UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master's Thesis

MISSING MARKETS AND MISSING PIPELINES: THE PROBLEM OF RESOURCE ADEQUACY IN A NATURAL- GAS-FIRED DOMINATED SYSTEM

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Madrid, January 2016

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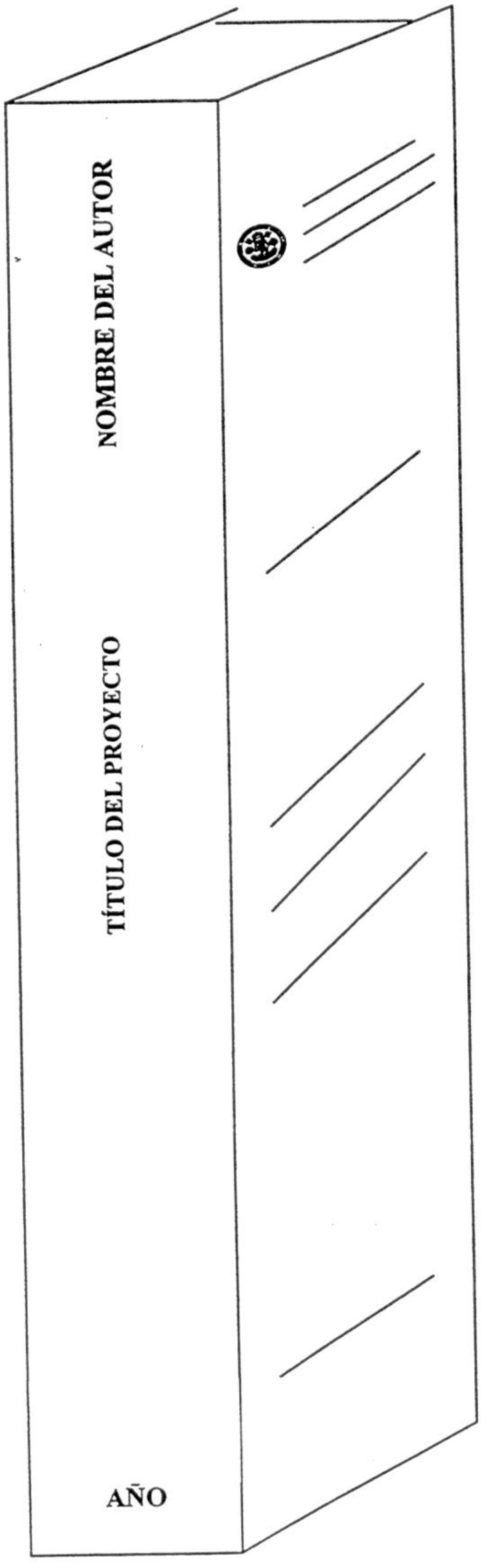
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Abstract

Since the beginning of the century, US electric power systems have increasingly become dominated by natural gas-fired power plants. In this context, the traditional concern of electricity regulators to ensure that market agents take efficient power generation investment decisions expands to the gas system, as the system requires adequate investments also in pipeline or regasification capacity. The problem is that ensuring pipeline capacity, even or particularly under tight supply conditions, involves entering into very long-term firm transportation contracts, and therefore introduces a major source of risk for power generators: the possibility that electricity demand does not evolve as forecasted, or probably more importantly that renewable energy sources massively deploy in the future, creates a significant quantity risk to the gas-fired generator which as a result tend to just contract for interruptible gas supply.

This is particularly the case in New England (Black and Veatch, 2014), whose high dependency on natural gas has become troublesome in the last few years during cold winter months, due to the lack of natural gas pipeline capacity. When temperatures drop significantly, natural gas demand for both space heating and electric generation rises. Since most of New England's natural gas is imported through pipelines, high gas demand results in pipeline capacity shortage events that have a significant impact in the electric power system. Bringing new pipeline capacity to the system is seen as fundamental today.

In this paper we analyse this problem of the gas and electricity long-term planning coordination and the security of supply consequences. Since pipeline contracts are capital intensive and therefore subject to long-term risk, in the absence of any financial tools that allow investors to hedge the market price risk in the long-term, uncertainty in general reduces the incentives to enter into such firm contracts. We assess how a risk-averse natural gas power plant owner underinvests in pipeline capacity when no hedging tools are available. We discuss how this market incompleteness leads to a socially inefficient result, and how the gap could be bridged by creating markets for risk, for example via any sort of long-term capacity obligation,.

The present theoretical analysis addresses the investment problem in gas-fired thermal capacity and pipeline capacity in a context characterised by (i) perfect competition, (ii) risk-averse agents and (iii) missing long-term financial markets. It explores the impact derived from these missing markets, which translate into less socially efficient investments. The model simultaneously represents and solves the short-term electricity and gas markets. Following a similar approach as the one developed by Rodilla et al. (2009), four different settings are considered in the analysis:

- a (cost-minimizing) context with a risk neutral centralized planner who decides both the thermal capacity and the pipeline capacity to maximize social welfare. This framework constitutes the benchmark solution.

- a market in which risk-averse generators have to decide the thermal capacity to be installed and the firm pipeline capacity contracts to be signed to maximize their profit, and where no long-term financial instruments are available.
- a market setting similar to the previous one, but where a long-term forward contract for electric energy is available.
- a market setting similar to the previous one, but where both a forward and an option contract are available.

The market equilibrium model developed is stochastic (different renewable generation scenarios are considered) and solved by means of an MCP. Risk constraints are modelled through the conditional value-at-risk (CVAR) (Rockafellar and Uryasev, 2000). The gas market is modelled in such a way that generators which do not enter into contracts for firm pipeline capacity have still access to gas supply, but they are exposed to the short-term market price of natural gas (endogenously calculated). Agents must first take long-term investment decisions (in both pipeline capacity, and power plant investment), as well as the hedging instruments, and then they decide in the short term the hourly power plant production.

Results show an equivalence between the central planner's welfare-maximizing decisions and the profit maximizing decisions of risk-neutral agents. Nevertheless, if agents are risk-averse and no risk-hedging instruments are available, results deviate from the central planner's. Risk-averse agents base their decisions on lower profit scenarios, rather than using expected profit, which generates long-term inefficient investment decisions.

However, when given the possibility to hedge their risk by participating in a forward market, agents' decisions come closer to replicating those of a central planner, thus improving social welfare. Moreover, if an option is included in addition to the forward market, results come even closer to the social optimum. These findings concur with Willems and Morbee (2010) where conclusions show that increasing market completeness is welfare enhancing.

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1 INTRODUCTION

1.1 Gas-electricity coordination

In the past twenty years, electricity power systems all over the world have increased significantly the natural gas installed capacity and production, thus generating a high interdependency between these two industries.

This is due to climate change concerns generating large penetration of intermittent renewables which call for flexible resources that can quickly adapt to large output variations. Furthermore, this shift to natural gas in the technology mix is exacerbated in the U.S. electric power industries due to the emergence of shale gas, which allows to produce natural gas at a cheaper cost. Natural gas in the U.S. is usually transported to consumption points through long-haul transport pipelines, whose operation and investments are regulated by FERC.

Consequently, this high dependency on natural gas requires a perfect coordination among the two industries. Nevertheless, given the abrupt penetration of natural gas, problems have arisen across different timeframes due to a lack of gas-electricity coordination. This thesis's main focus is brought to resource adequacy issues resulting from the long-term investment gas-electricity coordination in New England.

To this respect, gas-fired generators play a crucial role, since they must coordinate their gas needs for electricity production with capacity contracting on natural gas pipelines. Pipeline companies offer basically two types of capacity contracts. Their customers must choose between very long-term firm capacity contracts and short-term interruptible contracts. The former offer higher security since they give priority of being supplied whenever pipelines face scarcity events while interruptible contract holders are the first to be curtailed.

Pipeline congestion has become in the past few years one of the main concerns of the New England ISO (ISO-NE), due to high gas demand from both electricity-related and non-electricity related gas consumers. When temperatures drop, gas demand peaks, as a result the prices in the natural gas market peak as well, and interruptible contract holders (i.e. gas generators) are curtailed.

This obviously has a significant impact in the electricity spot market due to the correlation between the two sectors. There is a considerable increase in overall production and operation, which obviously cause a rise in electricity prices. Indeed, electricity prices in New England have been abnormally high during the past few winters, subjecting electricity consumers to the highest tariff increase in the country.

This problem could be solved if generators contracted long-term firm capacity. Nonetheless, contracting firm capacity implies entering into a very long-term (usually twenty years) capital intensive investment. Gas-fired generators face a unique set of uncertainties (electricity demand, renewable penetration, etc.)

that makes them reluctant to sign these long-term agreements, settling instead for short-term interruptible capacity.

One of the main objectives of regulation is for agents to take the most socially efficient decisions. That is to say to replicate the decisions that would be taken under a centralized context. Any deviation in agent's decisions from the social optimum is a failure in market design, as agents are lacking the proper incentives that lead to the social optimum.

In the case of New England, generators must face a long-term risk without access to the proper instruments to hedge said risk. This thesis proves that the combination of these two factors, risk-averse generators and incomplete financial markets, steer the market away from the social optimum.

1.2 Objectives

This thesis' main objective is to assess the problem of resource adequacy derived from high natural gas dependency in New England through the development of a mathematical model in gams. This objective can be divided into two.

The first consists in developing a GAMS market equilibrium model following a similar approach to Rodilla et al. (2015) in the definition of different market settings that will be applied to the model. To this purpose, it is necessary to formulate the model as a mixed complementary problem to solve the market equilibrium and calculate endogenously the natural gas, electricity, and long-term financial respective equilibrium prices.

The second objective is to analyse the effect on long-term investment decisions and social welfare of risk-averse generators under renewable generation uncertainty, and to what extent it depends on market completeness. In order to do so, performing a critical analysis of the results obtained in the model under the different market settings is needed.

1.3 Structure of the report

The structure of this reports is as follows. This first section gives a brief overview of the issues addressed in this thesis, and presents its main objectives. Section 2 reviews the literature on the area related to gas-electricity coordination, as well as the effect of risk-aversion and market completeness on EPS. Section 2 describes in more depth the problems resulting from long-term gas-electricity coordination while providing a focus on the New England case. Section 3 presents the model developed and the different contexts considered for its application. Section 4 introduces and analyses the main results obtained after executing the model for the New England case. Section 5 sums up the main conclusions drawn from the work developed in this theses and introduces future lines of work. Section 6 introduces the most relevant references used. Finally, the annex presents the list of variables intervening, the complete MCP formulation of the model, as well as the GAMS code.

2 STATE OF THE ART

Until recently, electricity models assumed that thermal generators had unlimited access to gas supply. Nevertheless, in the recent years the increasing dependency of electric power systems on natural gas has resulted in numerous gas-electricity coordination problems affecting different timeframes. This is currently a hot topic, and consequently numerous recent references can be found in literature related to it, to name a few:

- Dueñas et al. (2014) simulates a generation company that owns a set of GFFPS, and purchases gas in a spot market and contracts pipeline capacity, modeling how long and medium term decision related to pipeline capacity contracting influence short-term decisions related to GFFP operation, while subject to renewable power uncertainty.
- Dueñas et al. (2013) models the behavior of a generation company that owns a set of natural gas power plants, purchases gas in spot markets, and contracts capacity its power plants. The model represents the long- to medium-term decisions related to contracting pipeline capacity and the short-term decisions related to natural gas power plant operation subject to uncertainty in renewable power generation.
- Dueñas et al (2012) presents a methodology to incorporate both the characteristic of long-term natural gas supply contracts and the congestions in the natural gas system in an electricity market equilibrium model that could support the decision-making process on behalf of the electricity generators.
- Li et al. (2008) proposes an integrated model for assessing the impact of interdependency of electricity and natural gas networks on power system security. The integrated model incorporates the natural gas network constraints into the optimal solution of security-constrained unit commitment.
- Wu (2009) develops a multi-time period optimization model which minimizes the total operation cost of the combined gas and electricity networks, whilst meeting the demand requirements over the entire time horizon. A case study is applied to Great Britain.

While all these paper focus on the gas-electricity coordination, none addresses the issue of risk-aversion deviating decisions from the social optimum. The following papers focus on this issue across different time frames, in some cases combined with the effect of market completeness on social welfare, however none is related to the gas-electricity coordination.

- Meunier (2013) studies the influence of firms' risk aversion on the technology mix in an electricity market if the variable cost of a technology is random. To this purpose it develops a model where firms can invest in baseload plants with a fixed variable cost and peak plants with a random variable cost, and electricity varies over time but is perfectly predictable.

- Rodilla et al. (2015) analyzes the effect of generating companies' risk aversion on their medium-term (typically 1 year) hydroelectric resource planning along with its possible inducement of system operation that deviates from the centralized (maximum social welfare) solution while also assessing the impact of missing financial markets.
- Willems and Morbee (2008) assess how welfare and investment incentives are affected when markets are introduced, and to what extent it depends on market completeness.
- Willems and Morbee (2010) develops an equilibrium model of the electricity market with risk-averse firm and a set of traded financial products (a forward contract and an increasing number of options), in order to assess the evolution of aggregate welfare and investment decisions with the number of derivatives offered.

Finally, this thesis models the agent's risk-aversion through means of the CVaR formulation, similar approaches on which this these is based are:

- García-González (2007) presents a profit-based model for short-term hydro scheduling adapted to a pool-based electricity market with two different risk-aversion criteria in the model: a minimum profit constraint and a minimum CVaR requirement, which is formulated linearly.
- Rockafellar and Uryasev (2000) introduces an approach to optimizing or hedging a portfolio of financial instruments to reduce risk which focuses on minimizing conditional Value-at-Risk.

This thesis focuses on the long-term gas-electricity coordination issues, which is currently the topic of many articles, but it does so from a new perspective by analyzing the effect of risk-averse generators and market incompleteness on social welfare in a gas-electricity interdependency context.

3 PROBLEM OVERVIEW

3.1 High natural gas-dependency in today's EPS

Since the beginning of the century, US electric power systems have increasingly become dominated by natural gas-fired power plants, due to both environmental and financial concerns.

The road towards de-carbonization has boosted the development and as a result penetration of renewable generation technologies, especially weather dependent variable energy resources (VER), such as wind and solar. In consequence, even though these technologies reduce significantly the environmental impact of generating electricity, their intermittency and unpredictability cause sudden and large variations in output that require the presence of flexible technologies such as gas-fired power plants. Due to stricter emission reduction commitments worldwide, this increasing VER penetration trend is not likely to change in the coming years, and subsequently neither is the growing natural gas dependency in EPS.

Although the issue of electricity-natural gas interdependence is becoming a major energy policy and regulatory issue in all jurisdictions undergoing the transformation to a lower-carbon and/or renewables-based energy system, it is even more exacerbated in the US due to the emergence of shale-gas. This resource, which estimations show reserves in North America hold a 100-year supply, has reduced considerably the cost of generating electricity with gas, making it the cheaper alternative to oil.

This thesis focuses on the case of New England, whose electric power industry is a good example of high natural gas dependency.

The emergence of shale gas has specially impacted this EPS causing not only cost reduction in natural gas production, but also decreasing the need of long-haul pipeline transport by moving production from Western Canada and the Gulf of Mexico to the Marcellus area which is closer to the region.

Twenty years ago, New England's electricity was mainly produced by oil, coal, and nuclear plants however, there has been since then a huge shift in the technology mix. While the share of natural gas has more than doubled during those years reaching over 43% in 2014, and VER penetration is expected to reach % by 2023, oil-fired power plants' share has dropped from 34% to 21% in 2014, and is expected to decrease to 16% by 2023 and coal's installed capacity has been reduced by half to 6% in 2014, and is expected to almost disappear by 2025 (ISO-NE, 2014).

The vast majority of New England's natural gas is imported through long-haul transport pipelines, however the natural gas pipeline system has not kept pace with demand from the power sector, thus resulting in long-term coordination issues between gas and electricity industries. For a better understanding of this topic, a brief overview of the U.S. natural gas transportation market is provided in the following section.

3.2 Brief overview of the US natural gas pipeline capacity market

There are two components of gas supply to electric generations. The first is the wellhead supply of the gas commodity, the other components is the infrastructure necessary to deliver gas when and where it is needed. Natural gas is priced and traded at different locations throughout the country. These locations, referred to as "market hubs", are located at the intersection of major pipelines. There are over 30 major market hubs in the U.S. Other major pricing locations include the locations at which distribution companies receive gas from a pipeline referred to as city-gates.

Henry Hub (HH), located in Louisiana, is the most liquid hub in the U.S and, therefore, it is taken as the price reference for the commodity component of the natural gas price. The price at which natural gas trades differs across the major hubs, depending on the supply and demand for natural gas at that particular point. The difference between the Henry Hub price, and another hub is called location differential. The location differential, also referred to as basis differential, represents the infrastructure component of the natural gas price set in the natural gas transportation market. Consequently, spot prices can be expected to differ systematically whenever there is congestion.

In the U.S., natural gas is generally transported from producing areas to industrial end users, storage areas and local distribution companies through high pressure pipelines. However, the United States currently imports about 3% of its natural gas from overseas producers in the form of liquefied natural gas. (Agustine et al., 2006)

Interstate pipeline companies' operation and investments are regulated by the Federal Energy Regulatory Commission (FERC).

FERC limits their business to providing transportation services (including storage), and does not allow these companies to buy and sell natural gas. In order to transport natural gas through these pipelines, gas consumers need to contract capacity in one of the two principal transportation markets (primary and a secondary market).

In the primary market, pipeline companies offer two main services, firm and interruptible, both of which have regulated tariffs supervised by FERC. Pipeline users may sign long-term firm capacity contracts, which require a monthly fixed fee, in exchange this provides firm capacity owners first priority to be served in case of a constraint. Whereas, interruptible capacity owners pay a variable fee that depends on the actual amount of capacity used. These are the most flexible contracts, but offer little security to their holders as they give no priority when being dispatched in case of a constraint. Interruptible shippers use the firm capacity leftovers, and may be curtailed if firm contract holders need to increase their daily capacity. Any capacity excess may be sold by firm capacity holders in the secondary market.

In the secondary market, firm capacity holders release unused capacity at an unregulated rate. The secondary market allows primary purchasers of firm transport capacity to realize the market value of available capacity. At first, FERC established a price cap on this market, as there is on the primary market, however this gave primary customers little incentive to release capacity during peak demand periods when its market value was highest. The situation changed in 2008, when Order 712 was approved, eliminating price caps for short-term releases (less than one year) (FERC, 2008). This allows firm capacity owners to recollect scarcity rents. In times of constraints the prices in the secondary market will spike reflecting the congestion in the pipeline, thus resulting on a higher location differential.

As far as pipeline investments are concerned, pipelines companies cannot build infrastructure on speculation, rather, they build pipelines once the market expresses its support for a project by contracting for firm transportation capacity. A pipeline development or expansion project involves several steps. First, the pipeline owner has to determine demand for new capacity. If a real market interest is detected, the project is announced publicly. At this point, FERC will have to give regulatory approval to the construction project. In order to do so, the Commission will ask the pipeline company to prove there is an actual demand for this new capacity. The pipeline company has to present long-term capacity contracts signed by potential customers for the projected capacity. Usually, a minimum term of ten years is requested for these contracts. Once the project is approved, construction and testing may begin.

3.3 Impact of long-term G&E coordination in New England

Until now, the electricity market and the natural gas market were relatively independent and have performed well. Since the electric power system has become increasingly reliant on natural gas, the actions in either of the systems have a more significant impact in the other. The "in-time" characteristic of electricity combined with the lack of gas storage at most power plants increases the importance of coordination between them both in the short and long run.

As previously mentioned, natural gas demand in the New England ISO (ISO-NE) has experienced a boom in the past fifteen years. This rapid growth has resulted in a lack of coordination between the natural gas and electricity market with clear economic and environmental impacts that affect different time scopes.

In the short and mid-term, there are scheduling mismatches between the gas market and the electricity market in ISO. Moreover, pipeline maintenance scheduled during summers, which is the off-peak season for natural gas, has led to unavailable gas-fired power plants during the electricity peak season. These issues should be addressed by modifying timing in electricity markets, and increasing information sharing between the ISO and pipeline operators.

However, the focus here is brought to long-term issues where changes in ISO market designs will be necessary to deal with problems of reliability and flexibility.

Resource adequacy in a gas-fired power plant dominated system

New England's natural gas consumers can be divided into two separate consumers. On the one hand, we have non electric customers. This includes all pipeline users whose consumption is independent from the electric industry, i.e. residential, commercial, and industrial consumers. While industrial consumers have a relatively flat consumption all throughout the year, residential and commercial gas consumption is characterized by a strong seasonal pattern. Their main use for gas is for heating, and in consequence their consumption rises sharply during cold months. Residential and commercial customers are usually supplied by local distribution companies (LDCs), who buy natural gas and pipeline capacity on their behalf. LDCs are regulated companies, forced to buy firm capacity contracts to cover their customer's demand to ensure their customer will not experience any gas shortage.

On the other hand are electric customers, who also have a seasonal pattern which is correlated to electric demand. New England's electric demand rises during winter and summer months, and as a result so does its gas consumption. Gas-fired power plants usually rely on interruptible contracts and secondary capacity contracts to secure pipeline capacity, hence facing high probability of being curtailed in case of pipeline congestion, as firm capacity holders (i.e. LDCs) have priority over them.

As a consequence, New England's EPS high dependency on natural gas has become troublesome in the past few years during cold winter months. When temperatures drop significantly, natural gas demand for both space heating and electric generation rises, and as a result so does the frequency of pipeline capacity shortage events

Impact on the New England natural gas and electricity spot markets

Increasingly maxed out natural gas pipelines have had a significant impact in the natural gas market prices. Figure 1 shows the yearly prices for both the Algonquin City-gate (usually taken as the natural gas price reference in New England) and the Henry Hub. While the Henry Hub prices are fairly constant all throughout the year, Algonquin City-Gate prices increase sharply during cold months, even reaching prices seven times higher than HH's. The difference between these two, reflects the pipeline transportation charge for New England shippers hence proving that pipeline congestion events are responsible for natural gas prices spikes in New England during winter.

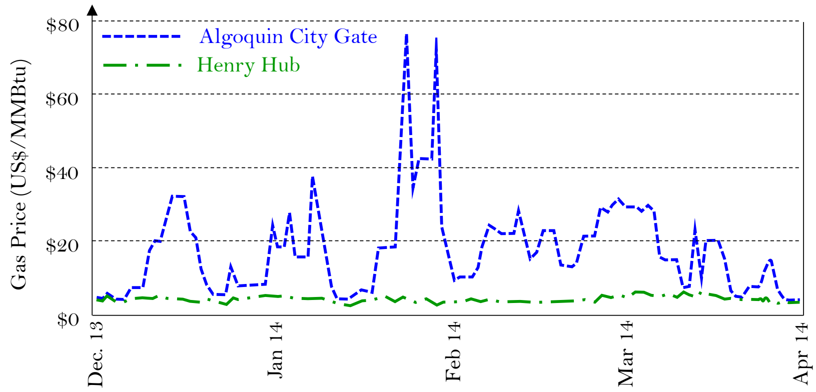


Figure 1 Daily Natural Gas Spot Prices, July 2014 – June 2014 Source: EIA

This increase in natural gas prices has subsequently resulted in an overall increase in operating and production costs within the electricity sector.

Gas-fired power plants are usually the marginal, price setting technology in the market (in 2012 more than 80 percent of the time gas-fired units set prices in ISO New England energy), it is only logical that a price increase in natural gas translates into a price increase during these hours. Moreover, pipeline congestion has originated gas shortages for gas-fired generators. In order to avoid reliability issues, ISO-NE has been forced to dispatch other technologies which are less competitive (i.e. more expensive) than gas-fired, subsequently oil and coal production increases sharply during this period. Under some circumstances, oil might even become less expensive than natural gas, thus replacing it as the marginal technology. Figure 2 which represent fuel usage (%) in average for 2014 (left), and strictly during winter months (right), very much confirms so. Coal and, specially, oil, whose participation in the market is barely significant during the whole year, play an active role in the electricity production during cold months.

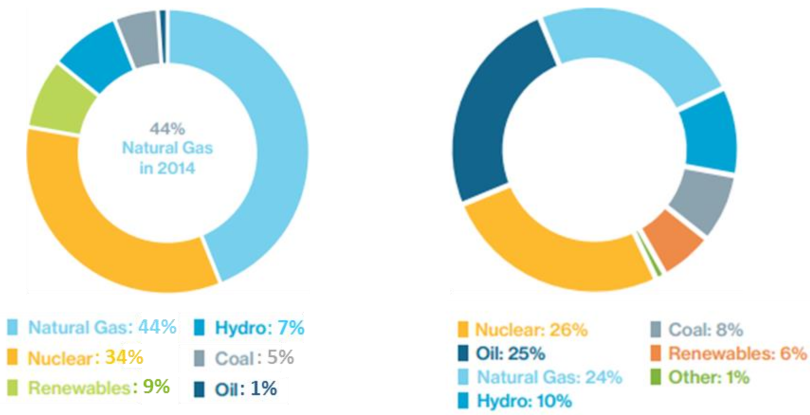


Figure 2 Fuel usage (%) in New England in 2014 (left) and during the 2014 winter (right) Source: ISO-NE (2015)

Since coal power plants are expected to almost disappear by 2023 (ISO-NE, 2014), until long-term solutions to this issue are implemented ISO-NE will have to rely solely on oil production as an alternative to gas production during pipeline scarcity events in order to avoid further reliability problems.

Consequently, as the New England gas and wholesale power prices comparison in Figure 3 shows, not only are these two industries physically coupled, but financially coupled too.

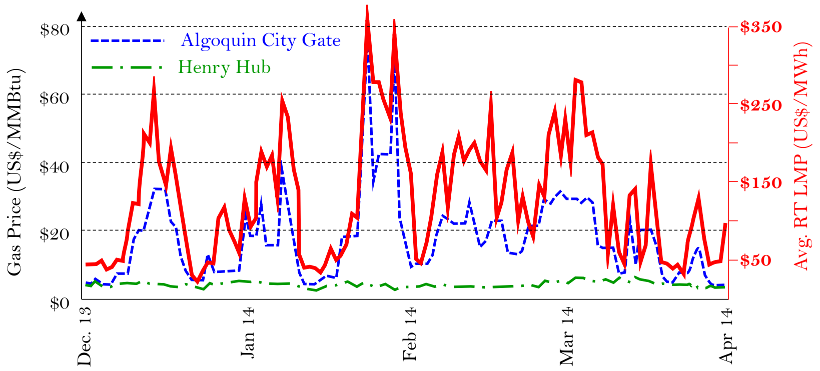


Figure 3 Comparison of New England gas and wholesale power prices (Source: EIA, ISO-NE)

Figure 4 shows the impact of this price increase on residential electricity consumers, who according to EIA data have faced the highest single-year growth rate in the country, having to pay for wholesale power an extra $3.2 billion above last year's total $3.4 billion (ICF, 2015)

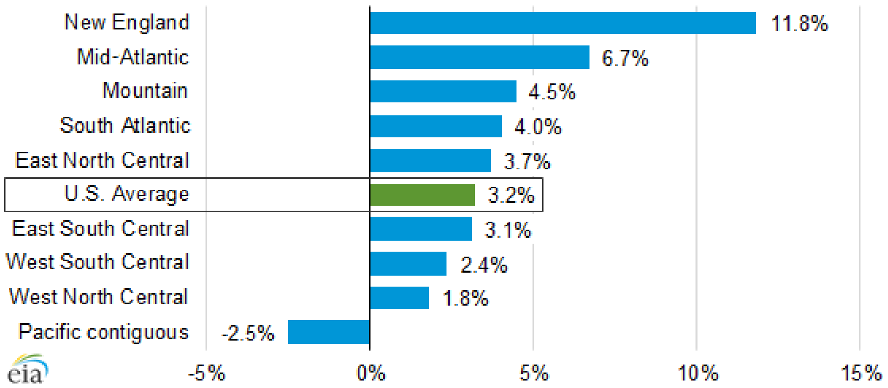


Figure 4 Change in average residential electricity prices by Census division (first half 2014 versus first half of 2013) Source: EIA

Proposed solutions

This extreme sensitivity to weather events may become very costly for New England's electricity consumers if left unaddressed. ISO-NE has implemented for three years in a row a Winter Reliability Program (WRP) whose main purpose is to address concerns about the ability of power systems resources to perform. Under this purpose, it provides agents with incentives to invest in short-term solutions that will mitigate winter reliability risk associated with retirements of key non-gas generators, gas pipelines constraints and generators' difficulties in replenishing oil supplies.(ISO-NE, 2015), to name a few:

- Increasing LNG imports are a possible alternative to face congestion events. Unfortunately, shipments can be limited when international markets offer higher prices. As an added complication, transporting LNG in winter, when the region needs it most, is subject to weather delays. These factors make LNG prices volatile in New England, exceeding global prices on days when LNG facilities cannot keep up with regional demand. However, when pipelines' capacity is constrained, spikes in prices make LNG both economical and necessary,

- LNG peak-shaving facilities constitute an alternative to LNG imports that can also increase the use of LNG in the region. These facilities liquefy natural gas and store it. This technology and underground gas storage (UGS) are possible methods for meeting peak day. Still, geographic constraints, regulatory hurdles, and economic barriers make it unlikely that either technology will increase its presence in the future. (MITEI, 2013)
- Demand response is one of the major market changes that could help solve network constraints. However, its impact on the market remains uncertain.
- Dual-fuel power plants are units that can run either on gas or oil. They can switch to oil whenever gas is not available or it is more expensive than oil. However, emissions regulations are increasingly strict, and the extent and duration of oil-fired generators' ability to comply with them are not certain.

Nevertheless, these are largely contemplated as interim solutions intended to soften the blow until new pipeline capacity is brought into the system (Black and Veatch, 2013). The aforementioned solutions fail to offer consistent incentives to reduce New England's dependence on natural gas, therefore to increase pipeline capacity seems unavoidable with the estimated gas demand predictions (Patton et al, 2013) (Arcate and High, 2014)

This is confirmed by a study performed by Black and Veatch (2013) under which future pipeline capacities were assessed under three different scenarios (low demand, base case, high demand). Findings show that only under the low demand scenario no infrastructure expansions were necessary. This scenario assumes that gas demand is decreasing in all scenarios, which according to forecasts is highly unlikely.

Moreover, according to ICF (2014), the New England market is likely to remain supply constrained through 2020 if no additional infrastructures expansions are considered.

Although bringing new pipeline capacity is considered fundamental, there is a lack of unanimity as to the amount of additional capacity the system requires.

In a letter submitted by NESCOE to ISO-NE an increase of 6 bcf/d of additional capacity is suggested. However, capacity expansion needs estimations from ICF (2014), Arcate and High (2014) and Black and Veatch (2013) are far more conservative.

ICF indicates a need for up to 1.1 bcf/d of additional gas supply by 2020 to meet projected power plant fuel requirements. (ICF, 2014) Power Options reached a similar conclusion, sustaining that 1 bcf/d should be the maximum capacity added. This would increase reliability, decrease price but leave room to minimize costs.(Arcate and High, 2014). Finally, Black and Veatch (2013) report's findings show that a natural gas pipeline with a design capacity of 1.2 bcf/d could potentially relieve constraints during peak winter months and provide the necessary flexibility to meet future demand growth.

3.4 Risk-averse generators and incomplete financial markets

Regardless of the actual amount of capacity needed, the key issue here seems to be why aren't generators investing in new pipeline capacity? If, clearly, they are the ones who need it, and all there is to do acquire it is sign a long-term firm capacity contract with a pipeline company, why aren't they signing these contracts?

Given the financial and physical coupling of the gas and electricity markets, generation firms face a unique set of uncertainties as simultaneous consumers in both these markets. The possibility that electricity demand does not evolve as forecasted, or probably more importantly that renewable energy sources massively deploy in the future, creates a significant quantity risk to the gas-fired generator who will be reluctant to sign long-term firm capacity contracts, opting instead for short-term interruptible capacity contracts. The former are ten-twenty year, capital intensive contracts involving a large risk for these generators .Consequently, generation firms would rather sign short-term contracts and face scarcity issues, than risk signing for additional capacity they might not need twenty years down the road.

One of the main objectives of regulation in electric power systems is to provide agents with the necessary incentives to take the most socially efficient decisions. Results obtained under a centralized context have been largely acknowledged as the social optimum reference. However, market failures are inherent to power systems, and whenever liberalized systems fail to replicate these results, one may conclude that market design is not providing agents with the proper incentives.

Or as explained in MITEI (2013):

"To understand how this is a problem with electricity market design think about a competently managed, vertically integrated utility that is required by law to provide reliable power to a substantial region. Would it consider signing a contract for firm gas supplies in order to ensure that it was able to meet that obligation? Would it also look at LNG storage and dual-fuel options on a plant-by-plant basis to see how much use it could safely make of interruptible gas supply? Of course it would. In order to mimic this central planning process, organized markets need to give proper incentives for generators to consider these options."

Currently, there is an on-going discussion in New England to create performance incentives for generators to make firm fuel arrangements. ISO-NE believes that incentives to acquire firm fuel be created in the long-term through changes in the Forward Capacity Market (FCM) and the Forward Reserve Market (FRM).

However, as of today, agents remain without access to proper tools to hedge the long-term risk that acquiring firm fuel entails. In the absence of any financial instrument that allows investors to hedge the market price in the long-term, uncertainty in general reduces the incentives to enter into such firm contracts.

As a result, agents are forced to take very long-term decisions in a context of incomplete long-term financial markets. Incomplete markets are defined as those in which perfect risk transfer is not possible. Despite the ever increasing sophistication of financial and insurance markets, markets remain significantly incomplete with important consequences for their participants. (Staum. 2008).

Staum (2008) analyzes different possible causes for market incompleteness, among which is cited "An insufficiency of marketed assets relative to the class of risk that one wishes to hedge" This describes quite accurately the problem in New England, where no risk-hedging instruments properly adapted to the very long-term needs of generators are offered.

This thesis assesses the impact on social welfare of risk-averse generators in a context of incomplete long-term financial markets.

Moreover, Willems and Morbee (2010) show that increasing market completeness is welfare-enhancing, where market completeness is measured as the number of electricity options available to producers and retailers, in addition to a forward contract. Following a similar approach, this thesis will also assess the impact on social welfare of increasing market completeness by sequentially offering generators to hedge their risk with a forward contract, then a forward contract with an option.

4 PROPOSED METHOD

The present theoretical analysis addresses the investment problem in gas-fired thermal capacity and pipeline capacity in a context characterized by (i) perfect competition, (ii) risk-averse agents and (iii) missing long-term financial markets. It explores the impact derived from these missing markets, which translate into less socially-efficient investments.

To address this issue, following a similar approach as the one developed by Rodilla et al. (2009) four different settings are considered for which the different obtained outcomes will be compared and analyzed:

- a (cost-minimizing) context with a risk-neutral centralized planner who decides both the thermal capacity and the pipeline capacity to maximize social welfare. This framework constitutes the benchmark solution.
- a market in which risk-averse generators have to decide the thermal capacity to be installed and the firm pipeline capacity contracts to be signed to maximize their profit where no long-term financial instruments are available.
- a market setting similar to the previous one, but where a long-term forward contract for electric energy is available.
- a market setting similar to the previous one, but where both a forward and an option contract are available.

Under the different settings, agents must first take long-term investment decisions (in both pipeline capacity contracts and power plant investment), as well as hedging instruments, and then decide in the short-term the hourly power plant production. Uncertainty in variable renewable energy (VER) production is factored-in through different scenarios each considering a different VER penetration level.

Market equilibrium settings simultaneously represent the short-term electricity and gas markets, and, when included, the long-term financial markets. The equilibrium prices for all of these markets are endogenously determined by the model.

4.1 Benchmark problem: Risk-neutral central planner

Under this first setting, a risk-neutral central planner takes both long-term decisions (in power plant investment, and pipeline capacity contract) that lead to cost minimization, i.e. social-welfare maximization.

Model hypothesis

Some hypothesis are introduced in the formulation to simplify the problem, elements that add excessive complexity to the model yet do not contribute to the analyzed topic are excluded.

Investment decisions in power plant are limited to one technology that may produce with two types of fuel. The central planner invests in dual-fuel power plant that can produce with oil or natural gas

All integer and binary variables have been eliminated to simplify the problem formulation, consequently:

- The power plant may produce simultaneously with oil (qoil [MWh]) and natural gas (qgas [MWh])
- Only linear costs are considered. As a result, short-term costs include variable fuel costs, whereas no-load fuel costs and start-up costs are disregarded, and, in the long-term investment decisions are linearized.

All scenarios have the same probability, thus Pr is equal to the inverse of the number of scenarios.

Problem formulation

The objective function (

Eq. 1) in the benchmark problem is to minimize expected generation costs in a centralized risk-neutral context, this includes short-term variable costs (fuel costs (VC_{gas}·VF_{gas} [$/MWh], VC_{oil} VF_{oil} [$/MWh]), non-served energy cost (CNSE [$/MWh])) and long-term investment costs ((Dual-fuel technology investment cost ICT [$/MW], pipeline capacity investment cost ICC [$/MW]). The o.f. is subject to four different constraints.

First, Eq. 2 ensures that the investment decision in power plant capacity, t, is higher than production with that same power plant for every period p and scenario sc.

Then, Eq. 3 caps oil production at T_{oil}, to reflect that the power plant's capacity to produce with oil is limited with respect to gas.

The other two constraints, Eq. 4 Eq. 5 represent respectively, the electricity demand balance equation which ensures that net demand is equal to hourly production plus non-served energy, nse, and the gas balance equation. Natural gas, contrary to electricity, does not need to be produced and consumed simultaneously, as a result Eq. 5 ensures that pipeline capacity (exiting pipeline capacity, C_{ex} [MWh/d] , and pipeline capacity contract investment c [MWh/h]) is higher than gas demand. Two types of consumers are considered, gas-fired generators, and non-electric consumers, LDC [MWh/h] (commercial, industrial and residential demand).

Eq. 1

$$Min_{qgas,qoil,t,c} \sum_{sc}[Pr_{sc} \cdot \sum_{p}[VF_{gas} \cdot qgas_{p,sc} \cdot VC_{gas} + VF_{oil} \cdot qoil_{p,sc} \cdot VC_{oil} + nse_{p,sc} \cdot CNSE]] + 24 \cdot c \cdot ICC + \quad t \cdot ICT$$

Eq. 2

$$qgas_{p,sc} + qoil_{p,sc} \leq t$$

Eq. 3

$$qoil_{p,sc} \leq T_{oil}$$

Eq. 4

$$qgas_{p,sc} + qoil_{p,sc} + RES_{sc} \cdot (WG_p + SG_p) = D_p - nse_{p,sc}$$

Eq. 5

$$qgas_{p,sc} \cdot VF_{gas} \leq c + \frac{C_{ex}}{24} - LDC_p$$

As shown in Eq. 4, the model includes stochasticity in both wind generation (WG [MWh]) and solar generation (SG [MWh]). Each scenario has a different VER penetration level, which is defined by RES.

c is the investment decision in pipeline capacity contract. To reflect the actual regulation in the Unites States where FERC (Federal Energy Regulatory Commission) requires pipeline companies to sign long-term capacity contracts with pipeline users in order to authorize the construction of new pipeline capacity, signing pipeline contracts for c [MWh/h] results in increased pipeline capacity for the same amount.

4.2 Risk-neutral market equilibrium with no hedging instruments

The previous centralized problem can also be formulated as a perfectly competitive market with risk-neutral agents and no hedging instruments.

Assuming perfect competition in the central planner's welfare-maximization problem, we can formulate and solve a cost-minimization problem from the central planner's perfective that also yields the profit-maximizing decisions of individual agents in the system. Therefore, this the risk-neutral market equilibrium formulation of the problem is equivalent to the centralized risk-neutral formulation.

The problem is formulated as the joint maximization of the objective functions of each agent, as well as, the demand objective functions.

Generation side problem formulation

The formulated problem is addressed assuming perfect competition among different agents, therefore all agents are price takers and must sell their output at the price provided by the market. Agents have no market power which, mathematically, can be translated by assuming that the derivative of the price with respect to an agent's production is equal to 0.

Eq. 6

$$\frac{\partial p}{\partial q_i} = 0$$

In conclusion, on a perfectly competitive electricity market, each producer's optimum output and price are defined by its marginal cost curve, and, in the aggregate, this ensures that demand is met by the most efficient units.

(Eq. 7 - Eq. 10) represent the problem of one agent, i. Agents have no distinctive qualities, they all face the same problem, thus these equations appear in the model as many times as the number of agents.

The objective function of each agent, i, is to maximize its expected profit is equal to the weighted sum extended to all scenarios, sc, and periods, p, of market income minus variable costs (i.e. fuel costs), minus fixed costs (investment costs in power plant and pipeline capacity contracts). Moreover, all agents are subject to the same power plant capacity and oil capacity constraints, Eq. 8. Eq. 10 specifies which variables must be positive.

Eq. 7

$$Max_{qgas,qoil,t,c} \sum_{sc}\Big(\mathrm{Pr}_{sc} \sum_{p}\big(\lambda_{p,sc} \cdot \big(qgas_{p,sc,i} + qoil_{p,sc,i}\big) - (\mu_{p,sc} + VC_{gas}) \cdot \mathrm{qgas}_{p,sc,i} \cdot \mathrm{VF}_{gas} - \mathrm{VC_{oil}} \cdot \mathrm{qoil}_{p,sc,i} \cdot \mathrm{VF}_{oil} + \mathrm{c_i} \cdot \mu_{p,sc}\big)\Big) - \mathrm{ICT} \cdot \mathrm{t_i} - 24 * \mathrm{c_i} \cdot \mathrm{ICC} \qquad \forall \mathrm{i}$$

s.t.

Eq. 8

$$\mathrm{qoil}_{p,sc,i} + \mathrm{qgas}_{p,sc,i} - \mathrm{tgas_i} \leq 0 \quad \perp \beta_{p,sc,i} \geq 0 \qquad \forall\, \mathrm{p, sc, i}$$

Eq. 9

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall\, \mathrm{p, sc, i}$$

Eq. 10

$$qgas_{p,sc,i}, qoil_{p,sc,k}, c_i, t_i, \geq 0 \perp \eta gas_{p,sc,i}, \eta oil_{p,sc,i}, \sigma_i, \varepsilon_i, \geq 0 \qquad \forall\, \mathrm{p, sc, i}$$

Although, not all dual variables are necessary to solve the problem, they are needed to formulate the MCP, therefore, all dual variables are explicitly defined in the market equilibrium equations above.

Demand side problem formulation

The demand is aggregated into a single, inelastic, risk-neutral agent whose objective function is to maximize its expected utility (i.e. cost of non-served energy multiplied by the hourly consumption), minus the expected amount paid to the market as can be seen in Eq. 11.

Eq. 11

$$Max_{nse} \sum_{p}[\sum_{sc}[\big(D_p - nse_{p,sc}\big) \cdot (CNSE - \lambda_{p,sc})]] \qquad \forall\, \mathrm{p, sc}$$

s.t.

Eq. 12

$$nse_{p,sc} \geq 0 \perp \eta nse_{p,sc} \geq 0 \qquad \forall\, \mathrm{p, sc}$$

Assuming demand to be risk neutral is, under this setting, irrelevant, as demand cannot take any decisions. Nevertheless, once the financial markets are introduced, demand is the only counterpart to generation in signing forward and option contracts, and demand risk-neutrality is presumed then to have a significant impact on the results.

Global equations

Finally, the problem has two global equations that ensure that demand minus non-served energy is equal to generation for every period and scenario (Eq. 13), and that, for every period and scenario, gas consumers do not exceed pipeline capacity (Eq. 14).

Eq. 13

$$\sum_i [\, \mathrm{qgas}_{p,sc,i} + \mathrm{qoil}_{p,sc,i}] + \mathrm{WG}_p \cdot \mathrm{res}_{sc} + \mathrm{SG}_p \cdot \mathrm{res}_{sc} = \mathrm{D}_p - \mathrm{nse}_{p,sc} \perp \lambda_{p,sc} \qquad \forall p, sc$$

Eq. 14

$$\sum_i [\, qgas_{p,sc,i} \cdot VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC(p) \quad \perp \quad \mu_{p,sc} \geq 0 \qquad \forall p, sc$$

The value of dual variables of Eq. 13 and Eq. 14 are, respectively, the electricity market spot price ($\lambda_{p,sc}$ [$/MWh]) and the gas market spot price location differential ($\mu_{p,sc}$ [$/MWh]) , which are endogenously calculated by the model.

The representation of the natural gas market has been simplified into a market with two hubs connected through a pipeline with limited capacity.

There is an exporting hub with infinite production capacity at a fixed variable cost (VC_{gas}). Therefore, the price at this node is constant and equal to the variable production cost. At the other end of the pipeline, there is an importing hub. The price difference between these two hubs is named location differential. The location differential is equal to zero when the pipeline is not congested, (hence the nodal price at both hubs is equal), and positive when there is a congestion in the pipeline. When the pipeline is congested, demand at the importing hub is higher than supply at the importing hub, consequently the price increases. Consequently, the price at the importing hub is equal to the sum of the location differential and the fixed variable cost ($\mu_{p,sc} + VC_{gas}$).

There are two types of gas consumers at the importing end of the pipeline, electric and non-electric (considered input data).

Electric demand is composed of generation agents who consume natural gas to produce with their CCGTs. Generation agents must choose whether or not to invest in natural gas pipeline capacity. If they do invest, then they pay for the natural gas consumed the price at the exporting hub, still all gas consumption above the contracted capacity is paid at the price of the importing hub.

This is reflected in the agents' objective function, Eq. 7. In the formulation, all agents, regardless of their pipeline capacity investment decision pay their gas consumption at the importing hub price ($\mu_{p,sc} + VC_{gas}$). However if an agent has contracted pipeline capacity, it receives in return the location differential for the capacity contracted ($\mu_{p,sc} \cdot c$), but has to pay for said capacity a fixed investment cost ($ICC \cdot c$).

The result is that agents use the pipeline contracted capacity to import low priced gas either for their own consumption, or to sell to other customers at the importing hub high price whenever there is a scarcity event.

Mixed Complementarity Problem

Four out of the five models are non-linear problems, where different objective functions must be taken into account in the maximization problem, and where different markets are simultaneously represented while endogenously calculating the equilibrium prices.

Mixed Complementarity Problems have been proven to be especially important in modeling the various liberalized energy markets around the world given its flexibility and ability to directly manipulate both primal (physical) variables as well as dual (price) variables.

Therefore, these three models are formulated as MCPs in order to be solved.

To formulate the MCP, it is necessary to calculate derivate the Lagrangian to obtain the Karush-Kuhn-Tucker optimality conditions. This process can be found in the annex for all models.

The final MCP formulation (Eq. 15 - Eq. 23) of the problem include, first order optimality conditions rearranged and combined, second order optimality conditions and global equations (Eq. 13, Eq. 14).

Eq. 15

$$Pr_{sc} \cdot (-\lambda_{p,sc} + (VC_{gas} + \mu_{p,sc})VF_{gas} + \beta_{p,sc,i} \geq 0 \perp qgas_{p,sc,i} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 16

$$Pr_{sc} \cdot (-\lambda_{p,sc} + VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} \geq 0 \perp qoil_{p,sc,i} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 17

$$24 * ICC - \sum_p [\sum_{\mathrm{sc}} [\ \mu_{p,sc} \ \cdot \mathrm{Pr_{sc}}]] \geq 0 \perp c_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 18

$$ICT - \sum_p [\sum_{sc} [\beta_{p,sc,i}]] \geq 0 \ \perp t_i \ \geq 0 \qquad \forall \mathrm{i}$$

Eq. 19

$$CNSE - \lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall \mathrm{p, sc}$$

Eq. 20

$$0 \geq \mathrm{qgas_{p,sc,i}} + \mathrm{qoil_{p,sc,i}} - \mathrm{t_i} \quad \perp \beta_{p,sc,i} \ \geq 0 \qquad \forall \mathrm{\ p, sc, i}$$

Eq. 21

$$qoil_{p,sc} \ \leq T_{oil} \perp \varphi_{p,sc,i} \ \geq 0 \qquad \forall \mathrm{\ p, sc, i}$$

Eq. 22

$$\sum_i [\, \mathrm{qgas}_{p,sc,i} + \mathrm{qoil}_{p,sc,i}] + \mathrm{WG}_p \cdot \mathrm{res}_{sc} + \mathrm{SG}_p \cdot \mathrm{res}_{sc} = \mathrm{D}_p - \mathrm{nse}_{p,sc} \perp \lambda_{p,sc} \qquad \forall p, sc$$

Eq. 23

$$\sum_i [\, q_{p,sc,i,gas} VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \quad \perp \quad \mu_{p,sc} \geq 0 \qquad \forall p, sc$$

4.3 Risk Averse market equilibrium with no hedging instruments

The previous risk-neutral formulation is modified to model agents as risk-averse.

Generation side problem formulation

Risk-averse agents base their decision on low profits scenarios instead of taking into account the expected profit. As a results, instead of taking socially efficient decisions, agents take decisions that tend to maximize the low scenario's profit.

The agent's risk-aversion formulation is based on the Conditional Value-at-Risk (CVaR) (Rockafellar and Uryasev, 2000) The CVaR technique has two main advantages. First is the protection that this criterion provides against severe scenarios. Second is that it can be formulated as linear programming for the discrete scenario-setting (García-González J, 2006).

Although usually expressed in terms of losses, in this formulation, the VaR estimates the likelihood that a given agent's profits, B, will exceed a certain amount. Let ζ be the VaR at a confidence level of δ is the minimum profit that will be reached with a probability δ . Given the percentile δ , CVaR^{δ} represents the mean of the profit in the worst δ 100% scenarios.

Mathematically, this can be formulated as follows:

Eq. 24

$$CVaR^{\delta}(B) = E(B | B < \zeta)$$

For a discrete number of scenarios, the CVaR can also be formulated as:

Eq. 25

$$CVaR^{\delta}(B) = \frac{\sum_{sc|B_{sc}<\zeta} Pr_{sc} \cdot B_{sc}}{\sum_{sc|B_{sc}<\zeta} Pr_{sc}} = \frac{\sum_{sc|B_{sc}<\zeta} Pr_{sc} \cdot B_{sc}}{1 - \delta}$$

To compute the CVaR, it is necessary to create an auxiliary variable ΔB_{sc}, which is equal to zero when the profit is higher than the VaR, and, in the opposite case, equal to the difference between the VaR and corresponding profit The CVaR can be introduced in the model with the following equations:

Eq. 26

$$\zeta - \frac{\sum_{sc|B_{sc}<\zeta} Pr_{sc} \cdot B_{sc}}{1 - \delta} \geq CVaR$$

Eq. 27

$$\Delta B_{sc} \geq \zeta - B_{sc}$$

Eq. 28

$$\Delta B_{sc} \geq 0$$

With this CVaR formulation, the objective function is also modified and it is transformed in the maximization of the weighted sum of the expected profit and the CVaR:

Eq. 29

$$\max(1-\alpha)\cdot E(B) + \alpha \cdot CVaR$$

α represents the weight of the risk-aversion in the objective function, and its value is bounded between 0 and 1. High values of α increase the importance of the CVaR, and reduce the importance of the expected profit in the objective function. Agents 'decisions seek to protect themselves against low profit scenarios, rather than maximizing the expected profit, thus ensuring that profit increases in severe scenarios regardless of the overall effect. Consequently, an agent with high risk aversion is modeled with a high value of α and vice-versa.

Introducing the CVaR formulation in the generation side equations results in Eq. 30 - Eq. 36, where constraints Eq. 34 - Eq. 36 represent the risk-aversion constraints.

Eq. 30

$$Max_{qgas,qoil,t,c}\,(1-\alpha_i)\cdot\Big(\sum_{sc}\Big(\mathrm{Pr}_{sc}\sum_p\Big(\lambda_{p,sc}\cdot\big(qgas_{p,sc,i}+qoil_{p,sc,i}\big)-(\mu_{p,sc}+VC_{gas})\cdot \mathrm{qgas}_{p,sc,i}\cdot \mathrm{VF}_{gas}-\mathrm{VC}_{oil}\cdot \mathrm{qoil}_{p,sc,i}\cdot \mathrm{VF}_{oil}-\mathrm{c}_i\cdot(\mu_{p,sc})\Big)\Big)-\mathrm{ICT}\cdot \mathrm{t}_i-24*\mathrm{c}_i\cdot \mathrm{ICC}\Big)+\alpha_i\cdot CVaR_i \qquad \forall \mathrm{i}$$

s.t.

Eq. 31

$$\mathrm{qoil}_{p,sc,i}+\mathrm{qgas}_{p,sc,i}-\mathrm{tgas}_i \leq 0 \;\perp \beta_{p,sc,i,} \geq 0 \qquad \forall\, \mathrm{p,sc,i}$$

Eq. 32

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall\, \mathrm{p,sc,i}$$

Eq. 33

$$qgas_{p,sc,i}, qoil_{p,sc,k}, c_i, t_i, \geq 0 \perp \eta gas_{p,sc,i}, \eta oil_{p,sc,i},\ \sigma_i, \varepsilon_i, \geq 0 \qquad \forall\, \mathrm{p,sc,i}$$

Eq. 34

$$VaR_i - \frac{\sum_{sc} Pr_{sc}\cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \qquad \perp \tau_{1_i} \geq 0 \qquad \forall \mathrm{i}$$

Eq. 35

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\sum_p(\lambda_{p,sc} \cdot (\mathrm{qoil}_{p,sc,i} + \ \mathrm{qgas}_{p,sc,i}) - (\mu_{p,sc} + VC_{gas}) \cdot \mathrm{qgas}_{p,sc,i} \cdot \mathrm{VF}_{gas} - \mathrm{VC}_{oil} \cdot \mathrm{qoil}_{p,sc,i} \cdot \mathrm{VF}_{oil} + \mathrm{c}_i \cdot \mu_{p,sc}) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC\ ] \ \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall \mathrm{sc}, \mathrm{i}$$

Eq. 36

$$\Delta B_{sc,i} \geq 0 \ \ \perp \tau_{3_{sc,i}} \geq 0 \qquad \forall \mathrm{sc}, \mathrm{i}$$

The demand-side and global equations remain the same as in the risk-neutral formulation (Eq. 11 - Eq. 14) and therefore are not included again here.

Mixed Complementarity Problem

The step by step process to obtain the MCP formulation presented below can be found in the annex.

Eq. 37

$$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas}) + \beta_{p,sc,i} \cdot (\lambda_{p,sc} - (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas} \geq 0 \perp q_{p,sc,i,gas} \geq 0 \qquad \forall \mathrm{p}, \mathrm{sc}, \mathrm{i}$$

Eq. 38

$$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} - \tau_{2_{sc,i}} \cdot \left(\lambda_{p,sc} - VC_{oil} \cdot VF_{oil} \cdot \right)) \quad \geq 0 \perp q_{p,sc,i,oil} \geq 0 \qquad \forall \mathrm{p}, \mathrm{sc}, \mathrm{i}$$

Eq. 39

$$(1-\alpha_i) \cdot (24 * ICC - \sum_p[\sum_{sc} \mu_{p,sc} \ \cdot \mathrm{Pr}_{sc}]]) - \sum_{sc}[\tau_{2_{sc,i}} \cdot (\mu_{p,sc} - 24 \cdot ICC\ )\ ] \ \geq 0 \qquad \perp c_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 40

$$(1-\alpha_i) \cdot ICT - \sum_p[\sum_{sc}[\beta_{p,sc,i}]] - \sum_{sc}[\tau_{2_{sc,i}} \cdot (-ICT)] \geq 0 \perp t_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 41

$$-\tau_{1_i} + \sum_{sc}[\tau_{2_{sc,i}}] = 0 \ \perp \mathrm{VaR}_i \qquad \forall \mathrm{i}$$

Eq. 42

$$\tau_{1_i} - \alpha_i = 0 \qquad \perp \mathrm{CVaR}_i \qquad \forall \mathrm{i}$$

Eq. 43

$$\frac{\tau_{1_i} \cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} \geq 0 \quad \perp \Delta B_{sc,i} \geq 0 \qquad \forall \mathrm{sc}, \mathrm{i}$$

Eq. 44

$$VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \quad \perp \tau_{1_i} \geq 0 \qquad \forall \mathrm{i}$$

Eq. 45

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\textstyle\sum_p \left(\lambda_{p,sc} \cdot \sum_f \left(q_{p,sc,i,f}\right) - (\mu_{p,sc} + VC_{gas}) \cdot q_{p,sc,i,gas} \cdot VF_{gas} - VC_{oil} \cdot q_{p,sc,i,oil} \cdot VF_{oil} + c_i \cdot \mu_{p,sc} \right) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC\ ] \ \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall sc, i$$

Eq. 46

$$CNSE - \lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall p, sc$$

Eq. 47

$$0 \geq qgas_{p,sc,i} + qoil_{p,sc,i} - t_i \quad \perp \beta_{p,sc,i} \ \geq 0 \qquad \forall\ p, sc, i$$

Eq. 48

$$qoil_{p,sc} \ \leq T_{oil} \perp \varphi_{p,sc,i} \ \geq 0 \qquad \forall\ p, sc, i$$

Eq. 49

$$\textstyle\sum_i [\ qgas_{p,sc,i} + \ qoil_{p,sc,i}] + WG_p \cdot res_{sc} + SG_p \cdot res_{sc} = D_p - nse_{p,sc} \ \perp \ \lambda_{p,sc} \qquad \forall p, sc$$

Eq. 50

$$\textstyle\sum_i [\ q_{p,sc,i,gas} VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \quad \perp \quad \mu_{p,sc} \geq 0 \qquad \forall p, sc$$

4.4 Risk-averse market equilibrium with forward contract

Under this setting, generator owners still behave as risk-averse agents, however a forward market is now included. Agents may hedge their risk by participating in the long-term financial market, where they have as only counterpart the risk-neutral demand.

Generation side problem formulation

In addition to the short-term gas and electricity market, a long-term forward market is now added to the model. The equilibrium price of the forward contract, λ^f [$/MW], is also calculated endogenously. In terms of formulation, this only affects agents' objective function, with the new o.f. presented below:

Eq. 51

$$Max_{qgas,qoil,t,c,qfg}\ (1 - \ \alpha_i) \cdot \left(\textstyle\sum_{sc} \left[\Pr_{sc} \sum_p [\ \lambda_{p,sc} \cdot \left(qgas_{p,sc,i} + qoil_{p,sc,i}\right) - (\mu_{p,sc} + VC_{gas}) \cdot qgas_{p,sc,i} \cdot VF_{gas} - VC_{oil} \cdot qoil_{p,sc,i} \cdot VF_{oil} + c_i \cdot (\mu_{p,sc})\right]\right] - ICT \cdot t_i - \ 24 \cdot ICC \cdot c_i + \textstyle\sum_{sc} [Pr_{sc} \cdot \sum_p [\left(\lambda^f - \lambda_{p,sc}\right) \cdot \ qfg_i]]\Big) + \alpha_i \cdot CVaR_i \qquad \forall i$$

Eq. 52

$$qfg_i \ \geq 0 \ \perp \ \ \kappa_i \geq 0 \qquad \forall i$$

An additional source of income (or payment depending on the scenario) is added to the objective function. The agent that enters into a forward contract receives for each period, p, and scenario, sc, the difference between the contract price and the electricity spot price for the capacity contracted, qfg [MW]. If, said difference is negative, the generator has to pay the demand.

Demand side problem formulation

The objective function of the demand is also altered by the addition of a forward market. Under this context, the hypothesis of demand risk-neutrality becomes particularly important. If demand were to behave as risk-averse agent then, its tendency to protect itself from low profit scenarios would lead to overinvestment in forward contracts, qfd [MW].

Eq. 53

$$Max_{nse,qfd} \sum_p [\sum_{sc}[(D_p - nse_{p,sc}) \cdot (CNSE - \lambda_{p,sc})]] + \sum_{sc}[Pr_{sc} \cdot \sum_p[(\lambda_{p,sc} - \lambda^f) \cdot qfd]] \qquad \forall\, p, sc$$

Eq. 54

$$qfd \geq 0 \quad \perp \varrho \geq 0$$

Global equations

A new global equation, to ensure that the forward capacity contracted by the demand, qfd, is equal to the added forward capacity contracted by generator, qfg. The dual variable of this equation is the forward contract price.

Eq. 55

$$\sum_i qfg_i = qfd \quad \perp \lambda^f$$

Mixed complementarity problem

The MCP formulation is obtained rearranging and combining the KKT optimality conditions equations, which can be found in the annex.

Eq. 56

$$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas}) + \beta_{p,sc,i} \cdot (\lambda_{p,sc} - (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas} \geq 0 \perp q_{p,sc,i,gas} \geq 0 \qquad \forall p, sc, i$$

Eq. 57

$$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} - \tau_{2_{sc,i}} \cdot (\lambda_{p,sc} - VC_{oil} \cdot VF_{oil} \cdot)) \geq 0 \perp q_{p,sc,i,oil} \geq 0 \qquad \forall p, sc, i$$

Eq. 58

$$(1-\alpha_i)\cdot(24*ICC-\sum_p[\sum_{sc}\mu_{p,sc}\cdot \mathrm{Pr}_{sc}]])-\sum_{sc}[\tau_{2_{sc,i}}\cdot(\mu_{p,sc}-24\cdot ICC)] \geq 0 \quad \perp c_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 59

$$(1-\alpha_i)\cdot ICT-\sum_p[\sum_{sc}[\beta_{p,sc,i}]]-\sum_{sc}[\tau_{2_{sc,i}}\cdot(-ICT)] \geq 0 \perp t_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 60

$$(1-\alpha_i)\cdot\sum_p[\sum_{sc}Pr_{sc}\cdot(\lambda_{\mathrm{p,sc}}-\lambda^f)+\sum_p[\sum_{sc}[\tau_{sc,i}\cdot(\lambda_{p,sc}-\lambda^f)]] \geq 0\cdot \quad \perp qfg_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 61

$$-\tau_{1_i}+\sum_{sc}[\tau_{2_{sc,i}}]=0 \perp \mathrm{VaR}_i \qquad \forall \mathrm{i}$$

Eq. 62

$$\tau_{1_i}-\alpha_i=0 \qquad \perp \mathrm{CVaR}_i \qquad \forall \mathrm{i}$$

Eq. 63

$$\frac{\tau_{1_i}\cdot Pr_{sc}}{1-\delta}-\tau_{2_{sc,i}} \geq 0 \quad \perp \Delta B_{sc,i} \geq 0 \qquad \forall \mathrm{sc,i}$$

Eq. 64

$$VaR_i-\frac{\sum_{sc}Pr_{sc}\cdot\Delta B_{sc,i}}{1-\delta} \geq CVaR_i \quad \perp \tau_{1_i} \geq 0 \qquad \forall \mathrm{i}$$

Eq. 65

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i-[\sum_p(\lambda_{\mathrm{p,sc}}\cdot\sum_f(\mathrm{q_{p,sc,i,f}})-(\mu_{\mathrm{p,sc}}+VC_{gas})\cdot \mathrm{q_{p,sc,i,gas}}\cdot \mathrm{VF}_{gas}-\mathrm{VC_{oil}}\cdot \mathrm{q_{p,sc,i,oil}}\cdot \mathrm{VF}_{oil}+\mathrm{c_i}\cdot\mu_{\mathrm{p,sc}})-ICT\cdot t_i-24\cdot c_i\cdot ICC] \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall \mathrm{sc,i}$$

Eq. 66

$$CNSE-\lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall \mathrm{p,sc}$$

Eq. 67

$$\sum_p[\sum_{sc}[Pr_{sc}\cdot(-\lambda_{p,sc}+\lambda^f)]] \geq 0 \perp qfd \geq 0$$

Eq. 68

$$0 \geq \mathrm{qgas_{p,sc,i}}+\mathrm{qoil_{p,sc,i}}-\mathrm{t_i} \quad \perp \beta_{p,sc,i} \geq 0 \qquad \forall\ \mathrm{p,sc,i}$$

Eq. 69

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall\ \mathrm{p,sc,i}$$

Eq. 70

$$\sum_{\mathrm{i}}[\mathrm{qgas_{p,sc,i}}+\mathrm{qoil_{p,sc,i}}]+\mathrm{WG_p}\cdot\mathrm{res_{sc}}+\mathrm{SG_p}\cdot\mathrm{res_{sc}}=\mathrm{D_p}-\mathrm{nse_{p,sc}} \perp \lambda_{\mathrm{p,sc}} \qquad \forall \mathrm{p,sc}$$

Eq. 71

$$\sum_i [\, q_{p,sc,i,gas} VF_{gas}] \le \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \quad \perp \quad \mu_{p,sc} \ge 0 \qquad \forall p, sc$$

Eq. 72

$$\sum_i qfg_i = \; qfd \quad \perp \; \lambda^f$$

4.5 Risk-averse market equilibrium with forward and option contracts

This model increases market completeness, by adding an option contract to the forward contract. Generator owners have now access to a variety of instruments to hedge their risk.

Generation side problem formulation

The inclusion of an additional hedging instruments affects, once again, the objective function.

Eq. 73

$$Max_{qgas,qoil,t,c,qfg,qog} \; (1 - \; \alpha_i) \cdot (\sum_{sc}[\mathrm{Pr_{sc}} \sum_p [\, \lambda_{\mathrm{p,sc}} \cdot (qgas_{p,sc,i} + qoil_{p,sc,i}) - (\mu_{\mathrm{p,sc}} + VC_{gas}) \cdot \mathrm{qgas_{p,sc,i}} \cdot \mathrm{VF}_{gas} - \mathrm{VC_{oil}} \cdot \mathrm{qoil_{p,sc,i}} \cdot \mathrm{VF}_{oil} + \mathrm{c_i} \cdot (\mu_{\mathrm{p,sc}})]] - \mathrm{ICT} \cdot \mathrm{t_i} - \; 24 \cdot \mathrm{ICC} \cdot \mathrm{c_i} + \sum_{sc}[Pr_{sc} \cdot \sum_p[(\, \lambda^f - \lambda_{\mathrm{p,sc}}) \cdot \; qfg_i]] + \; \sum_{sc}[Pr_{sc} \cdot \sum_{p1}[(\, \gamma - \lambda_{\mathrm{p,sc}}) \cdot \; qog_i]] + \; \pi^f \cdot qog_i) + \alpha_i \cdot CVaR_i \qquad \forall \mathrm{i}$$

Eq. 74

$$qog_i \ge 0 \quad \perp \; \omega_i \ge 0 \qquad \forall \mathrm{i}$$

The agent has an additional source of income (or payment depending on the scenario), which corresponds to the settlement of the option contract. The periods, p1, when the electricity spot price, $\lambda_{\mathrm{p,sc}}$ is higher than the option strike price γ [\$/MW], the generator pays the demand the difference between the two for the capacity contracted, qog [MW]. In return, the generator receives a payment from the demand for the capacity contracted, qog [MW] at the contract price, π^f [\$/MW], determined by the model.

Demand side problem formulation

The demand side objective function is also modified due to the addition of the option contract. The demand signs an option contract for qod [MW] for which it has to make a payment, and receives an income whenever the strike price, γ , is higher than the electricity spot price.

Eq. 75

$$Max_{nse,qfd,qfd,qod} \sum_p [\sum_{sc}[(D_p - nse_{p,sc}) \cdot (CNSE \; - \; \lambda_{\mathrm{p,sc}})]] + \sum_{sc}[Pr_{sc} \cdot \sum_p[(\, \lambda_{\mathrm{p,sc}} - \lambda^f) \cdot \; qfd]] + \; \sum_{sc}[Pr_{sc} \cdot \sum_{p1}[(\, \lambda_{\mathrm{p,sc}} - \; \gamma) \cdot \; qod]] - \; \pi^f \cdot qod$$

Eq. 76

$qod \geq 0 \quad \perp \upsilon \geq 0$

Global equations

The following equation ensures that the quantity of option contract signed by the demand, is equal to the added quantities of option contracts signed by all generator owners. The dual variable of this equation is the contract price of the payment from demand to generation.

Eq. 77

$$\sum_i qog_i = qod \quad \perp \ \pi^f$$

Option strike price

Since this model does not include integer and binary variables, the option contract price is calculated through the following iteration process.

Since the strike price is set between the cost of non-served energy, and the cost of the most expensive fuel in the market (oil), the option is settled during periods where the demand is higher than the installed capacity. As a consequence, a hypothesis is done as to the power plant investment decision, t^k_i (k is the number of iterations). The periods where the option is settled are calculated based on this hypothesis.

Eq. 78

$$D_{p1} - RES_{sc} \cdot \left(SG_{p1} + WG_{p1}\right) \geq t^k$$

The model is solved, and the option is settled during periods which Eq. 78 is verified. The results of the model concerning investment decisions in power plant, are compared to the hypothesis.

If, for iteration, k, $\sum_i t_i = t^k$, then the problem is solved, if not then a new iteration is performed with $t^{k+1} = \sum_i t_i$. The process is repeated until $\sum_i t_i = t^k$.

Mixed complementarity problem

The MCP formulation is obtained rearranging and combining the KKT optimality conditions equations, which can be found in the annex.

Eq. 79

$$(1-\alpha_i)\cdot(-Pr_{sc}\cdot\lambda_{p,sc} + Pr_{sc}\cdot(VC_{gas}+\mu_{p,sc})\cdot VF_{gas}) + \beta_{p,sc,i}\cdot(\lambda_{p,sc} - (VC_{gas}+\mu_{p,sc})\cdot VF_{gas} \geq 0 \perp q_{p,sc,i,gas} \geq 0 \qquad \forall p, sc, i$$

Eq. 80

$$(1-\alpha_i)\cdot(-Pr_{sc}\cdot\lambda_{p,sc} + Pr_{sc}\cdot VC_{oil}\cdot VF_{oil}) + \beta_{p,sc,i} - \tau_{2_{sc,i}}\cdot\left(\lambda_{p,sc} - VC_{oil}\cdot VF_{oil}\cdot\right)) \geq 0 \perp q_{p,sc,i,oil} \geq 0 \qquad \forall p, sc, i$$

Eq. 81

$$(1-\alpha_i)\cdot(24 * ICC - \sum_p[\sum_{sc} \mu_{p,sc} \cdot \mathrm{Pr_{sc}}]]) - \sum_{sc}[\tau_{2_{sc,i}} \cdot (\mu_{p,sc} - 24 \cdot ICC\ )\ ]\ \geq 0 \qquad \perp c_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 82

$$(1-\alpha_i)\cdot ICT - \sum_p[\sum_{sc}[\beta_{p,sc,i}]] - \sum_{sc}[\tau_{2_{sc,i}} \cdot (-ICT)] \geq 0 \perp t_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 83

$$(1-\alpha_i)\cdot \sum_p[\sum_{sc} Pr_{sc} \cdot \left(\lambda_{\mathrm{p,sc}} - \lambda^f\right) + \sum_p[\sum_{sc}[\tau_{sc,i} \cdot (\lambda_{p,sc} - \lambda^f)]]\ \geq 0 \cdot \quad \perp qfg_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 84

$$(1-\alpha_i)\cdot(\sum_{p1}[\sum_{sc}[Pr_{sc} \cdot \left(\lambda_{p,sc} - \gamma\right)]] - \pi^f)\ +\ \sum_p\left[\sum_{sc}[\tau_{sc,i}]\right] \cdot \left(\sum_{p1}[\sum_{sc}[Pr_{sc} \cdot \left(\lambda_{p,sc} - \gamma\right)]\right] - \pi^f)\ \geq 0 \quad \perp qfg_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 85

$$-\tau_{1_i} + \sum_{sc}[\tau_{2_{sc,i}}] = 0\ \perp \mathrm{VaR}_i \qquad \forall \mathrm{i}$$

Eq. 86

$$\tau_{1_i} - \alpha_i = 0 \qquad \perp \mathrm{CVaR}_i \qquad \forall \mathrm{i}$$

Eq. 87

$$\frac{\tau_{1_i} \cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} \geq 0 \quad \perp \Delta B_{sc,i} \geq 0 \qquad \forall \mathrm{sc,i}$$

Eq. 88

$$VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \quad \perp \tau_{1_i} \quad \geq 0 \qquad \forall \mathrm{i}$$

Eq. 89

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\sum_p\left(\lambda_{\mathrm{p,sc}} \cdot \sum_f\left(\mathrm{q_{p,sc,i,f}}\right) - (\mu_{\mathrm{p,sc}} + VC_{gas}) \cdot \mathrm{q_{p,sc,i,gas}} \cdot \mathrm{VF}_{gas} - \mathrm{VC_{oil}} \cdot \mathrm{q_{p,sc,i,oil}} \cdot \mathrm{VF}_{oil} + \mathrm{c_i} \cdot \mu_{\mathrm{p,sc}}\right) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC\ ]\ \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall \mathrm{sc,i}$$

Eq. 90

$$CNSE - \lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall \mathrm{p,sc}$$

Eq. 91

$$\sum_p[\sum_{sc}[Pr_{sc} \cdot (-\lambda_{p,sc} + \lambda^f)]]\ \geq 0 \perp qfd \geq 0$$

Eq. 92

$$\sum_{p1}[\sum_{sc}[Pr_{sc} \cdot \left(-\lambda_{p,sc} + \gamma\right) + \pi^f$$

Eq. 93

$$0 \geq \mathrm{qgas}_{\mathrm{p,sc,i}} + \mathrm{qoil}_{\mathrm{p,sc,i}} - \mathrm{t}_{\mathrm{i}} \quad \perp \beta_{p,sc,i} \ \geq 0 \qquad \forall\ \mathrm{p, sc, i}$$

Eq. 94

$$qoil_{p,sc} \ \leq T_{oil} \perp \varphi_{p,sc,i} \ \geq 0 \qquad \forall\ \mathrm{p, sc, i}$$

Eq. 95

$$\sum_{\mathrm{i}}[\ \mathrm{qgas}_{\mathrm{p,sc,i}} + \ \mathrm{qoil}_{\mathrm{p,sc,i}}] + \mathrm{WG}_{\mathrm{p}} \cdot \mathrm{res}_{\mathrm{sc}} + \mathrm{SG}_{\mathrm{p}} \cdot \mathrm{res}_{\mathrm{sc}} = \mathrm{D}_{\mathrm{p}} - \mathrm{nse}_{\mathrm{p,sc}} \ \perp \ \lambda_{\mathrm{p,sc}} \qquad \forall \mathrm{p, sc}$$

Eq. 96

$$\sum_i [\ q_{p,sc,i,gas} VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \quad \perp \quad \mu_{\mathrm{p,sc}} \geq 0 \qquad \forall \mathrm{p, sc}$$

Eq. 97

$$\sum_i qfg_i = \ \ qfd \qquad \perp \ \lambda^f$$

Eq. 98

$$\sum_i qog_i = \ \ qod \qquad \perp \ \pi^f$$

5 RESULTS ANALYSIS

5.1 Problem Data

The developed model is applied to a New England-like system. The input data is obtained from actual New England data estimations from the year 2025. To reduce the computational burden, the year 2025 is modelled through representative days split into periods of one hour. All periods have the same weight, consequently each season is represented by 25% of the hours.

The demand input into the model is based on New England's hourly demand expected to be covered by gas, solar and wind in the coming years. That is the total demand, minus hydro, nuclear and refuse production. (Source: ISO-NE).

The input data also includes renewable generation (both solar and wind) that varies depending on the scenario. Based on ISO-NE (2015) predictions, the solar generation penetration will be considerably higher than wind. Generators have to cover the difference between demand and RES generation for each scenario.

Figure 5 represents both demand and RES generation according to scenario.

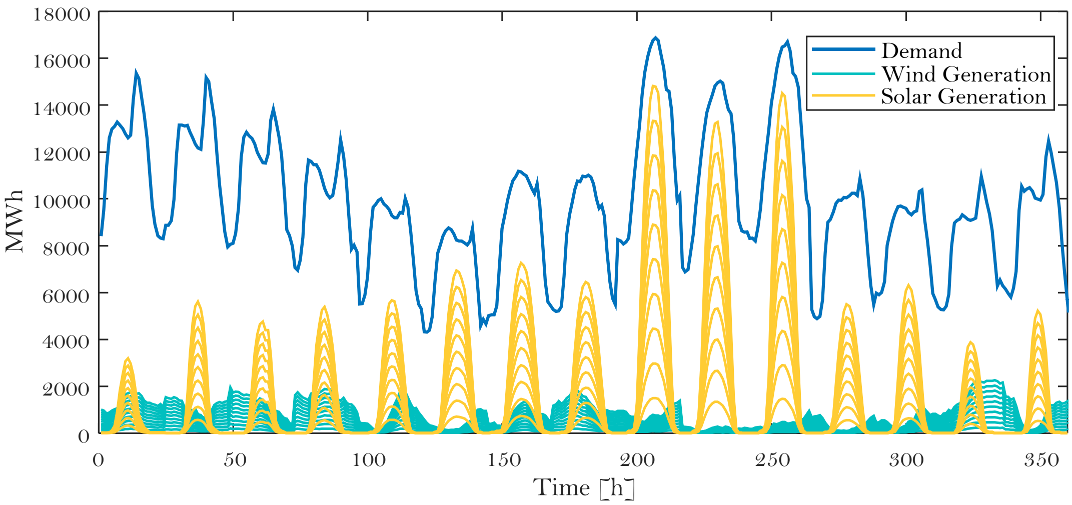


Figure 5. Demand and RES generation

In the model, generators must take long-term investment decisions in dual-fuel power plants and pipeline. capacity contracts. Investment costs for both, presented in the table below, are annualized, assuming an economic life of 20 years for pipelines capacity contracts, and 30 years for power plants. The interest rate used is 9%.

	Total cost	Economic life	Annualized cost
Pipeline Capacity Contract (EIA, 2012)	10236 [$/(MWh/d)]	20 years	1120 [$/(MWh/d)]
Power plant (Jaber et al, 2004)	500000 [$/MW]	30 years	49000 [$/MW]

Table 1. Investment costs

Once agents take long-term investment decisions, they must take short-term decisions concerning hourly production with both gas and oil fuel. Fuel costs are presented in the table below

	Variable cost [$/$MWh_t$]	[MWh_t/MWh_e]
Natural Gas	35	2
Oil	70	3.1

Table 2. Fuel costs (SOURCE: ISO-NE http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2012/imm_q1_2012_qmr_final.pdf)

Generators have two fuel alternatives to produce with, with natural gas being the less costly alternative.

The model includes two types of demand in the gas-market: demand from generators, and non-electric demand (both represented in Figure 6). While the former is a variable, the latter is an input data to the model and comprises two different types of customers; industrial, and residential and commercial. Industrial gas consumers' demand is fairly flat all throughout the year, as it is not weather dependent. Whereas, demand from residential and commercial consumers is mostly related to space heating, hence extremely sensitive to weather conditions therefore, it presents a seasonal pattern with high demand during winter months. Peak demand from industrial, residential, and commercial customers is 3.2 bcf/d based on actual pipeline flows reported on January 3, 2014, one of the coldest days in the past 20 years (Energyzt, 2014).

To represent New England's situation more accurately, it is necessary to include in the model an initial pipeline capacity to cover non-electric gas demand, otherwise generation agents would have to invest in pipeline capacity to cover their demand as well as the demand from non-electric consumers. According to Energyzt (2014), actual pipeline capacity for natural gas in New England is 3.5 bcf/d, two-thirds of which is on the Tennessee and Algonquin systems Figure 6 represents the pipeline capacity, and gas demand from firm contract holders. Interruptible contract holders such as generators rely on residual capacity which, as shown in Figure 6, is, during cold winter months, scarce.

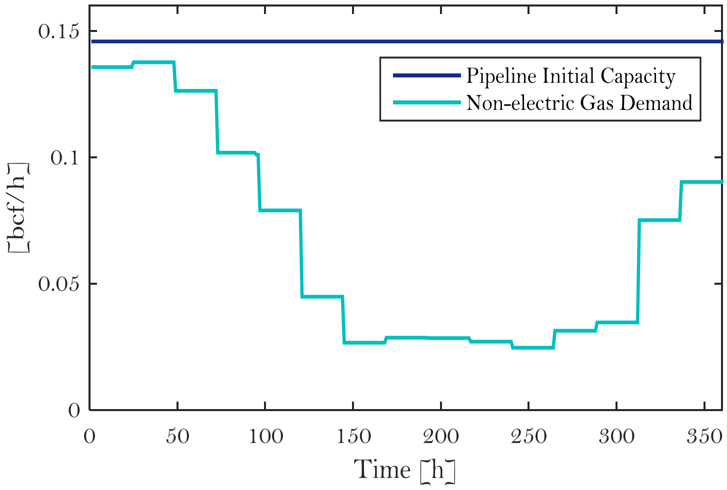


Figure 6. Pipeline capacity in New England

5.2 Benchmark results

The setting with a risk-neutral central planner is considered the benchmark reference against which results from the other cases are compared to.

Results show an equivalence between the centralized risk-neutral context and a market equilibrium with risk-neutral agents. The latter introduces "n" identical agents. Since all agents are defined with the same characteristics the decisions they take to maximize the profit are also identical among agents. Moreover the aggregated decisions (both in the short-term and in the long-term) are equal to the decisions the central planner takes. When assuming perfect competition among agents, as this problem does, the centralized cost-minimization decisions are the same than the profit maximization ones risk-neutral agents take.

Consequently, the results presented in this section from the benchmark problem, are also the results from the risk-neutral market equilibrium.

Long-term decisions

The focus here is brought to the long-term decisions agents take both in the electricity market (power plant investment) and in the natural gas market (pipeline capacity contract), which are presented in the table below.

Power plant [MW]	1.4132e+04
Pipeline capacity contract [bcf/h]	0.0761

Table 3. Long-term investment decisions under a centralized context

Short-term decisions

The long-term decisions which constitute the most efficient decisions, obviously influence the short-term decisions presented in the figures below.

Figure 7 presents the resulting hourly dispatch in two different scenarios. The top graph is for a scenario with a high penetration of RES, whereas the lowest graph is for a scenario with a very low penetration of RES:

The first graph shows that under high RES penetration, there is no scarcity event in the electricity market. Indeed, the absence of non-served energy proves the installed capacity in dual-fuel power plant is sufficient to cover the electricity net demand. There is however a few hours with pipeline congestion events. Although it is barely noticeable, there are a few hours during winter with a slight oil production. Since these are dual-fuel power plants, the only difference between natural gas and oil production comes down to the short-term variable cost, where oil is the more expensive alternative. Consequently, power plants will only recur to oil when facing a pipeline capacity shortage that limits their access to natural gas.

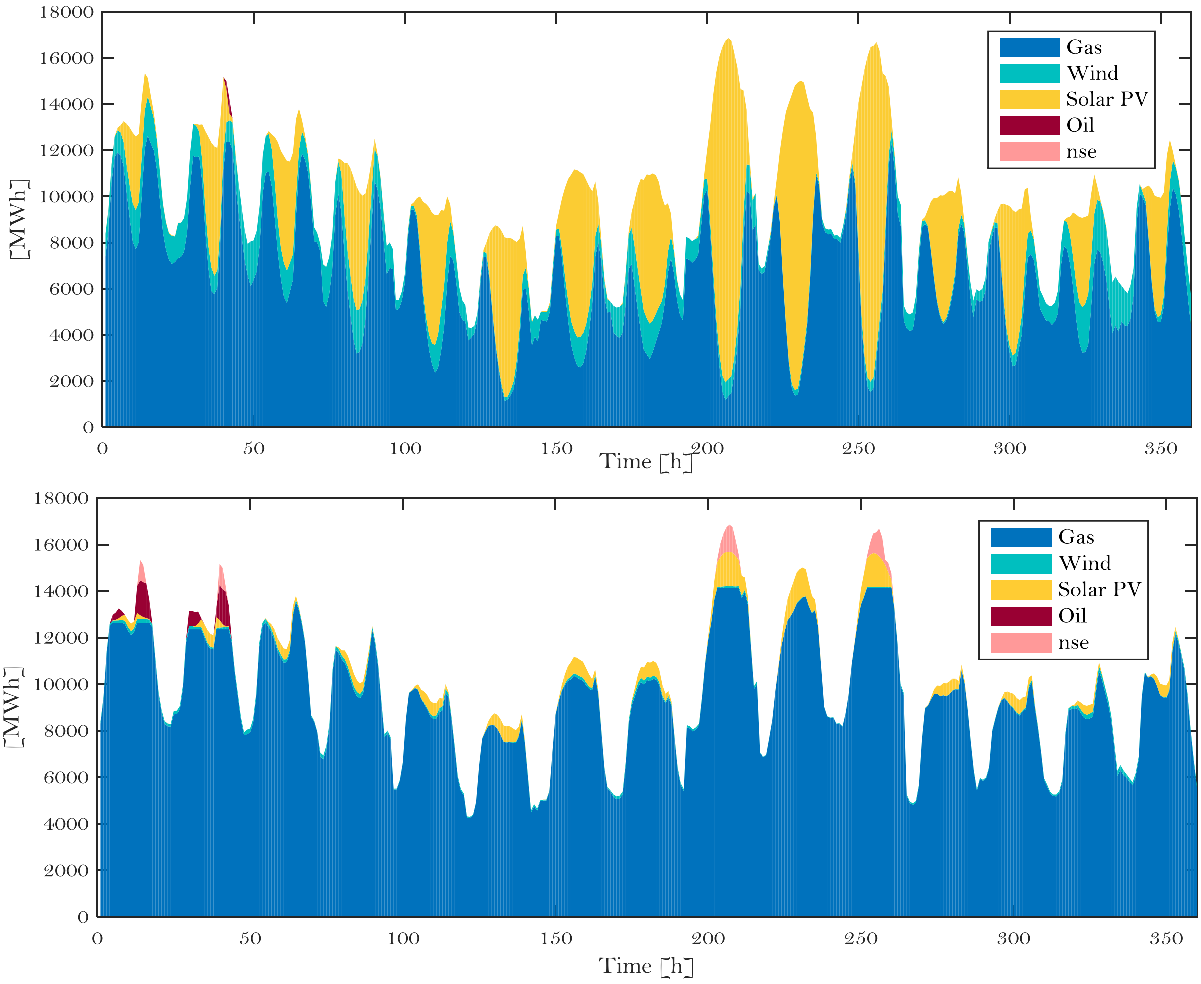


Figure 7. Hourly dispatch under a centralized context

The comparison of the two graphs proves the level of RES penetration has a significant impact on the hourly dispatch. Indeed, the bottom graph reveals a large increase in the number of hours with oil production during winter months. Pipeline capacity shortage events increase forcing generators to use oil instead of natural gas. Moreover, the electricity market is also facing scarcity events during that same period. This is due to the fact that oil capacity (MW) of power plants is limited. Once they reach said limit, their capacity production is exhausted even if they haven't reached the hourly production is lower than the installed capacity. While non-served energy during cold winter months is due to the combination of pipeline capacity shortage and limited oil production capacity and/or power plants at maximum capacity, scarcity events during summer months are of a different nature. In this case power plants are at their maximum capacity, and cannot produce any further.

As seen in Figure 7, pipeline capacity is maxed out in the two most extreme scenarios (high RES and low RES), this is also proved in Figure 8 which shows the existing pipeline capacity and additional investments by gas-fired generators (as previously explained, if generators sign pipeline capacity contracts, the pipeline capacity increases, hence reflecting the actual U.S. regulation for pipeline capacity expansion) and hourly natural gas demand for its two main type of customers. The demand from gas generators is added to that of non-electric consumers, thus reflecting congestion events in two different scenarios. Pipeline congestion only occurs during the first and colder months of the year during both electric and non-electric gas demand peak hence depriving gas generators from access to natural gas.

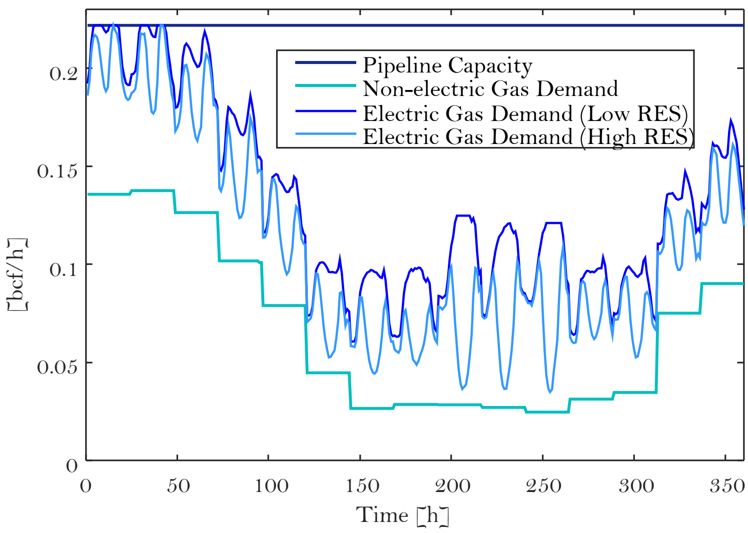


Figure 8. Pipeline capacity under a centralized context

The figure shows that natural gas pipeline congestion is much more frequent when RES penetration is low.

Short-term natural gas and electricity markets

These scarcity events in both the natural gas and electricity markets will logically impact the prices on both markets. To properly understand natural gas market pricing and electricity market pricing it is necessary to assess the influence of the three different capacity constraints imposed in the model:

- Oil capacity constraint: Power plants oil production cannot exceed 1.5 GW
- Power plant capacity constraint: Power plant production (with both natural gas and oil) cannot exceed installed capacity
- Pipeline capacity constraint: Natural gas demand cannot exceed pipeline capacity.

Depending on the constraints activated in the model, the prices in the natural gas and electricity markets change. Figure 9 represents the evolution of these three constraints, whenever one of these curves reaches 0, it means the corresponding constraint is activated.

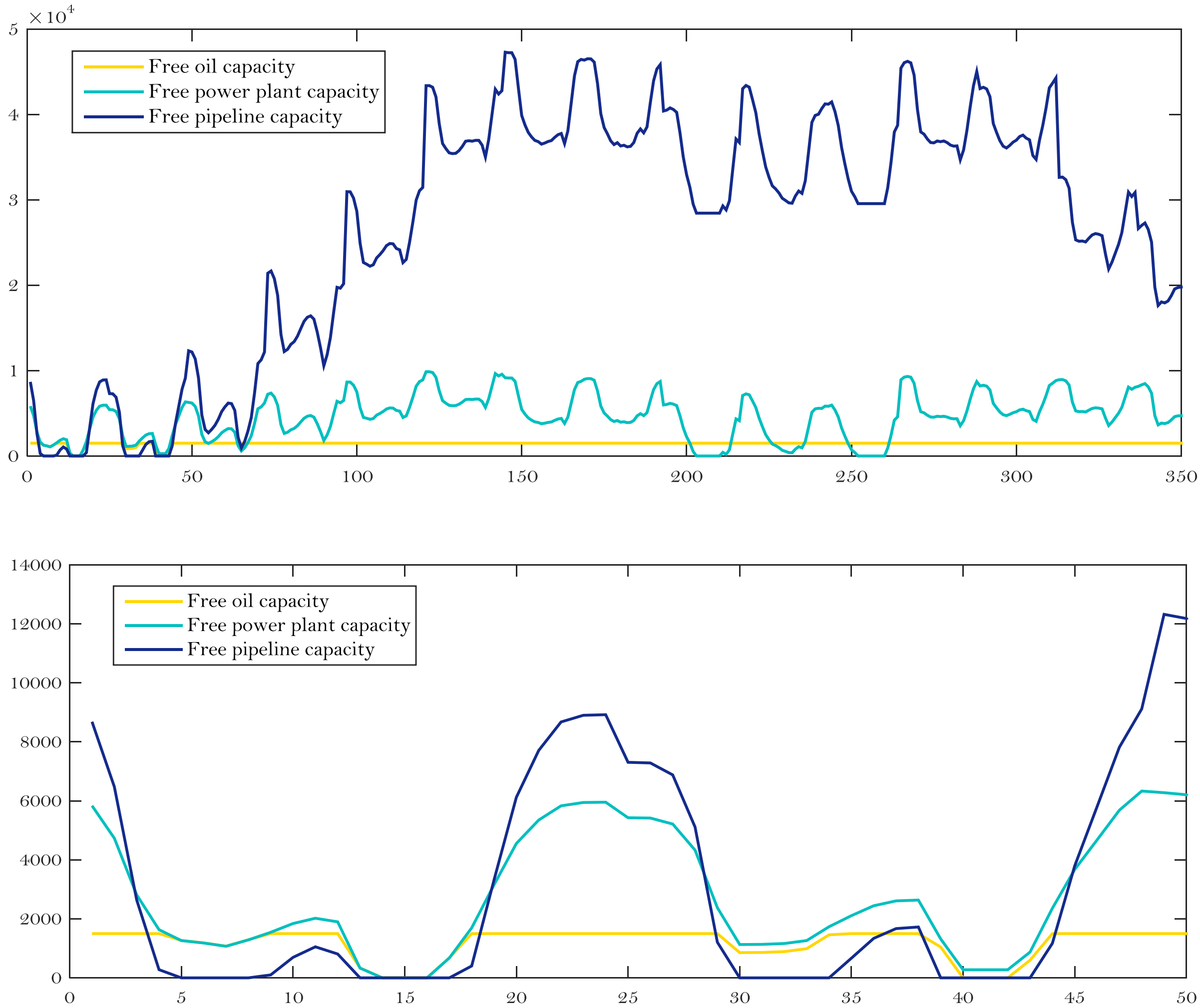


Figure 9. Model constraints evolution. (Whole year (top), winter (bottom))

This figure shows that high prices during summer time are due to pipeline capacity constraints, whereas high prices during winter are a combination of the three aforementioned constraints. The comparison of Figure 9 and Figure 10 allow to understand electricity spot market pricing.

Figure 10 depicts the electricity market spot prices for two different scenarios (high RES and low RES). The first obvious observation is that electricity spot prices are much lower when RES penetration is high. Indeed, gas-fired generators are the marginal price setting technology in all hours but one (as already observed in the hourly dispatch). However, as RES penetration decreases, prices rise. There are two price spikes that coincide with net electricity demand peaks.

In addition to gas fuel, oil fuel cost sets the price during some hours in winter, and the non-served energy cost sets the price during both winter and summer hours.

Non-served energy prices in summer are due mainly to power plant congestion. Whereas, in winter the matter is more complicated. Oil sets the price during several hours during winter, observing Figure 9 we can conclude that this is due to pipeline congestion events. Moreover, there are two periods with non-served energy prices. During the first (around period 15), the three main constraints are activated which obviously results in non-served energy prices. However, during the second, there is still free power plant capacity.This capacity is useless since generators have no access to natural gas (pipeline congestion), and cannot produce with oil (oil production capacity is maxed out), hence scarcity prices arise in the market.

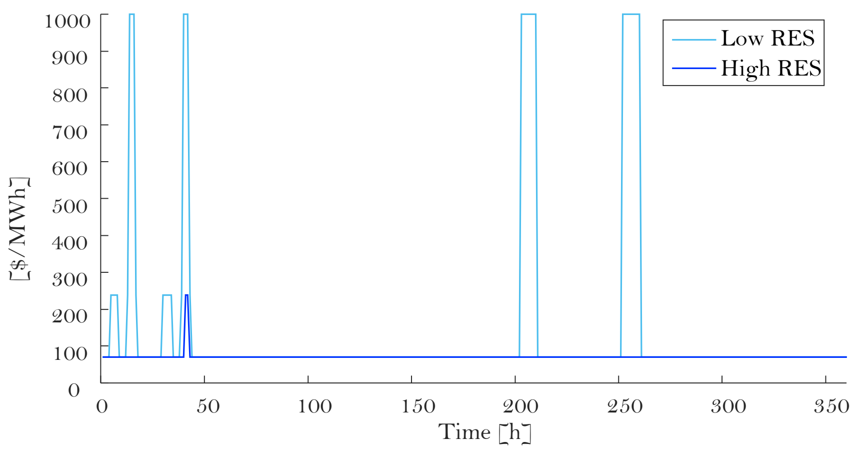


Figure 10. Electricity market spot prices under a centralized context

The comparison of Figure 9 and Figure 11 will allow to understand natural gas market pricing. Figure 11 represents gas market spot prices only for the first quarter of the year (which is the only time of the year that presents pipeline congestion events hence gas price peaks).

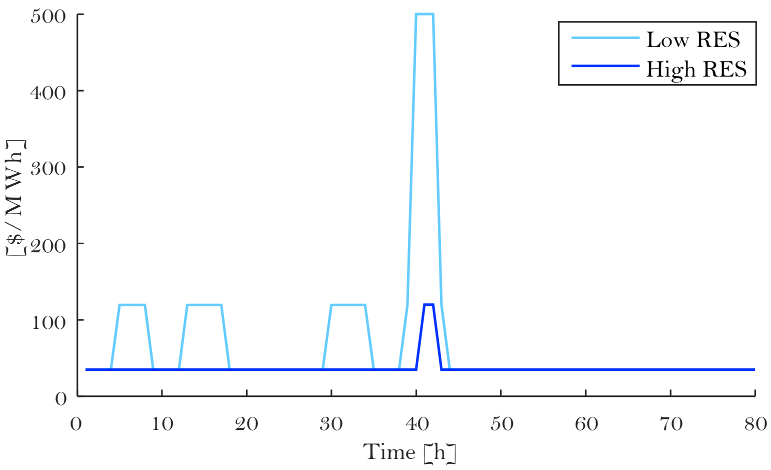


Figure 11. Gas market spot prices under a centralized context

Natural gas markets and electricity markets are highly correlated during periods where demand in both markets increases. Whenever natural gas pipelines become congested, the gas prices at the importing hub increase, and is set at the opportunity cost of natural gas. This opportunity cost depends on the situation of the electricity spot market.

The opportunity cost of natural gas during scarcity events is the cost of fuel. Indeed, during these events the only alternative for generators is to produce with oil, therefore gas prices will only go as high as oil fuel cost. The rest of the time the price at the importing hub is equal to the price at the exporting hub, the cost of natural gas fuel.

To define the exact correlation between these two markets, it is necessary to take into account the efficiency of the power plants producing with oil and gas as the price in the gas market is measured in [$/MWh$_t$] and the price in the electricity market is measured in [$/MWh]. The following equation establishes the mathematical correlation between these two markets, it is important to note that this correlation is not valid whenever the electricity market faces scarcity events due to power plant shortage.

Eq. 1

$$VC_{gas} + \mu = \frac{\lambda}{VF_{gas}}$$

When applying Eq. 1 to different situations we find:

- When natural gas sets the price in the electricity market, results in a basis differential, μ, equal to zero, hence the price at the natural gas market will be the variable cost of natural gas [$/MWh$_t$].
- When oil sets the price in the electricity market, the price at the gas market will not be the variable cost of oil, due to the different efficiencies from the power plant depending on the fuel used, instead the price will be 108.5 $/MWh$_t$.

- When the non-served energy cost sets the price in the electricity market, the price in the natural gas market depends on the constraints activated:
  - If non-.served energy is strictly due to power plants producing at maximum capacity (as happens in summer time), the opportunity cost of natural gas is the cost of producing natural gas. Indeed, in these situations power plants have no use for natural gas, therefore price in the gas market don't increase.
  - If the three aforementioned constraints are activated, the opportunity cost of gas, is the cost of producing with oil. Since power plants are producing at maximum capacity, and oil is producing at maximum capacity, additional natural gas supply would give generators the possibility to replace oil with natural gas. In consequence, the price in the natural gas market is the cost of producing with oil (taking into account the difference in efficiencies): 108.5 $\$/MWh_t$.
  - If non-served energy is due to pipeline congestion combined with maxed out oil production capacity, the opportunity cost of natural gas is the cost of non-served energy). During these events, additional natural gas supply would replace non-served energy. The price at the natural gas market is, applying the equation above, 465$/MWh.

The following sections present the impact of risk-aversion and long-term financial market completeness by comparing the outcomes of the model under the different settings considered.

5.3 Models comparison

This section compares the agent's decisions to the benchmark in the long-term and short-term, as well as the impact on the agent's profit, market prices and system-wide social welfare.

Long-term decisions

As mentioned above, in this model generation agents must take two long-term decisions: investment in power plant capacity, and investment in pipeline capacity contracts. The decisions from risk-neutral agents represent the social optimum. **¡Error! No se encuentra el origen de la referencia.** shows how investment decisions deviate from those provided by the benchmark. Since all agents have the exact same characteristics, their investment decisions are aggregated into one single decision to simplify the results' analysis. The numerical results are provided in Table 4.

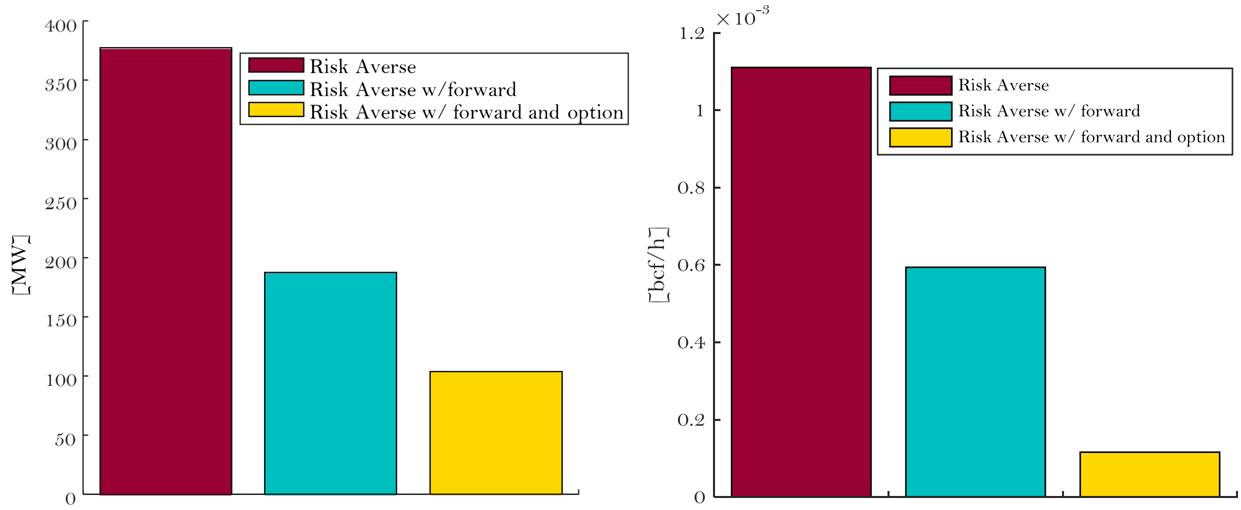


Figure 12. Investment decisions deviation from benchmark (power plant (left), pipeline capacity contract (right))

	Investment decision		**Deviation with respect to benchmark**	
	Power plant [MW]	**Pipeline [bcf/h]**	**Power plant [MW]**	**Pipeline [bcf/h]**
Risk-averse	13755	0.075	377	0.0011
Risk-averse w/ forward	13945	0.0767	187	0.000594
Risk-averse w/ forward and option	14029	0.0762	103	0.00011594

Table 4. Investment decisions

The first conclusion drawn from the analysis of these figures is that under no setting are the agents able to replicate the decisions from the benchmark reference. Nevertheless, there is a clear progress towards the social optimum as market completeness increases.

When agents are risk-averse and have no risk-hedging tools available, they underinvest in both pipeline capacity contracts and power plant capacity. This is the case where decisions deviate the most from the social optimum.

The figure above represents the absolute value of the deviation with respect to the benchmark. While in the risk-averse case agents underinvest in both pipeline capacity contracts and power plant, when financial markets are introduced in the model, agents still underinvest in power plant, but overinvest in pipeline capacity contracts.

When a forward market is introduced, agents may hedge their risk by signing a forward contract with the demand. This does not allow agents to completely neutralize the risk, because decisions still deviate from the social optimum, but progress is made with respect to the case with no long-term financial market.

Finally, when market completeness is increased, decisions come even closer to the social optimum. Agents may now contract in addition to a forward contract, an option to hedge their risk, thus further neutralizing the risk.

Short-term decisions

Long-term decisions, logically, have influence short-term decisions. The impact under market equilibrium with risk-averse agents and no financial market can be observed in Figure 13

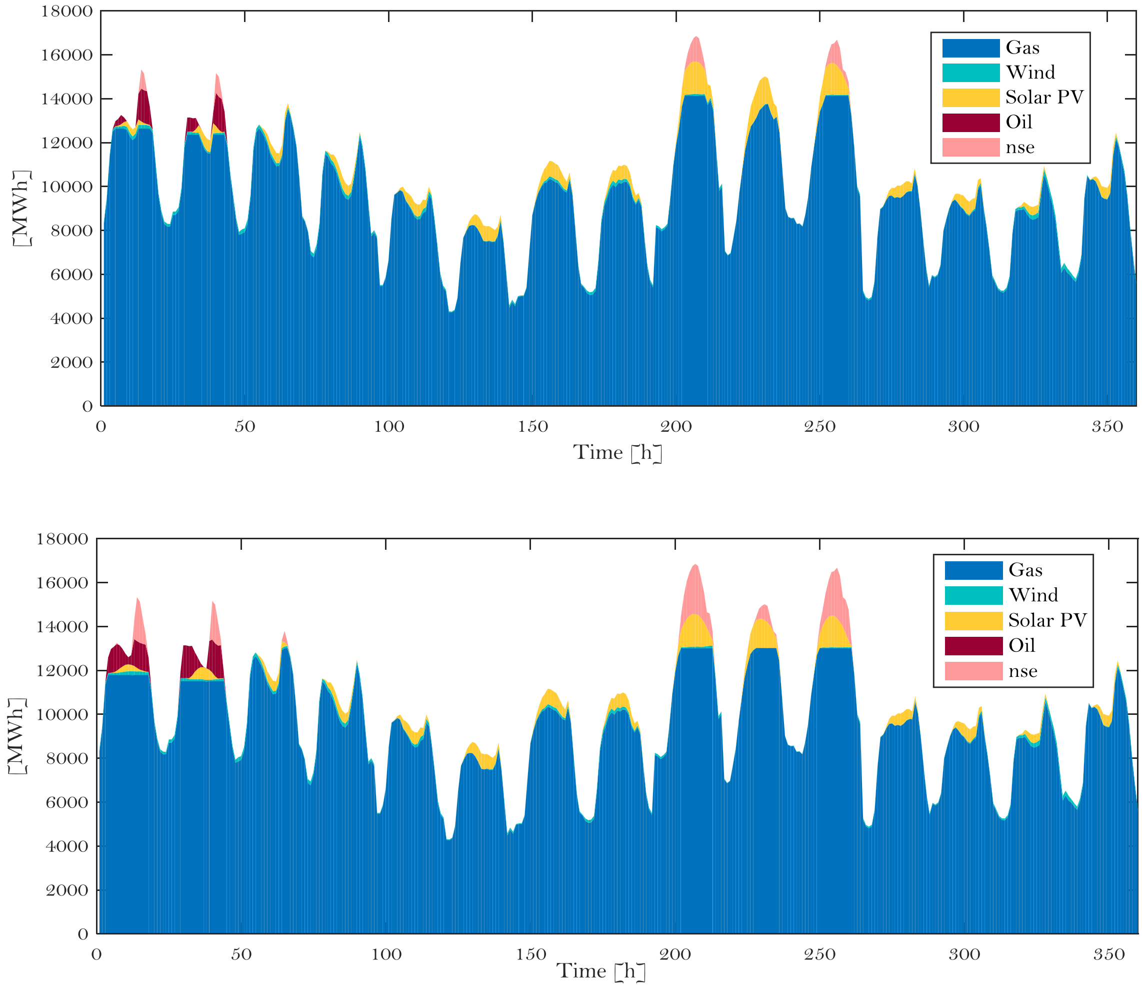


Figure 13. Hourly dispatch with a central planner (top) and a market equilibrium for risk-averse agents (bottom) for a high RES scenario.

The figure above compares the hourly dispatch under two different contexts. The number of hours of non-served energy increases during summer months when agents are risk-averse instead of risk-neutral, and even more so when the agent's risk-aversion increases. The underinvestment in power plant capacity when agents are risk-averse drives the number of hours with non-served energy up.

This issue, although relevant in the model results, is not a significant problem in New England's electricity whose main concerns revolve around pipeline capacity shortages in cold winter months.

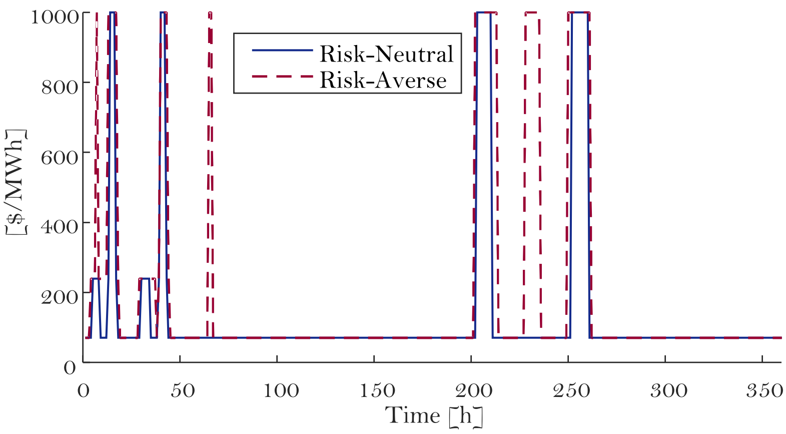
If the winter period in both graphs is compared, an increase in the number of hours with oil production, as well as non-served energy can be seen. This is the result of long-term underinvestment in pipeline capacity contracts. Lower pipeline capacity obviously causes a higher number of pipeline congestion events. Generation agents are cut off of access to natural gas, and must rely increasingly on oil fuel. Once the oil fuel production reaches its cap, electricity demand is curtailed.

Since the settings with a forward market, and both a forward and an option market come quite close to replicating the centralized decisions, the impact long-term decisions' deviation has on short-term hourly production is less significant.

Short-term and long-term prices

The model calculates endogenously market equilibrium prices both in the short-term and the long-term. These prices are the outcome of agents' decisions, and whenever these decisions deviate from the social optimum, prices are affected.

Figure 14 allows to compare electricity market prices under two different contexts (risk-neutral market equilibrium, and risk-averse market equilibrium with no financial market). When agents are risk-averse they cause a price increase in the market during the most constrained periods (winter and summer). The graph on the bottom represents the price evolution during winter period, which shows that the number of hours with oil-cost price, and non-served cost prices burgeons when agents are risk-averse. This is only logical, as the previous section shows that underinvestment in pipeline capacity contracts leads to more hours with oil production



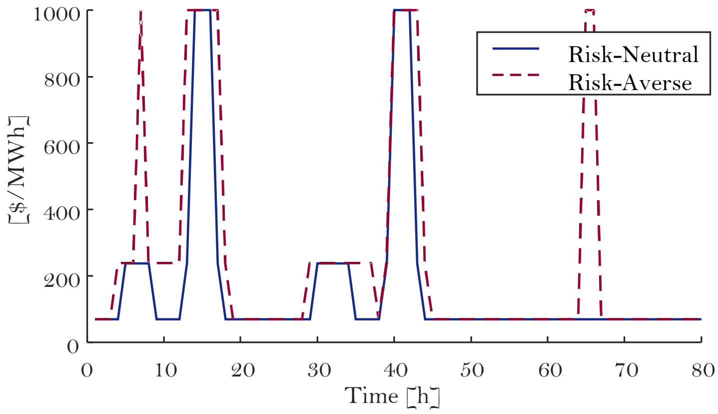


Figure 14. Electricity spot market prices comparison between market equilibrium with risk-neutral agents and market equilibrium with risk-averse agents with no financial instruments (Whole year (top), winter (bottom)).

Figure 15 represents the hourly price evolution under market equilibrium with risk-neutral agents against hourly prices under a market equilibrium with risk-averse agents who may hedge their risk with a forward contract. The model almost replicates the prices obtained in the risk-neutral case, once again proving that the short-term impact when introducing financial markets is barely significant.

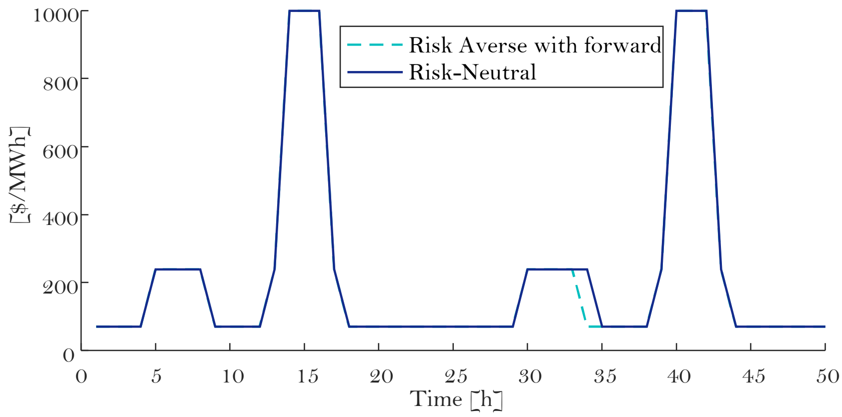


Figure 15. Electricity spot market prices comparison between market equilibrium with risk-neutral agents and market equilibrium with risk-averse agents and a forward market during winter.

Long-term decisions also impact the natural gas spot market prices. Figure 16compares gas spot prices under different contexts, focusing only on winter period (the rest of the year gas prices do not experience any variations).

The top graph compares a risk-neutral setting with a risk-averse setting. It is clear, that gas prices increase when agents are risk-averse. The underinvestment in pipeline capacity increases the number of pipeline scarcity events, hence gas prices.

Once again, when adding a forward market (bottom graph), prices come closer to replicating those of a centralized context. The number of hours with congested pipelines is clearly reduced.

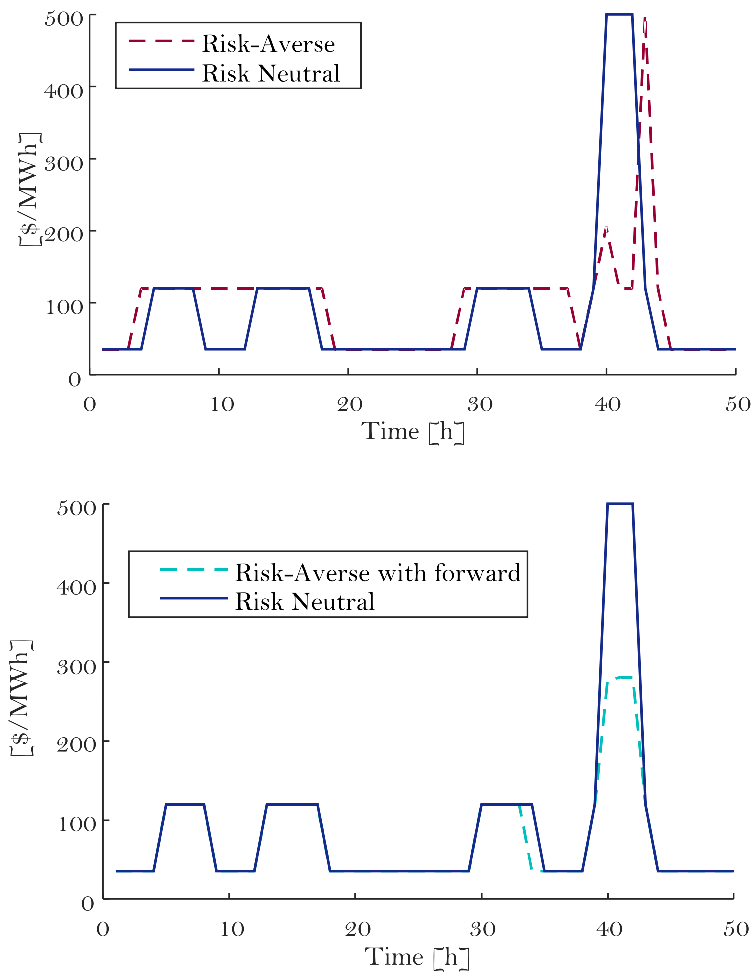


Figure 16. Natural gas spot market prices comparison between market equilibrium with risk-neutral agents and market equilibrium with risk-averse agents (top), and a forward market (bottom) during winter.

Finally, the model also calculates the market equilibrium prices both in the forward market and in the financial market.

	Risk-averse agents with access to forward market	**Risk-averse agents with access to forward and option markets**
Forward market price [$/MWh]	89.73	89.73
Option market price [$/MW]		2100

Table 5. Long-term financial markets equilibrium prices

The forward equilibrium price is an average of the electricity spot prices. Since prices converge under the two settings considered in Table 5, the forward equilibrium price is the same.

Profit distribution

The profit, as calculated in the model, includes a rate-of-return on investment consequently the benchmark expected profit is zero.

Figure 17 represents the profit evolution across different scenarios for the different cases considered in the model. The profit represented is the aggregated profit of all agents. As we move right on the horizontal axis, RES penetration increases.

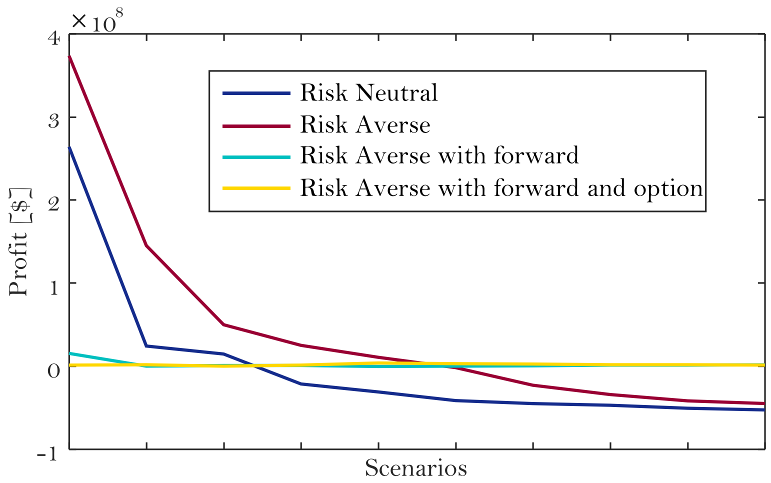


Figure 17. Profit evolution across different scenarios.

For the risk-neutral case, profit varies significantly when RES penetration is low. However, as RES penetration increases the profit distribution is flattened. This means that as RES penetration increases, its effect on profit softens. Moreover, in scenarios with low RES penetration agents have profits, whereas in scenarios with high RES penetration agents have losses. (This is logical since the expected profit is zero, and profit varies from scenario to scenario). Agents take their long-term investment decisions based on expected profit. This means, that under a low RES scenario, the agent will have underinvested, and as result prices in the electricity market will increase and so will the agent's profit. On the other hand, under a high RES scenario, the investment decision will be an overinvestment with respect to the optimal capacity. This, in addition to the effect of RES will drive prices down, which obviously makes it much more complicated to recover the investment, hence generating losses.

When agents are risk-averse but lack an access to financial instruments, the profits are higher than in the risk-neutral case. This, at first, might seem contradictory. If risk-aversion makes agents' decisions deviate from the social optimum, how come there is a profit increase? As the CVaR gains importance in agents' objective functions, agents tend more and more to base their decisions on low profit scenarios. This is to say they try to protect themselves from severe scenarios, and take long-term decisions that help push profits up in these scenarios.

Figure 18 presents the profit probability distribution. All scenarios have the same probability, consequently so do the profits. This figure clearly represents, the effect explained in the risk aversion formulation (p.24) where risk-averse agents tend to push low profit scenarios to the right. To do so in this case, agents have to modify their long-term investment decisions. Since these affect all scenarios, the result is that all scenarios move to the right.

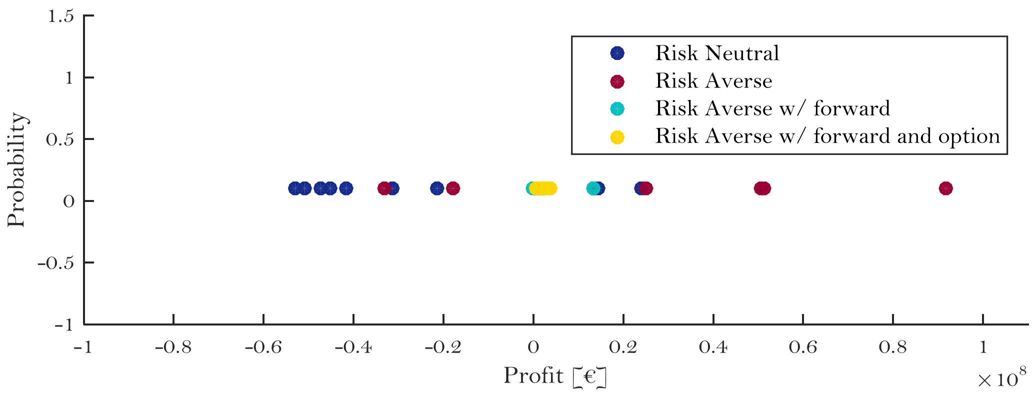


Figure 18. Profit probability distribution.

As previously explained, in this model, severe scenarios for generation agents are scenarios with high RES penetration. So, when agents are risk-averse, they take long-term investment decisions based on the low profit scenario investment needs, rather than expected profit. Since severe scenarios are scenarios with high RES penetration, obviously the investment needs in both power plant and pipeline capacity are lower than in the other scenarios. In consequence, when risk-averse agents base their long-term decisions on these scenarios, they tend to underinvest.

However, this results in a profit increase in all scenarios, and not only low profit scenarios. Indeed, when agents underinvest in power plant capacity and pipeline capacity, the prices in both markets increase (as seen in the previous section). The agents are, inadvertedly exercising market power. To maximize profit in severe scenarios, agents withdraw capacity from the market, hence driving prices up in all scenarios. This effect is heightened in scenarios with high RES penetration where capacity needs in power plant and pipeline are even larger.

When risk-averse agents are given financial tools to hedge their risk the shape of the profit evolution is completely modified, and it becomes much more flat. Since both distributions are quite similar, Figure 19 allows to take a closer look.

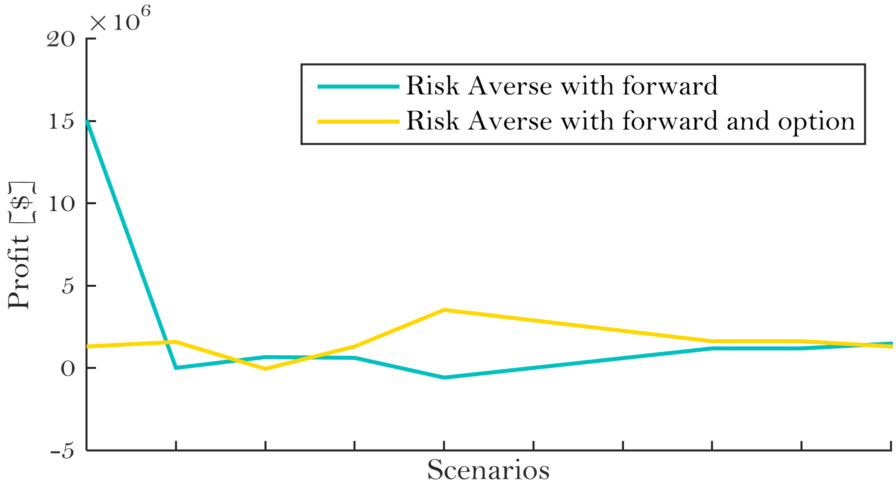


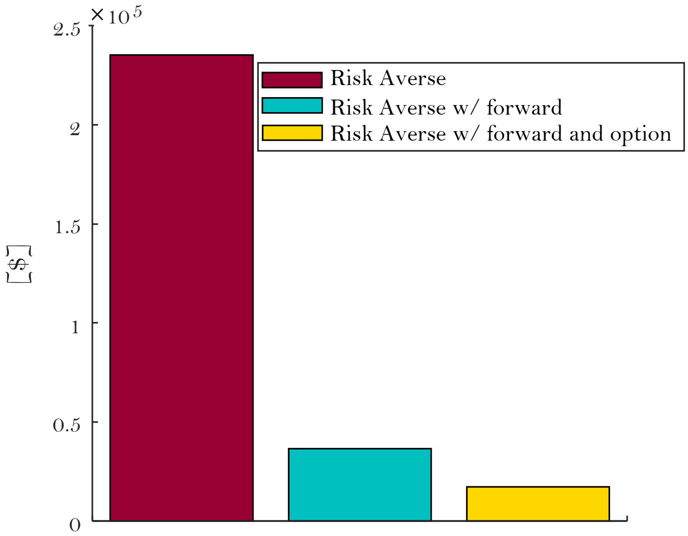
Figure 19. Profit evolution across different scenarios when including financial markets

When agents sign a forward contract or an option contract with the demand, the expected wealth transfer from one to the other as result of this contract is zero; the demand will make a profit off the contract in some scenarios that the generator will pay for and vice-versa. So, the overall effect of signing a contract for a generation agent is the wealth transfer from high profit scenarios (low RES) to lower profit scenarios (high RES). Agents lose money in scenarios with high profits (i.e. high prices), but in contrast, they make a profit in scenarios with low profits (low RES). This wealth transfer flattens the profit distribution neighboring the profit zero value. This can be observed in both figures above, where the profit evolution is flattened, are all profits are concentrated around one single value close to zero. This neutralizes, to some extent, the risk for generation agents. Flat profit distributions means agents cannot differentiate between low profit scenarios and high profit scenarios, as all scenarios have the same profit. Risk-averse agents tend to protect themselves from severe scenarios, however when there are no severe scenarios, the risk-aversion decreases.

Agents are 100% hedged against risk when all scenarios have the exact same profit and equal to the expected profit in the benchmark. In this case, all scenarios would have to have profit zero. Figure 17 and Figure 19 shows that agents are able to neutralize, to some extent their risk when introducing a forward contract. The effect is slightly heightened when adding an option to the forward market.

Social welfare

As we have seen decisions deviate from the social optimum under all contexts considered, but what is the



impact on social welfare?

Figure 20 compares the social welfare of the different settings considered to the benchmark, based on the numerical results presented inTable 6. As it can be easily observed, the more long-term decisions deviate from social welfare, the more social welfare decreases.

	Social welfare[$]	**Social welfare difference with respect to benchmark [$]**
Risk averse	3.5125e+09	2.35e+05
Risk averse w/ forward	3.5127e+09	3.64e+04
Risk averse w/ forward and option	3.5127e+09	1.72e+04

Table 6. Social welfare comparison to benchmark

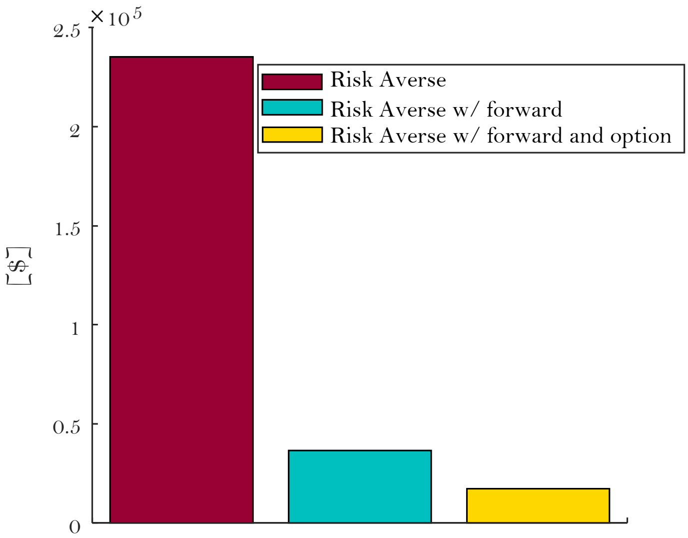


Figure 20. Social welfare comparison to benchmark[1]

First, of all the system-wide social welfare is computed taking into account generation agent's surplus, demand surplus, RES generators' income, and pipeline congestion rents.

These results clearly prove that when agents are risk averse, social welfare decreases, despite the increase in agents' profits.

Moreover, when including a long-term forward market, agents are able to some extent to hedge their risk, as a result their behavior is more similar to that of a risk-neutral agents and social welfare increases with respect to the previous case.

Although, including a forward market in the model generate a significant improvement in social welfare, there is still room for improvement. Therefore, this thesis analyzes the effect of increasing market completeness, following a similar approach to Willems and Morbee (2009) who study the effect of increasing market completeness on agents' long-term decisions and social welfare. In this context, market completeness is measured as the number of options available in addition to a forward contract.

Results show that adding an option to the long-term financial market, improves the results, bringing them closer to the social optimum.

[1] The social welfare decrease is small in relative terms but quite significant in absolute terms.

6 CONCLUSION

6.1 Main findings

A model accurately representing the addressed topic has been developed. The model represents the simultaneous participation of generation agents in the natural gas and electricity markets. Agents must take long-term investment decisions in both sectors (pipeline capacity contract, and power plant investment) and subsequently short-term decisions (gas demand, hourly production) while facing RES penetration uncertainty. Then, a long-term financial market is included, in which generators can hedge their risk by trading forward contracts, or a combination of forward and option contracts.

This model is applied to four different settings:

- Risk neutral central planner to be used as benchmark
- Market equilibrium with risk-averse agents with no long-term financial market
- Market equilibrium with risk-averse agents with a forward market
- Market equilibrium with risk-averse agents with an option and forward market.

Therefore, the model represents different markets both in the long and short term, and must endogenously calculate for each of them the corresponding equilibrium price. To that end, the model has been formulated as Mixed Complementary Problem.

The results obtained under the different settings considered have been compared against the benchmark reference and critically analysed to assess the effect on long-term investment decisions and social welfare of risk-averse generators, and to what extent it depends on market completeness.

The first conclusion that may be drawn is the equivalence between the risk-neutral centralized context and the market equilibrium with risk neutral agents. The perfect competition hypothesis is crucial here, when agents have no market power their decisions lead to the social optimum.

Nonetheless, when risk-aversion is included, agents' decisions are steered away from the benchmarks' socially efficient decisions, which obviously results in a social welfare reduction. Nevertheless, it is interesting to note that despite the social welfare depression, agent's profits increase under this setting. When agents are risk-averse they tend to base their decisions on low profit scenarios, rather than expected profit. In this case, low profit scenarios are those with high RES penetration. As a result, risk-averse agents tend to underinvest with respect to benchmark in order to protect these low profit scenarios. Agents are inadvertedly exercising market power, by withdrawing capacity from the market which results in a price increase in all scenarios, hence a profit increase in all scenarios.

Finally, risk-hedging financial instruments are gradually added to the model. Results show that when having to take long-term decisions whilst facing uncertainty (electricity price volatility, renewable penetration), risk-averse agents have a natural tendency to hedge their risk. Agents sign long-term contracts with the demand, as a result, under some scenarios generation agents have to pay the demand and vice-versa. The main impact is that profit evolution across scenarios is flattened, hence all scenarios have more or less the same profit. From the agent's perspective, there will be no low profit scenarios, which logically reduces the risk-aversion.

In consequence, when given the possibility to hedge their risk by participating in a forward market, agents' decisions come closer to replicating those of a central planner, thus improving social welfare. Moreover, if an option is included in addition to the forward market, results come even closer to the social optimum. These findings concur with Willems and Morbee (2010) where conclusions show that increasing market completeness is welfare enhancing.

6.2 Future work

We present two possible lines of work to further develop the problematic presented here.

First, we suggest to carry out a more accurate representation of real markets by also modeling the demand as a risk-averse agent. It should be noted, that this will only affect the results when financial markets are included, as under the other two contexts the demand does not take any decisions.

When a risk-neutral demand participates in the long-term risk-hedging markets, the equilibrium price in these markets is the average of electricity prices in the settlement period. However, a risk-averse demand, contrary to a risk-averse generator, is interested in high prices in financial markets. Including risk-aversion in the demand's formulation affects the equilibrium of long-term markets which will obviously impact the rest of the model.

Second, we propose to analyse the effect of the long-term financial contract's duration on the agent's decisions. The current formulation represents a single year, that is repeated infinite times. Therefore, the long-term financial contracts cover the agent's risk for the whole duration of the pipeline capacity contract.

However, this is not the case in real markets. For instance, ISO-NE believes that incentives to acquire firm fuel can be created through modifications in the Forward Capacity Market (FCM). This would allow gas-fired generators to hedge the risk inherent to long-term pipeline capacity contracts for the year the FCM is applied to.

Since the pipeline capacity contract duration is usually of twenty years, it is highly unlikely that a risk-hedging contract of one year will neutralize the generators risk.

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8 ANNEX

8.1 Variables

i: Generation agent

p: Time periods

p1: Peak periods

sc: scenario

f: fuel /gas, oil/

α_i: Risk-aversion weight in the o.f. function of agent i

Pr_{sc}: Probability of scenario sc

VF_f: Variable fuel consumption [MWht/MWhe]

VC_f: Fuel variable cost [$/MWht]

WG_p: Wind generation in p [MWh]

SG_p: Solar generation in p [MWh]

D_p: Demand in p [MWh]

LDC_p: Non-electric gas consumption in p [MWh/h]

RES_{sc}: RES penetration in sc

ICT: Investment cost of dual-fuel technology [$/MW]

ICC: Pipeline investment cost [$/(MWht/d)]

Toil: Maximum oil capacity [MW]

C_{ex}: Existing pipeline capacity [MWh/d]

δ : Confidence level

$\lambda_{p,sc}$: Dual variable of demand balance equation (price of electricity) [$/MWh]

γ: Option strike price [$/MWh]

π^f: Option capacity payment price [$/MW]

λ^f: Forward contract price [$/MWh]

$qgas_{p,sc,i}$: Production in period p, scenario sc, by agent i using gas[MW]

$qoil_{p,sc,k}$: Production in period p, scenario sc, by agent i using oil [MW]

qfg_i: Capacity signed in a forward contract by agent i [MW]

qog_i: Capacity signed in an option contract by agent i [MW]

qfd: Capacity signed in a forward contract by the demand [MW]

qod: Capacity signed in an option contract by the demand [MW]

$nse_{p,sc,j}$: Non-served energy [MW]

t_i: Dual-fuel power plant investment decision by agent i (MW)

c_i: Pipeline capacity investment decision by agent i [MWh/h]

$\mu_{p,sc}$: Dual variable of gas equation (natural gas market basis differential) [$/MWh]

$\beta_{p,sc,i}$: Dual variable of power plant capacity constraint [$/MW]

$\varphi_{p,sc,i}$: Dual variable of oil capacity constraint [$/MW]

$\eta\, gas_{p,sc,I}$, $\eta\, oil_{p,sc,k}$, $\eta\, nse_{p,sc,j}$, $\tau_{3sc,i,}$ σ_i, ε_i, ϱ, κ_i, ω_i, υ: Dual variables of constraints that declare variables as positive.

τ_{1i}: Dual variable of risk constraint 1 [$/$]

$\tau_{2sc,i}$: Dual variable risk constraint 2 [$/$]

$CVaR_i$: Conditional value-at-risk for agent i [$]

VaR_i : Value-at-risk for agent i [$]

$\Delta B_{sc,i}$: Auxliary variable which is equal to zero when the profit is higher than the value-at-risk, and is equal to the difference between them in the opposite case [$]

8.2 MCP formulation

Risk-neutral market equilibrium with no hedging instruments

KKT optimality conditions

In order to define the Mixed Complementarity Problem (MCP) formulation, it is necessary to calculate the Karush-Kuhn-Tucker (KKT) optimality conditions of the problem. KKT conditions are calculated by doing the derivative of the Lagrangian (Eq. 99, Eq. 100). with respect to the dual and primal variables. Although, not all dual variables are necessary to solve the problem, they are needed to formulate the MCP, therefore, all dual variables are defined in the market equilibrium equations above.

Eq. 99

$$L_i(\mathrm{qgas_{p,sc,i}}, \mathrm{qoil_{p,sc,i}}, t_i, c_i, \beta_{p,sc,i}, \eta gas_{p,sc,i}, \eta oil_{p,sc,i}, \sigma_i, \varepsilon_i) = \sum_{sc}\Big(\mathrm{Pr_{sc}} \sum_p\big(-\lambda_{\mathrm{p,sc}} \cdot (\mathrm{qgas_{p,sc,i}} + \mathrm{qoil_{p,sc,i}}) + (\mu_{\mathrm{p,sc}} + VC_{gas}) \cdot \mathrm{qgas_{p,sc,i}} \cdot \mathrm{VF}_{gas} + \mathrm{VC_{oil}} \cdot \mathrm{q_{oilp,sc,i}} \cdot \mathrm{VF}_{oil} - \mathrm{c_i} \cdot \mu_{\mathrm{p,sc}}\big)\Big) + \mathrm{ICT} \cdot \mathrm{t_i} + 24 * \mathrm{c_i} \cdot \mathrm{ICC} + \Big(\sum_{sc}[\sum_p[\beta_{p,sc,i} \cdot (\mathrm{qgas_{p,sc,i}} + \mathrm{qoil_{p,sc,i}})]] - \sum_{sc}[\sum_p[\beta_{p,sc,i}]] \cdot \mathrm{t_{i,}} + \sum_{sc}[\sum_p[\varphi_{p,sc,i} \cdot (qoil_{p,sc,i} - T_{oil})]]\Big) - \sum_p[\sum_{sc}[\eta gas_{p,sc,i} \cdot qgas_{p,sc,i} + \eta oil_{p,sc,i} \cdot qoil_{p,sc,i}]] - \sigma_i \cdot c_i - \varepsilon_i \cdot t_i - \kappa_i \cdot qfg_i - \omega_i \cdot qog_i \qquad \forall \mathrm{i}$$

Eq. 100

$$L(nse_{p,sc}) = \sum_p[\sum_{sc}[(D_p - nse_{p,sc}) \cdot (CNSE - \lambda_{p,sc})]] + \sum_p[\sum_{sc}[nse_{p,sc} \cdot \eta nse_{p,sc}]] \qquad \forall\ \mathrm{p,sc}$$

(Eq. 101 -

Eq. 104) are the result of doing the derivative of the Lagrangian representing the agents' problem with respect to the primal variables, i.e. the first order optimality conditions.

Eq. 101

$$\frac{\partial L_i}{\partial q_{gas}} = Pr_{sc} \cdot \left(-\lambda_{p,sc} + (\mu_{p,sc} + VC_{gas}\right) \cdot VF_{gas}) + \beta_{p,sc,i} \frac{\partial y}{\partial x} - \eta_{gas_{p,sc,i}} = 0 \qquad \forall \text{ p, sc, i}$$

Eq. 102

$$\frac{\partial L_i}{\partial q_{oil}} = Pr_{sc} \cdot (-\lambda_{p,sc} + VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} - \eta_{oil_{p,sc,i}} = 0 \qquad \forall \text{ p, sc, i}$$

Eq. 103

$$\frac{\partial L_i}{\partial t_i} = ICT - \sum_{sc}[\sum_p[\beta_{p,sc,i}]] - \varepsilon_i = 0 \qquad \forall \text{ i}$$

Eq. 104

$$\frac{\partial L_i}{\partial c_i} = -\sum_{sc}[\sum_p[\mu_{p,sc}]] + 24 \cdot ICC - \sigma_i = 0 \qquad \forall \text{ i}$$

When doing the derivative of the Lagrangian with respect to a dual variable, the constraint corresponding to that same dual variable is obtained as a result. Therefore Eq. 105, which is the derivative of Lagrangian representing the agents' problem with respect to dual variable $\beta_{p,sc,I}$ is equal to Eq. 8, which is the capacity constraint.

Eq. 105

$$\mathrm{qoil}_{p,sc,i} + \mathrm{qgas}_{p,sc,i} - \mathrm{tgas}_i \leq 0 \perp \beta_{p,sc,i,} \geq 0 \qquad \forall \text{ p, sc, i}$$

Eq. 106

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall \text{ p, sc, i}$$

Eq. 107

$$qgas_{p,sc,i}, qoil_{p,sc,k}, c_i, t_i \geq 0 \perp \eta gas_{p,sc,i}, \eta oil_{p,sc,i}, \sigma_i, \varepsilon_i \geq 0 \qquad \forall \text{ p, sc, i}$$

The KKT conditions for the demand maximization problem are obtained following the same methodology.

Eq. 108

$$\frac{\partial L}{\partial nse} = \left(CNSE - \lambda_{p,sc}\right) - \eta nse_{p,sc} = 0 \qquad \forall \text{ p, sc}$$

Eq. 109

$$nse_{p,sc} \geq 0 \perp \eta nse_{p,sc} \geq 0 \qquad \forall \text{ p, sc}$$

MCP Formulation

To obtain the final MCP formulation it is necessary to combine rearrange the previous equations.

Eq. 110 is obtained combining Eq. 101 and Eq. 107.

Eq. 110

$$Pr_{sc} \cdot \left(-\lambda_{p,sc} + (VC_{gas} + \mu_{p,sc})VF_{gas} + \beta_{p,sc,i}\right) = \eta_{gas_{p,sc,i}} \geq 0 \perp qgas_{p,sc,i} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 111 is obtained combining

Eq. 102 and Eq. 107.

Eq. 111

$$Pr_{sc} \cdot (-\lambda_{p,sc} + VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} = \eta_{oil_{p,sc,i}} \geq 0 \perp qoil_{p,sc,i} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 112 is obtained combining

Eq. 103 and Eq. 107.

Eq. 112

$$24 * ICC - \sum_p \left[\sum_{\mathrm{sc}}\left[\left(\mu_{p,sc}\right) \cdot \mathrm{Pr}_{\mathrm{sc}}\right]\right] = \varepsilon_i \geq 0 \perp c_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 113 is obtained combining

Eq. 104 and Eq. 107.

Eq. 113

$$ICT - \sum_p [\sum_{sc}[\beta_{p,sc,i}]] = \sigma_i \geq 0 \perp t_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 114 is obtained combining Eq. 108 and Eq. 109

Eq. 114

$$CNSE - \lambda_{p,sc} = \eta nse_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall \mathrm{p, sc}$$

The final MCP formulation (Eq. 115 - Eq. 123) of the problem include, first order optimality conditions rearranged and combined (Eq. 110 - Eq. 114), second order optimality condition (Eq. 105) and global equations (Eq. 13, Eq. 14).

Eq. 115

$$Pr_{sc} \cdot (-\lambda_{p,sc} + (VC_{gas} + \mu_{p,sc})VF_{gas} + \beta_{p,sc,i} \geq 0 \perp qgas_{p,sc,i} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 116

$$Pr_{sc} \cdot (-\lambda_{p,sc} + VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} \geq 0 \perp qoil_{p,sc,i} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 117

$$24 * ICC - \sum_p [\sum_{\mathrm{sc}}[\ \mu_{p,sc} \cdot \mathrm{Pr}_{\mathrm{sc}}]] \geq 0 \perp c_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 118

$$ICT - \sum_p [\sum_{sc}[\beta_{p,sc,i}]] \geq 0 \perp t_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 119

$CNSE - \lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0$ $\forall$p, sc

Eq. 120

$0 \geq \mathrm{qgas_{p,sc,i}} + \mathrm{qoil_{p,sc,i}} - \mathrm{t_i} \quad \perp \beta_{p,sc,i} \ \geq 0$ $\forall$ p, sc, i

Eq. 121

$qoil_{p,sc} \ \leq T_{oil} \perp \varphi_{p,sc,i} \ \geq 0$ $\forall$ p, sc, i

Eq. 122

$\sum_{\mathrm{i}}[\, \mathrm{qgas_{p,sc,i}} + \ \mathrm{qoil_{p,sc,i}}] + \mathrm{WG_p} \cdot \mathrm{res_{sc}} + \mathrm{SG_p} \cdot \mathrm{res_{sc}} = \mathrm{D_p} - \mathrm{nse_{p,sc}} \ \perp \ \lambda_{\mathrm{p,sc}}$ $\forall$p, sc

Eq. 123

$\sum_i[\, q_{p,sc,i,gas} VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \cdot CONV \quad \perp \quad \mu_{\mathrm{p,sc,1}} \geq 0$ $\forall$p, sc

Risk-averse market equilibrium with no hedging instruments

KKT optimality conditions

Following the same steps than in the risk-neutral formulation, the Lagrangian and corresponding KKT conditions are obtained. Three new variables are introduced in the model and three new constraints with the corresponding dual variables, therefore there three more first order optimality conditions, and three additional second order optimality conditions.

Eq. 124

$$L_i\left(\mathrm{qgas_{p,sc,i}}, \mathrm{qoil_{p,sc,i}}, t_i, c_i, \beta_{p,sc,i}, \eta_{p,sc,i,f}, \sigma_i, \varepsilon_i, VaR_i, CVaR_i, \tau_{1_i}, \tau_{2_{sc,i}}, \tau_{3_{sc,i}}\right) = (1 - \alpha_i) \cdot (\sum_{sc}\big(\mathrm{Pr_{sc}} \sum_p\big(-\lambda_{\mathrm{p,sc}} \cdot (\mathrm{qgas_{p,sc,i}} + \ \mathrm{qoil_{p,sc,i}}) + (\mu_{\mathrm{p,sc}} + VC_{gas}) \cdot \mathrm{qgas_{p,sc,i}} \cdot \mathrm{VF}_{gas} + \mathrm{VC_{oil}} \cdot \mathrm{q_{oilp,sc,i}} \cdot \mathrm{VF}_{oil} - \mathrm{c_i} \cdot (\mu_{\mathrm{p,sc}})\big)\big) + \mathrm{ICT} \cdot \mathrm{t_i} + 24 * \mathrm{c_i} \cdot \mathrm{ICC} + \big(\sum_{sc}[\sum_p PD \cdot [\, \beta_{p,sc,i} \cdot (\mathrm{qgas_{p,sc,i}} + \ \mathrm{qoil_{p,sc,i}})]] - \sum_{sc}[\sum_p PD \cdot [\, \beta_{p,sc,i}]] \cdot \mathrm{t_{i,}}\big) + \sum_{sc}[\sum_p[\varphi_{p,sc,i} \cdot (qoil_{p,sc,i} - \ T_{oil})]] - \ \sum_{sc}\sum_p[[\eta gas_{p,sc,i} \cdot qgas_{p,sc,i} + \eta oil_{p,sc,i} \cdot qoil_{p,sc,i}]] - \ \sigma_i \cdot c_i - \varepsilon_i \cdot t_i \ ) - \alpha_i \cdot CVaR_i \ - \tau_{1_i} \cdot (VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} - CVaR_i) - \sum_{sc}\Big[\tau_{2_{sc,i}} \cdot \big(\Delta B_{sc,i} - \mathrm{VaR}_i + \sum_p\big(\lambda_{p,sc} \cdot (\mathrm{qgas_{p,sc,i}} + \ \mathrm{qoil_{p,sc,i}}) - \big(\mu_{p,sc} + VC_{gas}\big) \cdot qgas_{p,sc,i} \cdot VF_{gas} - VC_{oil} \cdot qoil_{p,sc,i} \cdot VF_{oil} + c_i \cdot \mu_{p,sc}\big) - \ ICT \cdot t_i - \ 24 \cdot c_i \cdot ICC - \kappa_i \cdot qfg_i - \ \omega_i \cdot qog_i \big)\Big] - \sum_{sc}[\tau_{3_{sc,i}} \cdot \Delta B_{sc,i}] \qquad \forall \mathrm{i}$$

Eq. 125

$L\big(nse_{p,sc}\big) = \sum_p[\, \sum_{sc}[\big(D_p - nse_{p,sc}\big) \cdot (CNSE - \ \lambda_{p,sc})]] + \sum_p[\sum_{sc}[\, nse_{p,sc} \cdot \eta nse_{p,sc}]]$ $\forall$ p, sc

Eq. 126

$$\frac{\partial L}{\partial q_{p,sc,i,gas}} = ((1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas}) + \beta_{p,sc,i} - \eta_{p,sc,i,gas} - \tau_{2_{sc,i}} \cdot (\lambda_{p,sc} - (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas}) = 0 \qquad \forall p, sc, i$$

Eq. 127

$$\frac{\partial L}{\partial q_{p,sc,oil}} = ((1-\alpha_i) \cdot Pr_{sc}(-\lambda_{p,sc} + VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} - \eta_{p,sc,i,oil} - \tau_{2_{sc,i}} \cdot \left(\lambda_{p,sc} - VC_{oil} \cdot VF_{oil}\right)) = 0 \qquad \forall p, sc, i$$

Eq. 128

$$\frac{\partial L}{\partial c_i} = (1-\alpha_i) \cdot (24 * ICC - \sum_p [\sum_{sc} [\mu_{p,sc} \cdot Pr_{sc}]]) - \sigma_i - \sum_{sc} [\tau_{2_{sc,i}} \cdot (\mu_{p,sc} - 24 \cdot ICC)] = 0 \qquad \forall i$$

Eq. 129

$$\frac{\partial L}{\partial t_i} = (1-\alpha_i) \cdot ICT - \sum_p [\sum_{sc} [\beta_{p,sc,i}]] - \varepsilon_i - \sum_{sc} [\tau_{2_{sc,i}} \cdot (-ICT)] = 0 \qquad \forall i$$

Eq. 130

$$\frac{\partial L}{\partial VaR_i} = -\tau_{1_i} + \sum_{sc} [\tau_{2_{sc,i}}] = 0 \qquad \forall i$$

Eq. 131

$$\frac{\partial L}{\partial CVaR_i} = \tau_{1_i} - \alpha_i = 0 \qquad \forall i$$

Eq. 132

$$\frac{\partial L}{\partial \Delta B_{sc,i}} = \frac{\tau_{1_i} \cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} - \tau_{3_{sc,i}} = 0 \qquad \forall sc, i$$

Eq. 133

$$VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \qquad \perp \tau_{1_i} \geq 0 \qquad \forall i$$

Eq. 134

$$\Delta B_{sc,i} \geq VaR_i - [\sum_p PD \cdot \left(\lambda_{p,sc} \cdot \sum_f (q_{p,sc,i,f}) - (\mu_{p,sc} + VC_{gas}) \cdot q_{p,sc,i,gas} \cdot VF_{gas} - VC_{oil} \cdot q_{p,sc,i,oil} \cdot VF_{oil} + c_i \cdot \mu_{p,sc}\right) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC \ ] \ \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall sc, i$$

Eq. 135

$$qoil_{p,sc,i} + qgas_{p,sc,i} - tgas_i \leq 0 \ \perp \beta_{p,sc,i,} \geq 0 \qquad \forall p, sc, i$$

Eq. 136

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall p, sc, i$$

Eq. 137

$qgas_{p,sc,i}, qoil_{p,sc,k}, c_i, t_i, \Delta B_{sc,i} \geq 0 \perp \eta gas_{p,sc,i}, \eta oil_{p,sc,i}, \sigma_i, \varepsilon_i, \tau_{3_{sc,i}} \geq 0 \qquad \forall\, p, sc, i$

Eq. 138

$\frac{\partial L}{\partial nse} = \left(CNSE - \lambda_{p,sc}\right) - \eta nse_{p,sc} = 0 \qquad \forall\, p, sc$

Eq. 139

$nse_{p,sc} \geq 0 \perp \eta nse_{p,sc} \geq 0 \qquad \forall\, p, sc$

MCP Formulation

The MCP formulation is obtained combining and re-arranging the KKT optimality conditions.

Eq. 140

$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas}) + \beta_{p,sc,i} \cdot (\lambda_{p,sc} - (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas} \geq 0 \perp q_{p,sc,i,gas} \geq 0 \qquad \forall p, sc, i$

Eq. 141

$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} - \tau_{2_{sc,i}} \cdot \left(\lambda_{p,sc} - VC_{oil} \cdot VF_{oil} \cdot\right)) \geq 0 \perp q_{p,sc,i,oil} \geq 0 \qquad \forall p, sc, i$

Eq. 142

$(1-\alpha_i) \cdot (24 * ICC - \sum_p [\sum_{sc} \mu_{p,sc} \cdot \mathrm{Pr}_{sc}]]) - \sum_{sc} [\tau_{2_{sc,i}} \cdot (\mu_{p,sc} - 24 \cdot ICC)] \geq 0 \qquad \perp c_i \geq 0 \qquad \forall i$

Eq. 143

$(1-\alpha_i) \cdot ICT - \sum_p [\sum_{sc} [\beta_{p,sc,i}]] - \sum_{sc} [\tau_{2_{sc,i}} \cdot (-ICT)] \geq 0 \perp t_i \geq 0 \qquad \forall i$

Eq. 144

$-\tau_{1_i} + \sum_{sc} [\tau_{2_{sc,i}}] = 0 \perp \mathrm{VaR}_i \qquad \forall i$

Eq. 145

$\tau_{1_i} - \alpha_i = 0 \qquad \perp \mathrm{CVaR}_i \qquad \forall i$

Eq. 146

$\frac{\tau_{1_i} \cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} \geq 0 \quad \perp \Delta B_{sc,i} \geq 0 \qquad \forall sc, i$

Eq. 147

$VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \quad \perp \tau_{1_i} \geq 0 \qquad \forall i$

Eq. 148

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\sum_p(\lambda_{p,sc} \cdot \sum_f(q_{p,sc,i,f}) - (\mu_{p,sc} + VC_{gas}) \cdot q_{p,sc,i,gas} \cdot VF_{gas} - VC_{oil} \cdot q_{p,sc,i,oil} \cdot VF_{oil} + c_i \cdot \mu_{p,sc}) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC\ ] \perp {\tau_2}_{sc,i} \geq 0 \qquad \forall sc, i$$

Eq. 149

$$CNSE - \lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall p, sc$$

Eq. 150

$$0 \geq qgas_{p,sc,i} + qoil_{p,sc,i} - t_i \quad \perp \beta_{p,sc,i} \geq 0 \qquad \forall\ p, sc, i$$

Eq. 151

$$\sum_i[qgas_{p,sc,i} + qoil_{p,sc,i}] + WG_p \cdot res_{sc} + SG_p \cdot res_{sc} = D_p - nse_{p,sc} \perp \lambda_{p,sc} \qquad \forall p, sc$$

Eq. 152

$$\sum_i[q_{p,sc,i,gas} VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \quad \perp \quad \mu_{p,sc} \geq 0 \qquad \forall p, sc$$

Risk averse market equilibrium with forward contract

KKT optimality conditions

Following the same steps than in the risk-neutral formulation, the Lagrangian and corresponding KKT conditions are obtained.

Eq. 153

$$L_i \left(qgas_{p,sc,i}, qoil_{p,sc,i}, t_i, c_i, \beta_{p,sc,i}, \eta_{p,sc,i,f}, \sigma_i, \varepsilon_i, VaR_i, CVaR_i, {\tau_1}_i, {\tau_2}_{sc,i}, {\tau_3}_{sc,i}\right) = (1 - \alpha_i) \cdot (\sum_{sc}(Pr_{sc} \sum_p(-\lambda_{p,sc} \cdot (qgas_{p,sc,i} + qoil_{p,sc,i}) + (\mu_{p,sc} + VC_{gas}) \cdot qgas_{p,sc,i} \cdot VF_{gas} + VC_{oil} \cdot q_{oilp,sc,i} \cdot VF_{oil} - c_i \cdot (\mu_{p,sc}))) + ICT \cdot t_i + 24 \cdot ICC \cdot c_i - \sum_{sc}[Pr_{sc} \cdot \sum_p[(\lambda^f - \lambda_{p,sc}) \cdot qfg_i]]\ ) + (\sum_{sc}[\sum_p[\beta_{p,sc,i} \cdot (qgas_{p,sc,i} + qoil_{p,sc,i})]] - \sum_{sc}[\sum_p[\beta_{p,sc,i}]] \cdot t_{i,}) + \sum_{sc}[\sum_p[\varphi_{p,sc,i} \cdot (qoil_{p,sc,i} - T_{oil})]] - \sum_p[\sum_{sc}[\eta gas_{p,sc,i} \cdot qgas_{p,sc,i} + \eta oil_{p,sc,i} \cdot qoil_{p,sc,i}]] - \sigma_i \cdot c_i - \varepsilon_i \cdot t_i - \kappa_i \cdot qfg_i - \omega_i \cdot qog_i) - \alpha_i \cdot CVaR_i - {\tau_1}_i \cdot (VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} - CVaR_i) - \sum_{sc}\Big[{\tau_2}_{sc,i} \cdot \big(\Delta B_{sc,i} - \mathrm{VaR}_i + \sum_p(\lambda_{p,sc} \cdot (qgas_{p,sc,i} + qoil_{p,sc,i}) - (\mu_{p,sc} + VC_{gas}) \cdot qgas_{p,sc,i} \cdot VF_{gas} - VC_{oil} \cdot qoil_{p,sc,i} \cdot VF_{oil} + c_i \cdot \mu_{p,sc}) - ICT \cdot t_i - 24 \cdot ICC \cdot c_i + \sum_{sc}[Pr_{sc} \cdot \sum_p[(\lambda^f - \lambda_{p,sc}) \cdot qfg_i]]\big)\Big] - \sum_{sc}[{\tau_3}_{sc,i} \cdot \Delta B_{sc,i}] \qquad \forall i$$

Eq. 154

$$L(nse_{p,sc}) = \sum_p[\sum_{sc}[(D_p - nse_{p,sc}) \cdot (CNSE - \lambda_{p,sc})]] + \sum_{sc}[Pr_{sc} \cdot \sum_p[(\lambda_{p,sc} - \lambda^f) \cdot qfd_i]] + \sum_p[\sum_{sc}[nse_{p,sc} \cdot \eta nse_{p,sc}]] + \varrho \cdot qfd \qquad \forall\ p, sc$$

Eq. 155

$$\frac{\partial L}{\partial q_{p,sc,i,gas}} = ((1-\alpha_i)\cdot(-Pr_{sc}\cdot\lambda_{p,sc} + Pr_{sc}\cdot(VC_{gas} + \mu_{p,sc})\cdot VF_{gas}) + \beta_{p,sc,i} - \eta_{p,sc,i,gas} - \tau_{2_{sc,i}}\cdot (\lambda_{p,sc} - (VC_{gas} + \mu_{p,sc})\cdot VF_{gas}) = 0 \qquad \forall p, sc, i$$

Eq. 156

$$\frac{\partial L}{\partial q_{p,sc,oil}} = ((1-\alpha_i)\cdot Pr_{sc}(-\lambda_{p,sc} + VC_{oil}\cdot VF_{oil}) + \beta_{p,sc,i} - \eta_{p,sc,i,oil} - \tau_{2_{sc,i}}\cdot\big(\lambda_{p,sc} - VC_{oil}\cdot VF_{oil}\big)) = 0 \qquad \forall p, sc, i$$

Eq. 157

$$\frac{\partial L}{\partial c_i} = (1-\alpha_i)\cdot(24 * ICC - \textstyle\sum_p[\sum_{sc}[\mu_{p,sc}\cdot \mathrm{Pr}_{sc}]]) - \sigma_i - \sum_{sc}[\tau_{2_{sc,i}}\cdot(\mu_{p,sc} - 24\cdot ICC)] = 0 \qquad \forall i$$

Eq. 158

$$\frac{\partial L}{\partial t_i} = (1-\alpha_i)\cdot ICT - \textstyle\sum_p[\sum_{sc}[\beta_{p,sc,i}]] - \varepsilon_i - \sum_{sc}[\tau_{2_{sc,i}}\cdot(-ICT)] = 0 \qquad \forall i$$

Eq. 159

$$\frac{\partial L}{\partial qfg_i} = (1-\alpha_i)\cdot\textstyle\sum_p[\sum_{sc}[Pr_{sc}\cdot(\lambda_{p,sc} - \lambda^f)]] + \sum_p[\sum_{sc}[\tau_{sc,i}\cdot(\lambda_{p,sc} - \lambda^f)]] - \kappa_i = 0 \qquad \forall i$$

Eq. 160

$$\frac{\partial L}{\partial VaR_i} = -\tau_{1_i} + \textstyle\sum_{sc}[\tau_{2_{sc,i}}] = 0 \qquad \forall i$$

Eq. 161

$$\frac{\partial L}{\partial CVaR_i} = \tau_{1_i} - \alpha_i = 0 \qquad \forall i$$

Eq. 162

$$\frac{\partial L}{\partial \Delta B_{sc,i}} = \frac{\tau_{1_i}\cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} - \tau_{3_{sc,i}} = 0 \qquad \forall sc, i$$

Eq. 163

$$VaR_i - \frac{\sum_{sc} Pr_{sc}\cdot\Delta B_{sc,i}}{1-\delta} \geq CVaR_i \qquad \perp \tau_{1_i} \geq 0 \qquad \forall i$$

Eq. 164

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\textstyle\sum_p PD\cdot\big(\lambda_{p,sc}\cdot\sum_f(q_{p,sc,i,f}) - (\mu_{p,sc} + VC_{gas})\cdot q_{p,sc,i,gas}\cdot VF_{gas} - VC_{oil}\cdot q_{p,sc,i,oil}\cdot VF_{oil} + c_i\cdot\mu_{p,sc}\big) - ICT\cdot t_i - 24\cdot c_i\cdot ICC] \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall sc, i$$

Eq. 165

$$\mathrm{qoil}_{p,sc,i} + \mathrm{qgas}_{p,sc,i} - \mathrm{tgas}_i \leq 0 \perp \beta_{p,sc,i,} \geq 0 \qquad \forall p, sc, i$$

Eq. 166

$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall \text{ p, sc, i}$

Eq. 167

$qgas_{p,sc,i}, qoil_{p,sc,k}, c_i, t_i, \Delta B_{sc,i}, qfg_i \geq 0 \perp \eta gas_{p,sc,i}, \eta oil_{p,sc,i}, \sigma_i, \varepsilon_i, \tau 3_{sc,i}, \kappa_i \geq 0 \qquad \forall \text{ p, sc, i}$

Eq. 168

$\frac{\partial L}{\partial nse} = \left(CNSE - \lambda_{p,sc}\right) - \eta nse_{p,sc} = 0 \qquad \forall \text{ p, sc}$

Eq. 169

$\frac{\partial L}{\partial qfd} = \sum_p [\sum_{sc} [Pr_{sc} \cdot \left(-\lambda_{p,sc} + \lambda^f\right) + \varrho = 0$

Eq. 170

$nse_{p,sc}, qfd \geq 0 \perp \eta nse_{p,sc}, \varrho \geq 0 \qquad \forall \text{ p, sc}$

MCP Formulation

The MCP formulation is obtained rearranging and combining the previous equations:

Eq. 171

$(1 - \alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas}) + \beta_{p,sc,i} \cdot (\lambda_{p,sc} - (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas} \geq 0 \perp q_{p,sc,i,gas} \geq 0 \qquad \forall \text{p, sc, i}$

Eq. 172

$(1 - \alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} - \tau 2_{sc,i} \cdot \left(\lambda_{p,sc} - VC_{oil} \cdot VF_{oil} \cdot\right)) \geq 0 \perp q_{p,sc,i,oil} \geq 0 \qquad \forall \text{p, sc, i}$

Eq. 173

$(1 - \alpha_i) \cdot (24 * ICC - \sum_p [\sum_{sc} \mu_{p,sc} \cdot Pr_{sc}]]) - \sum_{sc} [\tau 2_{sc,i} \cdot (\mu_{p,sc} - 24 \cdot ICC)] \geq 0 \perp c_i \geq 0 \qquad \forall \text{i}$

Eq. 174

$(1 - \alpha_i) \cdot ICT - \sum_p [\sum_{sc} [\beta_{p,sc,i}]] - \sum_{sc} [\tau 2_{sc,i} \cdot (-ICT)] \geq 0 \perp t_i \geq 0 \qquad \forall \text{i}$

Eq. 175

$(1 - \alpha_i) \cdot \sum_p [\sum_{sc} Pr_{sc} \cdot \left(\lambda_{p,sc} - \lambda^f\right) + \sum_p [\sum_{sc} [\tau_{sc,i} \cdot (\lambda_{p,sc} - \lambda^f)]] \geq 0 \cdot \perp qfg_i \geq 0 \qquad \forall \text{i}$

Eq. 176

$-\tau 1_i + \sum_{sc} [\tau 2_{sc,i}] = 0 \perp \text{VaR}_i \qquad \forall \text{i}$

Eq. 177

$$\tau_{1_i} - \alpha_i = 0 \qquad \perp \mathrm{CVaR}_i \qquad \forall \mathrm{i}$$

Eq. 178

$$\frac{\tau_{1_i} \cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} \geq 0 \quad \perp \Delta B_{sc,i} \geq 0 \qquad \forall \mathrm{sc, i}$$

Eq. 179

$$VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \quad \perp \tau_{1_i} \geq 0 \qquad \forall \mathrm{i}$$

Eq. 180

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\textstyle\sum_p \big(\lambda_{\mathrm{p,sc}} \cdot \sum_f \big(\mathrm{q}_{\mathrm{p,sc,i,f}}\big) - (\mu_{\mathrm{p,sc}} + VC_{gas}) \cdot \mathrm{q}_{\mathrm{p,sc,i,gas}} \cdot \mathrm{VF}_{gas} - \mathrm{VC}_{\mathrm{oil}} \cdot \mathrm{q}_{\mathrm{p,sc,i,oil}} \cdot \mathrm{VF}_{oil} + \mathrm{c_i} \cdot \mu_{\mathrm{p,sc}} \big) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC \,] \ \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall \mathrm{sc, i}$$

Eq. 181

$$CNSE - \lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall \mathrm{p, sc}$$

Eq. 182

$$\textstyle\sum_p [\sum_{sc} [Pr_{sc} \cdot (-\lambda_{p,sc} + \lambda^f)]] \geq 0 \perp qfd \geq 0$$

Eq. 183

$$0 \geq \mathrm{qgas}_{\mathrm{p,sc,i}} + \mathrm{qoil}_{\mathrm{p,sc,i}} - \mathrm{t_i} \quad \perp \beta_{p,sc,i} \geq 0 \qquad \forall \ \mathrm{p, sc, i}$$

Eq. 184

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall \ \mathrm{p, sc, i}$$

Eq. 185

$$\textstyle\sum_{\mathrm{i}} [\, \mathrm{qgas}_{\mathrm{p,sc,i}} + \mathrm{qoil}_{\mathrm{p,sc,i}}] + \mathrm{WG_p} \cdot \mathrm{res_{sc}} + \mathrm{SG_p} \cdot \mathrm{res_{sc}} = \mathrm{D_p} - \mathrm{nse_{p,sc}} \perp \lambda_{\mathrm{p,sc}} \qquad \forall \mathrm{p, sc}$$

Eq. 186

$$\textstyle\sum_i [\, q_{p,sc,i,gas} VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \quad \perp \quad \mu_{\mathrm{p,sc}} \geq 0 \qquad \forall \mathrm{p, sc}$$

Eq. 187

$$\textstyle\sum_i qfg_i = \ qfd \ \perp \ \lambda^f$$

Risk averse market equilibrium with forward and option contract

KKT optimality conditions

Following the same steps than in the risk-neutral formulation, the Lagrangian and corresponding KKT conditions are obtained.

Eq. 188

$$L_i\left(\mathrm{qgas}_{\mathrm{p,sc,i}}, \mathrm{qoil}_{\mathrm{p,sc,i}}, t_i, c_i, \beta_{p,sc,i}, \eta_{p,sc,i,f}, \sigma_i, \varepsilon_i, VaR_i, CVaR_i, \tau_{1_i}, \tau_{2_{sc,i}}, \tau_{3_{sc,i}}\right) = (1-\ \alpha_i)\cdot (\textstyle\sum_{sc}\big(\mathrm{Pr}_{\mathrm{sc}}\sum_p\big(-\lambda_{\mathrm{p,sc}}\cdot\big(\mathrm{qgas}_{\mathrm{p,sc,i}}\ +\ \mathrm{qoil}_{\mathrm{p,sc,i}}\big)+(\mu_{\mathrm{p,sc}}\ +\ VC_{gas})\cdot \mathrm{qgas}_{\mathrm{p,sc,i}}\cdot \mathrm{VF}_{gas}\ +\ \mathrm{VC}_{\mathrm{oil}}\cdot \mathrm{q}_{\mathrm{oilp,sc,i}}\cdot \mathrm{VF}_{oil}-\mathrm{c_i}\cdot(\mu_{\mathrm{p,sc}})\big)\big)+\mathrm{ICT}\cdot \mathrm{t_i}+24\cdot \mathrm{ICC}\cdot \mathrm{c_i}\ -\ \sum_{sc}[Pr_{sc}\cdot\sum_p[(\lambda^f-\lambda_{\mathrm{p,sc}})\cdot\ qfg_i]]\ -\ \sum_{sc}[Pr_{sc}\cdot\sum_{p1}[(\gamma-\lambda_{\mathrm{p,sc}})\cdot\ qog_i]]-\ \pi^f\cdot qog_i)+\big(\sum_{sc}[\sum_p[\beta_{p,sc,i}\cdot(\mathrm{qgas}_{\mathrm{p,sc,i}}+\ \mathrm{qoil}_{\mathrm{p,sc,i}})]]-\sum_{sc}[\sum_p[\beta_{p,sc,i}]]\cdot \mathrm{t_{i,}}\big)+\sum_{sc}[\sum_p[\varphi_{p,sc,i}\cdot(qoil_{p,sc,i}-\ T_{oil})]]-\ \sum_p[\sum_{sc}[\eta gas_{p,sc,i}\cdot qgas_{p,sc,i}+\eta oil_{p,sc,i}\cdot qoil_{p,sc,i}]]-\ \ \sigma_i\cdot c_i-\varepsilon_i\cdot t_i-\kappa_i\cdot\ qfg_i\ -\ \omega_i\cdot qog_i)-\alpha_i\cdot CVaR_i\ \ -\ \tau_{1_i}\cdot(VaR_i-\frac{\sum_{sc}Pr_{sc}\cdot\Delta B_{sc,i}}{1-\delta}-CVaR_i)\ -\ \sum_{sc}\Big[\tau_{2_{sc,i}}\cdot\big(\Delta B_{sc,i}-\mathrm{VaR}_i+\sum_p\big(\lambda_{p,sc}\cdot(\mathrm{qgas}_{\mathrm{p,sc,i}}+\ \mathrm{qoil}_{\mathrm{p,sc,i}})\ -\big(\mu_{p,sc}+VC_{gas}\big)\cdot qgas_{p,sc,i}\cdot VF_{gas}-VC_{oil}\cdot qoil_{p,sc,i}\cdot VF_{oil}+c_i\cdot\mu_{p,sc}\big)-ICT\cdot\ \mathrm{t_i}-24\cdot \mathrm{ICC}\cdot \mathrm{c_i}\ +\sum_{sc}[Pr_{sc}\cdot\sum_p[(\lambda^f-\lambda_{\mathrm{p,sc}})\cdot\ qfg_i]]+\sum_{sc}[Pr_{sc}\cdot\sum_{p1}[(\gamma-\lambda_{\mathrm{p,sc}})\cdot\ qog_i]]+\ \ \pi^f\cdot qog_i\big)\Big]-\sum_{sc}[\tau_{3_{sc,i}}\cdot\Delta B_{sc,i}]\quad \forall \mathrm{i}$$

Eq. 189

$$L(nse_{p,sc})=\textstyle\sum_p[\sum_{sc}[(D_p-nse_{p,sc})\cdot(CNSE-\ \lambda_{p,sc})]]\ +\ \sum_{sc}[Pr_{sc}\cdot\sum_p[(\lambda_{\mathrm{p,sc}}-\ \lambda^f)\cdot\ qfd_i]]\ +\ \sum_{sc}[Pr_{sc}\cdot\sum_{p1}[(\lambda_{\mathrm{p,sc}}-\ \gamma)\cdot\ qod]]-\ \pi^f\cdot qod\ +\ \sum_p[\sum_{sc}[nse_{p,sc}\cdot\eta nse_{p,sc}]]+\ \varrho\cdot qfd+\ \upsilon\cdot qod\quad \forall\ \mathrm{p,sc}$$

Eq. 190

$$\frac{\partial L}{\partial q_{p,sc,i,gas}}=\ ((1-\alpha_i)\cdot(-Pr_{sc}\cdot\lambda_{p,sc}+Pr_{sc}\cdot(VC_{gas}+\mu_{p,sc})\cdot VF_{gas})+\beta_{p,sc,i}-\eta_{p,sc,i,gas}-\tau_{2_{sc,i}}\cdot(\lambda_{\mathrm{p,sc}}-(VC_{gas}+\mu_{p,sc})\cdot VF_{gas})=0\quad \forall \mathrm{p,sc,i}$$

Eq. 191

$$\frac{\partial L}{\partial q_{p,sc,oil}}=\ ((1-\alpha_i)\cdot Pr_{sc}(-\lambda_{p,sc}+VC_{oil}\cdot VF_{oil})+\beta_{p,sc,i}-\eta_{p,sc,i,oil}-\tau_{2_{sc,i}}\cdot(\lambda_{\mathrm{p,sc}}-VC_{oil}\cdot VF_{oil}))=0\quad \forall \mathrm{p,sc,i}$$

Eq. 192

$$\frac{\partial L}{\partial c_i}=\ (1-\alpha_i)\cdot(24*ICC-\textstyle\sum_p[\sum_{\mathrm{sc}}[\mu_{p,sc}\ \cdot \mathrm{Pr_{sc}}]])-\sigma_i-\sum_{sc}[\tau_{2_{sc,i}}\cdot(\mu_{p,sc}-24\cdot ICC\ )\ ]=0\quad \forall \mathrm{i}$$

Eq. 193

$$\frac{\partial L}{\partial t_i}=\ (1-\alpha_i)\cdot ICT-\textstyle\sum_p[\sum_{sc}[\beta_{p,sc,i}]]-\varepsilon_i-\sum_{sc}[\tau_{2_{sc,i}}\cdot(-ICT)]=0\quad \forall \mathrm{i}$$

Eq. 194

$$\frac{\partial L}{\partial qfg_i} = (1-\alpha_i) \cdot \sum_p [\sum_{sc} [Pr_{sc} \cdot (\lambda_{p,sc} - \lambda^f)]] + \sum_p [\sum_{sc} [\tau_{sc,i} \cdot (\lambda_{p,sc} - \lambda^f)]] - \kappa_i = 0 \qquad \forall \mathrm{i}$$

Eq. 195

$$\frac{\partial L}{\partial qog_i} = (1-\alpha_i) \cdot (\sum_{p1} [\sum_{sc} [Pr_{sc} \cdot (\lambda_{p,sc} - \gamma)]] - \pi^f) + \sum_p \left[\sum_{sc} [\tau_{sc,i}]\right] \cdot (\sum_{p1} [\sum_{sc} [Pr_{sc} \cdot (\lambda_{p,sc} - \gamma)]\right] - \pi^f) - \omega_i = 0 \qquad \forall \mathrm{i}$$

Eq. 196

$$\frac{\partial L}{\partial VaR_i} = -\tau_{1_i} + \sum_{sc} [\tau_{2_{sc,i}}] = 0 \qquad \forall \mathrm{i}$$

Eq. 197

$$\frac{\partial L}{\partial CVaR_i} = \tau_{1_i} - \alpha_i = 0 \qquad \forall \mathrm{i}$$

Eq. 198

$$\frac{\partial L}{\partial \Delta B_{sc,i}} = \frac{\tau_{1_i} \cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} - \tau_{3_{sc,i}} = 0 \qquad \forall \mathrm{sc, i}$$

Eq. 199

$$VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \qquad \perp \tau_{1_i} \geq 0 \qquad \forall \mathrm{i}$$

Eq. 200

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\sum_p PD \cdot (\lambda_{\mathrm{p,sc}} \cdot \sum_f (\mathrm{q_{p,sc,i,f}}) - (\mu_{\mathrm{p,sc}} + VC_{gas}) \cdot \mathrm{q_{p,sc,i,gas}} \cdot \mathrm{VF}_{gas} - \mathrm{VC_{oil}} \cdot \mathrm{q_{p,sc,i,oil}} \cdot \mathrm{VF}_{oil} + \mathrm{c_i} \cdot \mu_{\mathrm{p,sc}}) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC \,] \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall \mathrm{sc, i}$$

Eq. 201

$$\mathrm{qoil_{p,sc,i}} + \mathrm{qgas_{p,sc,i}} - \mathrm{tgas_i} \leq 0 \perp \beta_{p,sc,i,} \geq 0 \qquad \forall \mathrm{\ p, sc, i}$$

Eq. 202

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall \mathrm{\ p, sc, i}$$

Eq. 203

$$qgas_{p,sc,i}, qoil_{p,sc,k}, c_i, t_i, qfg_i, qog_i \geq 0 \perp \eta gas_{p,sc,i}, \eta oil_{p,sc,i}, \sigma_i, \varepsilon_i, \kappa_i, \omega_i \geq 0 \qquad \forall \mathrm{\ p, sc, i}$$

Eq. 204

$$\frac{\partial L}{\partial nse} = (CNSE - \lambda_{p,sc}) - \eta nse_{p,sc} = 0 \qquad \forall \mathrm{\ p, sc}$$

Eq. 205

$$\frac{\partial L}{\partial qfd} = \sum_p [\sum_{sc} [Pr_{sc} \cdot (-\lambda_{p,sc} + \lambda^f) + \varrho = 0$$

Eq. 206

$$\frac{\partial L}{\partial qod} = \sum_{p1}[\sum_{sc}[Pr_{sc} \cdot (-\lambda_{p,sc} + \gamma) + \pi^f + \upsilon = 0$$

Eq. 207

$$nse_{p,sc}, qfd, qod \geq 0 \perp \eta nse_{p,sc}, \varrho,\ \upsilon \geq 0 \qquad \forall\, \mathrm{p, sc}$$

MCP Formulation

The MCP formulation is obtained rearranging and combining the previous equations:

Eq. 208

$$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas}) + \beta_{p,sc,i} \cdot (\lambda_{\mathrm{p,sc}} - (VC_{gas} + \mu_{p,sc}) \cdot VF_{gas} \geq 0 \perp q_{p,sc,i,gas} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 209

$$(1-\alpha_i) \cdot (-Pr_{sc} \cdot \lambda_{p,sc} + Pr_{sc} \cdot VC_{oil} \cdot VF_{oil}) + \beta_{p,sc,i} - \tau_{2_{sc,i}} \cdot (\lambda_{\mathrm{p,sc}} - VC_{oil} \cdot VF_{oil} \cdot)) \geq 0 \perp q_{p,sc,i,oil} \geq 0 \qquad \forall \mathrm{p, sc, i}$$

Eq. 210

$$(1-\alpha_i) \cdot (24 * ICC - \sum_p[\sum_{sc} \mu_{p,sc} \cdot \mathrm{Pr_{sc}}]]) - \sum_{sc}[\tau_{2_{sc,i}} \cdot (\mu_{p,sc} - 24 \cdot ICC)] \geq 0 \quad \perp c_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 211

$$(1-\alpha_i) \cdot ICT - \sum_p[\sum_{sc}[\beta_{p,sc,i}]] - \sum_{sc}[\tau_{2_{sc,i}} \cdot (-ICT)] \geq 0 \perp t_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 212

$$(1-\alpha_i) \cdot \sum_p[\sum_{sc} Pr_{sc} \cdot (\lambda_{\mathrm{p,sc}} - \lambda^f) + \sum_p[\sum_{sc}[\tau_{sc,i} \cdot (\lambda_{p,sc} - \lambda^f)]] \geq 0 \cdot \quad \perp qfg_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 213

$$(1-\alpha_i) \cdot (\sum_{p1}[\sum_{sc}[Pr_{sc} \cdot (\lambda_{p,sc} - \gamma)]] - \pi^f) + \sum_p \left[\sum_{sc}[\tau_{sc,i}]\right] \cdot (\sum_{p1}[\sum_{sc}[Pr_{sc} \cdot (\lambda_{p,sc} - \gamma)]] - \pi^f) \geq 0 \quad \perp qfg_i \geq 0 \qquad \forall \mathrm{i}$$

Eq. 214

$$-\tau_{1_i} + \sum_{sc}[\tau_{2_{sc,i}}] = 0 \ \perp \mathrm{VaR}_i \qquad \forall \mathrm{i}$$

Eq. 215

$$\tau_{1_i} - \alpha_i = 0 \qquad \perp \mathrm{CVaR}_i \qquad \forall \mathrm{i}$$

Eq. 216

$$\frac{\tau_{1_i} \cdot Pr_{sc}}{1-\delta} - \tau_{2_{sc,i}} \geq 0 \quad \perp \Delta B_{sc,i} \geq 0 \qquad \forall sc, i$$

Eq. 217

$$VaR_i - \frac{\sum_{sc} Pr_{sc} \cdot \Delta B_{sc,i}}{1-\delta} \geq CVaR_i \quad \perp \tau_{1_i} \geq 0 \qquad \forall i$$

Eq. 218

$$\Delta B_{sc,i} \geq \mathrm{VaR}_i - [\textstyle\sum_p \big(\lambda_{p,sc} \cdot \sum_f \big(q_{p,sc,i,f}\big) - (\mu_{p,sc} + VC_{gas}) \cdot q_{p,sc,i,gas} \cdot VF_{gas} - VC_{oil} \cdot q_{p,sc,i,oil} \cdot VF_{oil} + c_i \cdot \mu_{p,sc}\big) - ICT \cdot t_i - 24 \cdot c_i \cdot ICC\ ] \ \perp \tau_{2_{sc,i}} \geq 0 \qquad \forall sc, i$$

Eq. 219

$$CNSE - \lambda_{p,sc} \geq 0 \perp nse_{p,sc} \geq 0 \qquad \forall p, sc$$

Eq. 220

$$\textstyle\sum_p [\sum_{sc} [Pr_{sc} \cdot (-\lambda_{p,sc} + \lambda^f)]] \geq 0 \perp qfd \geq 0$$

Eq. 221

$$\textstyle\sum_{p1} [\sum_{sc} [Pr_{sc} \cdot \big(-\lambda_{p,sc} + \gamma\big) + \pi^f$$

Eq. 222

$$0 \geq qgas_{p,sc,i} + qoil_{p,sc,i} - t_i \quad \perp \beta_{p,sc,i} \geq 0 \qquad \forall\ p, sc, i$$

Eq. 223

$$qoil_{p,sc} \leq T_{oil} \perp \varphi_{p,sc,i} \geq 0 \qquad \forall\ p, sc, i$$

Eq. 224

$$\textstyle\sum_i [\ qgas_{p,sc,i} + qoil_{p,sc,i}] + WG_p \cdot res_{sc} + SG_p \cdot res_{sc} = D_p - nse_{p,sc} \ \perp \ \lambda_{p,sc} \qquad \forall p, sc$$

Eq. 225

$$\textstyle\sum_i [\ q_{p,sc,i,gas} VF_{gas}] \leq \sum_i c_i + \frac{C_{ex}}{24} - LDC_p \quad \perp \quad \mu_{p,sc} \geq 0 \qquad \forall p, sc$$

Eq. 226

$$\textstyle\sum_i qfg_i = \ qfd \quad \perp \quad \lambda^f$$

Eq. 227

$$\textstyle\sum_i qog_i = \ qod \quad \perp \quad \pi^f$$

MISSING MARKETS AND MISSING PIPELINES: THE PROBLEM OF RESOURCE ADEQUACY IN A NATURAL-GAS-FIRED DOMINATED SYSTEM

Missing markets and missing pipelines: the problem of resource adequacy in a natural-gas-fired dominated system

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***Abstract*—.Given the increasing dominance of natural gas in the U.S. electric power systems, the traditional concern of electricity regulators to ensure that market agents take efficient power generation investment decisions expands to the gas system, as the system requires adequate investments also in pipeline or regasification capacity. The problem is that ensuring pipeline capacity, even or particularly under tight supply conditions, involves entering into very long-term firm transportation contracts, and therefore introduces a major source of risk for power generators. This is particularly the case in New England, whose high dependency on natural gas has become troublesome in the last few years during cold winter months, due to the lack of natural gas pipeline capacity. In this paper we analyse this problem of the gas and electricity long-term planning coordination and the security of supply consequences. We assess how a risk-averse natural gas power plant owner underinvests in pipeline capacity when no hedging tools are available, and to what extent the gap could be bridged by adding long-term financial markets for risk.**

***Keywords*— Gas-electricity coordination, New England, Risk-aversion, Incomplete markets**

NOMENCLATURE

The general nomenclature of the model will be explained in this section. Uppercase letters are used for denoting parameters. Lowercase letters denote variables, sets and indexes.

Indexes and Sets:

$i \in I$	Generation agents.
$p \in P$	Time periods in the model.
$p1 \in P$	Peak periods
$f \in F$	Fuel /gas, oil/
$sc \in SC$	Scenarios.

Parameters:

Pr_{sc}	Probability of scenario sc [p.u.].
VF_f	Variable fuel consumption [MWh$_t$/MW].
VC_f	Variable fuel cost [$/MWh]
WG_p	Wind generation in p [MWh].
SG_p	Solar generation in p [MWh].
D_p	Electricity demand in p [MWh]
LDC_p	Non-electric gas consumption in p [MWh/h].
RES_{sc}	RES penetration in sc [p.u.].
ICT	Investment cost of dual-fuel technology [$/MW].
ICC	Pipeline investment cost [$/(MWh$_t$/d)].
$Toil$	Maximum oil capacity [MW]
C_{ex}	Existing pipeline capacity [MWh/].
$CNSE$	Cost of non-served energy [$/MWh]
α_i	Risk aversion weigh in the objective function of agent i [p.u.].
δ	Confidence level [p.u.].
γ	Option strike price

Primal variables:

$nse_{p,sc}$	Non-served energy [MWh] in period p, scenario sc
$qgas_{p,sc,i}$	Gas production in period p, scenario sc, by agent i [MWh]
$qoil_{p,sc,i}$	Oil production in period p, scenario sc, by agent i [MWh].
qfg_i	Capacity signed in a forward contract by agent i [MW].
qog_t	Capacity signed in an option contract by agent i [MW]

qfd Capacity signed in a forward contract by the demand [MW]

qod Capacity signed in an option contract by the demand [MW]]

t_i Dual-fuel power plant investment decision by agent i [MW]

c_t Degradation cost for period t [€]

$CVaR_i$ Conditional Value-at-Risk for agent i

VaR_i Value-at-Risk for agent i

$\Delta B_{sc,i}$ Auxliary variable which is equal to zero when the profit is higher than the value-at-risk, and is equal to the difference between them in the opposite case [$]

Dual variables

$\lambda_{p,sc}$ Dual variable of demand balance equation (price of electricity) [$/MWh]

$\mu_{p,sc}$ Dual variable of gas equation (natural gas market basis differential) [$/MWh]

λ^f Forward contract price [$/MWh]

π^f Option capacity payment price [$/MW]

$\varphi_{p,sc,i}$ Dual variable of oil capacity constraint [$/MW].

$\beta_{p,sc,i}$ Dual variable of power plant capacity constraint [$/MW]

τ_{1_i} Dual variable of risk constraint 1 [$/$]

$\tau_{2_{sc,i}}$ Dual variable of risk constraint 2 [$/$]

I. Overview

High natural gas dependency in electric power systems is becoming a major energy policy and regulatory issue in all jurisdictions undergoing the transformation to a lower-carbon and/or renewables-based energy system. This is even more exacerbated in the U.S. where the emergence of shale-gas has reduced considerably the cost of generating electricity with gas, making it the cheaper alternative to oil.

The vast majority of natural gas in the U.S. is transported through long-haul transport pipelines. Nevertheless, the natural gas pipeline system has not kept pace with demand from the power sector, thus resulting in long-term coordination issues between the gas and electricity sectors.

The natural gas pipeline industry in the U.S. is regulated by FERC, who in order to approve the construction of new pipeline capacity, requires gas consumers to sign very long-term firm capacity contracts. Natural gas generators face a unique set of uncertainties (electricity demand, renewable penetration, etc.) which makes them reluctant to assume the risk inherent to these capital intensive, long-term firm capacity contract, settling instead for short-term interruptible contracts. The main drawback from the latter is that they offer little security as to being dispatched, in case of pipeline congestion interruptible capacity is the first to be curtailed as firm capacity holders have priority.

This is one of the main concerns in New England whose high dependency in natural gas has become trouble the past few winters. High gas demand for both space heating and electric generation has resulted in pipeline capacity scarcity events, which increase gas prices and reduce gas-fired generators' access to natural gas.

This obviously has a significant impact in the electric power industry with an overall increase in operating and production costs that has subjected electricity consumers to the highest tariff increase in the country (EIA, 2014)

According to several reports, including Black and Veatch (2013), bringing new pipeline capacity is seen as fundamental. Nevertheless, this is unlikely to happen until gas-fired generators are given proper financial tools to hedge the long-term risk inherent to firm pipeline capacity contracts.

Resource adequacy issues in New England are a consequence of risk-averse generators in the presence of incomplete long-term financial markets.

II. Methodology

This paper analyses how social welfare and long-term investment decisions in New England are affected by risk aversion, and to what extent this depends on market completeness.

To address this issue, following a similar approach as the one developed by Rodilla et al. (2009) four different settings are considered for which the different obtained outcomes will be compared and analyzed:

- a (cost-minimizing) context with a risk-neutral centralized planner who decides both the thermal capacity and the pipeline capacity to maximize social welfare. This framework constitutes the benchmark solution.
- a market in which risk-averse generators have to decide the thermal capacity to be installed and the firm pipeline capacity contracts to be signed to maximize their profit where no long-term financial instruments are available.
- a market setting similar to the previous one, but where a long-term forward contract for electric energy is available.
- a market setting similar to the previous one, but where both a forward and an option contract are available.

Under the different settings, agents must first take long-term investment decisions (in both pipeline capacity contracts and power plant investment), as well as hedging instruments, and then decide in the short-term the hourly power plant production. Uncertainty in variable renewable energy (VER) production is factored-in through different scenarios each considering a different VER penetration level.

Market equilibrium settings simultaneously represent the short-term electricity and gas markets, and, when included, the long-term financial markets. The equilibrium prices for all of these markets are endogenously determined by the model. Market equilibrium model are formulated as Mixed Complementarity Problems (MCP), given their ability to directly manipulate both primal as well as dual variables.

A. *Model hypothesis*

Some hypothesis are introduced in the formulation to simplify the problem, elements that add excessive complexity to the model yet do not contribute to the analyzed topic are excluded.

Investment decisions in power plant are limited to one technology that may produce with two types of fuel. The central planner invests in dual-fuel power plants that can produce with oil or natural gas

All integer and binary variables have been eliminated to simplify the problem formulation, consequently:

- The power plant may produce simultaneously with oil and natural gas.
- Only linear costs are considered. As a result, short-term costs include variable fuel costs, whereas no-load fuel costs and start-up costs are disregarded, and, in the long-term investment decisions are linearized.

All scenarios have the same probability, thus Pr is equal to the inverse of the number of scenarios.

B. *Benchmark problem: Risk-neutral market equilibrium*

1) *Generation side problem formulation*

Assuming perfect competition, the profit maximizing decisions of individual agents in the system under a risk-neutral context lead to the same results than the central planner's social welfare maximization.

Consequently, we present here the risk-neutral market equilibrium formulation of the problem.

The objective function of each agent, i, is to maximize its expected profit- All agents are subject to the same constraints, which cap the hourly production at the investment decision (29, and limit the oil production capacity (3).

$$Max_{qgas,qoil,t,c} \sum_{sc}\Big(\mathrm{Pr_{sc}} \sum_{p}\big(\mathrm{\lambda_{p,sc}} \cdot (qgas_{p,sc,i} + qoil_{p,sc,i}) - (\mathrm{\mu_{p,sc}} + VC_{gas}) \cdot \mathrm{qgas_{p,sc,i}} \cdot \mathrm{VF}_{gas} - \mathrm{VC_{oil}} \cdot \mathrm{qoil_{p,sc,i}} \cdot \mathrm{VF}_{oil} + \mathrm{c_i} \cdot \mathrm{\mu_{p,sc}}\big)\Big) - \mathrm{ICT} \cdot \mathrm{t_i} - 24 * \mathrm{c_i} \cdot \mathrm{ICC} \tag{1}$$

s.t.

$$qgas_{p,sc} + qoil_{p,sc} \le t \qquad \forall\, \mathrm{p, sc, i} \tag{2}$$

$$qoil_{p,sc} \le T_{oil} \qquad \forall\, \mathrm{p, sc, i} \tag{3}$$

2) *Demand side problem formulation*

The demand is aggregated into a single, inelastic, risk-neutral agent whose objective function is to maximize its expected utility.

$$Max_{nse} \sum_{p}\big[\sum_{sc}\big[\big(D_p - nse_{p,sc}\big) \cdot (CNSE - \mathrm{\lambda_{p,sc}})\big]\big] \qquad \forall p, sc \tag{4}$$

3) *Global equations*

Finally, the problem has two global equations that ensure demand minus non-served energy is equal to generation (5), and that gas consumers do not exceed pipeline capacity (6).

$$\sum_{\mathrm{i}}[\mathrm{qgas_{p,sc,i}} + \mathrm{qoil_{p,sc,i}}] + \mathrm{WG_p} \cdot \mathrm{res_{sc}} + \mathrm{SG_p} \cdot \mathrm{res_{sc}} = \mathrm{D_p} - \mathrm{nse_{p,sc}} \qquad \forall p, sc \tag{5}$$

$$\sum_{i}[qgas_{p,sc,i} \cdot VF_{gas}] \le \sum_{i} c_i + \frac{C_{ex}}{24} - LDC(p) \quad \perp \quad \mathrm{\mu_{p,sc}} \ge 0 \qquad \forall p, sc \tag{6}$$

The dual variables of equations (5) and (6) are, respectively, the electricity market spot price ($\lambda_{p,sc}$) and the gas market spot price location differential ($\mu_{p,sc}$)m which are endogenously calculated by the model.

4) *Natural gas market representation*

The representation of the natural gas market has been simplified into a market with two hubs connected through a pipeline with limited capacity.

There is an exporting hub with infinite production capacity at a fixed variable cost (VC_{gas}). Therefore, the price at this node is constant and equal to the variable production cost. At the other end of the pipeline, there is an importing hub. The price difference between these two hubs is named location differential. The location differential is equal to zero when the pipeline is not congested, (hence the nodal price at both hubs is equal), and positive when there is a congestion in the pipeline. When the pipeline is congested, demand at the importing hub is higher than supply at the importing hub, consequently the price increases. Consequently, the price at the importing hub is equal to the sum of the location differential and the fixed variable cost ($\mu_{p,sc} + VC_{gas}$).

Generation agents must choose whether or not to invest in natural gas pipeline capacity. If they do invest, then they pay for the natural gas consumed the price at the exporting hub, still all gas consumption above the contracted capacity is paid at the price of the importing hub.

Agents use the pipeline contracted capacity to import low priced gas either for their own consumption, or to sell to other customers at the importing hub high price whenever there is a scarcity event.

C. Risk-averse market equilibrium with no hedging instruments

The previous risk-neutral formulation is modified to model agents as risk-averse.

1) Generation side problem formulation

The agent's risk-aversion formulation (9) is based on Rockafellar and Uryasev (2000)'s Conditional Value-at-Risk (CVaR) formulation.

Although usually expressed in terms of losses, in this formulation the VaR estimates the likelihood that a given agent's profits will exceed a certain amount. The VaR at a confidence level of δ is the minimum profit that will be reached with a probability δ. Given the percentile δ, $CVaR^{\delta}$ represents the mean of the profit in the worst δ 100% scenarios (García González et al. 2006).

The CVaR is introduced in the model, where the new objective function (7) is maximization of the weighted sum of the expected profit and the CVaR (α_i is the weight of the risk-aversion in the o.f.)

$$Max_{qgas,qoil,t,c}\,(1-\alpha_i)\cdot\Big(\sum_{sc}\big(\mathrm{Pr}_{sc}\sum_p\big(\lambda_{p,sc}\cdot\big(qgas_{p,sc,i}+qoil_{p,sc,i}\big)-(\mu_{p,sc}+VC_{gas})\cdot \mathrm{qgas}_{p,sc,i}\cdot \mathrm{VF}_{gas}-\mathrm{VC}_{oil}\cdot \mathrm{qoil}_{p,sc,i}\cdot \mathrm{VF}_{oil}-\mathrm{c_i}\cdot(\mu_{p,sc})\big)\big)-\mathrm{ICT}\cdot \mathrm{t_i}-24*\mathrm{c_i}\cdot \mathrm{ICC}\Big)+\alpha_i\cdot CVaR_i \qquad \forall i \tag{7}$$

s.t.

$$\mathrm{qoil}_{p,sc,i}+\mathrm{qgas}_{p,sc,i}-\mathrm{tgas_i}\le 0 \qquad \forall p,sc,i \tag{8}$$

$$VaR_i-\frac{\sum_{sc}Pr_{sc}\cdot\Delta B_{sc,i}}{1-\delta}\ge CVaR_i \qquad \forall i \tag{9}$$

$$\Delta B_{sc,i}\ge \mathrm{VaR}_i-\Big[\sum_p\big(\lambda_{p,sc}\cdot(\mathrm{qoil}_{p,sc,i}+\mathrm{qgas}_{p,sc,i})-(\mu_{p,sc}+VC_{gas})\cdot\mathrm{qgas}_{p,sc,i}\cdot\mathrm{VF}_{gas}-\mathrm{VC}_{oil}\cdot\mathrm{qoil}_{p,sc,i}\cdot\mathrm{VF}_{oil}+\mathrm{c_i}\cdot\mu_{p,sc}\big)-ICT\cdot t_i-24\cdot c_i\cdot ICC\Big] \qquad \forall \mathrm{sc,i} \tag{10}$$

$$\Delta B_{sc,i}\ge 0 \qquad \forall \mathrm{sc,i} \tag{11}$$

The demand-side and global equations remain the same as in the risk-neutral formulation ((4)-(6)).

D. Risk-averse market eqilibrium with forward contract

Under this setting, generator owners still behave as risk-averse agents, however a forward market is now included. Agents may hedge their risk by participating in a long-term financial market where they have as only counterpart the risk-neutral demand.

1) Generation side problem formulation

In addition to the short-term gas and electricity market, a long-term forward market is now added to the model. The equilibrium price of the forward contract, λ^f [$/MW], is also calculated endogenously. In terms of formulation, this only affects agents' objective function.

$$Max_{qgas,qoil,t,c,qfg}\,(1-\alpha_i)\cdot\Big(\sum_{sc}\big[\mathrm{Pr}_{sc}\sum_p\big[\lambda_{p,sc}\cdot\big(qgas_{p,sc,i}+qoil_{p,sc,i}\big)-(\mu_{p,sc}+VC_{gas})\cdot\mathrm{qgas}_{p,sc,i}\cdot\mathrm{VF}_{gas}-\mathrm{VC}_{oil}\cdot\mathrm{qoil}_{p,sc,i}\cdot\mathrm{VF}_{oil}+\mathrm{c_i}\cdot(\mu_{p,sc})\big]\big]-\mathrm{ICT}\cdot\mathrm{t_i}-24\cdot\mathrm{ICC}\cdot\mathrm{c_i}+\sum_{sc}\big[Pr_{sc}\cdot\sum_p\big[\big(\lambda^f-\lambda_{p,sc}\big)\cdot qfg_i\big]\big]\Big)+\alpha_i\cdot CVaR_i \qquad \forall i \tag{12}$$

An additional source of income (or payment depending on the scenario) is added to the objective function. The agent that enters into a forward contract receives for each period, p, and scenario, sc, the difference between the contract price and the electricity spot price for the capacity contracted, qfg [MW]. If, said difference is negative, the generator has to pay the demand.

2) Demand side problem formulation

The objective function of the demand is also altered:

$$Max_{nse,qfd}\sum_p\big[\sum_{sc}\big[\big(D_p-nse_{p,sc}\big)\cdot\big(CNSE-\lambda_{p,sc}\big)\big]\big]+\sum_{sc}\big[Pr_{sc}\cdot\sum_p\big[\big(\lambda_{p,sc}-\lambda^f\big)\cdot qfd\big]\big] \tag{13}$$

3) Global equations

A new global equation is added to ensure the forward capacity contracted by the demand, qfd, is equal to the added forward capacity contracted by generator, qfg.

$$\sum_i qfg_i = qfd \quad \perp \quad \lambda^f \tag{14}$$

E. Risk-averse market equilibirum with forward and option contracts

Market completeness is increased by adding an option contract to the long-term financial market, thus giving generator owners' access to a variety of risk-hedging instruments.

1) Generation side problem formulation

The new objective function for generation agents is:

$$Max_{qgas,qoil,t,c,qfg,qog}\,(1-\alpha_i)\cdot\Big(\sum_{sc}\big[\mathrm{Pr}_{sc}\sum_p\big[\lambda_{p,sc}\cdot\big(qgas_{p,sc,i}+qoil_{p,sc,i}\big)-(\mu_{p,sc}+VC_{gas})\cdot\mathrm{qgas}_{p,sc,i}\cdot\mathrm{VF}_{gas}-\mathrm{VC}_{oil}\cdot\mathrm{qoil}_{p,sc,i}\cdot\mathrm{VF}_{oil}+\mathrm{c_i}\cdot(\mu_{p,sc})\big]\big]-\mathrm{ICT}\cdot\mathrm{t_i}-24\cdot\mathrm{ICC}\cdot\mathrm{c_i}+\sum_{sc}\big[Pr_{sc}\cdot\sum_p\big[\big(\lambda^f-\lambda_{p,sc}\big)\cdot qfg_i\big]\big]+\sum_{sc}\big[Pr_{sc}\cdot\sum_{p1}\big[\big(\gamma-\lambda_{p,sc}\big)\cdot qog_i\big]\big]+\pi^f\cdot qog_i\Big)+\alpha_i\cdot CVaR_i \ \forall i \tag{15}$$

2) Demand side problem formulation

$$Max_{nse,qfd,qfd,qod} \sum_p [\sum_{sc}[(D_p - nse_{p,sc}) \cdot (CNSE - \lambda_{p,sc})]] + \sum_{sc}[Pr_{sc} \cdot \sum_p[(\lambda_{p,sc} - \lambda^f) \cdot qfd]] + \sum_{sc}[Pr_{sc} \cdot \sum_{p1}[(\lambda_{p,sc} - \gamma) \cdot qod]] - \pi^f \cdot qod \quad (16)$$

3) *Global equations*

The following equation is added to ensure that the quantity of option contract signed by the demand, is equal to the added quantities of option contracts signed by all generator owners.

$$\sum_i qog_i = qod \quad \perp \quad \pi^f \quad (17)$$

The dual variable, π^f, is the option contract price calculated by the model. Since the model does not include binary variables, the option contract price and the option settlement periods are calculated through an iterative process.

III. Results

A. *Problem data*

The model developed is applied to a New England-like system. The data is obtained from actual New England data estimations for the year 2025. To reduce the computational burden, the year 2025 is modelled through representative days split into periods of one hour. All periods have the same weight, consequently each season is represented by 25% of the hours.

B. *Generation agents' profit*

The profit, as calculated in the model, includes a rate-of-return on investment consequently the benchmark expected profit is zero.

Figure 1 represents the profit evolution across different scenarios for the different cases considered in the model. The profit represented is the aggregated profit of all agents. As we move right on the horizontal axis, RES penetration increases.

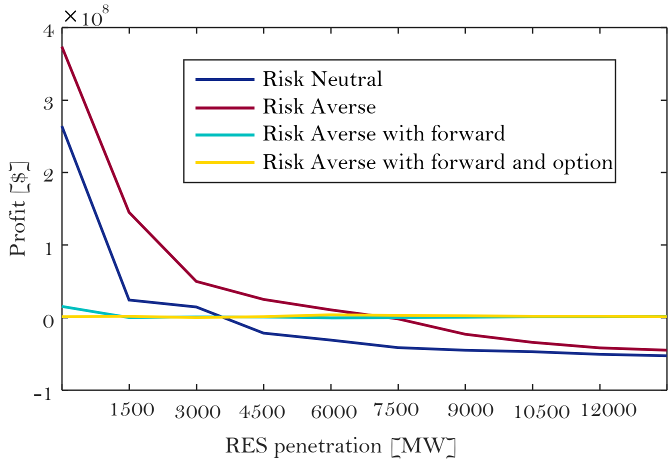

Figure 1. Profit evolution across different scenarios

For the risk-neutral case, profit varies significantly when RES penetration is low. However, as RES penetration increases, its effect on profit softens. Agents take their long-term investment decisions based on expected profit. This means that under a low RES scenario, the agent will have underinvested, and as result prices in the electricity market will increase and so will the agent's profit. On the other hand, under a high RES scenario, the investment decision will be an overinvestment with respect to the optimal capacity. This, in addition to the effect of RES will drive prices down, which obviously makes it much more complicated to recover the investment, hence generating losses.

When agents are risk-averse but lack an access to financial instruments, the profits are higher than in the risk-neutral case. This, at first, might seem contradictory. If risk-aversion makes agents' decisions deviate from the social optimum, how come there is a profit increase? As the CVaR gains importance in agents' objective functions, agents tend more and more to base their decisions on low profit scenarios rather than expected profit. That is to say they try to protect themselves from severe scenarios, and take long-term decisions that help push profits up in these scenarios.

However, this results in a profit increase in all scenarios, and not only low profit scenarios. Indeed, when agents underinvest in power plant capacity and pipeline capacity, they are inadvertedly exercising market power thus increasing electricity market spot prices up, and subsequently their profits too.

When risk-averse agents are given financial tools to hedge their risk the shape of the profit evolution is completely modified, and it becomes much more flat. Since both distributions are quite similar, Figure 2 allows to take a closer look.

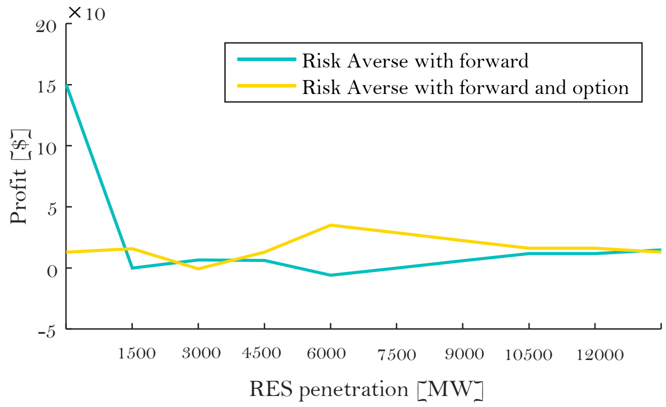

Figure 2. Profit evolution across different scenarios when including financial markets

When agents sign a forward contract or an option contract with the demand, the expected wealth transfer from one to the other as result of this contract is zero; the demand will make a profit off the contract in some scenarios that the generator will pay for and vice-versa. So, the overall effect of signing a contract for a generation agent is the wealth transfer from high profit scenarios (low RES) to lower profit scenarios (high RES) which flattens the profit distribution neighboring the profit zero value.

Flat profit distributions means risk-averse agents cannot differentiate between low profit scenarios and high profit scenarios, in consequence their decisions will come closer to the social optimum.

Agents are 100% hedged against risk when all scenarios have the exact same profit and equal to the expected profit in the benchmark. Figure 2 shows that agents are able to neutralize, to some extent their risk when introducing a forward contract. The effect is slightly heightened when adding an option to the forward market.

C. *Long-term decisions*

The aggregated long-term decisions agents take both in the electricity sector (power plant investment) and in the natural gas market (pipeline capacity contract) are presented in the table below. The decisions from risk-neutral agents constitute the social optimum.

	Investment decision	
	Power plant [MW]	**Pipeline [bcf/h]**
Risk-neutral	14132	0.0761
Risk-averse	13755	0.075
Risk-averse w/ forward	13945	0.0767
Risk-averse w/ forward and option	14029	0.0762

Table 1. Long-term investment decisions

Figure 4 and Figure 5 show how investment decisions deviate from those provided by the benchmark (in absolute value).

The first conclusion drawn from the analysis of these figures is that under no setting are the agents able to replicate the decisions from the benchmark reference.

When agents are risk-averse and have no risk-hedging tools available, they underinvest in both pipeline capacity contracts and power plant capacity. This is the case where decisions deviate the most from the social optimum.

Nevertheless, if agents are offered risk-hedging instruments, such as a forward contract, results improve significantly, even more so if market completeness is increased through the addition of an option contract.

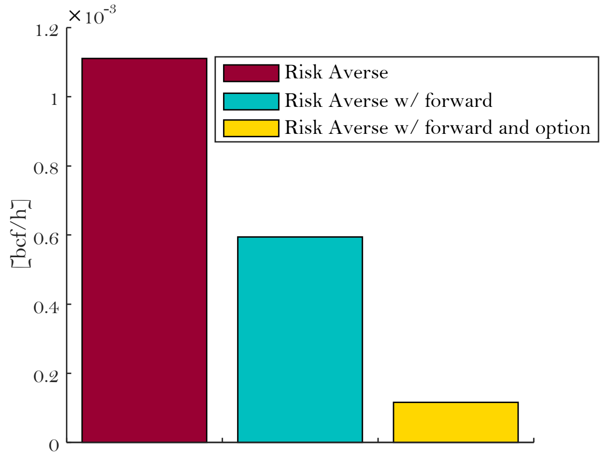

Figure 3. Pipeline capacity investment decisions deviation from benchmark

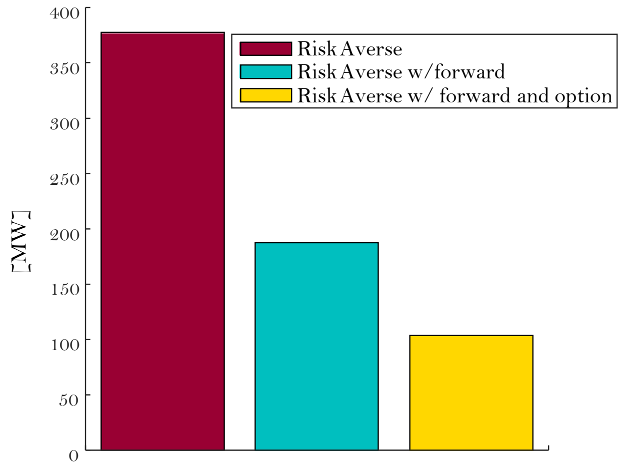

Figure 4. Power plant investment decisions deviation from benchmark

Even though risk-averse agents with access to risk-hedging tools are not able to exactly replicate the benchmark's socially efficient decisions, they do come quite close. As a result, it is only of interest to compare benchmark's short-term decisions and short-term prices against the risk-averse setting.

D. *Short-term decisions*

Figure 5 compares the hourly dispatch of risk-averse agents (bottom) to the benchmark (top).

When agents are risk-averse the number of hours with non-served energy increases in both winter and summer as a results of the underinvestment in pipeline and dual-fuel capacity.

Moreover, risk-averse agents increase oil fuel production during winter as it replaces natural gas. This is due to the underinvestment in pipeline capacity.

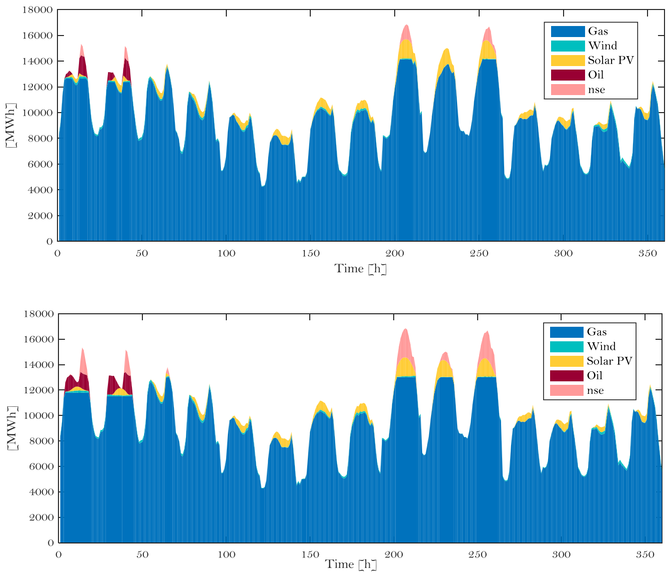

Figure 5. Hourly dispatch under a risk-neutral context

E. *Short- and long-term prices*

The market equilibrium prices calculated by the model are the result of agent's decisions, and whenever these decisions deviate from the social optimum, prices are affected.

	Forward market	Forward and option markets
Forward market price [$/MWh]	89.73	89.73
Option market price [$/MW]		2100

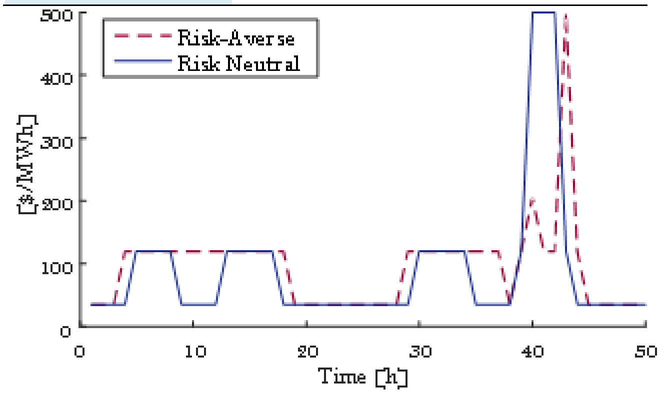

Figure 6. Natural gas spot price

Figure 7 compares the electricity spot prices under two different contexts (risk-neutral market equilibrium, and risk-averse market equilibrium with no financial market).

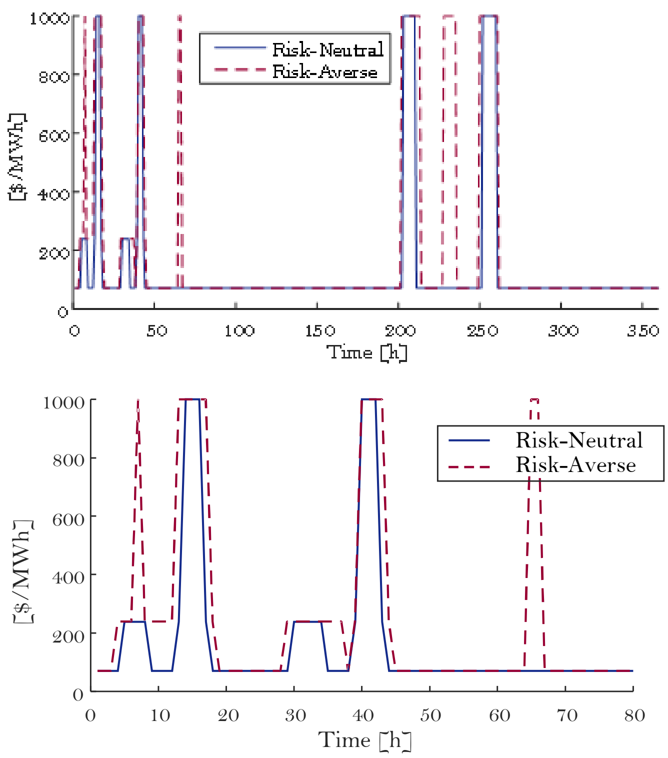

Figure 7. Electricity spot price (whole year (top), winter (bottom)

Table 2 represents the long-term prices of the financial markets under the two different contexts where financial markets are included.

Table 2. Long-term financial markets equilibrium prices

It is interesting to note that the forward market equilibrium price does not vary when an option contract is added. The forward price is the average of electricity spot market prices. Since electricity market prices are almost exact under these two contexts, so is the forward market price.

F. *Social welfare*

System-wide social welfare is computed taking into account generation agent's surplus, demand surplus, RES generators' income, and pipeline congestion rents.

Table 3 presents the social welfare under the different contexts considered, while Figure 8 represents the SW deviation with respect to the benchmark.

	Social welfare[$]
Risk neutral	3.5128e+09
Risk averse	3.5125e+09

Risk averse w/ forward	3.5127e+09
Risk averse w/ forward and option	3.5127e+09

Table 3. Social welfare[1]

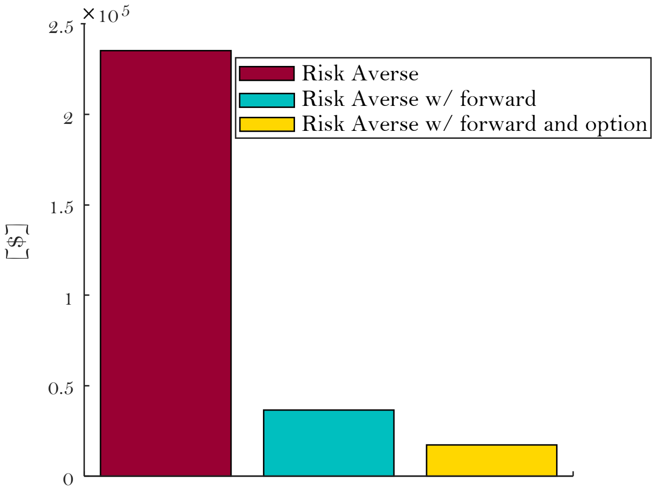

Figure 8. Social welfare comparison to benchmark

Results show that when agents are risk-averse and have no access to long-term financial markets, social welfare decreases, despite the increase in agent's profits.

Moreover, when including a long-term forward market, agents are able to some to extent to hedge their risk, which results in an increase in social welfare with respect to the previous case.

Despite the increase in social welfare when including a forward contract, the social increase generated by the addition of an option to the long-term financial market shows there is still room for improvement.

IV. CONCLUSIONS

Findings show an equivalence between the central planner's welfare-maximizing decisions and the profit maximizing decisions of risk-neutral agents. Nevertheless, the more agents' decisions deviate from the social optimum, the more social welfare decreases.

If agents are risk-averse and no risk-hedging instruments are available, results deviate from the central planner's. Risk-averse agents base their decisions on lower profit scenarios, rather than using expected profit, which generates long-term inefficient investment decisions.

However, when given the possibility to hedge their risk by participating in a forward market, agents' decisions come closer to replicating those of a central planner, thus improving social welfare, slightly more so if an option is included in addition to the forward market. These findings concur with Willems and Morbee (2010) where conclusions show that increasing market completeness is welfare enhancing.

[1] The social welfare decrease with respect to benchmakr is smail in relative terms but quite significant in absolute terms

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