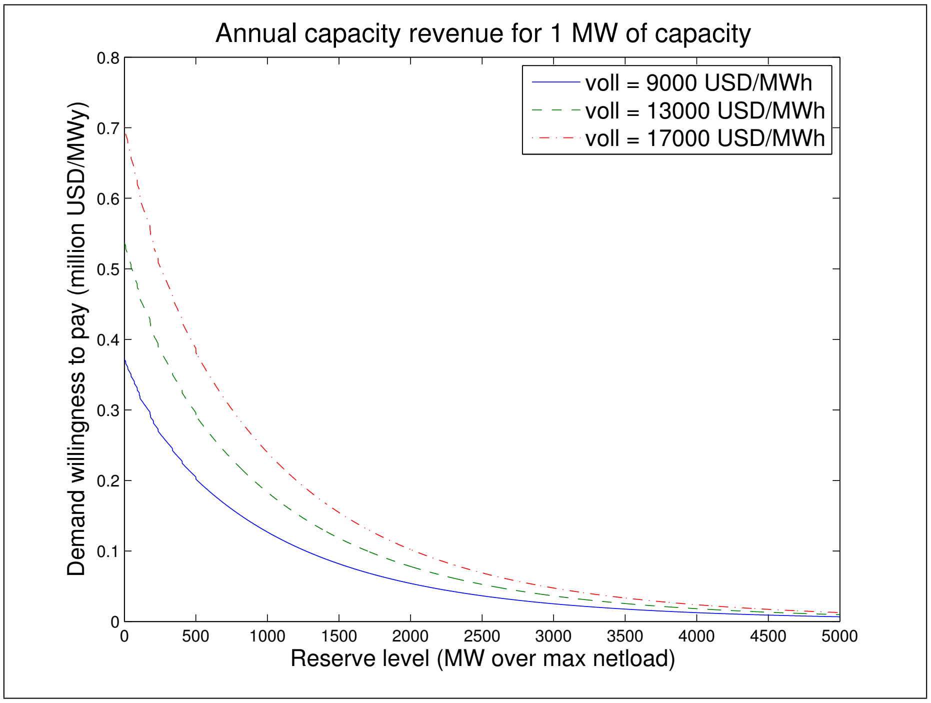

FIGURE 3.10. Revenue for 1 MW under three VOLL scenarios

3.4.3. Renewable technology mix sensitivity

In order to assess the effect that the renewable technology mix has in the outcome, we consider sensitivities varying the installed capacities of the solar and wind generators. Figure 3.11 shows the capacity revenue of 1 MW of capacity both under a ”pure solar” scenario (5000 MW of solar capacity and 0 MW of wind) and a ”pure wind” scenario (0 MW of solar capacity and 5000 MW of wind).

From the figure we can infer that the hours when the solar is not generating are very costly for the system when the margin is tight. This is reflected in a higher willingness to pay for 1 MW of wind capacity when the reserve margin falls below the security level of operating reserves. On the other hand, compared to the solar generator, the wind peak generation is nearer to the peak demand of the Chilean system.

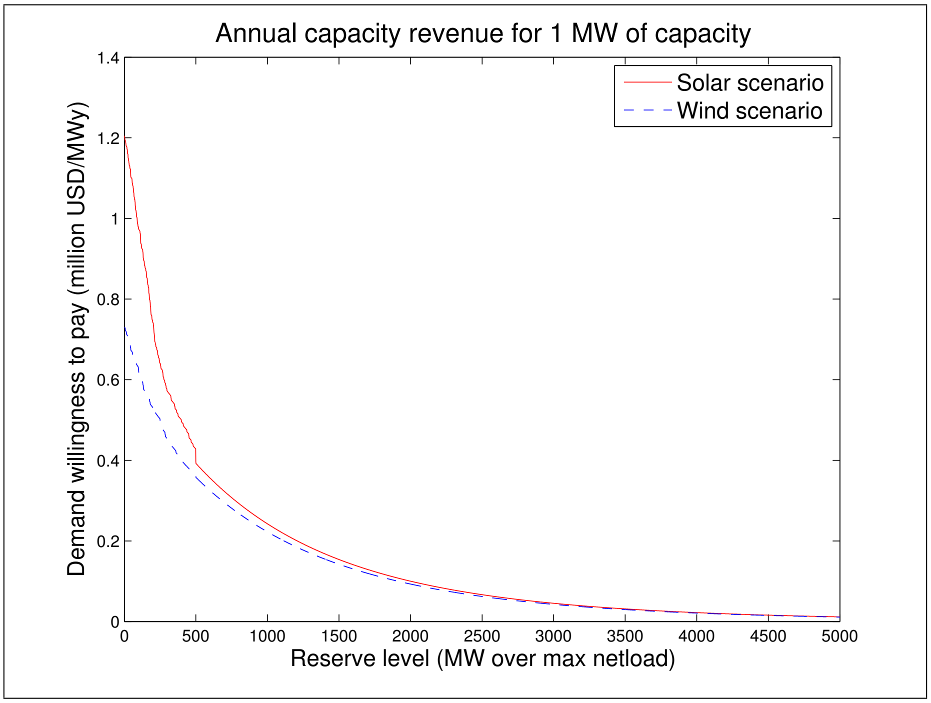

FIGURE 3.11. Revenue for 1 MW under two renewable mix scenarios

3.4.4. Renewable technology level sensitivity

As more renewable (non-dispatchable) generation enters the system, the system netload will present a more different profile than the original load. To see the impact that this has on the capacity value we ran two new scenarios, the first one is a ”Low renewable scenario”, where 2000 MW of renewable capacity (half solar and half wind) is in the system. The second is a ”High renewable scenario”, where a total of 10000 MW of renewable capacity is installed, in the same proportion as the low scenario. Figure 3.12 shows the result of this sensitivity.

It can be seen that for the same reserve margin, the demand in the high renewable scenario presents a lower willingness to pay for capacity. The reason for this is that we are using the same renewable generation profile on both scenarios, and moreover, both scenarios present the same maximum netload (equal to the maximum load). With this, the assumed conventional installed capacity on every point of the curve will be equal on both scenarios, so in the high renewable scenario we have a higher renewable installed

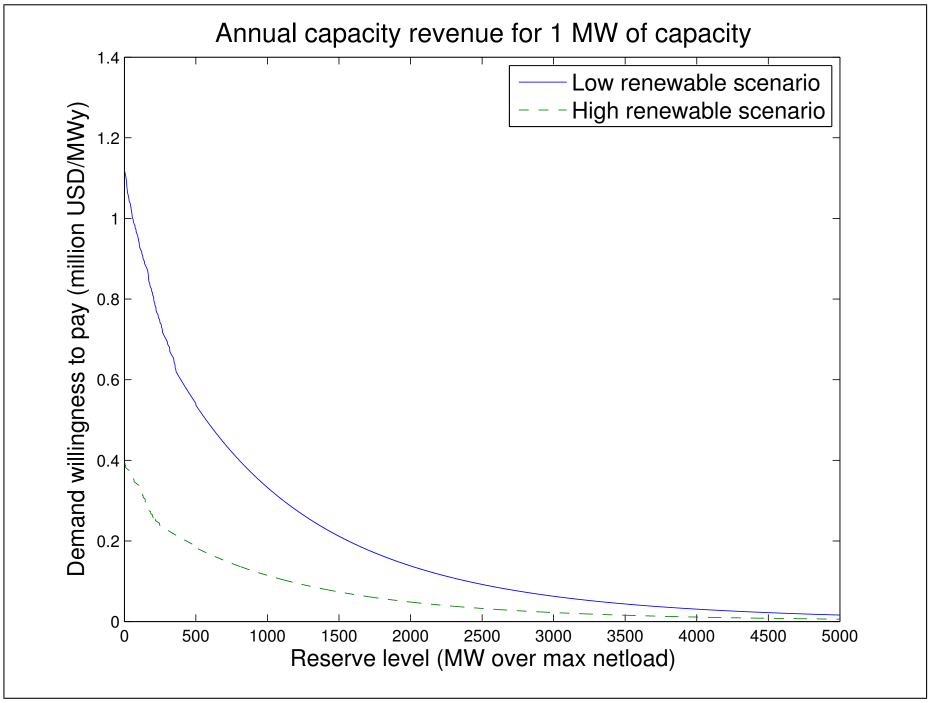

FIGURE 3.12. Revenue for 1 MW under two renewable level scenarios

capacity plus the same conventional capacity as in the low scenario, giving as a result the considerable lower overall capacity value. This sensitivity shows the importance of considering more hours than the peak hour in the process.

3.5. Conclusions of the chapter

- A capacity market design is presented, where the dynamic nature of renewable technologies is included in the demand curve calculation, and an analytical approach to the expected unserved energy valuation is used. Additionally, the demand curve derivation only relies on the value of lost load and system parameters, unlike actual designs which depend on a pre determined capacity target.
- With renewables incorporation is important to consider more hours than the peak one (as we saw in sensibility 3), which could lead to a curve that doesn't give the correct incentives.

- The proposed design provides a better representation of the demand preferences than actual designs, and moreover, the representation will continue to improve as more refined is the value of the VOLL.
- It is worth noting that the topic presented in this article is only one part of the whole. Another extremely important aspect to consider is the ancillary services remuneration, especially as more renewables enter into the power system.
- As a future work, it could be useful to differentiate *types* of offered capacity and to represent multiple zones in the system.

4. MARKET MECHANISM TO DETERMINE LNG IMPORT VOLUME

4.1. Background

Natural gas has become the fuel of choice for many residential, commercial and industrial applications, becoming an important factor in large economies today.

According to the data presented in (BP, 2014), as seen in figure 4.1, natural gas production has increased significantly during the last two decades, reaching a global production of 3370 billon cubic meters in 2013, with the largest natural gas conventional reserves in Iran, Russia and Qatar, with a total of 55% of the total world's reserves.

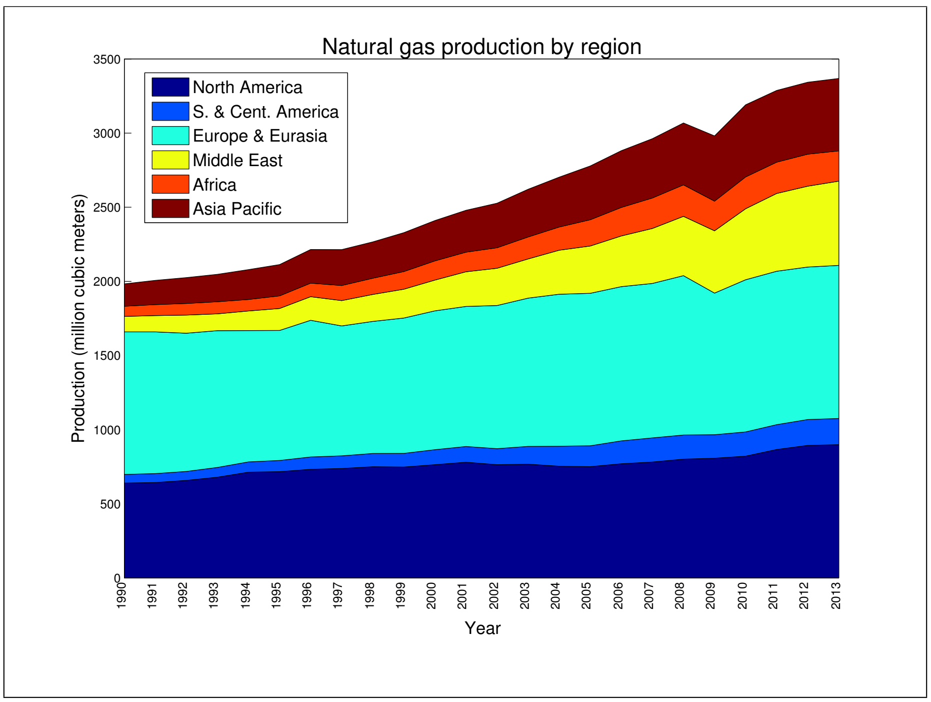

FIGURE 4.1. Natural gas production by region

On the other hand, as mentioned in (Calvo, 2011), there are also non-conventional reserves which extraction is relatively new compared with traditional gas, among which it is possible to find shale gas reserves (gas contained in porous rocks, with significant amounts found in North America), tight sand gas (gas found in compacted sands, found in high concentrations in United States, Russia and China), coal bed methane (methane gas in coal beds, with high potential in Asia, Africa and Australia) and gas hydrates (found in oceans).

Currently, the major natural gas producers correspond to the United States and Russia, with approximately 20.6% and 17.9% of the global production each one. With equal ranking, the major consumers are the United States and Russia, with 22.2% and 12.3% of the total.

An important characteristic of this fuel is that due to a high gas production concentration together with a low importation percentage compared to the total production, there is not a single global market for this fuel. Therefore, there are several regional and national markets with different market structures, resulting in a lack of a common price.

4.1.1. Liquefied Natural Gas (LNG)

Liquefied natural gas is natural gas that has been converted into a liquid form after cooling it up to its condensation point that is at approximately -162° C. In this manner its volume is reduced approximately 600 times, hence facilitating its storage and transportation.

As mentioned in (USDOE, 2005), the LNG value chain is made up by four components:

- *Exploration and production*: Natural gas exploration and production is a stage of high risk and cost for companies, because only 60% of the wells explored produce gas.
- *Liquefaction*: In this stage, LNG is subjected to cooling until reaching its liquid form to later be stored in insulated tanks that are specially designed to maintain their interior at extremely low temperatures.
- *Transportation*: During the following step, LNG is transported to different destinations in the world. For such purpose, vessels with specially designed hulls are used (fleet made up by approximately 362 vessels sailing around the world). The current designs used are the membrane and spherical engineered vessels.

- *Storage and Regasification*: Then, LNG is subjected to a regasification process at the destination point, later stored or injected in those market's gas pipelines.

According to the (IGU, 2014), the international LNG exchange is centered in three geographic basins:

- Atlantic-Mediterranean Basin: It includes all the countries bordering the Atlantic and Mediterranean Oceans.
- Pacific Basin: It includes all the countries bordering the Pacific Ocean.
- Middle East Basin: It includes countries as: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Oman, Qatar, Arab Emirates and Yemen.

The global LNG exchange in 2014 amounted to 236.8 million tons and the Middle East is the most important region in terms of supply with 42% of the total, followed by the Asia Pacific region with 30% of the total. On the demand side, the Pacific Basin is the most important one, with Japan and China being leaders in the list.

On the other hand, the LNG transaction prices have big fluctuations depending on the region, with values that range from 4 US$/mmBtu established by the Henry Hub index and the 15.3 US$/mmBtu experienced by transaction in Japan.

4.1.2. Natural Gas and LNG in the Electric Sector

The electric power sector is one of the largest natural gas consumers, becoming an essential driver in the natural gas industry development. This is due to the high efficiency in energy transformation, lower capital investment and shorter construction time for gas turbines compared to other types of thermal power stations. In addition, it has benefits as a low emission "clean energy", followed by many electric markets around the world, as mentioned in (Calvo, 2011), where natural gas is considered an important factor when facing climate change. On one hand, it has lower carbon dioxide content compared to other fuels such as oil and coal and in turn, there is less fuel required to generate the same amount of energy. These factors place natural gas as a fuel to be promoted in urban conglomerates and in the industry. In addition to the natural gas benefits per se, this fuel gives time to allow other alternative energies and new technologies to mature. In this same direction, gas turbines show high flexibility to accommodate their generation together with variable technologies such as wind and solar energies, hence allowing complementing the regulatory measures to drive those renewable technologies that are under way in different electric markets.

4.1.3. South America Overview

As mentioned in (Barroso et al., 2008), in the 90's there was a strong increase in natural gas in the energy mix of different countries in Latin America and gas pipelines were built between Bolivia and Brazil and between Chile and Argentina, among other examples. However, during these last years, the strategy has focused more on LNG than in imported natural gas through gas pipelines. The main reason for this phenomenon have been (i) gas unbalance (countries with natural gas surplus and deficits have seen LNG as an attractive manner to eliminate these unbalances), (ii) security (the exchange between neighbour countries in the region has shown to be untrustworthy, therefore several countries have seen LNG as a possible solution to diversify their energy dependence), (iii) flexibility in gas supply (due to the stochastic nature of the large hydroelectric presence in some countries in the region, flexibility is a valuable asset. In this direction, LNG imports are deemed to provide more flexibility at a lower cost than building large pipelines, but that is something that it remains to be seen). That is why since 2009, both Brazil and Chile have started importing this fuel through the implementation of regasification plants.

4.1.4. Take-or-pay Contracts

Due to the logistic complexity involved in the LNG supply chain mentioned in section "Liquefied Natural Gas (LNG)", the long term sales contracts for that fuel are usually under a "take-or-pay" mode that strictly implies paying for the entire cargo requested, independent if it is withdrawn or not. Besides, long term contracts permit to reach better prices than spot sales. Nevertheless, flexibility can be added in each particular case, with

Make Up clauses (gas that is not used in the period can be used in later months), Carry Forward clauses (excess of gas consumed can be considered as a credit in future periods) and Change of Destination clauses (the committed gas can be detoured to another destination), among others. However, in this work we are considering the strict definition of the take-or-pay mode, which does not change the core of the problem. The relationship between the take-or-pay contracts and the power system is not easily established, as described below.

4.1.5. Take-or-pay contracts effect for the LNG importers in the electric system

The Chilean electric market has a central dispatch based on audited costs, where the participant generators are to report their variable production cost. On the other hand, up to date, the generation power stations that operate with LNG supplied through take-or-pay contracts also must follow the norm; namely, they must declare a variable operating cost that can be corroborated by the system operator. This implies certain inefficiencies in the market, as presented in (Moreno et al., 2014). Conceptually, when considering a take-or-pay contract (where it is necessary to pay for all the fuel agreed beforehand, independent from its utilization), it is evident that once the decision to import is made, the best operation solution from the systemic viewpoint will be to use all the fuel, because at that moment it represents a sunk cost. From another viewpoint, at the moment of operation that fuel shows a nil marginal cost (*ie.* its total value does not change if 1 MWh more is produced or not).

Additionally, it is possible to consider the storage available in the regasification terminal as a reservoir, which can respond supplying LNG in the short term depending on the requirements that arise through time.

Considering both the nil variable cost and the storage capacity, the right way to represent the LNG variable cost would be through a “strategic LNG value” that reflects the real opportunity cost of using such fuel at any moment in particular.

In this work we will consider the form described above when calculating the electric market spot prices, because independent from the fact that those elements are not considered in the Chilean market, we assume that this will change in the medium term.

In power systems with high installed hydroelectric capacity whose production presents stochastic characteristics, an LNG importer is faced to important risks when deciding the amount of fuel to import through a take-or-pay contract. As observed in figure 4.2, the operational margin of a power station whose fuel is LNG shows a sudden drop if there is a total amount of LNG in the system that fully replaces the power stations production that present higher fuel unit costs.

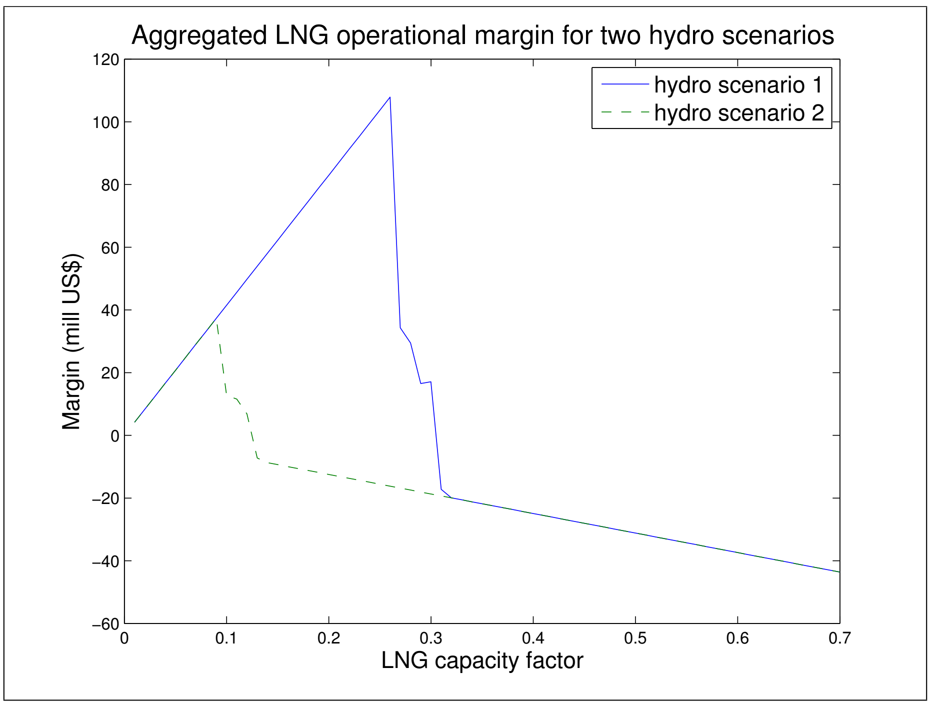

FIGURE 4.2. LNG plants operational margin

Although the magnitude of the values presented in the figure will change depending on the LNG price or the particular system conditions of the example used, the characteristic of a drop in the operational margin is maintained.

Conceptually, the drop happens because, as mentioned above, the system's spot price (the price that the generators receive for their generation) will be equal to the gas strategic value, which in this case would be equivalent to a lower unit cost than the LNG cost (*ie.* if there is 1 MWh less of electricity produced with LNG, it would be replaced by cheaper energy).

As mentioned in (Moreno et al., 2014), this could be one of the causes for which the Chilean system's natural gas generation fleet is being underused, showing a drop of about 26% in its generation during the last 3 years, while on the other hand, the power stations with higher variable costs are still generating.

To simplify the presentation of this work, we will only consider the uncertainty of the hydrological variable, because the essence of the proposal presented here can be extended to any type of uncertainty, such as the uncertainty in the demand and in renewable energy production (leaving out large hydro), among others.

4.1.6. LNG Importers as insurers

LNG importers whose supply is contracted under the take-or-pay mode are faced with the system's uncertainty (in this case, hydrological uncertainty) at the moment in which the LNG consignment is available for usage. In order to eliminate that uncertainty from the system, they would be happy if somebody commits to buy their gas at the cost price plus a delta that reflects their required profitability.

On the other hand, the economic dispatch considers the management of the LNG volume considering the LNG's strategic value at the moment of calculating the spot price, resulting in LNG dispatches always made during the hours with the highest prices (or in other words, LNG will have a peak shaving function). This implies the following corollary (if the dispatch is done correctly):

Corollary 4.1. *Independent from the system's operation, 1 MWh produced with LNG in an hour h receives a spot price that is at least equal to any other MWh produced in another hour of the period.*

This corollary suggests that a generator operating with LNG can provide a service that supplies the deficits of the generators with supply contracts without risks, and it is the essence of the mechanism proposals that we are presenting.

Although this is an ideal case, where the economic dispatch will show no uncertainties within the period, we assume that these uncertainties are reasonable predicted by the ISO.

4.1.7. Generators with supply contracts as insureds

Demand in the Chilean market does not have access to the spot market, only generators have access to it. Therefore, 100% of the demand must have a supply contract. If we assume that the amount demanded is under contract at a previously defined price, the system's short-term operation would only affect the generators in a direct manner, and they are faced to the spot market movements when complying with their supply contracts.

Under this assumption and considering that LNG can only decrease or maintain the spot prices, the benefit on deciding for LNG imports will be perceived by all the generators with supply contracts, while the decision's cost will impact either the LNG generators if the imports risk was accepted by them, or by all the generators if a mechanism to socialize the imports' cost was used.

Given the fact that all the demand is under contract, generators that have the supply contracts must provide the consumed energy independent if they are generating at the moment of consumption or not. For simplicity purposes, we are assuming that all the demand has a single hourly consumption profile similar to the aggregated demand, therefore a generator that has the obligation to supply a certain amount of MWh per day could be faced to the situation that is presented in figure 4.3, where in this case in particular a solar generator has a "deficit" status between 17:00 and 09:00 hours of the following day, namely, during these hours, it will have to buy the energy consumed for its contracted demand in the spot market.

If we assume that they are risk averse, then they would be happy to pay a fair price to mitigate the spot risk in the hours with deficit.

4.2. Mechanism design

In face of the possibility that the LNG import is being less than desirable from the systemic viewpoint, this work attempts to present a systemic alternative to face the challenge that it implies to import LNG supply through take-or-pay contracts that present an inherent

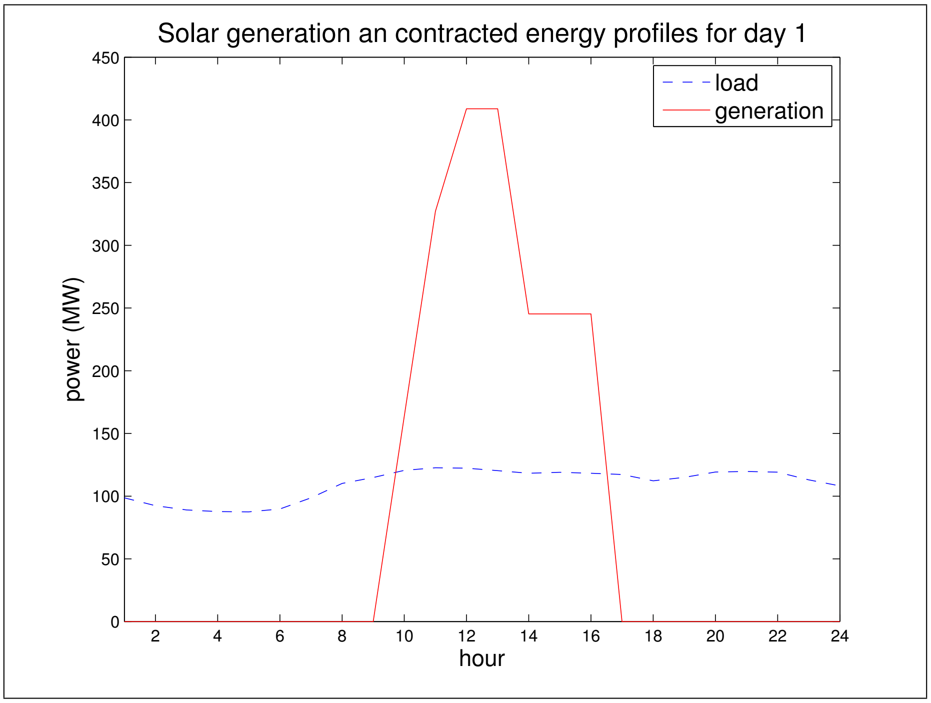

FIGURE 4.3. Solar daily generation and supply contract profiles

lack of flexibility, which becomes increasingly more relevant in the absence of developed secondary markets.

It must be mentioned that although the change in the operation and pricing of the Chilean electricity market (incorporating the LNG volume management and the price reflecting the opportunity cost) could be enough to have an increase in the imported LNG volume, the spot price could be excessively volatile (depending on the total imported volume) for an optimal imported amount that is stable through time.

4.2.1. System optimal amount to import

The first question we must ask is which is the optimal amount of LNG to import. In general terms, the answer would be:

- If the hydrological conditions are favourable for the system (*ie.* wet hydrology), then the optimal amount to import would be low, because on the contrary, there could be a displacement of cheap energy by the LNG.

- If the hydrological conditions are unfavourable for the system (*ie.* dry hydrology), then the optimal amount to import would be high in order to replace the generation from more expensive power stations.

The problem with the former answers is that the realization of the hydrological scenario is after the imports' scheduling and decision; therefore such scheduling has a substantial element of uncertainty.

Defined who assumes the consequences for the LNG imported volume, the next question that arises is how is the decision made regarding the magnitude of that volume. In this sense, according to our judgement, the options are to decide in a centralized manner (decision made by the regulator or the System Operator), or in a decentralized manner (decision made by generators, the demand or all the system's participants), and independent from the decision maker, such decision should consider the risk aversion of the affected parties (*ie.* the generators in this case).

In this work we propose a decentralized but coordinated alternative to make the decision about how much LNG must be imported.

4.2.2. LNG insurance market

The basis for the proposed mechanism is a market where the LNG importers and generators with supply contracts trade insurances for the energy that they have to supply without own generation backing up the commercial transaction. This is based in the corollary 4.1 and prevents the generator with contract to face the spot risk.

In principle this market would require each buyer and seller (*ie.* generator and LNG importer) to submit a price and a quantity in order to let the market be cleared in the point where the total surplus is maximized. However, the offers and thus the outcome of this market will be heavily influenced by the total amount of LNG present in the system, because for example, a higher amount will imply lower spot prices, so the generators will be reluctant to offer high prices for the insurance. For this reason, we are proposing that instead of offering a quantity and a price, each participant offers quantity and price curves as functions of total imported LNG. With this information, the total LNG quantity to import and its price will be added as a variable in the problem which maximises the total surplus.

For the rest of the work we are considering that the LNG volume that is traded refers to LNG already produced as energy, so it unit will be MWh.

4.2.3. Bids structure

The mechanism proposed requires the generators and LNG importers to submit purchase and sale bids respectively in order to have information about all the stakeholders at the moment of making a decision.

The LNG importers (insurers) bids will be made up by the following elements:

- Price of the LNG to be imported.
- Volume of LNG available for import.

where the offered price will depend both on the real cost of the fuel and on the importer's profitability expectations.

On the other hand, the generators (insureds) bids will be made up by the following elements:

- Offer price curve as a function of the total imported LNG volume
- Offer volume curve as a function of the total imported LNG volume

In this case, the prices and volumes offered will depend both on the generator's expectation regarding the system's operation and on its risk aversion. The fact that the generators' bids are in function of the total imported LNG volume avoids any speculation by the participants in this regard, allowing the participants to make their best bids, being more beneficial for the system.

4.2.4. Awarding of the auction

The auction coordinator must award the following:

- Total volume of LNG to be imported

- Uniform transaction price of the unitary insurance
- Awarding of the imported LNG volume among the participants to be used as insurance

in order to maximize the total surplus, where the problem to be solved will be the following:

$$
\begin{aligned}
\max_{Q,q_s,q_d} \quad \sum_d p_d(Q) \cdot q_d \quad &- \quad \sum_s p_s \cdot q_s \\
\sum_s q_s \quad &= \quad Q \\
0 \leq \quad q_s \quad &\leq q_s^{max} \qquad \forall s \in S \\
0 \leq \quad q_d \quad &\leq q_d^{max} \qquad \forall d \in D
\end{aligned}
\tag{4.1}
$$

where

Q total volume of LNG to import

q_s importer *s* awarded LNG volume to import

q_d generator *d* awarded LNG volume to use as insurance

p_s importer *s* ask price

p_d generator *d* bid price

Note that the problem presented corresponds to a general formula that does not exactly detail the bid functions. It can be seen that the objective function contains a non-linear term, however, the level of difficulty in the problem solution will be given by the detail of the functions requested from the participants.

4.3. Modeling

We attempted to make an estimate of the impact that this proposed mechanism could have compared to a centralized decision on the volume of LNG to be imported, which does not adequately consider the system's participants risk aversion.

4.3.1. System modeling

Clearly, the participants' perception of the spot market risk will depend on the system's configuration in the period in question, both in terms of the generation technologies mix and the demand. Although we assume a deterministic demand, we considered a set of 57 possible hydrological scenarios, which are considered as the only source of uncertainties in our simulations. We try to reproduce a system with the Chilean electric system characteristics; therefore we considered the information contained in the October 2014 Government Nodal Price Report. This is a biannual report prepared by the Chilean Energy Commission, which presents various estimates of the level of demand, fuel prices and expansion of the generation infrastructure and the transmission system, and simulations are made to obtain an estimate of the expected spot prices. Using this information, we considered a simplified version of the Central Interconnected System (SIC), one of the two major systems in Chile, and it is precisely the one that is affected by the hydrological variable. In particular, we are using the information estimated for the month of August of 2018. In relation to the physical configuration of the system, we are making the following assumptions and simplifications:

- All the hydraulic power stations are considered as run-of-river power stations (in the Discussions section we explain the effects of considering reservoir power stations).
- The aggregated installed power was maintained for each technology, however, the number of power stations was modified in order to homogenise the maximum power of the stations belonging to each technology.
- A deterministic demand is considered.
- A hydrological uncertainty represented by 57 possible hydrological scenarios is considered.

On the other hand, in relation to the commercial configuration of the system, we are considering the following assumptions and simplifications:

- We assume that each power station belongs to an independent generation company.

TABLE 4.1. Installed capacity by technology

Technology	# of generators	Installed capacity (MW)
LNG	10	2760
Coal	10	2299
Diesel	25	2544
Biomass	3	222
Other thermal	5	362
Hydro	12	4131
Solar	4	818
Wind	4	777

- The supply contracts with the demand were assigned to each generation company according to the energy generated by each one of them in the average hydrological scenario.
- It was considered that all supply contracts have the same hourly profile corresponding to the actual SIC demand during the month of August of 2013.
- We assume that no generator by itself can influence the total LNG volume to be imported, therefore they behave as "volume takers" when calculating their bids (the relaxation of this assumption will be reviewed in the Discussion section).

In this manner, the generation capacity in the system is defined as observed in table 4.1, while figure 4.4 shows the duration curve for the period's demand, which amounts to 59,878 GWh.

From the table, it is concluded that the total installed capacity of the system is 13,913 MW, which involves a surplus capacity of approximately 62% with respect to the maximum demand that we assume in 8,564 MW. However, we must consider that the installed capacity corresponds to the maximum and does not consider the specific hydrological scenario that could take place.

4.3.2. LNG Importers modeling

For our simulations we assume that the LNG importers are generation power plants that operate with that fuel in order to focus on the core of the problem and prevent entering into the problem caused by a negotiation between an LNG importer and an LNG power

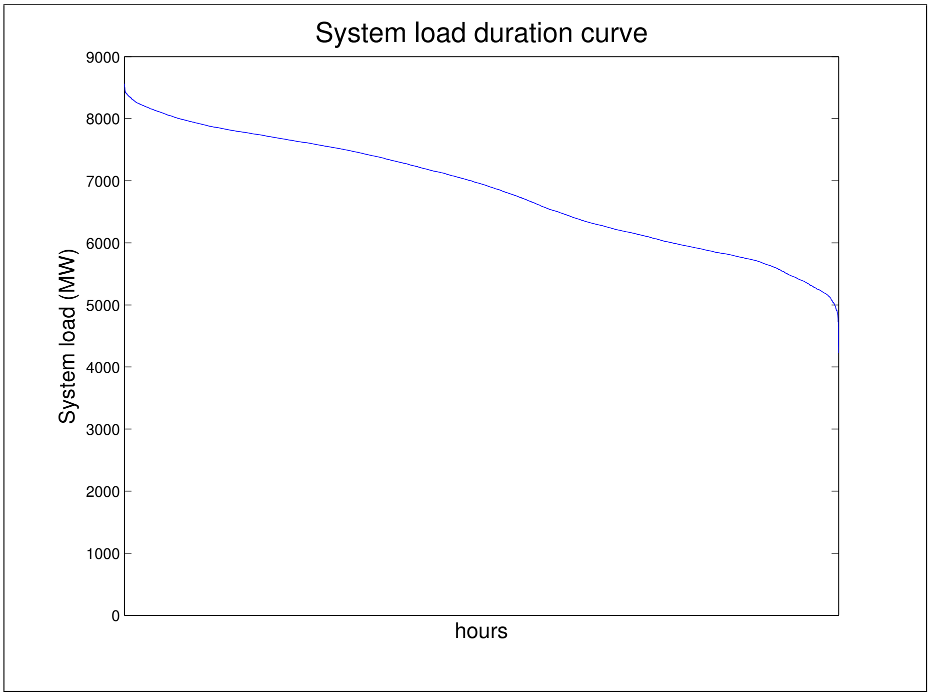

FIGURE 4.4. System load duration curve

station, something that is briefly mentioned in the Discussion section. Moreover, the LNG importers offers doesn't depend on system conditions, and will be based only in the cost of the fuel and a profitability expectation. Given the fact that an LNG importer *i* will charge a unit price that returns its purchase cost plus a delta π that reflects its required profitability, it will have a bid price as shown in the next equation:

$$p_i(q_{LNG}) = cost_i(q_{LNG}) + \pi_i \tag{4.2}$$

We assume that the cost has a linear relationship with respect to the imported amount q_{LNG}. This corresponds to a simplification, because probably the LNG importer will have access to better supply prices if the imported volume is higher, however that assumption does not change the conclusions of this work.

In this manner, the bid will consist of a maximum LNG volume to be imported and a sale price.

- *Volume to be imported*: We assume that each LNG power plant offers a maximum volume equivalent to the maximum production that its power station could generate (which in total corresponds to the 2760 MW mentioned in table 4.1).
- *Sale price*: To represent the differences that could exist in import prices, either due to the access to different conditions in the LNG contracts or due to various profitability expectation, we considered a random price from a uniform distribution in the range of [60, 150] US$/MWh.

Note that we are assuming that importers are not faced to any risk because they sell their production in an anticipated manner, knowing that as the LNG volume is imported, a sunk cost of its energy will be definitely generated.

4.3.3. Generators modeling

The offers of the generators will depend on the system conditions, because the value of the insurance for which they are offering will reflect depend on the spot price. In this case, the bid will consist on an insurance price and a volume curve, both in function of the total volume of LNG to be imported.

Given an insured quantity $\bar{q}$, and considering a set of hydrological scenarios $\mathbb{S}$ and a total LNG volume Q_{LNG} in the system, the price that a generator with contract would be indifferent to pay for a unitary insurance (and thus any price below that will imply a benefit for the generator) will be:

$$p_I(Q_{LNG}) = \frac{\sum_{s \in \mathbb{S}} prob_s[\, p_s^{spot} \cdot min(q_s^{DEF}, \bar{q})]}{\bar{q}} \tag{4.3}$$

Which depends on the expected spot price p_s^{spot} and the contracted quantity q_s^{DEF} that the generator will have to buy in the spot market. For this work we consider an approach similar to that of the Conditional Value at Risk (Uryasev, 2000) for every generator, determining the offered quantity $\bar{q}$ as the average value of the worst case scenarios given the generator risk aversion. Moreover, this same approach is used to obtain the probability $prob_s$ of each hydrologic scenario.

In the simulations, three systemic risk aversion trends are considered. These trends direct the expected value of the generators' risk aversions, but we allow a spread to reflect the resulting natural diversity in a more realistic manner.

These trends are low, medium and high, and for each one of them we prepared 100 realizations for the set of generators that make up the system. The generated random numbers come from a *Beta* distribution with parameters A and B of (2.8), (2.2) and (8.2) respectively, with which we obtained a representative spectrum for each systemic trend as shown in figure 4.5.

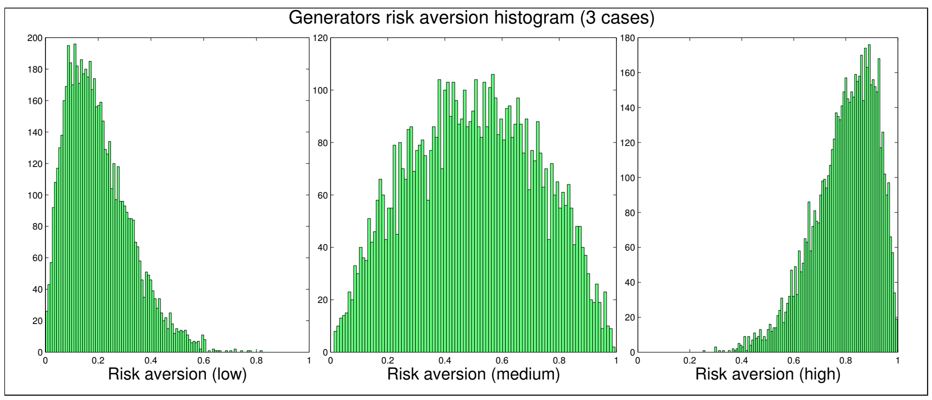

FIGURE 4.5. Generators risk aversion histogram

From the figure it can be concluded that in each case the trend is represented without sacrificing the spread that could be obtained in reality. With this information, the price bid and quantity curves are obtained as seen in figure 4.6 and figure 4.7 for coal-fired generators in the case of medium systemic trend. In the case of the price curves it is possible to note that after a certain volume of imported LNG the prices tend to be low and uniform, which is due to the strategic price of the LNG reflecting the spot prices given by baseload power plants. The exact point at which this happens will depend on the risk aversion of the particular generator.

On the other hand, it is observed that the energy requested by coal-fired power stations increases as there is more LNG in the system, because there will be scenarios where the LNG generation will displace the coal generation, but still those generators will need to

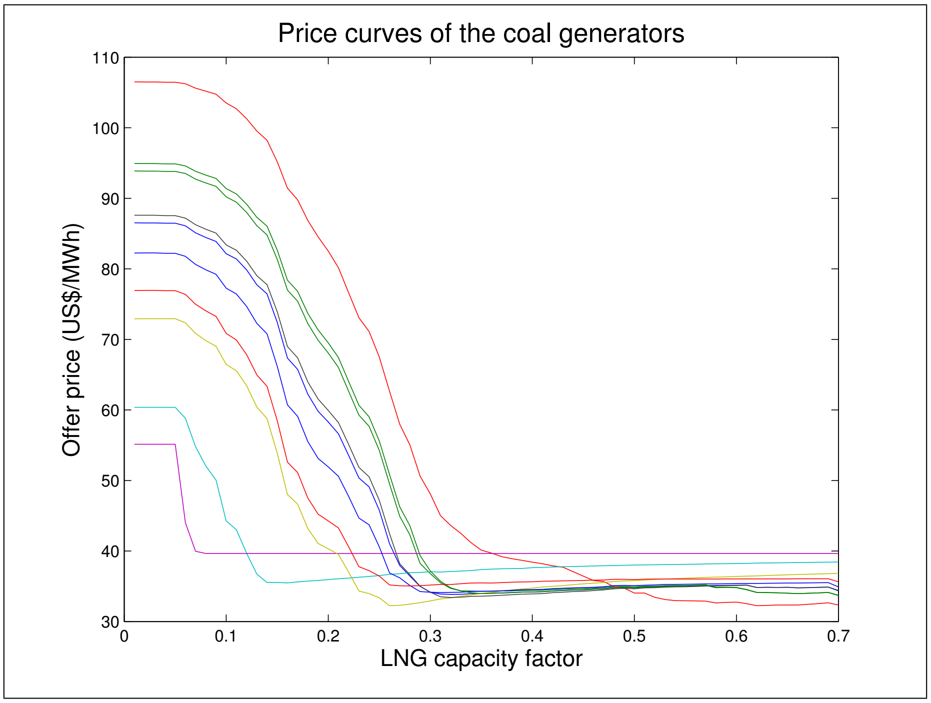

FIGURE 4.6. Price curves of the coal generators

fulfill their supply contracts. Again, the magnitude of that amount will depend on the risk aversion of the specific generator.

4.4. Results of the chapter

Two simulations were done. The first one is an implementation of the full mechanism presented before, that is using the insurance market to determine the total volume of LNG to import. The second simulation corresponds to a special implementation where the insurance market is used as a support mechanism for Non Conventional Renewable technologies.

4.4.1. System total amount to import

Figure 4.8 presents the total surplus for every simulation in the medium risk aversion trend, as a function of the imported LNG level. Note that in the chart the total volume of

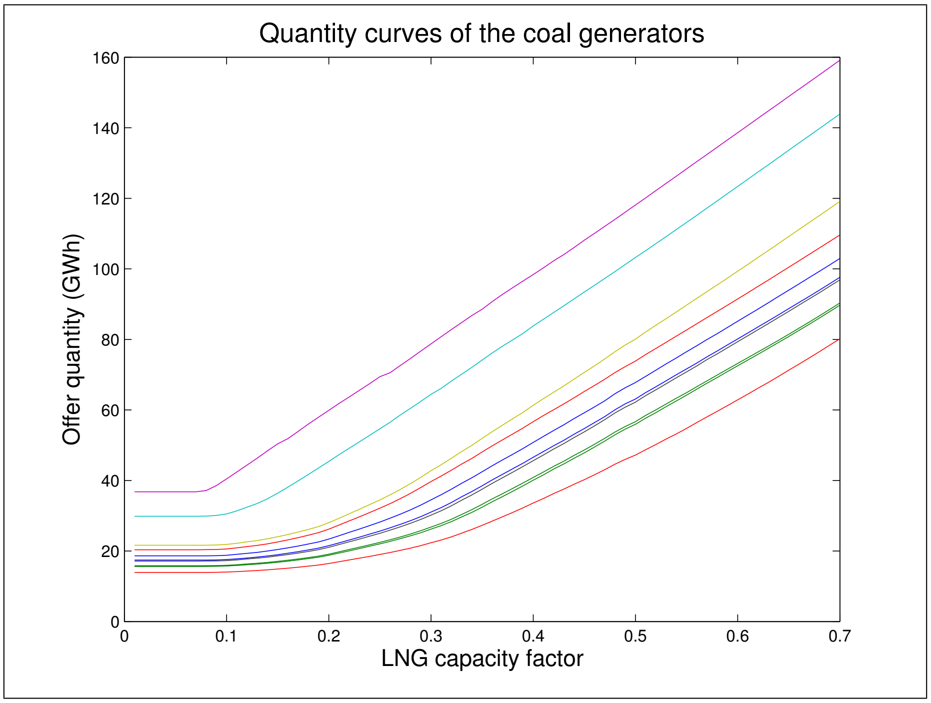

FIGURE 4.7. Quantity curves of the coal generators

imported LNG is expressed as the capacity factor of the installed capacity of LNG power stations.

In this direction, figure 4.9 presents the obtained total surplus from each systemic trend as a function of the imported LNG level. First, it can be observed that for each systemic trend a different LNG volume that maximizes the total surplus is obtained. Specifically, the maximum expected value of the total surpluses is obtained when in the system there is an LNG volume that is equivalent to a capacity factor of 24, 38 and 44% for the low, medium and high risk aversion trends, respectively.

It must be mentioned that although the charts emphasize the averages, actually the mechanism will make the decision based on the exact realization, ensuring that the decision is the optimal one according to the actual risk aversion of the participants.

Figure 4.10 shows the average "excessive cost" that it would imply for the participants to make a centralized decision without correctly considering their risk aversion in each case.

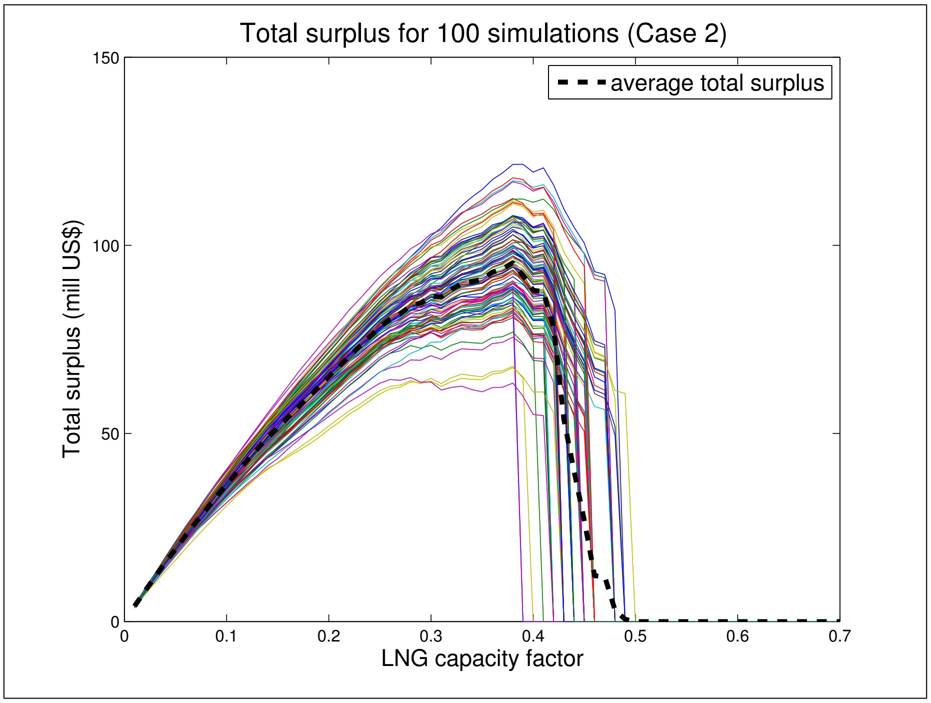

FIGURE 4.8. Total surplus as a function of imported LNG volume (medium risk aversion case)

It can be observed that for all the cases of systemic trends, small deviations in the capacity to import create considerable excessive costs for the system, especially in the case where the participants show higher risk aversion, where in extreme cases they can reach expected values in the order of 146 million US$.

4.4.2. Special case as renewables support

The idea behind this simulation is to show a simplification of the mechanism that can be used to support some kind of technology, in this case the non conventional renewable ones. In this particular example we are assuming that the implementation of the insurance market is small in comparison with the whole system, so the imported LNG volume will not affect the system total quantity (fixed as a capacity factor of 30%) in a significant manner. Moreover, the only generators participating as buyers (or insureds) are wind and solar power plants (5 of each technology, each one with a capacity of approximately 150 MW).

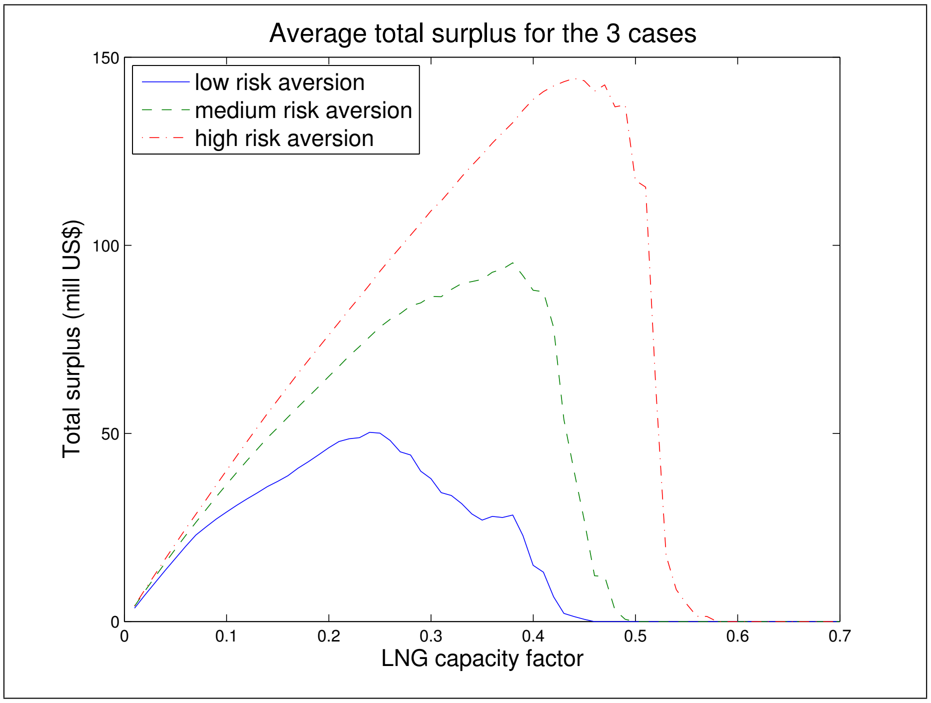

FIGURE 4.9. Average total surplus as a function of imported LNG volume

On the other hand, the LNG importer is only one power plant of 500 MW, with an offer price of 97 US$/MWh. Figure 4.11 shows the resulting offer prices for the three risk trends.

On the other hand we are assuming that the NCRE power plants have priority in the dispatch independent of the hydrologic scenario, so the risk aversion doesn't influence the offered quantity which are approximately 15 and 11 GWh for each wind and solar plant respectively.

Figure 4.12 presents the total surplus of the example.

It can be seen that the expected total surplus vary approximately between 9 and 22 million US$ depending of the risk trend, which could be a significant help for these kind of technologies.

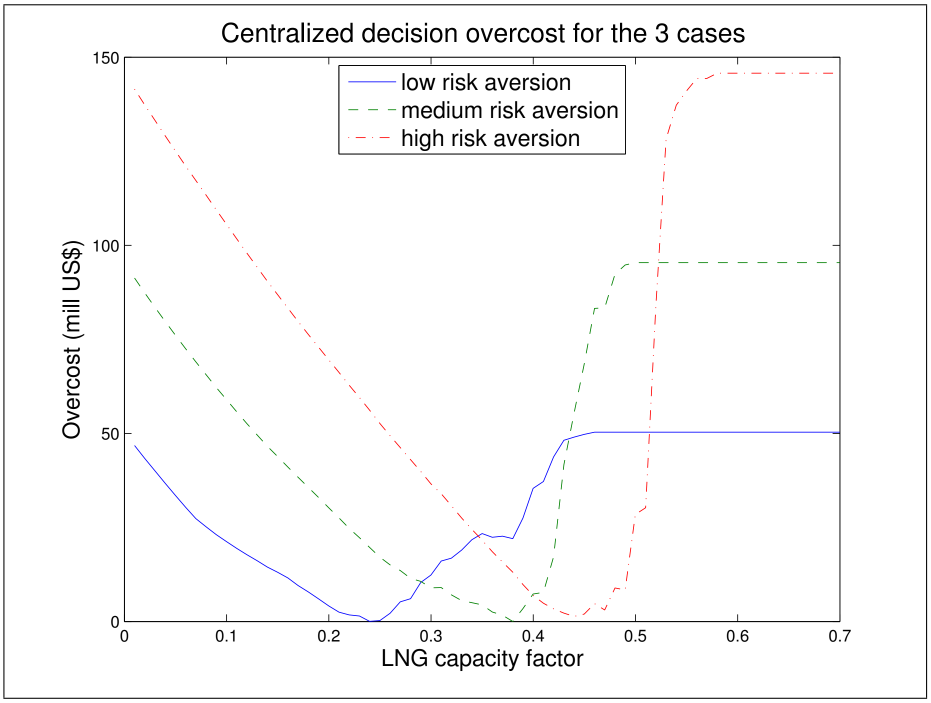

FIGURE 4.10. Centralized imported volume decision over cost

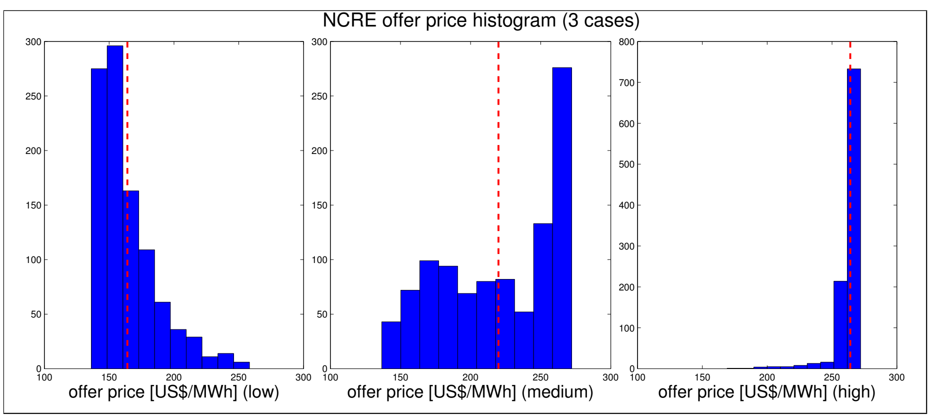

FIGURE 4.11. Offer prices in the NCRE market

4.5. Discussion

In this section we offer a qualitative analysis about some issues that influence the mechanism and that are relevant to comment.

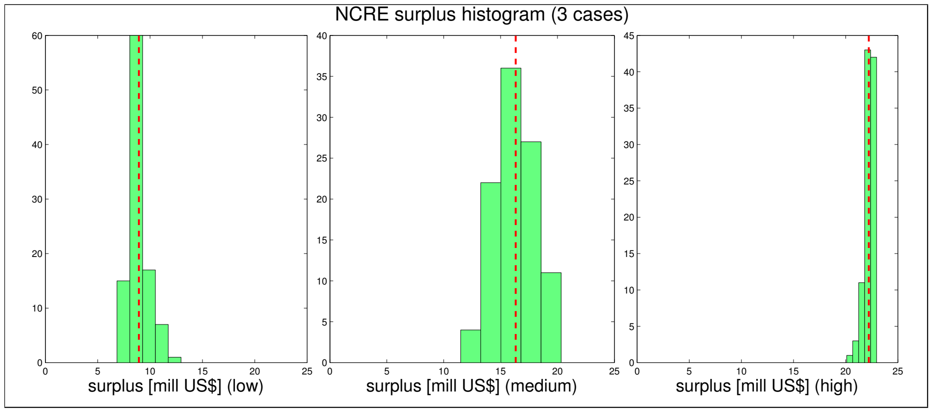

FIGURE 4.12. Total surplus in the NCRE market

- *Centralized v/s decentralized:* The essence of the problem we are trying to solve is the decision to centralize or decentralize, or simply said, up to what point we decentralize. This is a very broad and influencing issue, even becoming the issue that is behind the electric markets' liberalization. In the area of the LNG volume to be imported, it is important to consider which is the objective we are trying to achieve. In principle, such objective should be to allow the system to operate at a minimum total cost. However, given the uncertainty, it is not possible to make an ex ante decision of that type in a definite manner. Given this, the objective should be to allow the system to operate at a minimum total cost considering that there is a set of beliefs with respect to the future. However, there is the key question, which is the set of beliefs that best represents the system's participants (assuming that is what we want to represent). The mechanism proposed in this work tries to directly represent the system's participants. However, a centralized mechanism as the one by (Moreno et al., 2014), that tries to represent the participants is also a valid mechanism that can even be preferred in cases where there are difficulties to coordinate the participants or in the presence of strong market power among others. Of course, such centralized mechanism can be used as an intermediate step to reach the decentralized mechanism, or rather, a mix of both. In case a decentralized alternative is chosen, special consideration must be given when choosing the decision criteria to make these criteria transparent and open for the entire system. Finally, regardless if the mechanism is centralized or decentralized, if it is recognized that the LNG import can bring benefits for the system, it can be convenient to have an explicit support from the authority in the steps required for the importation itself, such as the formalities required, taxes and coordination, among others.

- *Market power:* In this work we are considering the assumption that no generator by itself can influence the total volume of LNG to import, behaving in this manner as a "total volume taker". This premise of perfect market is necessary to align the individual incentives of the participants with the system's benefits maximization. However, actually it might happen that this assumption is not fulfilled 100%, even more considering that several power stations can belong to a same generation company. Although this is beyond the scope of this work, we must mention that this is not a minor issue that must be specially considered when implementing the mechanism, either adopting measures to promote competition and also initially to somehow intervene the generation companies' bids that are misusing the proposed mechanism. On the other hand, not only the demand (*ie.* the generation companies) could be exerting some market power, because it might also be exerted both by the LNG importers and by the owners of infrastructure required for the import of LNG. As a future task, it would be interesting to understand to what extent the existence of market power could affect volumes and prices and which concrete measures could be used to prevent the application of that power.
- *LNG economic dispatch:* In practice, the economic dispatch within a period cannot manage the LNG volume in a 100% optimal manner, because there will be some differences with the optimal given by uncertain events such as failures, projected demand variation and weather events, among others. Among the effects of this, there could be an hour within the period with absence of LNG generation, but with prices higher than when there is LNG generation (in this manner not fulfilling corollary 4.1), resulting in losses for the LNG importer. However,

if most of the volume management and spot price fixation by the system operator is correct, the mechanism should work, because those differences would be minor with respect to the total.

- *Ownership of the LNG power stations:* In the simulations of this work we are assuming that the owners of the LNG power stations are the ones that act as LNG importers. In case that is not the fact, it would be necessary to make both parties reach a previous agreement to allow the mechanism to work, something that could be carried out through another mechanism similar to the one proposed.
- *Hydro reservoirs:* In this work reservoir power stations are represented as run-of-river power stations. Despite this is a simplification, it does not affect the conclusions of the work. In essence, there is no difference between the dispatch of a water reservoir and an LNG power station with a take-or-pay contract, except that in general a large reservoir will have an enhanced regulation capacity, allowing displacing its generation to later periods, while the LNG "reservoir" has the restriction of using all of its fuel within the period. For this reason, if you look at the period as a whole, the LNG power station will have priority in the dispatch before the water reservoir (not valid in the cases where there is an exceptional abundance of water resources). Additionally, this could give rise to ingenious mechanisms such as the Virtual Storage used in Brazil, described in (Barroso et al., 2008) and (Rudnick et al., 2014), that, briefly explained, implies using large water reservoirs as means to keep an "energy credit" from one period to the next one by LNG power stations with take-or-pay contracts.
- *NCRE support:* As stated in the special implementation for supporting NCRE technologies, the essence of the mechanism can be used as an alternative way to support specifics technologies. In this case, it could be useful for the regulator to assume a leading role, providing facilities for the LNG importers or even more using state owned power plants as LNG importers.

4.6. Conclusions of the chapter

- The incorporation of LNG contracts under the take-or-pay mode in the power system results in the need to modify the methodologies to carry out the economic dispatch and also the position to be adopted in face of the volume of LNG to be imported in order to bring benefits for the entire system.
- In the case of the decision about how much volume of LNG to import, it must be recognized that due to the inherent uncertainty of the process, the optimal will depend on the risk aversions of the system's participants, therefore it is important to somehow incorporate that variable in the decision methodology.
- A decentralized but coordinated mechanism was proposed to decide the magnitude of the LNG volume to be imported. In essence, the mechanism tries to reveal the participants' risk aversions for the different levels of possible imports and includes that information in a market structure to maximize the total surplus.
- Simulations were made under the context of the Chilean electric market assuming three systemic risk aversion trends among the participants. It can be observed that the optimal amount to be imported strongly depends on the participants' risk aversions and that the mechanism is more valuable for the system as more risk averse are the participants.
- From the simulations it can be concluded that arbitrarily fixing an LNG volume to be imported without correctly considering the participants' risk aversions can result in excessive costs, and that depends on how far the fixed volume is from the optimum and on the risk aversion level of the participants.
- When doing the specific implementation of the mechanism, apart from deciding the level of decentralization looked for, special care must be placed on implementing a correct methodology for the economic dispatch of the LNG power stations with take-or-pay contracts and also the possibility to exert market power by any of the participants must be considered. The idea is to take advantage of the benefit of this market mechanism preventing potential implementation failures.

- A special implementation of the mechanism was suggested as a mean to support NCRE technologies, where the total surplus for the participant NCRE generators range approximately between 9 and 22 million US$.

5. CONCLUSIONS

This thesis has developed market mechanisms in three areas of the generator sector, in order to better cope with the new challenges that the large scale inclusion of variable technologies brings to the system. Within chapters 2, 3 and 4, this work designs, implements and models market mechanisms for the areas of Energy, Capacity and Security within the generator sector in order to measure and compare the results of their application with respect to other mechanisms that have the same purpose. Those chapters also presented detailed conclusions and future work related with the content within each chapter.

The findings of this dissertation can be summarized in 3 points:

(i) A better allocation of risk between the participants of the long term energy auction allows the demand to obtain a lower purchase cost
(ii) A better representation of the demand in the capacity market creates incentives for an installed capacity in line with demand preferences, allowing higher levels of total surplus
(iii) To consider the risk coverage capability that the LNG has for market participants, allows the import of a LNG volume that maximizes the total surplus

Considering these points, we can state the main conclusion of the research: Within a renewable environment, improving the agents preferences representation in market mechanisms, for the generation sector, allows the system to obtains better performances in the areas of Energy, Capacity and Security.

It is worth mentioning that the work considered the implementation of each mechanism alone, that is, without considering the interaction with the other two mechanisms at the same time. For example, the capacity mechanism could have an effect on the perceived risk by the generators, what in turns could affect their offer prices in the energy auction mechanism. Nevertheless, each mechanism on its own has a positive effect in the total surplus of the market, so we can infer that the aggregated effect of implementing the three mechanisms at the same time will also be positive in terms of total surplus, although possibly at a different level and considering a different surplus distribution between the consumers an producers.

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