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Abstract
Over the last two decades, the growing installation and utilization of natural gas fired power plants has led to increasing interactions between natural gas and electricity systems. In the long run, it is thus essential that investments in natural gas and electricity infrastructure proceed in a coordinated manner. This document presents a new approach and its associated tool for the assessment of investments in electricity and natural gas network infrastructures considering that both energy systems are operated in a combined way. The characteristics and fundamentals of natural gas systems are comprehensively described and compared with those of electric power systems. This background provides the basis for a clear identification and quantification of interactions between electricity and natural gas systems. In addition, an extensive literature review of the latest approaches and procedures to address the integrated operation and planning of multiple energy systems, in particular for natural gas and electricity (NG&E) systems, has been carried out along with summary of the current transmission expansion approaches as well as the basic techniques for the valuation of investments. The approach, proposed in this document, has been adequately tailored to suit with the general framework defined in the REALISEGRID project, in which the results of the long-term energy model are used as inputs for the new assessment approach. The core of the proposed tool is a natural gas and electricity operational planning model which is used to assess the cost savings due to the investments in natural gas and electricity transmission infrastructure. The mathematical formulation of optimization problem and the adopted natural gas and electricity models are described in detail throughout this document.

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ACRONYMS AND DEFINITIONS

AC: Alternating Current.
CCGT: Combined Cycle Gas Turbine.
CHP: Combined Heat and Power.
EU: European Union.
EU27: 27 EU Member States: Austria, Belgium, Bulgaria, Cyprus, Czech Rep., Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom.
EU36: 36 European Countries: Albania, Austria, Belgium, Bosnia & Herzegovina, Bulgaria, Croatia, Cyprus, Czech Rep., Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Macedonia (FYR), Malta, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, United Kingdom.
FACTS: Flexible Alternating Current Transmission System.
GDP: Gross Domestic Product.
LDC: Load Duration Curve.
LNG: Liquefied Natural Gas.
NG: Natural Gas.
NG&E: Natural gas and electricity – Natural gas and electric power.
NGFPP: Natural gas fired power plant.
NPV: Net Present Value.
OECD: Organization for Economic Co-operation and Development.
OF: Objective Function.
PET: Pan European TIMES.

1 EXECUTIVE SUMMARY

The growing installation and utilization of natural gas fired power plants (NGFPPs) over the last two decades has led to increasing interactions between electricity (E) and natural gas (NG) sectors. The installation of NGFPPs has been driven by technical, economic and environmental reasons. The high thermal efficiency of combined-cycle gas turbine (CCGT) power plants and combined heat and power (CHP) units, their relatively low investment costs, short construction lead time and the prevailing low natural gas prices until 2004 have made NGFPPs more attractive than traditional coal, oil and nuclear power plants, particularly in liberalized electricity markets. Additionally, burning NG has a smaller environmental footprint and a lower carbon emission rate than any other fossil fuel.

NGFPPs are the link between electric power and NG systems, since they play the role of producers for the former and consumers for the latter. Therefore, the growing use of NGFPPs has had a great impact on the NG market. Power generation accounted for around half of the growth in NG use in the past decade, and this proportion has almost risen up to the 80% in the last five years. This fact is especially notable in those countries where large capacities of NGFPPs have been installed.

Under the light of the conditions previously described, there is a strong and rising interdependency between natural gas and electricity sectors. These interactions establish close links between NG&E decision-making processes at all time horizons, ranging from long-term planning to short-term operational decisions. Therefore, it is essential to include NG system models in electric power systems operation and planning. On the other hand, NG system operation and planning require, as input data, the NG demands of NGFPPs, whose values can only be obtained accurately from the electric power systems dispatch.

Natural gas and electricity network infrastructures, i.e., transport and storage facilities compete and complement each other in the energy supply task. Thus, it is necessary that the investments in NG&E network infrastructure proceed in a coordinated manner. Then, a new approach to a coordinated assessment of investments in electricity and gas infrastructures is proposed. This approach can be seen as a new step in the hierarchical energy planning procedure, filling the gap between the long-term energy models and the current decoupled NG&E planning approaches. The basis, assumptions and main features of the proposed approach are as follows:

- Centralized (regulated) perspective: this approach seeks to maximize the social welfare without pursuing profit objectives for any particular agent involved in the energy supply chain. Consequently, the different type of markets (spot, forward, futures) and different forms of trading (bilateral, multilateral, pool) developed within NG&E markets are not modeled. In fact, to tackle the problem from a centralized perspective implies that *perfect competition* is assumed in the NG&E markets. Indeed, under such market conditions, the resulting infrastructures and the operation plan of each energy system will match those that would be obtained from a purely centralized decision-making process (i.e. *benevolent monopolist*).

- The assessment of investments in NG&E network infrastructure uses as a frame of reference the inputs and the results of the technological based (bottom-up) PET (Pan European TIMES) energy model that has been adopted in the REALISEGRID project to provide the long-term energy supply scenarios. The results of the PET model provide the so-called *adapted* systems, i.e., the optimal NG&E production, conversion and network infrastructures whose capacities have been obtained by minimizing the sum of investment and operating cost subject to the scenario constraints. The PET energy model provides these data for each explored scenario and for the years 2010, 2015, 2020, 2025 and 2030 at pan-European level. The selected scenarios drivers cover some of the most relevant non-random uncertainties for the future supply of energy, such as the climate change mitigation policies, the availability of new technologies at affordable costs, and the availability of oil and NG supply according to two possible and markedly separated ranges of prices.

- The approach to assess the investment in NG&E transmission infrastructure has the following characteristics:

    - The analysis is focused on proposed or possible transmission expansion projects, thus the capacity of these expansion projects is not a variable within the optimization procedure.
    - The performance or benefits of the transmission expansion projects are evaluated by means of their contributions to reduce the NG&E production and shortage costs. The installation or construction of new transmission infrastructures ease the transmission capacity constraints, therefore, in general, the production costs decrease (or shortage costs are avoided) because the transmission network imposes fewer limitations on the production dispatch. Other possible benefits arising from additional transmission assets are not considered in the proposed approach.
    - The demands for electricity and NG not used for electric power generation are modeled as totally inelastic, thus the maximization of social welfare is equivalent to a minimization of the NG&E production and shortage costs. In this context, the cost savings, associated with each transmission expansion project, are calculated using the *with/without analysis.*
    - The transmission expansion problem is formulated as a *static* problem since the timing of the commissioning of the new transmission infrastructure is not a decision variable. It is considered that the expansion projects are installed at the beginning of the assessment period. However, the evaluation takes into account a multi-period analysis with a 20 year investment time horizon (until 2030).
    - Some relevant random uncertainties, such as NG&E demands, fuel costs and wind power production, are considered in the proposed *probabilistic* approach. A Monte Carlo simulation is used to calculate the probability distribution functions of the cost savings due to the installation of the different transmission expansion projects.
    - A probabilistic net present value (NPV) for each transmission expansion project is calculated to rank the expansion alternatives. Each probabilistic distribution of the NPV is calculated through the convolution of the probability distribution of the cost saving at years 2010, 2015, 2020, 2025 and 2030, and considering that the total investment cost is spent at year 2010 (beginning of the assessment period). The expected value of the NPV, a risk neutral metric, is used to build the expansion alternatives' ranking.

- The core of the proposed approach is a NG&E operational planning model which is used as the main tool to assess the cost savings due to the investments in NG&E transmission infrastructure. This model is essentially a multi-period optimal NG&E flows subject to time coupling constraints. The main characteristics of this model are:

- The coordination of NG&E operations is addressed using a combined approach, i.e., a single optimization problem integrating the models of the natural gas and electricity systems.
- The time horizon considered in the NG&E operational planning covers a whole year to deal properly with the seasonal behavior of NG&E demands and some energy resources such as water inflows and wind power production. This one year time horizon, usually classified as medium-term time horizon, also allows us to model the energy storages adequately and, thus, to include their scheduling in the optimization problem. This is important since transmission and storage facilities are complementary, and therefore, the cost savings due to a transmission expansion are affected by the storages capacities.
- Mathematical programming algorithms are implemented to solve the optimization problem.
- The medium-term NG&E operational model is used within the Monte Carlo simulation method to assess the impact of the considered random uncertainties on the cost savings.

From a deterministic viewpoint, the combined medium-term NG&E operational planning model can be mathematically described as an optimization problem whose objective function is the minimization of the total NG&E operating and shortages costs over the considered time horizon. This cost minimization is subject to the following constraints:

- Electric power system constraints
  - Global power balance
  - Maximum transmission capacities
  - Maximum capacities of the generating units
- Natural gas system constraints
  - Nodal flow balances
  - Production capacity limits of each supplier
  - Maximum transport capacities of each pipeline
- Storage and time coupling constraints
  - Inventory equation of each water reservoir
  - Inventory equation of each NG storage
  - Capacity limits of water reservoirs
  - Capacity limits of NG storages
  - Injection/withdrawal flow limits of NG storages
  - Power output function of hydro power plants (maximum water flow rate)
- Time horizon coupling constraints
  - Initial volume equals to final volume at each water reservoir
  - Initial volume equals to final volume at each NG storage

However, most of the input parameters required by the medium-term NG&E operational planning model are uncertain. Thus, this operational planning is, in fact, a stochastic optimization problem. Among other methodologies, the simulative Monte Carlo method can be implemented to deal with these uncertainties. This simulation method is based on statistical sampling experiments which are performed on the mathematical model of the system to estimate its stochastic behavior. Therefore, the deterministic medium-term NG&E operational planning problem is solved by a finite quantity of realizations representing different possible values of the uncertain input parameters. The more uncertain input parameters are taken into account, the more simulation time is required to achieve the convergence target. For this reason, it is then necessary to select the most relevant uncertain parameters to be characterized explicitly and assume simplified probabilistic models for the other random parameters (or even neglect their random behavior). The proposed approach adopts electricity demands, non-for-power NG demands, wind power productions and fuel prices as the main uncertain parameters to be represented explicitly. The uncertainties related to these parameters are introduced adding residuals to the forecasted values, which are provided by the results of the PET energy model.

In this way, using the medium-term NG&E operational planning model within the Monte Carlo simulation process, it is possible to obtain the probability distribution of the cost saving due to the investments in NG&E transmission infrastructure for a certain year. Thus, the probabilistic NPV for each transmission expansion project is calculated by means of the convolution of the probability distribution of the cost saving at years 2010, 2015, 2020, 2025 and 2030, and considering that the total investment cost is spent at year 2010. The ranking of the expansion alternatives is based on the expected value of the NPV for each one of the considered alternatives.

2 INTRODUCTION

2.1 Objectives of this deliverable

The development of highly efficient natural gas-fired power plants (NGFPPs), in particular Combined Cycle Gas Turbines (CCGT), has made natural gas (NG) one of the preferred primary fuels for the production of electricity. Over the last two decades, this has led to a very significant increase in the proportion of the electricity generation capacity that is gas-fired. This has also created a very significant interdependency between the NG and electricity (E) infrastructures. In the long run, it is thus essential that investments in NG and electricity infrastructure proceed in a coordinated manner. In this context, the general aim of this document is to identify and propose a methodology and a tool for a coordinated assessment of investments in electricity and NG network infrastructures. The achievement of this main objective requires the analysis of several issues that are stated in the following partial objectives:

- Describe and analyze the supply chain of NG systems in order to indentify its characteristics and the basis for the expansion and operational planning of these energy systems
- Indentify and quantify the extent of the interactions between electricity and NG systems, recognizing the main coordinating parameters that are typically used for modeling these interrelations
- Review and describe the current and the latest proposed approaches and procedures to address the coordinated expansion planning of NG and electricity network infrastructures
- Propose a new approach for coordinated assessment of investments in NG and electricity transmission expansions taking into account the general framework defined in the REALISEGRID project
- Describe the selected tool to assess the performance of the transmission infrastructure investments including a detailed explanation of the adopted electricity and NG systems models

The consistent development of the listed specific objectives leads to the achievement of the general objective defined for this document: ensuring that the related background has been properly reviewed and that the approach to be proposed is based on solid fundamentals. It is important to point out that the goal of this document is to present a state-of-the-art methodology and its associated tool able to fully capture the interactions and synergies between NG and electricity systems, in particular those which are relevant when transmission expansions are decided.

The approach to be proposed should also meet the adequate characteristics to be applied to real NG and electricity systems according to the available information. This is because the proposed tool and methodology will be applied in REALISEGRID Deliverable D3.4.1, to identify the weak points in the existing infrastructures in continental Europe and the evaluation of possible investment scenarios to deal with such weak points.

2.2 Expected outcome

In order to achieve the above described objectives, this report has been organized to introduce firstly the required basis with regard to NG systems and their interdependencies with the electricity systems, and finally present the proposed methodology and toll for the coordinated assessment of investments in NG&E network infrastructures.

Chapter 3 describes and compares the main characteristics of natural gas and electric power supply chains. The organizational structure of both energy sectors are contrasted highlighting their similar features. The description includes the main technical characteristics of both energy systems and the physical laws that govern the steady-state power flows through their associated networks. In contrast to the electric power systems, NG can be easily stored. The different types of NG storage facilities are listed and the typical operating schedule of these reservoirs is conceptually presented.

The interactions between the NG and the electricity systems are explained from a technical and economical perspective in Chapter 3. These close interrelations have been mainly driven by the growing and sustained installation of NGFPPs. Two major indexes are defined to grade the level of interrelations between NG&E systems. Their values for the EU27, EU36 and many European countries are presented and analyzed. The current trends in the integration of NG and electricity systems are presented and analyzed, in particular using the preliminary results of the "Long term scenarios for European power systems" REALISEGRID Deliverable D2.3.2.

Chapter 4 presents the framework for a coordinated assessment of investments in NG&E network infrastructures. The outline of the integrated planning procedure of energy systems is introduced since it provides the general context in which transport and storage infrastructures are carried out. The decoupled and combined approaches to coordinate NG&E systems operations are presented as the possible alternatives to be used to assess the value of the network investments. Then, some relevant aspects about electric power transmission planning are reviewed including the characteristics of transmission investments, the valuation of these investments and the different methodologies proposed to deal with the problem. Finally, the proposed approach to a coordinated assessment of investments in electricity and gas infrastructures is described.

Chapter 5 presents and describes extensively the mathematical models and formulation of the combined medium-term NG&E operational planning model. A review of the approaches that address the integrated modeling and analysis of NG&E systems is discussed. The general concepts of medium-term operational planning are introduced including: the purposes and main results of the medium-term optimization, the temporal couplings and the optimal scheduling of storage facilities. The mathematical modeling of NG&E systems is presented including the adopted models for electric power flows and NG flows in pipeline networks. Then, the deterministic operational optimization problem of NG&E systems is formulated. Finally, the implementation of the Monte Carlo simulation procedure that takes into account the relevant uncertainties is described. Appendixes A.1 and A.2 describe the generation of multivariate normally distributed residuals and Monte Carlo stopping criteria, both procedures related to the probabilistic approach of the problem.

2.3 Approach

The development of a methodology and a tool for a coordinated assessment of investments in electricity and NG network infrastructures has involved a comprehensive review of the fundamentals of NG systems and the optimization process associated with the operational optimization of these energy systems. The identification and quantification of the interactions between electricity and NG systems has requested the analysis of statistical data from different sources. These evaluations show objectively the extent of the interdependencies between energy sectors, justifying the need of a combined analysis, modeling, and planning of them. The development of the objectives established for this document has requested an extensive literature review of the current and latest approaches and procedures to address the integrated operation and planning of multiple energy systems, and in particular for NG&E systems. All the reviewed documents, reports and scientific papers have been conveniently referenced for further explanations.

Based on the investigations described above and on the experience of the authors in the combined modeling and optimization of NG&E systems as well as on electric power transmission expansion planning, it is proposed a new approach for coordinated assessment of investments in NG and electricity transmission infrastructure. This new approach has been adequately tailored to suit with the general framework defined in the REALISEGRID project, in which the results of the long-term energy model (PET) are used as inputs for the new approach.

The approach for coordinated assessment of investments in NG and electricity transmission infrastructure proposed in this document will be applied to a test case and to a simplified real system. The results of these studies will be reported in REALISEGRID D3.4.1, which will focus on the identification of the weak points in the existing NG&E infrastructures in continental Europe and the evaluation of possible investment scenarios to deal with such weak points. Then, the complete picture about the features of the proposed approach can be better discussed analyzing this report along with REALISEGRID D3.4.1.

3 INTERCONNECTED NATURAL GAS AND ELECTRIC POWER SYSTEMS

Natural gas and electricity (NG&E) are energy carriers, i.e., a substance or phenomenon that can be used to produce mechanical work or heat or to operate chemical or physical processes [1]. While natural gas (NG) is a primary energy because it exists in a naturally occurring form and has not undergone any technical transformation, electrical energy is a secondary energy, which is the result of the conversion of primary energy sources. Both energy carriers can be defined as *final* energy carriers since they arrive to consumer's location to be transformed into the required *energy services* or *useful energy*, such as, space heating/cooling, lighting, cooking or refrigeration.

This section describes and compares the main characteristics of natural gas and electric power supply chains and the interactions between both energy carriers.

3.1 Description of the Supply Chain Structures

Natural gas and electric power systems have a remarkable common feature which is that extensive networks are used to transport the energy carriers from suppliers to customers. This characteristic results in both of these energy sectors having very similar organization structure and supply chains as shown in Table 3.1. Natural gas can also be carried in the form of Liquefied Natural Gas (LNG), which requires liquefaction trains, LNG ships and regasification terminals to accomplish with transport and re-inject the gas into the pipeline network. Natural gas transportation as LNG is typically used in transcontinental carriage or between two regions which are separated by thousands of kilometers including oversea routes. This, due to pipeline transportation, is more cost-effective over short and onshore distances than LNG transport [2]. If the analyzed NG supply chain covers a region which is large enough to include LNG transport as an economical option within the region, it can be taken into account as point-to-point transport modeling LNG regasification terminals as NG supply points and LNG liquefaction trains as NG demands points.

Natural gas-fired power plants (NGFPPs) create the link between the natural gas and the electricity systems, being consumers for the NG sector and producers for the electricity sector. Therefore, the interactions and interdependencies between both energy systems depend on the installed capacity of NGFPPs and their utilization for electricity production.

Table 3.1: Organization of natural gas and electricity sectors

Segments	Natural Gas Sector	Electricity Sector
Production (suppliers)	Gas Wells LNG regasification terminals	Electrical power plants: coal, nuclear, gas-fired, hydro
Transmission	High pressure pipeline network	High voltage network
Distribution	Medium/low pressure pipeline network	Medium/low voltage network
Consumption	Small consumers : commercial and residential customers Large consumers: NGFPPs, industries, LNG liquefaction trains	Small consumers Large consumers

Figure 3.1 shows a schematic representation of interconnected NG and electric power systems. The electric power system consists of a 3-bus network connecting NGFPPs, hydroelectric power plants, and non-gas thermal power plants to electrical loads. The NG supply system is analogous to the electric power system, with high-, medium- and low-pressure pipelines connecting remote sources - gas wells and LNG regasification terminals – to large/small consumers and NGFPPs.
In the electric power systems, large generation units (hydro, nuclear, coal, etc.) are usually far from consumption centers, so the delivery of the energy involves several voltage levels (from 750kV to 0.4kV) of transmission and distribution networks to interconnect production areas to consumption centers. The electric power generation system consists of a heterogeneous set of technologies (hydro, CCGT, nuclear, coal/NG fired steam turbine, wind, etc.) with different capacities and operating constraints.

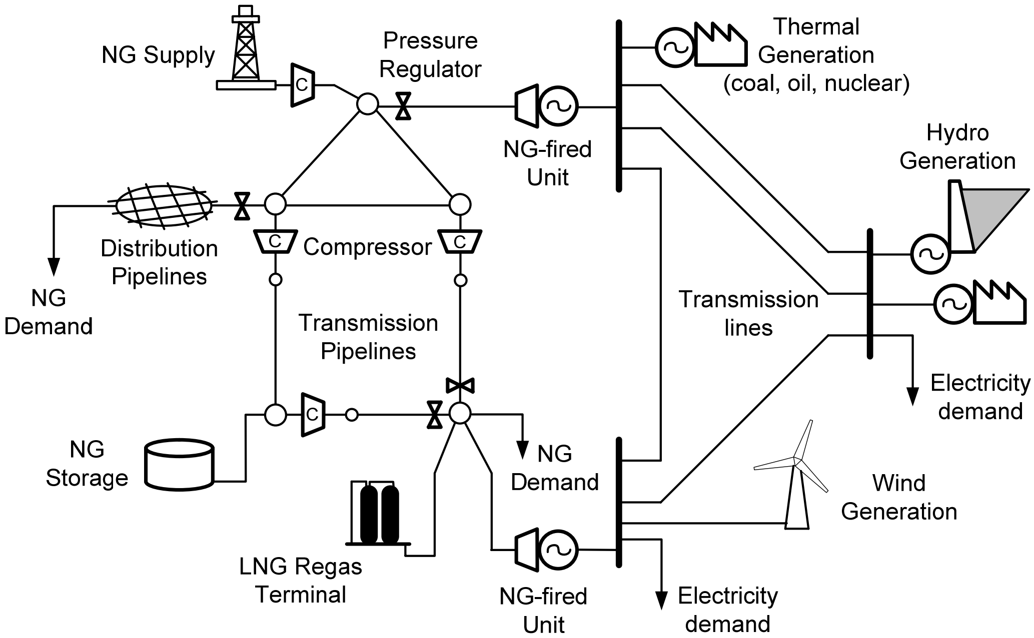

Figure 3.1: Natural gas and electric power systems

In electrical networks, the steady-state electric power flows are governed by Ohm's and Kirchhoff's laws. These laws can be expressed by means of nodal power balances and line power flows. Mathematically, the power flow through a transmission line depends on the complex voltage difference at its ends and its physical characteristics (serial and shunt resistances and reactances). The maximum capacity of each line is limited by its thermal limit (maximum conductor temperature) or by stability margins set for the whole electrical network. The energy losses in the electrical networks are due to line resistance (Joule losses) and to a lesser extent to shunt losses (Corona effect). The conversion between different voltage levels is performed by means of power transformers. The supervision, control and protection of transmission and distribution networks are performed by complex systems of switchgears and measurements equipments.

Like in the electricity production segment, a great diversity of technical characteristics can be found among NG suppliers. Gas wells – commonly located at sites far from load centers – and LNG regasification terminals – usually at harbor locations – have a wide diversity of capacity and operating constraints. The flexibility in NG production at gas wells depends on geological characteristics such as high pressure and high permeability as well as the investments made in production facilities. When these conditions are met, typically in dry gas wells located at non-associated gas fields[1], NG production is able to follow seasonal demand variations. This flexibility in NG production is called *swing gas* supply. In contrast, all LNG regasification terminals provide a flexible gas supply that is constrained by their maximum rates of deliver and associated storage capacity.

Natural gas transmission and distribution networks provide the same services as their electricity counterparts. Transmission pipelines transport NG from producers to local distribution companies or directly to large consumers. Distribution networks generally provide the final link in the NG delivery chain, taking it from city gate stations and additional gas supply sources to large and small customers. Four basic types of facilities are considered in the modeling of the NG transmission network: pipelines, compression stations, pressure regulators, and nodes. These nodes represent gathering or interconnection hubs within the pipeline network or city gate stations that provide an interface between the transmission and distribution NG networks. Despite the many analogies between NG and electric power transmission systems, these networks are usually operated in complete different manner. While the NG transmission network is operated in radial mode, the electric power transmission grid is operated in meshed mode to enhance the system's reliability.

A priority scheme for the supply of NG is generally in place to cope with situations where not enough gas is available to supply all the NG demands. Residential and commercial customers typically take precedence over large consumers and NGFPPs in this allocation because these sorts of consumers do not have the capability to switch to another energy source to substitute NG.

With some similarities to electric power systems, the steady-state gas flow through a pipeline is a function of the pressure difference between the two ends, gas properties (e.g., compressibility factor, specific gravity) and the physical characteristics of the pipe (e.g., diameter, length, friction factor) [3], [4]. Therefore, the pressure represents the state variable which is analogous to voltage angle in power systems.

During transportation of NG in pipelines, the gas flow loses a part of its initial energy due to frictional resistance which results in a loss of pressure. To compensate for these pressure losses and to maximize the pipeline transport capacity, compressor stations are installed at different network locations. In contrast to electricity networks, where theoretically no significant active power is necessary to maintain a certain voltage, compressors are usually driven by gas turbines. The amount of NG consumed at compressor stations depends on the pressure added to the fluid and the volume flow rate through it. However, the operating pressures are constrained by the maximum pressure allowed in pipelines and the minimum pressure required at city gate stations. Therefore, the transmission capacity of a gas pipeline is limited.

Valves are protective and control devices whose functions are similar to switchgears in electric power systems. Isolating valves are used to interrupt the flow and shut-off sections of a network. Pressure relief valves can prevent equipment damage caused by excessive pressure. Pressure regulators can vary the gas flow through a pipeline and maintain a preset outlet pressure. Compressor stations and pressure regulators make possible a high degree of control of NG flow

[1] Dry gas wells located at non-associated gas fields typically produce only raw natural gas that does not contain any hydrocarbon liquids

through the networks. On the other hand, it is currently not economical to control flows in individual transmission lines using flexible alternating current transmission system (FACTS).

While steady-state operation of power electric systems requires a constant balance between supply and demand, gas storage facilities are typically used for load balancing at all times, on hourly, daily, weekly or seasonally bases. Thus, the NG supply can be maintained at a much more constant level of production throughout the year. Natural gas storage also allows a more efficient NG network design since some pipelines can be smaller and more fully used throughout the year. Additionally, NG storage facilities, in particular those with large capacities, perform a security of supply function, keeping strategic NG stocks to cope with emergency situations, like supply disruptions.

Unlike electricity, where large scale storage is not yet technically or economically feasible, NG can be stored for later consumption. There are three major types of NG storage facilities. These storage facilities differ in terms of capacities (working volumes), maximum injection and withdrawal (deliverability) rates:

a) Underground storages:
   - a.1) Depleted oil/gas fields: former oil or gas- producing reservoirs that have been exhausted of NG. These long/medium-term storage facilities usually have high working volumes but limited withdrawal rates (average of less than 2% of working volume per day in OECD countries' depleted fields [5]). This makes them suitable for seasonal demand balancing and for storing strategic reserves.
   - a.2) Aquifers: naturally-occurring rock formations that are saturated with water. The development and operation of aquifers are more expensive than depleted fields. Therefore, aquifers are normally developed only close to demand centers where there are no available depleted fields, as they perform a similar role, given their high working volumes and low injection/withdrawals rates (average of less than 2.7% of working volume per day in OECD countries' aquifers [5]).
   - a.3) Salt caverns: natural or man-made salt beds or salt domes. These short-term storage facilities offer a high withdrawal rates but much lower volumes of gas than depleted fields. The average withdrawal rate from existing OECD countries' salt cavern storage is 6.5% of working volume per day but there is a high range between the minimum and maximum (min: 1.3%, max: 32.0%). Therefore, salt caverns can be cycled several times a year, allowing for daily or weekly demand balancing. However, their volume specific costs of development are higher than for depleted gas fields or aquifers.

b) LNG tanks:
   - b.1) LNG tanks at regasification terminals: these tanks receive LNG cargoes and are used as buffers before the NG regasification and send-out onto the NG network. Large storage volumes combined with high deliverability rates at regasification terminals make them suitable for dealing with short-term (daily- weekly) demand balancing, while a well-designed schedule of LNG cargoes helps with seasonal balancing.
   - b.2) Peak shaving units: small LNG storage, sometimes with its own liquefaction plant, a regasification plant with a very high send-out deliverability rate. During periods of extremely high demand, peak-shaving facilities can inject high amounts of gas into the system for a very short period of time, avoiding NG shortages.

c) Pipelines themselves: the amount of gas contained in the pipes is called *line-pack* and can be controlled by raising and lowering the pressure. It is normally used as peak/off-peak demand balancing resource on a daily basis.

Figure 3.2 shows how various types of storage can be used to ensure a reliable supply. It is based on the ideal situation where all demand information is known and all types of storage would be available. Figure 3.2 presents a yearly NG load duration curve, where days with highest demand are on the left, those with lowest demand on the right. An ideal and constant NG supply (production or imports) is indicated by the dotted line. For about half of the year, supply is higher than consumption. During this period gas storages can be filled. When gas demand is higher than gas supply (left side of the figure), storages are drawn. The more or less predictable summer/winter variations are covered by NG withdrawals from depleted fields and aquifers, as well as LNG terminals' *swing gas* when the required volumes are higher. Salt caverns or smaller depleted fields handle the more incidental demand peaks, and the extreme peaks are covered by peak shaving units or shedding the demand of interruptible consumers. *Line-pack* effect is not noticeable in Figure 3.2 because its main contribution is associated with intra-day demand balancing.

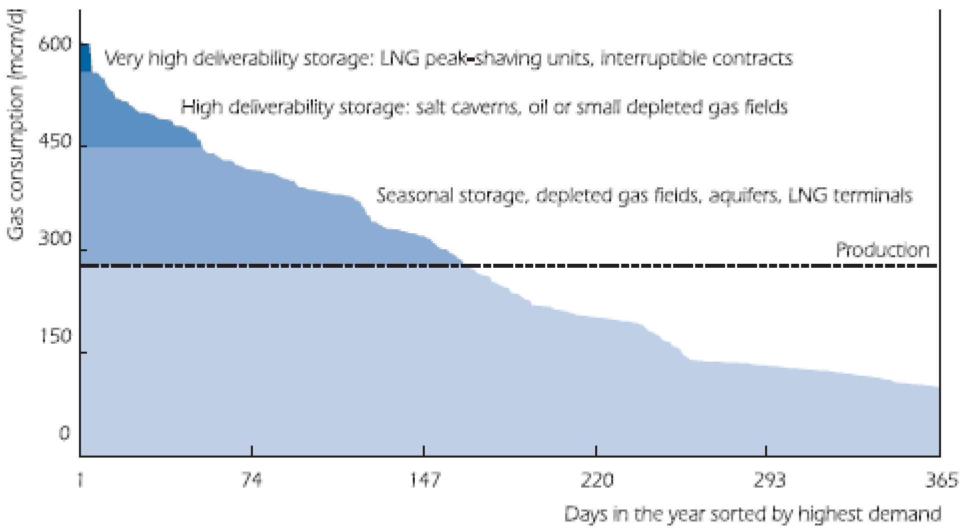

Figure 3.2: Use of various gas storage types, illustrative example [5]

Another important difference between NG and electricity is that electricity moves at the speed of light, while NG travels through the transmission network at a maximum speed lower than 30 km/h (reference value) [3],[6]. These facts imply that the dynamic behavior of NG systems is much slower than the dynamics of electric power system. Thus, while steady-state electric power flows are assumed for multi-period simulation with time steps longer than half hour (even up to several minutes), NG flows multi-period simulations with time steps shorter than several hours require pipeline distributed-parameters and transient models [3],[7]. However, many simplified models have been developed for NG flows simulation [3] and transmission system optimization [8],[9].

Table 3.2 summarizes the comparison between NG and electricity systems.

Table 3.2: Differences between natural gas and electric power systems

Characteristic	Power Electric System	Natural Gas System
Energy type	Secondary	Primary
State variables	Voltages	Pressures
Transmission losses (large systems)	Joule effect, up to 3%	Gas consumed in compressors stations, up to 6%
Transmission system operation	Meshed mode	Radial mode
Flow modelling	Steady-state can be assumed for operational simulations	Transient-state is required for operational simulation (time steps shorter than several hours)
Supply hierarchy	Not required in normal operation state	Frequently required in normal operation state. Usually NGFPPs and industry have lower priority
Individual flow controllability	Currently not economically practical (FACTS)	By means of pressure regulators and compressor stations
Storage facilities	Commercially marginal	Widely used in Europe and USA, not common in Latin America

3.2 Interactions: Drivers and Trends

The growing installation and utilization of NGFPPs over the last two decades has lead to increasing interactions between electricity and NG sectors. From 1990 to 2005, the worldwide share of NGFPPs in the power generation mix has almost doubled, from around 10% to nearly 19%; reaching in 2007, for instance, the 54% in Argentina, the 42% in Italy, the 40% in USA, and the 32% in UK [2],[10]. The installation of NGFPPs has been driven by technical, economic and environmental reasons. The high thermal efficiency of combined-cycle gas turbine (CCGT) power plants and combined heat and power (CHP) units, their relatively low investment costs, short construction lead time and the prevailing low natural gas prices until 2004 have made NGFPPs more attractive than traditional coal, oil and nuclear power plants, particularly in liberalized electricity markets. Additionally, burning NG has a smaller environmental footprint and a lower carbon emission rate than any other fossil fuel.

NGFPPs are the link between electric power and NG systems, since they play the role of producers for the former and consumers for the latter. Therefore, the growing use of NGFPPs has had a great impact on the NG market. Power generation accounted for around half of the growth in gas use from 1990 to 2004; over the most recent five years, this proportion rose to nearly 80% [2]. This fact is especially notable in those countries where large capacities of NGFPPs have been installed.

Two major indexes indicate the level of interrelations between NG&E systems. The first one is NG demand for power generation as a share of the total NG consumption, and the second one is the share of electrical energy produced by NGFPPs. Both shares depend not only on the NGFPPs installed capacity, but also on relative fuel prices (NG, coal, oil derivatives products) and the availability of other energy resources (hydroelectricity, wind power). Figure 3.3 shows year 2007 indexes for several European countries, EU27 and EU36 regions, and on a global basis [10], [11]. EU36 region consists on all the countries considered in the "Long term scenarios for European power systems" [14] of REALISEGRID project. The European countries, included in Figure 3.3, are those with the stronger interdependences between NG&E systems within the EU36. These close interactions are typically reflected in significant values of both indexes, like those reached in Ireland, Italy and the Netherlands. In the EU36 region, 20% of the generated electricity comes from NGFPPs which represent the 31.6% of the total NG demand.

In general, two sorts of countries (or regions) can be identified from Figure 3.3. There are some countries, like Italy, the Netherlands and the United Kingdom, with a well-developed NG industry, in which not only NGFPPs but also residential and industrial consumers have driven the growth of NG demand. In other countries, like Germany, Portugal and Spain, and to certain extent in EU27 and EU36, NGFPPs have been the clear predominant driver of NG demand increase. This fact can be noticed since share of electrical energy produced by NGFPPs is lower than the share of NG demand used for electricity generation.

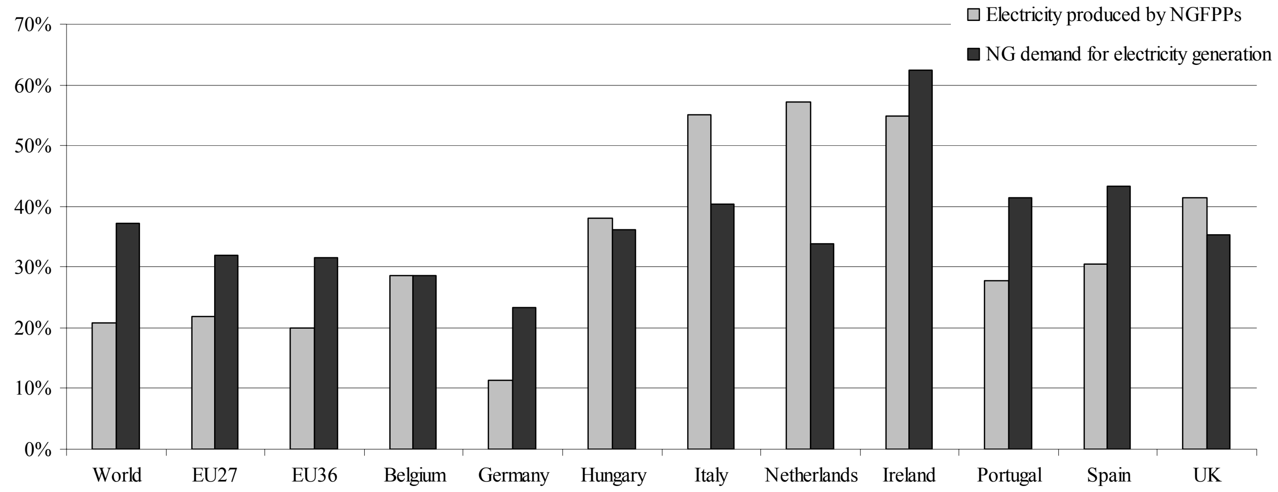

Figure 3.3: Indexes of interactions between NG&E systems in 2007

The interdependencies between NG&E systems can be described from a technical-operational viewpoint. The NGFPPs dispatch determines the total amount of NG consumption, and thus, its flows through the pipeline network. On the other hand, the NG availability for NGFPPs is constrained by:

- The maximum production/injection capacity of NG that gas wells, regasification terminals and NG storages are able to send-out into the pipeline network
- The maximum transmission capacity of the pipelines
- The priority scheme for the supply of NG in case of shortage, in which NGFPPs are usually the NG consumers most affected by curtailments.

Contingencies in NG infrastructure, such as interruption or pressure loss in pipelines may lead to a loss of multiple NGFPPs, and thus jeopardize the security of the power system.

These interactions can also be explained from a market perspective. The regulatory frameworks and the characteristics and designs of the existing electricity and NG markets, set the extent and the dynamics of the existing interdependencies. Generation companies that own NGFPPs participate simultaneously in both markets, therefore, they are best suited for price arbitrage between both commodities. Liberalized and flexible market structures facilitate this practice which is required to reach an electricity and gas partial economic equilibrium. According to electricity and NG market prices, and the marginal heat rate of their plants, these companies can decide to use gas and sell electricity in the power market, or resell previously contracted gas on the NG market and purchase electricity to meet their commitments. Therefore, electricity and NG market prices are increasingly interacting, which is particularly noticeable when no direct oil indexation is applied to NG pricing [2].

From 2005 to the first half of 2008, the raising NG prices have eroded the competiveness of NGFPPs, decreasing the pace of growth in NG use for electricity generation and reducing the incentives for future investments in these technologies. However, in 2008 NG accounted for 20% of global electricity production, overtaking nuclear as the second largest source of power [12]. The global recession has had a negative impact on electricity and NG sectors, decreasing electricity demand and particularly NG demand since the importance of gas demand for electricity generation and the marginal position of NGFPPs in the merit order. Nevertheless, as NG prices have converged to lower levels during 2009, the NGFPPs have recovered their investment attractiveness. For the coming decade, NGFPP capacity is estimated to continue to account for the bulk of electricity generation capacity additions. Beyond the factors in favor of NGFPP investments pointed out above, NGFPP could become one of the swing resources utilized to provide flexibility in power systems with large shares of intermittent renewable generation, underpinning the investments in these technologies [12]. On the other hand, from the NG market perspective, the electric power sector accounts for 45% of the projected increase in world NG demand by 2030. As a result, it is expected that the power sector's share of global NG use will rise to 42% in 2030 [13].

In particular, for the EU36 region, the preliminary results of the "Long term scenarios for European power systems" (Work package 2) within the REALISEGRID project, indicate that the interaction between NG&E will increase over the next two decades. Table 3.3 shows the share (percentage) of electricity produced by NGFPPs for the selected milestone years until 2030. Despite the wide range of scenarios considered as a combination of different drivers like high/low NG prices and strong/weak climate change mitigation actions [14], the share of electricity produced by NGFPPs will grow until 2020, except in the pessimistic scenario, in which the share will keep growing until 2030.

Table 3.3: Evolution of electricity production by NGFPPs in EU36 region

Scenario	Year				
	2010 [%]	2015 [%]	2020 [%]	2025 [%]	2030 [%]
Optimistic	25.4	31.7	37.4	37.0	34.7
Competing	25.3	31.7	37.4	37.2	32.8
EU-centered	25.4	31.1	36.1	32.8	26.5
Pessimistic	23.8	28.0	27.3	26.5	29.7

4 COORDINATED EXPANSION PLANNING OF NATURAL GAS AND ELECTRICITY NETWORK INFRASTRUCTURES

Under the light of all conditions previously described, there is a strong and rising interdependency between natural gas and electricity sectors. These interactions establish close links between NG&E decision-making processes at all time horizons, ranging from long-term planning to short-term operational decisions. Therefore, it is essential to include NG system models in electric power systems operation and planning. On the other hand, NG system operation and planning require, as input data, the NG demands of NGFPPs, whose values can only be obtained accurately from the electric power systems dispatch.

Natural gas and electricity network infrastructures, i.e., transport and storage facilities compete and complement each other in the energy supply task. Thus, it is necessary that the investments in NG&E network infrastructure proceed in a coordinated manner. Because of the complex nature of these network investments and because of the existing interaction described in the previous section, this coordination will require the development of a tool for the analysis and validation of investment scenarios.

This section presents the framework for a coordinated assessment of investments in NG&E network infrastructures. Firstly, the outline of the integrated planning procedure of energy systems is introduced since it provides the general context in which transport and storage infrastructures are carried out. Secondly, the two main approaches to coordinate NG&E systems operations are presented as the possible alternatives to be used to assess the value of the network investments. Then, some relevant aspects about electric power transmission planning are reviewed including the characteristics of transmission investments, the valuation of these investments and the different methodologies proposed to deal with the problem. Finally, the proposed approach to a coordinated assessment of investments in electricity and gas infrastructures is described.

4.1 Energy Systems Planning

The technical energy systems are the multiple and complex infrastructures that allow providing the consumers with the required energy services. These infrastructures include conversion, treatment, transport and storage facilities which comprise the supply chains from the primary energy sources (oil, coal, natural gas, nuclear, solar, wind) to final energy carriers (electricity, natural gas, water district heating).

Before the energy crisis of the 1970s, energy was relatively cheap, and the attention was focused on technological and engineering issues. The energy system planning was limited to some energy sectors such as electricity, oil, and coal, without almost no coordination between them. The growing demands were consistently dealt with by supply reinforcements without analyzing the possible substitutions or efficiency competition among the energy carriers [15].

Nowadays, there is a consensus among policy makers that energy sector investment planning, pricing, operation and management should be carried out in an integrated and coordinated manner in order to achieve an economic, reliable and environmentally sustainable energy supply. All these activities and procedures should be consistent with each other and help attain the established energy policy targets. To tackle this huge and complex decision-making problem, a wide diversity of approaches and models converge to a hierarchical and sequential optimization procedure.

The so-called energy models are the first stage in this hierarchical energy planning procedure. In such models, all (or most) energy carriers are considered in an integrated approach. Several of these energy models have been developed to analyze a range of energy policies and their impacts on the energy system infrastructures and on the environment. Others are focused on forecast of demand for energy services. An overview and a classification of some of the most relevant energy models, such as TIMES (integrated MARKAL-EFOM system) [16], MESSAGE [17], ENPEP-BALANCE [18] and LEAP [19], is presented in [20]. These models adopt a long term planning horizon, typically more than 20 years, and can be tailored to cover local, national, regional or world energy systems. The interactions between the energy sectors and the other sectors of the economy (e.g., transport, industry, commerce, agriculture) can be taken into account through model extensions or represented by means of constraints.

Because the dimensions of the problem, energy models are not developed to represent the characteristics of different transport modes or the complex physical laws that govern electric power and NG systems. Typically, only nodal energy balances are considered for each energy carrier. Another limitation of these models relates to the modeling of energy storage which is usually oversimplified or disregarded.

The results of these models provide the framework for the following stages, in which each energy carrier system is typically planned and operated in a decoupled manner. Thus, specific procedures and strategies are implemented according to specific value system, e.g., economic, technical, political and environmental context. Usually, a single energy carrier system expansion and operation planning is carried out at the time, and the other energy carriers availabilities and prices are incorporated as coordinating parameters. Electric power systems are a good example of this approach: they are planned and operated without taking into account the integrated dynamics of the fuel infrastructures and markets, i.e., costs and capacities of fuel production, as well as storage and transportation. The main assumption, in which this decoupled planning and operation approach, is based on the fact that there have not been significant energy exchanges between the energy carriers if they are compared with the total amount of energy supplied by each energy carrier.

More recently, new approaches to energy system planning have been presented. They are focused on a higher technological description of some energy sectors and their transport modes. Bakken et al [22] present a model that includes the topology of several energy systems, and the technical and economic properties of different investment alternatives. Among other energy modes of transport, simplified electricity and NG networks are considered. Other approaches and tools have been proposed to address specifically integrated NG&E systems planning [23]-[25]. The network models, included in these tools, consider not only the electricity and gas nodal balance, but also the loss factors and constrained capacity of each pipeline and electricity transmission line. It is important to point out that these approaches cover the whole NG&E supply chain infrastructure, i.e. electricity generation, NG supply (production and regasification), NG&E transport and NG storage. Nevertheless, no specific proposal for the coordinated expansion planning of NG&E network infrastructure is available in the literature.

4.2 Coordination of Natural Gas and Electric Power Systems Operations: Combined and Decoupled Approaches

Nowadays, the operational planning of electric power and NG systems is carried out in a decoupled manner, i.e. different operational optimization problems are solved where each system is self-contained. However, this does not mean that both systems are totally independent. In fact, the existing interactions are modeled by means of fixed coordinating parameters. Typically, three types of parameters can be identified:

a) The NG prices considered in the production cost functions of each NGFPP;
b) The NG availability for the NGFPPs;
c) NG consumption at each NGFPP

While the electric power operational planning requires, as input data, the (a) and (b) set of parameters, the NG operational planning needs, as input data as well, the (c) set of parameters.

The decoupled approach to coordinate NG&E operations consists of two stages. Usually, in the first step, the operational planning of electric power system is performed, considering NG prices and availabilities for electricity generation – set of parameters (a) and (b) – as given. The NG prices for NGFPPs are typically estimated according to the NG tariff for NGFPPs or the prices established in supply contracts signed between NGFPPs and NG marketers. The NG availability for NGFPPs is normally considered as it is informed by the companies that own the NGFPPs, otherwise NG supply adequacy is assumed. The main results of the electric power operational optimization include the operating schedule of generating units and the nodal electricity marginal costs. The NG consumption at each NGFPP is a byproduct of this procedure. Then, the operational planning of the NG systems can be carried out, giving the operating schedule of production, transmission and storage facilities as the main result. Also, the nodal NG marginal costs are obtained from this NG system optimization. Figure 4.1 shows a flow chart of the decoupled approach to optimize NG&E operations in a coordinated manner, including the main input data and the resulting outputs.

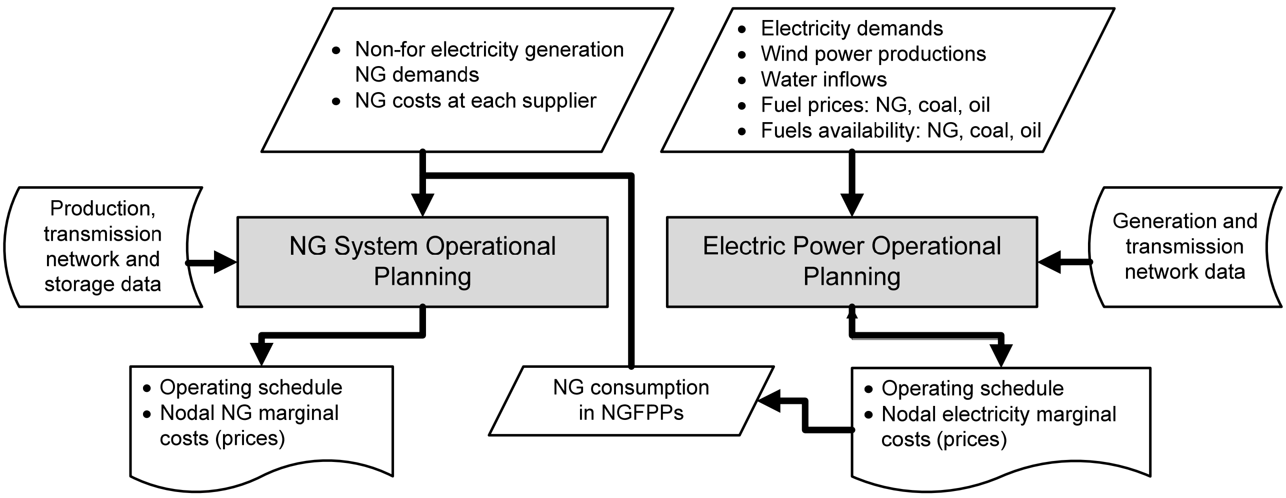

Figure 4.1: Decoupled approach

Nevertheless, this decoupled procedure can be also performed the other way around. First, the operational planning of NG system is carried out taking into account an estimate of the NG to be consumed by the NGFPPs according to the information provided by the generating companies. And then, the operational planning of the electric power system is performed using the NG prices for NGFPPs and assuming NG supply adequacy if the results of the NG system dispatch do not show shortages in NG availability.

However, some of the following situations can occur:

(1) The total NG supply is not sufficient to meet the total NG demand, including the NGFPPs' demands. The NG supply to NGFPPs can be curtailed before the other demands, since NGFPPs usually have a lower priority of supply.
(2) The limited transmission capacity in the NG network can caused the same situation as (1) to occur at specific node.
(3) The fixed NG prices, which determine the NGFPPs production costs, in general do not match the NG marginal costs at nodes where NGFPPs are placed. These marginal costs depend on NG consumption in the compressor stations (NG network losses) and binding pipelines (transmission) capacity constraints.

If the situation described in (1) actually occurs, a re-dispatch of the electric power is required to update the total NG availability for NGFPPs. If the situation described in (2) occurs, a re-dispatch of the electric power is also needed but after introducing additional constrains on NG availability for the NGFPPs connected to the NG nodes affected by the shortage of NG.

If nodal spot prices of NG were set at the NG short-run marginal costs at each node, then the differences stated in (3) will result in a profit (or loss) to be redistributed among the involved market agents (NGFPPs, NG marketers, NG Disco). However, the situation indicated in (3) means that the dispatch of NGFPPs is based on incorrect economic signals, which leads to economic inefficiencies (deadweight loss), i.e., higher electricity and NG operating costs, if price inelastic demands are considered. This is based on welfare economics theory [26], which states that a Pareto-efficient outcome situation is achieved in a competitive equilibrium where prices are set by the marginal costs of supply. Reference [27] shows an assessment of the social welfare losses when different fixed NG prices are considered. The authors demonstrate in a case study that these losses are only avoided when fixed NG prices match the NG marginal costs.

Therefore, in order to overcome the inconsistencies in the decoupled approach, shown by situations (1), (2) and (3), electric power and NG operational planning models must be run iteratively. However, the convergence of this procedure is slow and may be hard to reach when NG consumption in NGFPPs represents a significant share of the total NG demand.

On the other hand, in a combined operational planning of NG&E systems, the described coordinating parameters are endogenous results of the optimization problem. This ensures that the optimal operating schedule for both systems is achieved simultaneously. Figure 4.2 shows the main inputs and outputs of the combined approach to optimize NG&E operations.

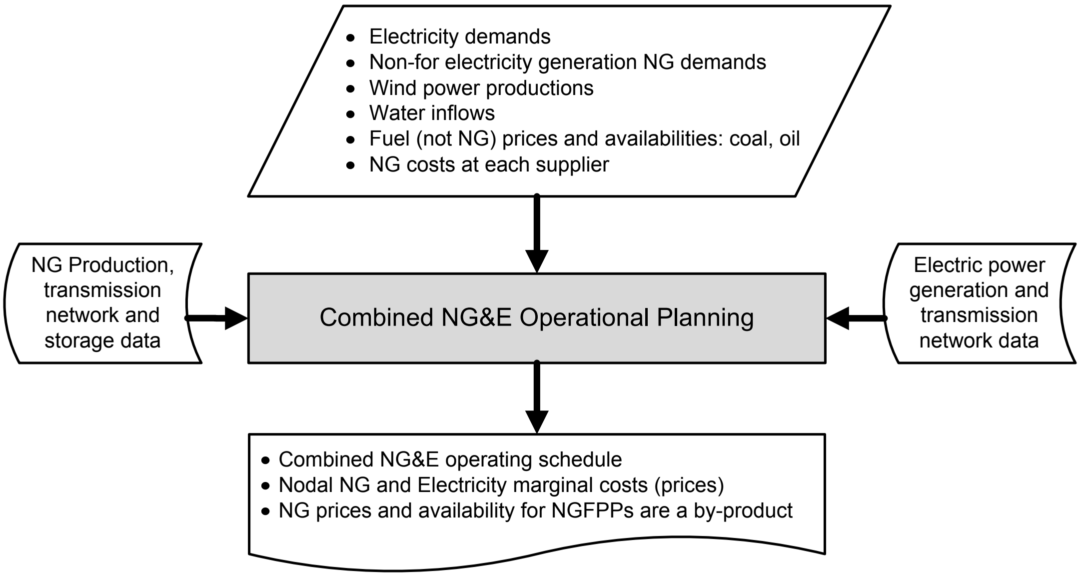

Figure 4.2: Combined approach

Several approaches have been proposed to address the combined modeling and operational planning of NG&E systems. To tackle this high-dimensional problem, a hierarchical and sequential optimization scheme is typically implemented. Under this scheme, different optimization models cover different time horizons with different modeling details of NG&E systems. Models with longer time horizons are more compatible with less detailed modeling in order to achieve reasonable computing times. On the other hand, approaches and models with shorter time horizons need as accurate modeling of NG&E systems as possible to obtain plausible results that can be implemented as the operating schedule of real NG&E systems. Reference [28] presents a review of the main approaches and models, which deal with the combined operational planning of NG&E systems. The different approaches are conveniently grouped according to the time horizon considered: long/medium-term [29]-[32], several months to 2 years; short-term, one day to 2 weeks [33]-[36]; and single period or snapshot [27], [37]-[42].

4.3 Transmission Expansion Planning

Basically, the transmission expansion planning problem is aimed at determining ex-ante the location, capacity, and timing of a set of transmission expansion projects –an expansion plan-, which maximizes the social welfare over the planning horizon while adequate reliability levels are maintained and technical constraints are fulfilled [45]. Under this traditional perspective, the transmission expansion planning problem can be mathematically formulated as a large-scale, stochastic, multi-period, non-linear, mixed-integer optimization problem. A large number of algorithms and approaches have been proposed for solving this complex task. Nevertheless, the current theory and tools for assessing transmission investments are still below the actual and practical requirements. These limitations are particularly emphasized in aspects such as the uncertainties management, the flexibility assessment of the embedded options within the expansion plans and coordination between the expansion plans of the different energy carrier networks, especially NG&E systems.

Throughout this section, the concepts of transmission expansion planning of electrical networks have been extended to include analogous problem in NG systems.

4.3.1 Nature of transmission investments

Many singular characteristics distinguish transmission expansion investments from any other type of investments. The distinctive nature of these characteristics has an effect on the investment performances and must be taken into account during the valuation and design of transmission expansion plans [43]-[45]:

- The transport of NG&E is subject to the physical laws that govern NG&E flows in their associated networks. Therefore, the flow through each transmission branch is affected by any variation of the flow of another grid component. Consequently, a new transmission asset could alter NG&E flows in other and apparently unrelated transmission branches.
- Transmission satisfies *natural monopoly* conditions and transmission infrastructure behaves to a certain extant as a *public good*. The provision of the transport service from only one company is socially less expensive (in terms of average costs) than the same service provided by several companies, i.e., the average cost function of transmission business are subadditive. This is the necessary and sufficient condition for the verification of a *natural monopoly*. Subadditive average cost functions put in evidence the existence of *economies of scale* in transmission service provision. Moreover, transmission infrastructure is usually conceived as open access facilities, where producers and consumers can use them as non-competing and non-excludable good. Therefore, when a new transmission expansion is incorporated, others users of the transmission service (free-riders), which are not the expansion investors, benefit from the transmission upgrade unless particular economic rights are reserved for the investors.
- Transmission investments are *lumpy* and present *economies of scale*. Transmission expansions cannot be designed or built in a continuous range of capacities. Because practical and standard aspects, transmission expansions are only available at certain capacities that can differ significantly. Also, investment expenditures are not proportional to the capacity they provide. In general, transmission expansions with higher capacities are cheaper than low capacities expansion in terms of unitary costs. These characteristics could lead to under- and over-investments scenarios and delay of possible transmission investments. Therefore, expansion investments generally remain operating under their maximum rate during their early life. Later on, they are usually utilized much more intensively, at least if the situation evolves as forecast.
- Transmitting electric power is *capital-intensive*. Large amount of expensive equipment are required to provide this service in a secure and efficient manner. The cost of this infrastructure is high compared to the cost of operating the system. Transmission investments also verify this cost relation.
- A substantial fraction of the total required capital expenditure must be spent prior to the commissioning of the new transmission equipment. This characteristic is known as *one-step* investments. On the other hand, transmission assets have a *long life* ranging from 20 to 40 years or even longer. Therefore, the depreciation period of these assets takes many years or even decades since it must be in accordance with their expected life.
- Investment projects in the transmission system are *vulnerable to unforeseen scenarios and long-run uncertainties* that can occur along the investment horizon. Technology development, future demands, fuel costs and investments in generation/production are uncertain variables when evaluating these investments.
- Transmission network investments are irreversible, i.e., once executed, they are considered as *sunk costs*, because these have a nearly zero residual value if the conditions unfold

adversely. Indeed, it is very unlikely that transmission equipment can serve other purposes if conditions change unfavorably.

- In general, opportunities to invest in the transmission system are not of the *now-or-never* kind. Thus, it is valuable to maintain the investment option open, i.e. wait for further information until uncertainties are partially resolved. Thus, transmission investments projects can be treated in the same way as a financial call option [46].

These uncertainties interact with the nature of transmission investments increasing radically the risks in the decision-making process. Thus, the features of transmission investments must be taken into account carefully when evaluating them. The methodologies used to deal with these characteristics could affect in the performance of a particular investment alternative and largely define its feasibility.

4.3.2 Transmission expansion approaches

In order to tackle the challenging problem of transmission expansion planning, a wide and diverse range of approaches have been proposed. An extensive and detailed description of the transmission expansion approaches is included in Deliverable D3.3.1 of the REALISEGRID project [47]. Notwithstanding, this section presents a classification of these methodologies to give a better understanding of the approach proposed for a coordinated expansion planning of NG&E network infrastructures.

The different methodologies for the transmission expansion planning and their associated models can be generally grouped according to the regulatory framework established for the transmission service [43], [47]-[50]:

- Regulated perspective: the approaches are based on a centralized planning led by the organism that operates the transmission infrastructure and/or the institution that regulates the transmission service, under instructions to build an economically efficient system. In practice, investments are remunerated on the basis of a regulated rate-of-return (ROR) with a requirement that investments be used and useful. This approach seeks to maximize the social welfare without pursuing profit objectives for any particular agent involved in the energy supply chain. When performance-based-regulation is in place instead of ROR, the revenues are adjusted based on costs and performance. The owner of the transmission infrastructure then has incentives to invest in expansion plans that enhance the efficiency of the transmission system.
- Merchant perspective: the approaches consider that transmission expansion investments are carried out by private companies or investors, subject to technical constraints. The investors are remunerated for such investments through the allocation of transmission rights. Opportunities for arbitrating energy between geographical locations provide the main incentive for building the new transmission infrastructure. Under this approach, the investors hope to obtain larger revenues than under ROR regulatory framework, but they face the whole risk that these revenues may be insufficient to recover the cost of their investment.

Transmission expansion approaches are also classified according to how relevant features of the transmission expansion problem are taken into account:

a) Time frame horizon:
   - a.1) Dynamic formulation: the objective of transmission expansion planning problem are not only to determine the location (*where*) and the capacity (*which*) of the facilities, but also the timing (*when*) they should be installed within the time horizon.
   - a.2) Static formulation: unlike the dynamic formulation, the timing of commissioning the new transmission infrastructure is not a decision variable. Thus, the static transmission expansion planning aims to determine *where* and *which* new infrastructure should be installed at the beginning of the selected planning period. Moreover, it is usually also assumed that the boundary conditions (demand profiles, production/generation assets, fuel costs) will be maintained over the planning period, thus the analysis can be reduced to a single year. These suppositions form the basis of the so-called *mono-period* approaches.

b) Uncertainties:
   - b.1) Deterministic approaches: this type of models assumes that all the problem's boundary conditions (the inputs parameters of the model) are known with complete certainty and, therefore, there is a unique and known scenario for the evolution of all the input parameters. Notwithstanding, most of these parameters are actually uncertain, and their expected values are used for planning.
   - b.2) Non-deterministic approaches: this type of models deals with the random and non-random uncertainties that affect the model's input parameters. These approaches can also be sub-classified according to the technique used to handle the uncertainties [45]:
     - b.2.i) Scenario analysis: this technique calculates independently the value of investments under N scenarios in order to explore and understand the main uncertain factors that affect the development of the transmission system. Each scenario covers a set of extreme outcomes or realizations of main the uncertainties considered.
     - b.2.ii) Probabilistic analysis: this technique considers random uncertainties than can be characterized through probability density functions. Stochastic optimization or Monte Carlo simulation method are used to evaluate the different transmission expansion plans under random inputs parameters. The decisions about which transmission infrastructures will be installed are usually based on the *expected value* (risk neutral behavior) of the objective function defined for the optimization problem. Moreover, the application of Monte Carlo method provides the probability distribution of the objective function, and thus, it is possible to quantify the risk of the transmission investment (unfavorable outcome of uncertainties) with some metrics, such as, the value at risk (VaR) and the conditional value at risk (CVaR). However, the decision-making handles the uncertainties and risks from a passive perspective.
     - b.2.iii) Risk analysis: the methods that use this technique, like probabilistic methods, deal with random uncertainties and quantify the risk of the investments, but incorporate a proactive management of the unfavorable consequences (risks) that could result from the investment decision in combination with unforeseen circumstances and future uncertainties. This can be achieved by means of adapting the expansion plan or the investment strategy to any change, foreseen or not, in the conditions that

were considered at the time it was planned. This ability within the investment plan is called *flexibility* [48]. In fact, these contingent decisions as well as available technical and managerial embedded options (e.g., deferral, reinforcement in later stage, operational flexibility, project abandonment at certain stage) in an investment project, also called flexibilities, are introduced as new decision alternatives. *Robustness analysis* is another technique to deal with risk in investment decisions, which is based on seeking an investment plan able to withstand unforeseen circumstances with no changes.

b.2.iv) Decision analysis: this method, also known as decision trees technique is successfully applied when random and non-random uncertainties are also considered in transmission investments. Decision analysis (DA) basically entails a graphical representation of the solution process through an *event tree*, which can include the results of probabilistic or risk-based approaches and non-random events.

From a mathematical point of view, transmission expansion planning is essentially a large-scale, multi-period, non-linear, mixed-integer (highly combinatorial) optimization problem. Therefore, independently of which approach is implemented to tackle this problem, an optimization procedure is at the core of the transmission expansion planning. The selection of the appropriate optimization technique depends on the mathematical formulation and properties of the objective function, constraints and decision variables. The different optimization algorithms can be classified as:

- Mathematical programming methods, such as: linear programming (LP), dynamic programming (DP), quadratic programming (QP), nonlinear programming (NLP), mixed-integer programming (MIP). Decomposition methods, such Bender's decomposition, have also been implanted to divide the large-scale problem in multiple and simpler sub-problems.
- Heuristic (or Meta-heuristic) methods, such as: genetic algorithms (GA), simulated annealing (SA) and tabu search (TS) algorithms, particle swarm optimization (PSO).

Another relevant aspect that differentiates transmission expansion approaches is related to the criteria and parameters used to evaluate the performance of the transmission expansion plans. New network infrastructures imply benefits for some participants in the NG&E supply chains (producers, consumers, transmission systems operators), but also could result in drawbacks for some of them. However, from a systemic perspective, transmission expansions must contribute to improve NG&E systems' performance as a whole, without discriminating between participants in the supply chains. Some of the most relevant systemic benefits that arise from network infrastructure investments are listed below grouped according to their final effects:

- Social welfare improvements: reduction in production costs and shortage costs, unlock of efficient generation, competitiveness increase.
- Technical performance improvements: system reliability improvement, better quality of supply, losses reductions (also imply a reduction in the cost of supply), system dynamic behavior improvement.
- Sustainability improvements: emission reductions, integration of renewable energy resources.

A thorough list and description of transmission expansion benefits is included in Deliverable D3.3.1 of the REALISEGRID project [47].

Transmission expansion approaches can include one or more (multi-criteria approaches) of the expansion's benefits in the objective function to be optimized. Some benefits can also be indirectly considered in the optimization problem as dominant constraints, e.g., establishing limits on the type of emissions or reliability indexes. When more than one benefit is used to assess the performance of transmission expansions in an aggregated objective function, the benefits must be expressed in the same unit, such as monetary units, through conversion factors, like the value of lost load (VOLL) or the price CO_2 emissions. These conversion factors can significantly influence the final solution since they balance the weight of the different benefits. Other approaches have been proposed to deal with multi-criteria optimization but they all rely in different way on weighting factors to compare and balance the benefits resulting from the transmission expansion.

To evaluate the benefits of a transmission investment, the performance of the NG&E must be assessed systems under two scenarios: with and without the transmission expansion. This procedure, also know as *with/without analysis*, must be performed maintaining all the input parameter and boundary conditions for both cases. The performance differences between the case that include the transmission expansion and the case that does not include the transmission expansion are the benefits of the transmission investment.

Finally, it is important to point out how objective function of the transmission expansion problem is defined. The obvious formulation should be to maximize the transmission expansions benefits in contrast with the investment, operation and maintenance costs associated with the expansion.
However, in practice, the benefits are expressed in monetary units, and thus, the optimization problem is more easily defined as a cost minimization, including typically:

- The investment, operation and maintenance costs associated with the transmission expansions;
- The NG&E production and operating costs
- The NG&E shortage costs

4.3.3 Valuation of transmission investments

Assuming that all the benefits (or negative externalities) derived from the inclusion in the system of a transmission infrastructure expansion can be expressed in monetary units, the net (or actual) value of this transmission expansion is equal to the difference between the benefits and the investment costs associated to the expansion. These benefits, which in this context are assessed as cost savings, occur over the depreciation period (asset's economic life) of the transmission expansion and the major fraction of investment cost are spent before the new infrastructure is commissioned. Therefore, financial appraisal methods need to be applied to compare these amounts of money, in the same way these methods are used to assess any other kind of investment project.

Net present value (NPV) is probably the most used and well-known technique for investment appraisal [51]. The NPV of the transmission investment project at time period $t = 0$ is defined by the following expression:

$$NPV_0 = \sum_{j=1}^{N} \left(\frac{CS_j}{\prod_{i=1}^{j} (1+k_i)} \right) - I_0 = PV_0 - I_0 \tag{1}$$

where I_0 is the immediate investment cost (outlay), CS_j are the cost savings (benefits) at year j and N is depreciation period (investment horizon) in years. The discount rate, k_i, represents the opportunity cost of capital of the company/institution making the investment in the year i [51], therefore it should reflect the level of risk[2] of the project. This rate is also known as *hurdle rate*, i.e., the minimum acceptable rate of return for investing resources in a project. If the investment cost is divided and made in more than one year, it is possible to generalize Equation (1) as follows:

$$NPV_0 = \sum_{j=0}^{N} \left(\frac{FF_j}{\prod_{i=0}^{j} (1+k_i)} \right) \tag{2}$$

where FF_j is the cash flow at year j and is obtained as $FF_j = CS_j - I_j$.

Therefore, NPV as a making decision tool tries to quantify the return on a proposed investment decision and contrast it to a minimum acceptable hurdle rate in order to decide whether the project is acceptable or not [52]. In this sense, the NPV represents the absolute value of the wealth that a new transmission investment project adds to the NG&E systems. Therefore, the investment project should be accepted (installed) is the NPV is positive (NPV > 0) [51]. If the project has a negative NPV (NPV < 0), then the project should be rejected since this means that the transmission expansion project does not add value to the systems.

On the other hand, the internal rate of return (IRR) for a transmission investment (or in general for any kind of investment project) is the rate of return that produces an NPV equal to zero. Mathematically, this definition can be expressed as:

$$\begin{aligned} &-FF_0 + \frac{FF_1}{(1+IRR)} + \cdots + \frac{FF_n}{(1+IRR)^n} = 0 \\ &FF_0 = \sum_{j=1}^{n} \frac{FF_j}{\prod_{i=1}^{j} (1+IRR)} \end{aligned} \tag{3}$$

[2] Not all investments are equally risky. For instance, a transmission investment is riskier than a US Treasury bill, but is probably less risky than investing in a start-up biotech company. For instance, suppose that investors believe the transmission development is as risky as an investment in the stock market and that they forecast a 15 percent rate of return for stock market investments. Then 15 percent would be the appropriate opportunity cost of capital. In addition, the hurdle rate has to be set higher for riskier projects and has to reflect the financing mix used, i.e., the owner's funds (equity) or borrowed money (debt) [52].

The IRR is a measure of the periodic returns on investment. Conventional capital budgeting strategy accepts an investment project, the IRR of which exceeds an estimated hurdle rate for the whole depreciation period. Thus, if the hurdle rates k_i used in NPV were the same for all years and this hurdle rate is used as the threshold in the IRR assessment, then NPV and IRR appraisal methods produce the same results in terms of accept or reject an investment project. However, one must not confuse the IRR with the hurdle rate used in NPV, since this represents the opportunity cost of capital while the IRR is the intrinsic rate within the project.

Unlike the NPV, IRR method takes into account the project's scale[3]. However, there are some problems in implementing the IRR method for evaluating investment projects. The IRR assumes that each cash flow is reinvested at the IRR rate for the same number of years that are missing to complete the project economic lifespan[4]. Other problems derive from the non-linear characteristic of Equation (3). In complex investment projects, where cash flows change sign more than once, two things can happen: a) the project can have more than one IRR (i.e. there is more than a rate that satisfies the equation NPV = 0) and b) the project does not have an IRR (there is no real rate that satisfies the equation NPV = 0).

NPV and IRR are also suitable financial metrics to rank transmission investment projects. The ranking list is established by sorting the analyzed investment project in ascending NPV or IRR order. In this way, it is possible to compare different transmission investments and to establish priorities in capital usage.

NPV and IRR appraisal technique or its underlying discounted cash flow method has been widely applied to the transmission expansion problem. Some multi-period (dynamic or static) transmission expansion approaches include in their objective function the discount rate in order to properly evaluate the different expansion projects. Other approaches rank the expansion projects using the NPV or IRR technique externally where cost savings are calculated using the *with/without analysis.* Conversely, mono-period (single year) static approaches usually include annuitized investment costs to assess the performance of the transmission investment.

The previous paragraphs describe NPV and IRR appraisal methods and how they are applied to the deterministic transmission expansion problem. However, most of the input parameters are uncertain, and therefore the resulting benefits (cost savings) from the transmission investments are directly affected by these uncertainties. In addition to the typical uncertainties in future demands and fuel costs, the hurdle rate (or rates) used to calculate the NPV of a transmission investment is also uncertain and can be characterized in a probabilistic way. Thus, the valuation of transmission expansion project and the NPV appraisal technique must be adapted to properly consider, assess and reduce the impact of the diverse uncertainties along the investment process lifetime. In a close relationship with the non-deterministic transmission expansion approaches described in the previous section, these are the most relevant techniques to apply NPV under uncertainties:

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[3] The NPV is based on absolute rather than on relative terms and does not, therefore, factor in the scale of the projects [52]. For instance, project A may have a net present value of $200, while project B has a net present value of $100, but project A may require an initial investment that is ten or 100 times larger than project B. Under NPV rule, both projects would be accepted, no matter what the investment is.

[4] The modified IRR method allows to use a different (from the IRR) reinvestment discount rate for the cash flow. However, this implies to estimate another hurdle rate which is not a trivial task.

a) Sensitivity analysis: this technique individually examines the impact of the fluctuations of one variable on the NPV of the expansion project. The basic idea is to keep all parameters constant except one, to see how sensitive the NPV of the project is to changes in this parameter. Sensitivity analysis identifies the key uncertainties within the investment project. However, the uncertain parameters are not independent variables, and their evolutions throughout the investment horizon are linked according to economic fundamentals [44]. Therefore, the use of sensitivity analysis in transmission expansion approaches is limited to certain particular cases.

b) Scenarios analysis: this technique considers the sensitivity of NPV with respect to some combination of changes in many uncertain (random) parameters and also variations in the fundamentals (non-random) of the investment project. Since this technique can only assesses a limited number of scenarios, the set of scenarios could be skewed by the subjectivity of the project evaluator. Therefore, this technique is extremely dependent on the capabilities and expertise of the evaluator.

c) Simulation analysis - Monte Carlo method: this technique considers most of the possible combinations because it takes into account the full distribution of the possible outcomes of the uncertain (random) inputs parameters, and thus, the wide possible outcomes of the investment project. Such simulation methods are statistical sampling experiments, which are performed a finite number of times, in order to assess the stochastic behavior of the system. This method provides the probability distribution of the variables studied within the procedure without extra calculation effort. In the case of the valuation of transmission investment, the application of the Monte Carlo method makes possible to calculate the probability distribution of the investment's NPV or the probability distribution of the objective function's value which include the evaluated attributes (benefits and costs) of the expansion plans.

The techniques described above are relevant for identifying and even quantifying the risk of an investment, but the basic decision principle is still fairly simple: calculate the NPVs of the investment projects and select the project with the higher positive NPV. If the probability distribution of the NPVs can be calculated, then the decision can also take into account the risk preference of the decision-maker. These appraisal techniques have an important underlying assumption: the passive attitude of the decision-maker over the investment lifespan. That is, once the decision is made, the possibilities to adapt/adjust the expansion plan (or an individual project), using their embedded options (*flexibilities*), depending on the potential unfavorable consequences resulting from the exiting uncertainties, are disregarded. However, expressing the value of flexibility in economic terms is not a trivial task and requires sophisticated assessment tools. The Real Option Valuation (ROV) technique provides a well-founded framework –based on the theory of financial options– to assess flexible investments under uncertainty [53].

4.4 Proposed Assessment Approach

Under the framework outlined in the previous sections, a new approach to a coordinated assessment of investments in electricity and gas infrastructures is described. This approach can be seen as a new step in the hierarchical energy planning procedure. Indeed, as was explained in section 4.1, energy carriers systems, such as NG&E systems, are typically planned and operated in a decoupled manner according to specific criteria defined for each energy carrier systems' optimization. The needed coordination between NG&E systems planning, in particular the transmission expansion planning, relies on some coordinating parameters that cannot consider the dynamic interdependencies between both systems. On the other hand, only within the long-term energy planning procedures performed by means of the energy models, all the energy carriers, including NG&E, systems are analyzed in an integrated way. However, these models have several limitations to represent NG&E transmission infrastructures and the physical laws that govern these systems. In this context, the methodology proposed in this section attempts to fill the gap between the energy models and the decoupled NG&E planning approaches. The basis, assumptions and main features of the proposed approach are as follows:

- Centralized (regulated) perspective: this approach seeks to maximize the social welfare without pursuing profit objectives for any particular agent involved in the energy supply chain. Consequently, the different type of markets (spot, forward, futures) and different forms of trading (bilateral, multilateral, pool) developed within NG&E markets are not modeled. In fact, to tackle the problem from a centralized perspective implies that *perfect competition* is assumed in the NG&E markets. Indeed, under such market conditions, the resulting infrastructures and the operation plan of each energy system will match those that would be obtained from a purely centralized decision-making process (i.e. *benevolent monopolist*).

- The assessment of investments in NG&E network infrastructure uses as a frame of reference the inputs and the results of the technological based (bottom-up) PET energy model that has been adopted in the REALISEGRID project to provide the long-term energy supply scenarios [21]. The results of the PET model provide the so-called *adapted* systems, i.e., the optimal NG&E production, conversion and network infrastructures whose capacities have been obtained by minimizing the sum of investment and operating cost subject to the scenario constraints. The PET energy model provides these data for each explored scenario and for the years 2010, 2015, 2020, 2025 and 2030. The selected scenarios drivers cover some of the most relevant non-random uncertainties for the future supply of energy, such as, the climate change mitigation policies, the availability of new technologies at affordable costs, and the availability of oil and NG supply according to two possible and markedly separated ranges of prices [14].

- The approach to assess the investment in NG&E transmission infrastructure has the following characteristics:
  - The analysis is focused on proposed or possible transmission expansion project, thus the capacity of these expansion project is not a variable within the optimization procedure.
  - The performance or benefits of the transmission expansion projects are evaluated by means of their contributions to reduce the NG&E production and shortage costs. The installation or construction of new transmission infrastructures ease the transmission capacity constraints, therefore, in general, the production costs decrease (or shortage costs are avoided) because the transmission network imposes fewer limitations on the production dispatch. Other possible benefits arising from additional transmission assets are not considered in the proposed approach.
  - The demands for electricity and NG not used for electric power generation are modeled as totally inelastic, thus the maximization of social welfare is equivalent to a minimization of the NG&E production and shortage costs. In this context, the cost

savings, associated with each transmission expansion project are calculated using the *with/without analysis.*

- The transmission expansion problem is formulated as a *static* problem since the timing of the commissioning of the new transmission infrastructure is not a decision variable. It is considered that the expansion projects are installed at the beginning of the assessment period. However, the evaluation takes into account a multi-period analysis with a 20 years investment time horizon (until 2030).
- Some relevant random uncertainties, such as NG&E demands, fuel costs and wind power production, are considered in the proposed *probabilistic* approach. A Monte Carlo simulation is used to calculate the probability distribution functions of the cost savings due to the installation of the different transmission expansion projects.
- A probabilistic NPV for each transmission expansion project is calculated to rank the expansion alternatives. Each probably distribution of the NPV is calculated through the convolution of the probability distribution of the cost saving at years 2010, 2015, 2020, 2025 and 2030, and considering that the total investment cost is spent at year 2010 (beginning of the assessment period). The expected value of the NPV, a risk neutral metric, is used to build the expansion alternatives' ranking.

- The core of the proposed approach is a NG&E operational planning model which is used as the main tool to assess the cost savings due to the investments in NG&E transmission infrastructure. This model is essentially a multi-period optimal NG&E flows subject to time coupling constraints. The main characteristics of this model are:
    - The coordination of NG&E operations is addressed using a combined approach, i.e., a single optimization problem integrating the models of the natural gas and electricity systems.
    - The time horizon considered in the NG&E operational planning covers a whole year to deal properly with the seasonal behavior of NG&E demands and some energy resources such as water inflows and wind power production. This one year time horizon, usually classified as medium-term time horizon, also allows us to model the energy storages adequately and thus, to include their scheduling in the optimization problem. This is important since transmission and storage facilities are complementary, and therefore, the cost savings due to a transmission expansion are affected by the storages capacities.
    - Mathematical programming algorithms are implemented to solve the optimization problem.
    - The medium-term NG&E operational model is used within the Monte Carlo simulation method to assess the impact of the considered random uncertainties on the cost savings.

5 COMBINED MEDIUM-TERM NATURAL GAS AND ELECTRICITY OPERATIONAL PLANNING

Under the proposed approach to assess investments in NG&E transmission infrastructures, the value of each expansion is determined by its contribution to reduce the NG&E production and shortage costs over the economic life time (depreciation period) of this new asset. Therefore, it is central to formulate a combined NG&E operational planning model able to calculate these costs adequately.

The characteristics of NG&E operational planning model must be consistent with the framework in which this tool is used. For each explored scenario, the PET energy model provides the *adapted* NG&E systems for the years 2010, 2015, 2020, 2025 and 2030. Thus, the yearly cost saving due to any transmission expansion, for each of these years, are evaluated using the NG&E operational planning model. This is not the only reason why the NG&E operational planning model must cover a single year (medium-term) time horizon. Coping with the seasonal behaviour of some input parameters, such as the NG&E demands, together with the optimal scheduling of energy storages, also requires a year-long (at least) simulations.

Several approaches that address the integrated modeling and analysis of energy systems in a more comprehensive and generalized way have been presented. Only a few of them deal with the combined medium-term operational planning of NG&E systems. Quelhas et al. [29] propose a generalized network flow model of an integrated energy system that incorporates the production, storage and transportation of coal, NG and electricity in a single mathematical framework. The integrated energy system is readily recognized as a network defined by a collection of nodes and arcs, where arcs also represent fuel production facilities, electric power plants and storage facilities. The objective of the generalized minimum cost flow problem is to satisfy electric power demands using the available fossil fuel supplies at the minimum total cost, subject to nodal balances, maximum and minimum flow in each arc and a global sulfur dioxide emission constraint. Additionally, the hydroelectric systems (hydropower plants and reservoirs) are also taken into account in [30], but the emission constraints are not considered in this model. Correia and Lyra [31] present also a generalized network flow model including only hydroelectric, NG and sugar cane bagasse as energy resources.

In contrast with the generalized network flow models, Bezerra et al. [32] present a methodology for representing the supply, demand and transmission network of NG within a medium-term stochastic hydrothermal scheduling model. Natural gas nodal balances, limited unidirectional pipeline flows and loss factors applied to NG flows, account for the adopted NG flow model. NG storage facilities are not taken into account in this approach. The minimization of NG supply costs is also disregarded because NG prices at each node are considered as given and thus are not results of the optimization process.

Ojeda-Esteybar [54] proposes a coordinated optimal scheduling of natural gas and hydrothermal power systems. In addition to [32], the NG network model also includes storages facilities and the line-pack associated with each pipeline. The interactions between natural gas and electric power systems are explicitly modeled by energy hubs that only include the NGFPPs. A combined approach (see section 4.2) is used for the coordination of NG and electric power systems optimization, i.e., NG marginal costs (prices) at each node are a by-product of the optimization process and not given data from the outset. The modeling and problem formulation presented in the following sections are based on this work.

The rest of this section describes the mathematical models and formulation of the combined medium-term NG&E operational planning problem. Firstly, the general concepts of medium-term operational planning are introduced. Secondly, the mathematical modeling of NG&E systems is presented including the adopted models for electric power flows and NG flows in pipeline networks. Then, the deterministic operational optimization problem of NG&E systems is formulated. Finally, the implementation of a Monte Carlo simulation procedure that takes into account the relevant uncertainties is described.

5.1 Introduction

The optimal operational planning of NG&E systems which include energy storages is a high dimensional optimization problem. These energy storages, such as water reservoirs and NG stocks create temporal coupling constraints which link the decision to be taken at different time steps. During this period, the regulating capacity of the energy storages is used as a supply/demand balance resource. The temporal coupling constraints can reach several hours to 2-3 years' duration depending on the capacities of the energy stores and the maximum energy store/withdrawal rates. Therefore, the time horizon considered in the operational planning must be equal or larger than the longest duration coupling constraint.

On the other hand, high detail NG&E system models are required to ensure that the results reflect the actual characteristics and operating constraints associated with the energy system infrastructures. Additionally, the NG&E systems models must take into account the physical laws that govern NG&E flows as well as the security and quality requirements for an adequate energy supply. An accurate model of all these features thus requires a discretisation of the period under analysis at intervals of several minutes. Also, these features increase the problem complexity because it becomes non-linear and non-convex.

In this context, solving the operational planning problem of NG&E systems in a single optimization is not possible with the current optimization techniques at a reasonable computing time. Neither is it justified considering the heterogonous structure of the problem. The solution of this huge and complex problem involves breaking it down into simpler problems within a time-scaled hierarchical decomposition. There is no a unique way to organize this procedure, however, the first stage typically comprises an optimization problem covering the whole time horizon. According to the duration of the time horizon, this problem is referred as long-term operational planning if the duration is longer than one year or as medium-term operational planning if the duration ranges from several months to one year. Simplified NG&E models are required to cope with this problem. The following stage in the hierarchical optimization procedure is short-term operational planning which considers a time horizon ranging from one day to a month, with a week being the most common time period. This optimization implements more detailed model of NG&E systems. Further stages with shorter time horizons usually proceed until real time operating conditions are taken into account. In this hierarchical scheme, the coordination between the stages is carried out using the results of the higher-level optimization problems as the frame of reference for the lower-level problems.

5.1.1 Purposes and main results of the medium-term optimization

The main objective underlying the combined medium-term planning of NG&E systems is to determine the optimal management of the energy resources to supply electric NG&E demands at minimum cost. This task includes the optimal scheduling of the energy storages (NG and water reservoirs) within the time horizon considered. The solution of the optimal NG&E operational planning problem is affected by the availabilities and prices of primary energy sources (oil derivatives fuels, coal, nuclear) used in thermal power plants, hydropower energy availability, and to a lesser extent the available renewable energy sources (wind, solar, etc). In the same way, the availabilities and prices of NG at different suppliers' locations (gas wells, LNG regasification terminals, and import pipelines) have a great influence on the results. Additionally, to obtain an adequate solution of the problem, the uncertainties associated with the input parameters included in the model (such as NG&E demands, fuel prices, water inflows, wind power production and generating units availability) must be considered.

The medium-term operational planning provides a NG&E prices forecast that can be used as a benchmark since *perfect competition* is assumed in the NG&E markets. Other important results are the fuel consumptions and NG supply requirements. This information is essential to schedule the fuel purchases for the analyzed time period, not only buying oil derivative products, coal, nuclear fuel and LNG in international markets, but also making shipping and storage arrangements, and taking all other necessary logistical measures to ensure the provision of the fuels. On the other hand, the results of the medium-term operational planning provide the frame of reference for the short-term operational optimization, by means of target (or a range of) capacities to be maintained at energy storages, fuel consumption quotas and emission limits.

Another important aspect to bear in mind is the actual meaning of the results of medium-term operational planning. This problem usually considers simplified NG&E models and a time discretisation which typically groups many hours without taking into account their chronology. Therefore, the resulting values of the decision variables, such as the output power of each generating unit or the NG productions, all of them at each time step, represent average values over these time periods. In other words, the results must be interpreted in terms of energy values and not as actual power values to be directly included in the operating schedule.

5.1.2 Temporal couplings

When the NG&E systems do not include storage facilities, the combined medium term operational planning is based on least-cost dispatches of NG suppliers and electric power generators to supply the NG&E demands at each time period. While there are additional factors that make the problem formulation more complex, like network energy losses, transport limitations, nonlinear production costs, etc, it has a basic characteristic: the dispatch is uncoupled in time, i.e. an operational decision in the present does not affect the operating cost in the near future, making the problem separable.

In contrast, if NG&E supply chain infrastructures include energy storage facilities, it is necessary to make a decision about the utilization of the energy stored in the NG and water reservoirs at each period. If the stored energy is used, the use of expensive fuel costs in thermal power plants can be saved. If the decision is to keep or increase the energy stored in the reservoirs, then a higher NG&E supply cost will arise. This feature, in addition to the limited capacity of energy storage facilities, creates a coupling between operational decisions taken in the present and the future consequences of these decisions.

There are other temporal coupling constraints that can also link decisions over the whole time horizon, such as the limited availability of certain types of fuel due to supply or transport restrictions and limited emission allowances considered individually for each electric power generating unit or for emissions produced by all the generating units. Minimum up and down times also represent a shorter temporal coupling constraint, however, this characteristic is disregarded in the medium-term operational planning because its modeling would require hourly and chronological time steps.

5.1.3 Optimal decisions in natural gas and electric power systems with storage facilities

Although a hydroelectric plant does not incurs directly on monetary expenditure when it produces power, it has an indirect economic cost associated with the available water stored for its future use, and with the additional cost of thermal generation or load shedding when the future hydro-generation is not available. The optimal management of stored water is associated with the minimum cost of thermal production over the time horizon, and thus is associated with its opportunity cost, since any deviation from the optimal scheduling produce additional thermal generation cost within the period considered. This opportunity cost is known as *expected water value* or simply *water value* [55], [56], and represents the economic value of stored water. The water value defines the economic suitability of accumulating water in the present for future use.

In the same way, NG storage allows the accumulation of NG in times of reduced fluid intake and low prices (summer), for use in times of increased consumption and higher prices (winter).

The optimal use of stored energy (NG and water in reservoirs) at a certain period t matches the operating state that minimizes the sum of the costs of immediate and future use, represented by a present cost function (PCF) and a future cost function (FCF). The PCF represents the production costs of the NG&E at stage t. This cost increases with increasing reservoir storage level since more NG must be produced or more thermal generation is needed to avoid hydropower generation or the use of the previously sorted NG. On the other hand, the FCF is associated with the expected cost of NG&E production, export and load shedding, starting from the end of stage t (beginning of stage t+1) to the end of the time horizon. This cost, contrary to the PCF, decreases as storage volume increases, because larger amount of NG and water available in the future avoids NG&E productions costs. The FCF can be calculated using specific decomposition approaches since it is necessary to divide a single optimization problem covering the whole time horizon into many optimization problems as stages are defined within this time horizon.

Figure 5.1 shows the PCF, FCF and PCF+FCF curves as a function of the volume stored in the NG reservoir. The minimum cost point is where the absolute derivative of PCF and FCF are equal. The derivative of PCF is the *marginal cost* of NG production of stage t. The derivative of the FCF represents the economic value of storage and is the *expected value of natural gas* [54], which relates the cost of using the NG stored in the present with the cost of NG production and shortage in the future.

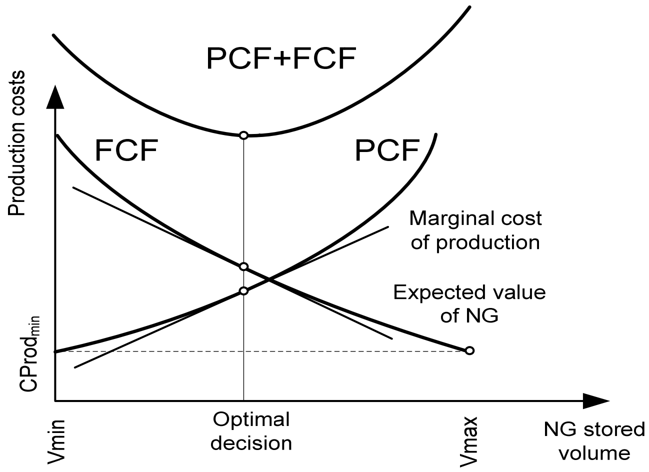

Figure 5.1: PCF, FCF and expected value of natural gas for a stage [54].

5.2 Modeling

5.2.1 Linear models

As introduced before, the medium-term operational optimization includes simplified NG&E models to deal with the high dimensionality of problem. One of the main limitations comes from the available optimization techniques used to solve the problem. In this sense, linear programming algorithms are robust and well-developed methods to tackle large-scale optimization problems. Therefore, to implement these algorithms, the features and operating constraints of the components that make up the NG&E systems are best represented by linear functions. Also, the NG and electric power flows models must be simplified into a set of linear equations. However, all these simplifications should preserve the essential features that affect the medium-term operational planning problem. The following subsections present the modeling that has been adopted for the NG&E systems.

5.2.2 Time horizon and time steps

There are boundary reasons to adopt one year as the time horizon for the combined medium-term operational planning model. Firstly, the framework defined by the proposed approach to assess investments in NG&E network infrastructures requires a tool to evaluate the yearly cost savings due to the expansions projects for the years 2010, 2015, 2020, 2025 and 2030. Secondly, as introduced before, an adequate evaluation of yearly cost saving needs to take into account the seasonal behaviour of some input parameters, such as the NG&E demands, along with the optimal scheduling of energy storages.

However, assuming one year as the time horizon implies that the time span for the temporal coupling constraints is also restricted to one year. In other words, it is assumed that the capacity and operating constraints of NG storages and water reservoirs can only be used as balancing resources within the year considered in the time horizon. The possibility to store energy to be used in the following year or to use stored energy in advance that will be recovered the following year is disregarded. Thus, the optimization problem includes constraints that force the initial and final (at the of the time horizon) water or NG volumes at each storage facility to be equal. These constraints are discussed in section 5.3.5.

On the other hand, the time discretisation within the time horizon is a trade-off between a more accurate modeling of NG&E demands and a larger optimization problem in terms of number of variables and constraints. Indeed, the time discretisation determines the modeling detail of NG&E demands which is a relevant factor to obtain plausible results.

Accurate models of NG&E demands should consider their tendency and periodical variations. Tendency variations refer to the demand increase due to the population growth, GDP growth or other socio-economic variables that affects the NG&E consumption. The periodical variations of NG&E demands show daily (day/night), weekly (working days/weekends) and yearly (winter/summer) periodicities.

Typically, for medium-term optimizations, the time horizon is divided into stages. These stages can have seasonal, monthly or weekly durations according to the detail required and the available data. Within each of these stages, the NG&E demands are modeled by means of approximated load duration curves (LDC) with a predefined number of steps and predetermined step durations. Figure 5.2 shows an example of an actual electricity demands for a month, its corresponding actual LDC with hourly time steps and an approximated LDC with 4 four time steps, also called time slices or demand blocks.

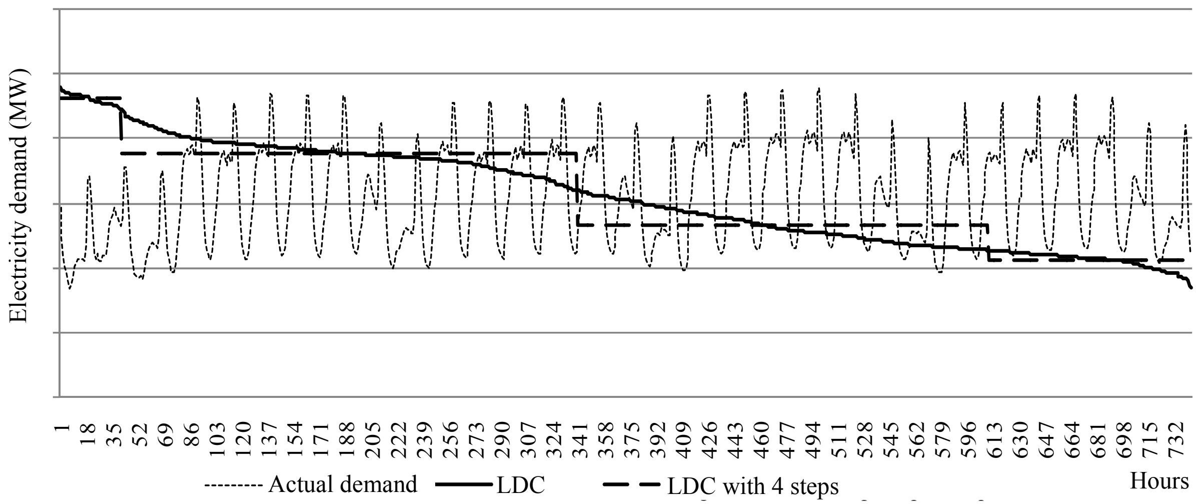

Figure 5.2 Monthly demands and LDC

In particular, taking into account the results of PET energy model, the modeling of NG&E demands in the proposed medium-term operational planning considers seasonal stages and 3 time steps LDC. If additional information about typical NG&E demand profiles is available, the modeling can be adjusted to a more detailed model, for instance, monthly stages and 4 time steps LDC. However, the generalized formulation to be presented in the following sections considers T stages $\{1,\ldots, t,\ldots T\}$ and LDCs with K time steps $\{1,\ldots, k,\ldots K\}$ whose duration is B_k.

The electricity demand in terms of average power at each stage t, time slice k and node j, $De_j^{k,t}$, is determined from the yearly demand at node j, De_j^a,using deterministic distribution factors. The non-for-power NG demands $Dg_j^{k,t}$ are calculated analogously.

$$De_j^{k,t} = \frac{De_j^a \; FT_e^t \; FK_e^k}{B_k} \quad (4)$$

$$Dg_j^{k,t} = \frac{Dg_j^a \; FT_g^t \; FK_g^k}{B_k} \quad (5)$$

where FT_e^t and FT_g^t distribute the yearly electricity and NG demands between the stages, and FK_e^k and FK_g^k consider the demand distribution between time slices.

5.2.3 Electricity System

5.2.3.1 Thermal generating Units

The production cost function of non-gas thermal power plants, $C_i(pg_i)$, is represented by the sum of the fuel cost and the variable operation and maintenance costs:

$$C_i\left(pg_i\right) = \frac{FP_i}{HHV_i} HR_i(pg_i) + COM_i(pg_i) \quad (6)$$

where FP_i and HHV_i are the price and higher heat value of the fuel used by the unit i, and $HR_i(pg_i)$ is the heat rate function (input-output function) [55], which indicates the energy consumed per time unit to generate a given output power pg_i. The use of HHV or its alternative measure the lower heating value (LHV) in Equation (6) depends on which of these two standard values was used to define de HR function [55]. The operating and maintenance cost $COM_i(pg_i)$ includes only the variable costs that can be expressed as a function of the energy produced.

The production cost function of NGFPPs has the same components as other thermal power plants, however throughout this presentation; they are discriminated for a clearer explanation.

$$C_i\left(pgn_i\right) = \frac{NGP_i}{HHV_i} HR_i(pgn_i) + COM_i(pgn_i) \quad (7)$$

where NGP_i is the price of the NG used by the unit i, and pgn_i is the output power of this unit.

The minimum output power of thermal units and NGFPPs is usually above the 30% of the rated output power [55]. This feature can only be modeled by introducing integer variables into the optimization problem. On the other hand, the HR function, which is obtained from test data, can be approximated by a convex non-linear (usually quadratic) function. In order to keep a linear modeling of the problem, the following simplifications are adopted:

- The output powers pg_i and pgn_i are considered to range from zero to the maximum output power
- The HR functions are approximated by linear equations. These formulations do not include constant (independent) terms because their consideration would also require integer variables. The linear factor in HR functions corresponds to the average heat rate (also known as net heat rate [55]) at the maximum output power.

However, for some thermal generating units with highly non-linear HR functions, the proposed linearization could imply significant errors. In these cases, it is possible to approximate the non-linear HR function with a piecewise linear function as shown in Figure 5.3.

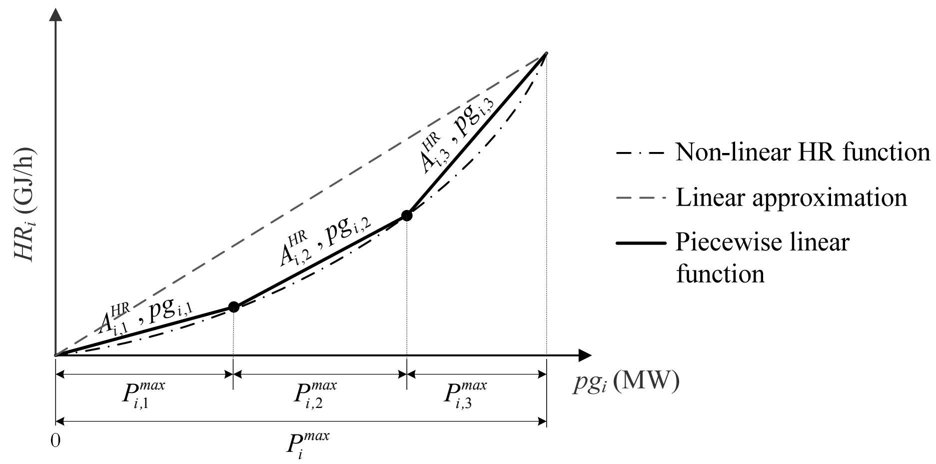

Figure 5.3: HR piecewise linear function

The accuracy of the piecewise linear approximation depends on the number of segments considered. For example, Figure 5.3 shows a 3-segment approximation. It is important to point out that the piecewise approximation can be applied only if the HR function is a convex function. Only under this condition, is it guaranteed that a segment with higher average heat rate, A^{HR} , will not be dispatched until the segments with lower A^{HR} are fully loaded. If the convexity is not respected, the piecewise linear approximation could also be applied but auxiliary integer variables would be required. This is outside of the scope of the proposed thermal unit model. Nevertheless, each piecewise linear function implies to increase the number of variables as segments (σ) are considered, and also to include the following constraints:

$$HR_i\left(pg_i\right) = \sum_{\sigma} A^{HR}_{i,\sigma}\ pg_{i,\sigma} \tag{8}$$

$$0 \le pg_{i,\sigma} \le P^{máx}_{i,\sigma} \qquad \forall \sigma \tag{9}$$

$$pg_i = \sum_{\sigma} pg_{i,\sigma} \tag{10}$$

The non-linear HR function of NGFPPs can also be modeled as a piecewise linear function, in the same way.

Some thermal power plants are capable of using more than one type of fuel, either mixing them or switching between them. The modeling of the possible switches between different fuels, consuming only one at each time, requires integer variables. However if it is assumed that any fuel proportion can be burnt, the fuel mixing feature of thermal power plant can be modeled considering as many production cost functions, equation (6) and (7), as fuels the power plant is able to use, and adding the following constraint:

$$\sum_f pg_{if} + pgn_i \le P_i^{\max} \tag{11}$$

where $pg_{i,f}$ is the partial output power produced by unit i with the fuel f different from NG. Fuel mixing also increases the number of variables in the problem since each generating units is represented by many output power variables as fuels the unit can burn.

Another characteristic of thermal power plants that should be taken into account in the medium-term operational planning problem is their availability over the time horizon. In general, generating units can be unavailable to be dispatched because of an unforeseen failure or a planned preventive maintenance. A deterministic formulation of the problem can consider this random behaviour through an index which is the probability that the unit will not be available for service when required, also known as the forced outage rate (FOR) [57]. This index is used to reduce (or derate) the maximum output power of each thermal as shown in Equation (12). Additionally, the maximum output power of the generating units can be set to zero for the periods when the preventive maintenance is scheduled. However, if the schedule of preventive maintenance of thermal units is unknown, then the maximum output power should be derated according to an index that reflects the number of hours the unit is on preventive maintenance over the total number of hours of the year. This index can be called as the preventive maintenance unavailability (PMU).

$$P_i^{d\,max} = P_i^{max}\left(1 - FOR_i\right)\left(1 - PMU_i\right) \tag{12}$$

where $P_i^{d\,max}$ is the derated maximum output power of generating unit i.

Finally, the secure operation of electric power systems requires a spinning reserve margin (SRM) that prevents the full loading of the dispatched generating units. Assuming that all the units provide the same reserve percentage margin (which is a simplification), this security constraint can be indirectly modeled by reducing the output power of all the generating units by this reserve margin. Thus, Equation (12) can be rewritten as:

$$P_i^{d\,max} = P_i^{max}\left(1 - FOR_i\right)\left(1 - PMU_i\right)\left(1 - SRM\right) \tag{13}$$

5.2.3.2 Hydro power plants and water reservoirs

Hydro power plants have been classified in two different types for their modeling in the medium-term operational planning. One type corresponds to hydro power plants that are fully controllable, i.e., the optimization of the energy stored in the water reservoir is not subject to additional constraints beyond the constraints resulting from the specific characteristics of the power plant and its associated water reservoir. Examples of additional restrictions are minimum output flow rates due to navigation, irrigation or other environmental reasons. Figure 5.4 shows the main variables and parameters of the adopted model of controllable hydro power plants.

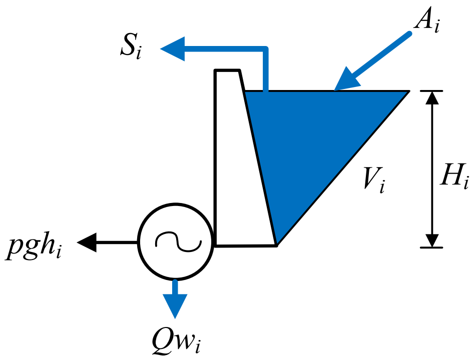

Figure 5.4: Hydro power plant

The electric output power pgh_i of the hydro power plant i is function of the water flow rate Qw_i through the turbine and production ratio ρ_i as follows:

$$pgh_i = \rho_i \left(Qw_i, H_i \right) Qw_i \tag{14}$$

In fact, the production ratio ρ_i is also a function of the flow rate Qw_i and the hydraulic head H_i, and thus Equation (14) is essentially non-linear. However, to maintain a linear modeling of the problem, the production ratio is taken to be a constant factor equal to the average production ratio for the entire range of operating conditions and independent of Qw_i and H_i.

The model considers that each hydro power plant i has an associated water reservoir, also denominated with the same index i. The inventory constraint of this water reservoir is stated at the end of each stage t (beginning of the stage $t+1$), as follows:

$$V_i^t = V_i^{t-1} + A_i^t \, ST - \sum_k B_k \, Qw_i^{k,t} - S_i^t \, ST \tag{15}$$

where V_i^t is a state variable that represent the water volume stored in the reservoir i at the end of stage t, A_i^t is the average flow arriving at the reservoir i over the stage t, $Qw_i^{k,t}$ represents the flow rate through the turbine in time slice k of stage t, S_e^t is a slack variable that represents the average spilled outflow of the water reservoir i over the stage t and ST is the total duration of stage t. In case of hydro power plants located in a cascade arrangement over the same hydrological basin, the upstream flow rate through the turbine should be added as water inflows to the downstream water reservoirs.

The capacity of water reservoir is limited by the topography and the dam height. On the other hand, a minimum hydraulic head must be maintained for the normal operation of the hydro power plant. This minimum head can also be expressed as a minimum water volume. Therefore, the water volume V_i^t is constrained to remain within maximum and minimum limits.

Unlike fully controllable hydro power plants, there is another type of these plants whose electricity generation is subject to the aforementioned additional restrictions. These constraints limit the optimal use of the energy stored in the water reservoir because they enforce certain output power at off-peak time periods when it would be a better solution to store this amount of energy (water) to be used at higher electricity demands periods. A simplified model is proposed for this type of hydro power plants, avoiding the explicit representation of hydro variables, such as water volumes, streamflows and flow rates through the turbine. A given amount of hydroelectric energy HE_i^t is considered to be available at each stage *t* in hydro power plant *i,* and therefore the inter-stage energy resource optimization is disregarded. Only a part of this fixed amount of energy can be optimally dispatched between the time slices. The other part of the hydroelectric energy should be dispatched as a constant output power throughout the stage. The regulating factor RF_i of the hydro power plant *i,* which varies between one and zero, determines the distribution between the free-dispatch energy and the constant-dispatch energy. Mathematically, this equivalent hydro power plant can be modeled by the following constraints:

$$\sum_k pgh_{i,o}^{k,t} = HE_i^t \; RF_i \tag{16}$$

$$pgh_{i,b}^{k,t} = \frac{HE_i^t \left(1 - RF_i\right)}{ST} \qquad \forall k \tag{17}$$

$$pgh_i^{k,t} = pgh_{i,b}^t + pgh_{i,o}^{k,t} \tag{18}$$

where $pgh_{i,o}^{k,t}$ and $pgh_{i,b}^{k,t}$ are the free-dispatch and the constant-dispatch output power of the equivalent hydro power plan *i* at the time slice *k* of stage *t*, respectively. With these definitions, a RF_i equal to one implies a fully controllable energy dispatch within the stage (intra-stage optimization), and a RF_i equal to zero can represent a run-of-river power plant with a constant dispatch over the stage.

Under the same considerations as for the thermal units, the output power pgh_i ranges from zero to the derated maximum output power for both types of hydro power plants. On the other hand, since the operation and maintenance costs of hydro power plants are mostly fixed costs, the variable production costs of these power plants are disregarded.

5.2.3.3 Wind power production

Wind power productions are modeled in an aggregated manner, considering a single equivalent power injection at each node *j*. The deterministic average wind power production at each stage *t*, time slice *k* and node *j*, $Pgw_j^{k,t}$, is determined from the forecast of the annual wind power production at node *j*, Pgw_j^a,using fixed distribution factors.

$$Pgw_j^{k,t} = Pgw_j^a \; FT_w^t \; FK_w^k \tag{19}$$

where FT_w^t distributes the predicted annual production between the stages, and FK_w^k consider the distribution of the wind power production between time slices. The typical profiles of wind power production at each location *j* are used to determine these distribution factors. As for hydro power plants, the variable production costs of wind generators can be disregarded because the operation and maintenance costs are mostly independent of the power produced.

5.2.3.4 Electric power flows

In electrical networks, the steady-state electric power flows are governed by Ohm's and Kirchhoff's laws. These laws can be expressed by means of nodal power balances and line power flows. The AC electric power flows are conventionally decomposed in active and reactive power flows. For energy analysis purpose, such as the medium-term operational planning, the modeling is focused on the active power flows because these are the real amounts of power transferred from one node to another. The active power balance at node j in an electrical AC network can be stated as:

$$P_j - \sum_{n \in N_j} P_{jn} = 0 \tag{20}$$

where P_j is the net active power injected at node j (sum of the production of local generators less the local demand), N_j is the set of nodes connected to node j, and P_{jn} is the outgoing active power flow from node j to any other node n. The outgoing active power flow P_{jk} from node j to k through the line m is a function of the complex nodal voltages U_j and U_k and the parameters of the line [58]:

$$P_{jk} = \frac{1}{\left|Z_{jk}\right|^2}\left\{\left|U_j\right|^2 R_{jk} - \left|U_j\right|\left|U_k\right|\left[R_{jk}\cos\left(\theta_j - \theta_k\right) - X_{jk}\sin\left(\theta_j - \theta_k\right)\right]\right\} \tag{21}$$

where Z_{jk} is the series impedance of the line m formed by the resistance R_{jk} and reactance X_{jk} m ($Z_{jk} = R_{jk} + \mathrm{j}\, X_{jk}$), and θ_j and θ_k are the phase angles of voltages U_j and U_k. Figure 5.5 shows a scheme of a transmission line and its associated active power flows.

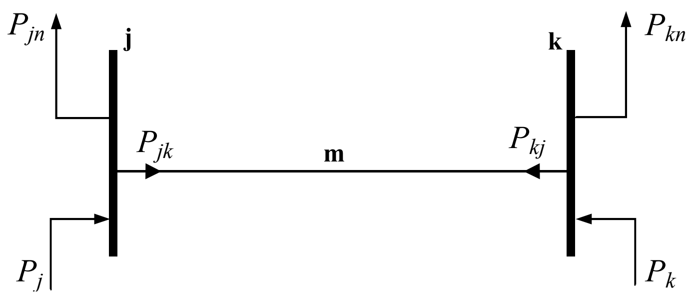

Figure 5.5: Transmission line and active power flows

Even though the active power flow P_{jk} through a line is a nonlinear function of the complex voltages at the line ends, a simplified model can be used to represent electric power flows. This is the so-called DC or MW-only power flow, which can be obtained from Equation (21) via a sequence of approximations [55], [59]-[61]; thus:

- Losses are neglected, $P_{jk} = P_{kj}$
- Voltages at all nodes are assumed equal to 1 per unit, $U_i = 1$ p.u. $\forall i$
- Phase angle differences corresponding to adjacent buses are small, $\cos(\theta_j - \theta_k) \approx 1$ and $\sin(\theta_j - \theta_k) \approx \theta_j - \theta_k$
- The reactance X_{jk} is much greater than the resistance R_{jk} for all the lines m, reactance $X_{jk} >> R_{jk}$ $\forall m$, thus $X_{jk} / (R^2_{jk} + X^2_{jk}) \approx 1/ X_{jk}$

Under these approximations, the active power flow shown in Equation (21) from node j to k in p.u. can be rewritten as:

$$F_m = \frac{1}{X_{jk}}\left(\theta_j - \theta_k\right) \tag{22}$$

This is the classical DC model whose accuracy and applications for different purposes are discussed extensively in [60]. Equation (22) can be extended to all system's branches as follows:

$$\mathbf{F} = -\mathbf{B_D}\,\mathbf{A}^{\mathrm{T}}\ \boldsymbol{\theta} \tag{23}$$

where **F** is the vector of lines active power flows, $\mathbf{B_D}$ is the diagonal matrix whose elements are 1/ X_{jk}, **A** is the node-branch incidence matrix whose A_{jm} element is +1 if line m enters node j, -1 if line m leaves node j, or 0 if line m is not connected to node j and $\boldsymbol{\theta}$ is the vector of phase angles. Another implicit approximation assumed in the extension of equations (22) to (23) is that the relation R_{jk} / X_{jk} is a constant for all the lines in the system. On the other hand, (20) can also be expressed in its matrix form as:

$$\mathbf{P} = -\mathbf{A}\,\mathbf{F} \tag{24}$$

in which **P** is the vector of net active power injections. The combination of equations (23) and (24) leads to:

$$\mathbf{P} = \mathbf{A}\,\mathbf{B_D}\,\mathbf{A}^{\mathrm{T}}\,\boldsymbol{\theta} = \mathbf{B}^{'}_{\mathbf{bus}}\,\boldsymbol{\theta} \tag{25}$$

where matrix $\mathbf{B}^{'}_{\mathbf{bus}}$ has the same structure (sparse and symmetric) as the system's nodal admittance matrix, but its values are computed solely in terms of branch reactances. Therefore, in order to calculate the active power flows through the lines, the procedure consist in solving equation (25) to obtain $\boldsymbol{\theta}$ since **P** is known, and then use $\boldsymbol{\theta}$ in equation (24) to obtain **F**. Alternatively, equations (24) and (25) can be combined, leading to a linear relationship between active power injections and active power flows:

$$\mathbf{F} = -\mathbf{B_D}\,\mathbf{A}^{\mathrm{T}}\left[\mathbf{A}\,\mathbf{B_D}\,\mathbf{A}^{\mathrm{T}}\right]^{-1}\mathbf{P} = -\mathbf{B_D}\,\mathbf{A}^{\mathrm{T}}\left[\mathbf{B}^{'}_{\mathbf{bus}}\right]^{-1}\mathbf{P} = \mathbf{H}\,\mathbf{P} \tag{26}$$

where **H** is the so-called sensitivity matrix. In the implementation of the model described by equations (24) to (26), it is important bear in mind that in electric power systems, not all the power injections are independent variables. The injection located at the slack node is dependent on the rest of the injections and its value is such that the sum of all injections is equal to zero. In other words, the slack injection provides the balance between the total production of generators and the total demand (and losses if they were modeled). The phase angle at the slack node is used as reference; therefore, its value is set as a parameter. The elements H_{mj} of matrix **H** are called sensitivity factors or power transfer distribution factors (PTDF) [55], [60]. Each factor relates the change in the power flow in the line m to an increase in the injection at node j, assuming the slack injection compensates for the injection in any node. The calculation of matrix **H** requires to make $\mathbf{B'}_{\mathbf{bus}}$ not nonsingular by replacing the row and column corresponding to the selected slack node with null vectors.

Although the classical DC model is lossless, actual power losses can be approximated and introduced to obtain a more general DC modeling. Considering that the active power losses in the transmission line m can be expressed as $L_m = L_{jk} = P_{jk} + P_{kj}$ and applying the same approximations used to derive the DC model, in per unit (p.u.) magnitudes, these losses are:

$$L_m = R_{jk} F_m^2 \tag{27}$$

The inherent bidirectional power flows in a transmission line (F_m can be a positive or a negative value) prevents a simple linearization of Equation (27). Thus, fixed injections representing transmission power losses should be allocated to nodes to which the line is connected [60]. These fixed equivalent injections can be estimated for typical operating states (demands and generation dispatch) of the electric power system. To include transmission losses in the previous formulation, the vector of nodal active power injection is:

$$\mathbf{P} = \mathbf{P_G} - \mathbf{P_D} - \mathbf{P_L} \tag{28}$$

where $\mathbf{P_G}$, $\mathbf{P_D}$ and $\mathbf{P_L}$ are the vectors of generating units' productions, demands and equivalent transmission losses, respectively. In the electric power flow model included in the proposed medium-term operational optimization, the transmission power losses have been disregarded.

5.2.4 Natural Gas System

5.2.4.1 Natural gas suppliers

In the proposed NG system model, the possible types of NG suppliers are: NG wells, LNG regasification terminals and cross-border pipelines (connections with bordering NG networks). They are modeled as *swing* NG suppliers because it is assumed that their NG production or injection to the NG network can vary between a minimum and a maximum flow rate. These limits correspond to their technical characteristics since contractual obligations coming from market agreements are not taken into account in the proposed approach. Supply adequacy of LNG cargoes and optimal management of the NG stored in LNG tanks is assumed for all LNG regasification terminals, and therefore, they can also be modeled simply as *swing* NG suppliers.

The NG supply cost function, $C_g(w_g)$, of each NG supplier is mathematically represented as:

$$C_g\left(w_g\right) = NGP_g \; w_g \tag{29}$$

where w_g is the production or NG injection into the network of NG supplier g and NGP_g is the prevalent NG price at which supplier g is willing to provide its NG resource. In fact, if the conditions for an efficient dynamic allocation of exhaustible resources were met, this NG price should match the NG marginal cost, composed of the marginal production cost and the user cost (reflects the inherent scarcity value of NG) of supplier g [62]. While the supply cost function is usually a non-linear function, this model only considers the linear approximation shown in Equation (29).

5.2.4.2 Natural gas flows in pipelines networks

Natural gas flows in pipeline networks can also be described by means of nodal flow balances and pipeline flows. In analogous way as for electricity, the flow balance at node *j* can be formulated as:

$$GI_j - \sum_{n \in N_j} Qg_{jn} = \sum_{g \in W_j w} w_g - Dg_j - \sum_{n \in N_j} Qg_{jn} = 0 \quad (30)$$

where GI_j is the net volume flow injected to the NG network at node *j*, N_j is the set of nodes connected to node *j*, Ω_j is the subset of gas suppliers injecting in node *j*, and Qg_{jn} is the outgoing NG flow from node *j* to any other node *n*.

The steady-state isothermal NG flow, Qg_m, through a horizontal pipeline *m* is a function of the upstream pressure s_j and downstream pressure s_k; the NG properties and the pipeline characteristic represented by the constant K_m [3].

$$Qg_{jk} = Qg_m = \mathrm{K}_m \delta_m \sqrt{\delta_m \left(s_j^{\ 2} - s_k^{\ 2} \right)} \quad (31)$$

$$\delta_m = \begin{cases} +1, & \text{si} \quad s_j \geq s_k \\ -1, & \text{si} \quad s_j < s_k \end{cases} \quad (32)$$

$$K_m = \sqrt{\frac{\pi^2 R_{\mathrm{air}}}{64}} \left(\frac{T_{\mathrm{st}}}{s_{\mathrm{st}}} \right) \sqrt{\frac{D_m^5}{f_m T\, G\, Z\, L_m}} \quad (33)$$

where R_{air} is the ideal gas constant of dry air, T_{st} and s_{st} are the standard or normal conditions of temperature and pressure, D_m the is the inside diameter of the pipe *m*, f_m is the dimensionless friction factor of the pipe *m*, *T* is the average gas flowing temperature, *G* the is gas gravity relative to air, *Z* is the dimensionless gas compressibility factor and L_m is the length of the pipe *m*. An additional term can be introduced in Equation (31) if a significant elevation difference exists between the upstream and downstream locations of the pipe [3], [4]. The parameter δ_m is the sign of the difference $\left(s_j - s_k \right)$ which defines the actual direction of the NG flow. This auxiliary parameter must be included to avoid an imaginary number as result of Equation (31) when the conventional defined as downstream pressure s_k; is higher than the upstream pressure s_j. Several flow equations are in use in the NG industry such as the Weymouth and the Panhandle equations, and all of them are modifications of Equation (31), which is called the *general flow equation for steady-state gas flow*.

In fact, Equation (31) denotes that pressures are the state variables to be optimized, and thus the pipeline transmission capacity is constrained to the allowed maximum and minimum operating pressures in the different sections of the NG network.

During transportation of NG in pipelines, the gas flow loses a part of its initial energy due to frictional resistance which results in a loss of pressure. To compensate these pressure losses and maximize the pipeline transport capacity, compressor stations are installed in different network locations. Compressor stations consist of compressors, which are arranged in series and parallel configurations depending on the requirements. Several types of compressor can be used, centrifugal compressors being the most commonly used. Many types of prime movers (e.g. electric motors, gas turbines, gas engines, steam turbines) have found application as compressor drivers. An amount of NG is withdrawn from the network, and eventually transformed on site into electricity or heat (steam), to provide the energy needed for the prime movers. While electric motors typically drive compressors and mains electric power supply is available in the compression station area, the electric power is not extracted from the electricity network for reliability reasons. Thus, the NG consumed in a compression station Lg_m can be considered as an additional NG flow into the pipeline section, as shown in Figure 5.6. This amount of NG depends on the pressure added to the fluid and the volume flow rate through the compressor. The value of Lg_m can be approximated as follows [37]:

$$Lg_m = KC_m \cdot Qg_m \cdot \left(s_j - s_u\right) \tag{34}$$

where KC_m is a constant characterizing the compression station; s_u and s_j are the suction and discharge pressures, respectively; $Qg_m = Qg_{jk} = Qg_{sj}$ is the flow through the compressor. It is important to point out that Equation (34) represents an equivalent and approximate model of an entire compression station. More advanced compression station models considering detailed compressor and prime movers characteristics are presented in [27], [3], [4]. As shown in Figure 5.6, compressor stations, like pipelines, can be modeled as branches in NG networks.

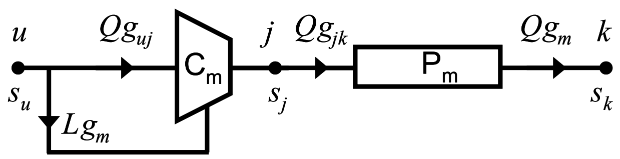

Figure 5.6: Model of NG pipeline link m including a compressor station C_m and a pipeline P_m

Natural gas flows can be converted to power using its HHV in order to make NG flows dimensionally comparable with any other energy flow. In the same way, a given volume of NG can be converted to an amount of energy.

In order to implement a NG flow model within the medium-term operational optimization problem, this model must be expressed using of linear functions. The non-convex and non-linear characteristics of NG flow functions (Equation 31) imply that a simple linearization using a piecewise linear functions cannot be applied. However, based on the high controllability of NG flows provided by the compression stations and pressure regulators, the NG flows can be represented by means of a nodal balance model, disregarding the physical laws that govern NG flows through pipelines. Moreover, the fact that NG pipeline networks are typically designed and operated in a radial mode reinforces the suitability of this simplified model for the medium-term analysis. The nodal balance model without taking into account the NG consumption in compressor stations, hereafter also referred to as the NG transmission losses, is mathematically expressed through the Equitation (30):

$$\sum_{g \in W_j} w_g + \sum_{m \in I_j} Qg_m - \sum_{m \in O_j} Qg_m = Dg_j \tag{35}$$

where I_j and O_j are the subsets of pipelines whose flows are coming in and out of node j, respectively. It is important to point out that in the NG nodal balance model, the gas flows through the pipelines Qg_m are independent state variables, since pressures are not explicitly modeled. In unidirectional flow pipelines, the NG flow rate Qg_m ranges between zero and the maximum transport capacity of the pipeline ($0 \le Qg_m \le Qg_m^{\max}$). In those particular branches where bidirectional NG flows are allowed, NG flow rate Qg_m ranges between the maximum transport capacity of the pipeline in both directions ($-Qg_m^{\max} \le Qg_m \le Qg_m^{\max}$).

The NG consumptions in compressor stations are also a non-linear function and their evaluation require to model explicitly the NG pressures at each node. However, these NG transmission losses can be represented approximately by means of average loss factors associated with each pipeline. Then, the nodal NG balances can be rewritten as:

$$\sum_{g \in W_j} w_g + \sum_{m \in I_j} (1 - LF_m) Qg_m - \sum_{m \in O_j} Qg_m = Dg_j \tag{36}$$

where LF_m is the average loss factor associated with pipeline m. In this way, the incoming flows at each node are reduced according the loss factor value. However, this simplified mode to take into account the NG transmission losses can only be applied to unidirectional flow pipelines, i.e., the NG flow, Qg_m, must be greater than zero. Nonetheless, if the NG flows in pipelines that can transport NG in both directions are modeled by two independent variables (instead of a single one), the application of loss factors can be generalized to all the NG network. Figure 5.7 illustrates how loss factors are applied to unidirectional and bidirectional flows in NG pipelines. In the bidirectional case, Qg_{md} and Qg_{mr} are the direct and reverse flows, respectively.

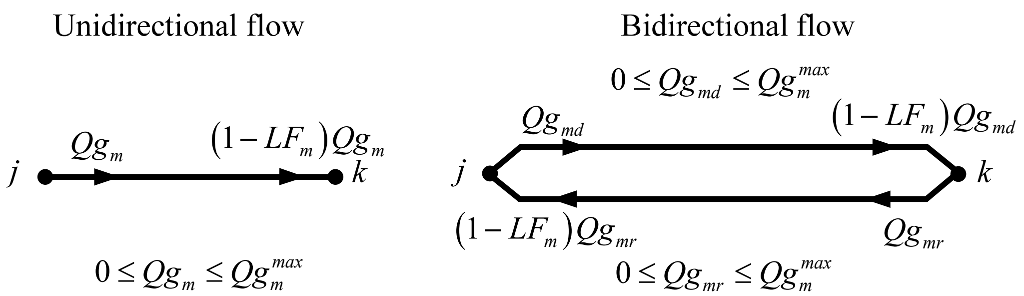

Figure 5.7: Modeling of natural gas losses in unidirectional and bidirectional pipelines

5.2.4.3 Natural gas storages

As described before, NG storage facilities perform an important function in NG systems providing balancing resources at all time, on hourly, daily, weekly or seasonal bases. The adequate representation of these facilities is essential to obtain plausible results in the medium-term operational optimization.

Figure 5.8 shows the proposed model for NG storage facilities. Any type of underground storage or LNG tank can be represented by this generalized model. The NG flow rates injected in or withdrawn from storage p at each time slice k of stage t, denoted $QIW_p^{k,t}$, are the main decision variables to be determined within the medium-term operational planning. The limits for the injection/withdrawal flow rates can be stated according to the following constraint:

$$-QI_p^{\max} \le QIW_p^{k,t} \le QW_p^{\max} \tag{37}$$

where $QI_p^{\max}$ and $QW_p^{\max}$ are the peak operating injection (inflow) and withdrawal (outflows) of the NG storage p. These parameters are usually a function of stored NG volume [36], but in order to simplify the problem, they are modeled as constant values.

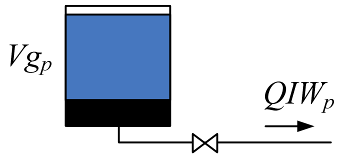

Figure 5.8: Natural gas storage facility

As for water reservoirs, the inventory constraint of each NG storage is stated at the end of each stage t (beginning of the stage $t+1$):

$$Vg_p^t = Vg_p^{t-1} - \sum_k B_k\, QIW_p^{k,t} \tag{38}$$

where Vg_p^t is a state variable that represents the stored volume of the NG reservoir p at the end of stage t. This NG volume ranges from a minimum value ($Vg_p^{\min}$) to a maximum value $Vg_p^{\max}$ which is the total gas capacity of the storage. The minimum NG volume, also called base or cushion gas, is intended as a the permanent inventory in the NG storage and is used to to maintain an adequate pressure and deliverability rate. The difference between the total gas capacity and the cushion gas is called as the working gas capacity of the NG storage.

The inventory constraint considers that the injection/withdrawal flow rate can take different values for the time slices k within the stage t. This formulation implies that injection/withdrawal flow rates can change on a daily and even hourly basis (peak-off peak balancing). However, large NG storage facilities, such as depleted oil/gas fields cannot be operated in this manner. Instead, the facilities maintain their injection or withdrawal flow rates throughout a week or longer periods. Thus, taking into account this operating constraint requires the inclusion of an additional restriction that sets the injection/withdrawal flow rates at the same value for all the time slices within a certain stage. The introduction of this constraint should also be analyzed considering the adopted stage time duration.

5.2.4.4 Pipeline line-pack

Line-pack is the storage of NG inside the pipeline network or a particular pipeline by boosting the line pressure above the delivery pressure. Usually, the amount of NG contained in a pipeline is what is called line-pack. It is normally used as a peak/off-peak demand balancing resource on a daily basis, although in extensive NG network the line-pack can reach a significant amount, and can then be used as an intraweek NG demand balancing resource.

The accurate modeling and quantification of the line-pack requires the modeling of transient NG flows since the NG accumulation in a pipeline implies the incoming NG flow into the pipe does not match the outgoing NG flow. However, in the context of the medium-term operational optimization, the line-pack can be modeled as a small NG storage associated with each of the pipelines. This feature is particularly relevant for long pipes where line-pack can be significant. As shown in Figure 5.9, a fictitious node is included within pipeline *m* to incorporate the small NG storage.

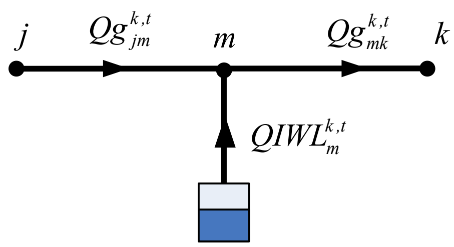

Figure 5.9: Pipeline line-pack

As for any other NG storage, an inventory constraint should be included but should take into account the fact that the line-pack cannot account for inter-stage balance. Thus, considering an initial and final line-pack equivalent volume is equal to zero, the inventory constraint can be stated as:

$$\sum_k B_k \, QWIL_m^{k,t} = 0 \tag{39}$$

where $QWIL_m^{k,t}$ is the NG flow rates injected in or withdrawn from the equivalent line-pack storage *m* at each time slice *k* of stage *t*. The limits for this flow rate can be defined as:

$$-QWIL_m^{\max} \le QWIL_m^{k,t} \le QWIL_m^{\max} \tag{40}$$

A NG nodal balance at the fictitious node completes the line-pack modeling:

$$Qg_{jm}^{k,t} + QWIL_m^{k,t} - Qg_{mk}^{k,t} = 0 \tag{41}$$

where $Qg_{jm}^{k,t}$ is the injected NG flow rate in pipeline *m*, $Qg_{mk}^{k,t}$ is the outgoing NG flow rate from pipeline *m*. Finally, because the line-pack does not increase the transport capacity of pipeline *m,* the maximum limits of injected and outgoing flow rates must be set at the same value as the maximum transport capacity of pipeline *m:*

$$Qg_{jm}^{\max} = Qg_{mk}^{\max} = Qg_{m}^{\max} \tag{42}$$

5.2.5 Uncertainties

As introduced before, most of the input parameters required by the medium-term NG&E operational planning model are uncertain. A rigorous modeling of all these parameters requires a large amount of information that need to be analyzed to determine the adequate mathematical model able to represent and characterize the behavior of these non-deterministic parameters. Among all the different methods, the probabilistic analysis is the most extended technique to deal with the inherent uncertainty associated with random variables (input parameters to the NG&E operational planning model). This technique assumes that random variables can be characterized through probability density functions, and thus stochastic process models can be applied to infer their future values.

On the other hand, the proposed probabilistic approach to assessing the value of NG&E transmission infrastructure investments (Section 4.4) is based on a Monte Carlos simulative procedure, where the medium-term NG&E operational optimization is performed hundreds of times until the convergence is finally reached. Each of these trials considers different realizations of the uncertain input parameters. Thus, while more uncertain input parameters are taken into account more simulation time is required to achieve the convergence target. Then, in order to obtain reasonable simulation times according to the proposed assessment, it is necessary to select the most relevant uncertain parameter to be characterized explicitly and assume simplified probabilistic models for the other random parameters (or even neglect their random behavior).

Additionally, other practical aspects must be considered to select which parameters and what types of probabilistic models are implemented. First, the amount and quality of the available information about these uncertain parameters is crucial. Without sufficient and consistent data, it is not possible to characterize the random behavior of these parameters. Furthermore, the modeling of the uncertain parameters must be subordinated to the general framework in which investments in transmission infrastructures are assessed. In the REALISEGRID project, the results of the technological based PET energy model determine the forecasted conditions in which the investments assessments must be performed. Thus, the results of the PET model provide the optimal NG&E production, conversion and network infrastructures capacities for each studied scenario and for the years 2010, 2015, 2020, 2025 and 2030. Moreover, the results of the PET model also include the forecasted values for the NG&E demands, the natural energy source availabilities (wind, solar, hydro and ocean power productions) and the fuel prices. All of these forecasted values and other input data, such as the NG prices of the different suppliers, are the main input parameters required by the medium-term NG&E operational planning model. Therefore, the probabilistic models used to represent the random behavior of these parameters must adequately take into account the forecasted values for these parameters.

Under the previously described conditions, the following relevant input parameters has been selected to be represented explicitly as random parameters within the NG&E operational planning model, which is the core of the proposed approach to assessing the investments in transmission in transmission infrastructure:

- The electricity demands
- The non-for-power NG demands
- Wind power productions
- Fuel prices including the NG prices of the different suppliers

Because the forecasted values for all these parameters must be specifically considered according to framework of the REALISEGRID project, the uncertainties related to these parameters are introduced adding residuals (differences between the samples and the estimated value) to the forecasted values.

It is important to point out that the uncertainties associated with the availabilities of the thermal power plants have been considered in an approximated manner as it was explained in the Section 5.2.3.1. The uncertainties in other input parameters, such as water inflows (hydro energy availabilities), has been disregarded, because their relative influence on the results given the typical characteristics of the European electric power systems.

The electricity demands and non-for power NG demands at each stage t, time slice k and node j, stated in Equations (4) and (5) can be rewritten as follows:

$$De_j^{k,t} = \frac{\left(De_j^a + \hat{\varepsilon}_{De_j}\right) FT_e^t \; FK_e^k}{B_k} \tag{43}$$

$$Dg_j^{k,t} = \frac{\left(Dg_j^a + \hat{\varepsilon}_{Dg_j}\right) FT_g^t \; FK_g^k}{B_k} \tag{44}$$

where $\hat{\varepsilon}_{De_j}$ and $\hat{\varepsilon}_{Dg_j}$ are the residuals of the yearly electricity and non-for power NG demands at node j, respectively. These residuals are arranged as a vector of random variables and each realization of this vector determines a realization (possible outcome) of the electricity and non-for power NG demands. It is assumed that these residuals are multivariate normally distributed in order to adequately consider the existing correlations between electricity and non-for power NG demands and the correlations between these demands at different locations.

$$\left(\hat{\varepsilon}_{De_j}, \hat{\varepsilon}_{Dg_j}\right) \approx N\left(\mu_D, \Sigma_D\right) \tag{45}$$

where the mean values $\boldsymbol{\mu}_D$ are equal to zero and the covariance matrix $\boldsymbol{\Sigma}_D$ includes the typical standard deviations related to the demand estimations for the corresponding time horizon (greater standard deviations for longer time horizons), and also the correlation factors between electricity and non-for power NG demands at different locations. Appendix A.1 describes the procedure for generating multivariate normally distributed random variables from a vector of non-correlated pseudo random numbers with a mean values equal to zero and unitary variances. The distribution of electricity and non-for power NG demands between the stages and time slices is considered as deterministic.

In a similar way, the wind power productions at each stage t, time slice k and node j can be expressed as

$$Pgw_j^{k,t} = \left(Pgw_j^a \; FT_w^t + \hat{\varepsilon}_{Pgw_j}^t\right) FK_w^k \tag{46}$$

where $\hat{\varepsilon}_{Pgw_j}^t$ is the residual of the wind power production at each stage t, and node j. The modeling of these residual is based on the available data about the historical Danish wind power production [63] that includes a 25 year-time series of the monthly wind energy index. From this historical information can be inferred that a monthly production can be the double (or a half) of the monthly mean value, being the monthly variance higher for those months with higher production. It can also be noticed that standardizing (removing the monthly pattern) the production series, the monthly deviations for the whole set of data can be adjusted to a lognormal distribution. Moreover, the autocorrelogram associated with this production series does not show any noticeable autocorrelation between the studied time series. However, since the major uncertainty about wind power production is related to the installed capacity for given year, and in general the historical information about the Danish wind power production cannot extended to the rest of the European countries, it is assumed that the vector of random residuals $\hat{\varepsilon}^t_{Pgw_j}$ are multivariate normally distributed, taking into account the correlations between the wind power productions at different locations. The monthly residuals for a given node are considered as independent values according to the analyzed Danish wind energy index.

$$\left(\hat{\varepsilon}^t_{Pgw_j}\right) \approx N\left(\mu_W, \Sigma_W\right) \tag{47}$$

where the mean values $\boldsymbol{\mu}_W$ are equal to zero and the covariance matrix $\boldsymbol{\Sigma}_W$ includes the typical standard deviations related to the monthly wind power productions (greater standard deviations for these month with higher productions), and also the correlation factors between the wind power productions at different nodes. The distribution of the wind power productions between the time slices (day/night pattern) is considered as deterministic.

Fuel prices, which also include the NG prices of each gas supplier, are modeled as constant values within each year (time horizon of the NG&E operational planning model) as shown in Equations (6) and (29). On the other hand, the medium-term NG&E operational optimization is based on a centralized perspective of the problem, therefore, it is reasonable to assume that all the generating unit located at the same node faces the same fuel prices. Thus, the price of the fuel f used by the generating unit i, $FP_{i,f}$ can be defined as:

$$FP_{i,f} = FP_{j,f} + \hat{\varepsilon}_{j,f} \qquad \forall i \in G_j \tag{48}$$

where $FP_{j,f}$ is the price of the fuel f at node j (result of the PET energy model), $\hat{\varepsilon}_{j,f}$ is the residual added to the forecasted value $FP_{j,f}$ and Γ_j includes all the generating units connected to node j. Similarly, the NG price of each gas supplier g, NGP_g, i.e., the prevalent NG price at which supplier g is willing to provide its NG resource can be expressed as:

$$NGP_g = GP_g + \hat{\varepsilon}_g \tag{49}$$

where GP_g is the forecasted NG price of each supplier g (result of the PET energy model) and $\hat{\varepsilon}_g$ is the residual added to take into account the uncertainty associated with GP_g. The random residuals $\hat{\varepsilon}_{j,f}$ and $\hat{\varepsilon}_g$ are jointly generated, by assuming that they are multivariate normally distributed. In this way, it is possible to consider the close correlation that exists between the prices of the NG and the other fuels which is also affected by the supply location.

$$\left(\hat{\varepsilon}^t_{j,f}, \hat{\varepsilon}_g\right) \approx N\left(\mu_F, \Sigma_F\right) \tag{50}$$

where the mean values $\boldsymbol{\mu}_F$ are equal to zero and the covariance matrix $\boldsymbol{\Sigma}_F$ includes the typical standard deviations related to the fuel price estimations for the corresponding time horizon (greater standard deviations for longer time horizons) and the correlation factors between NG and other fuels prices at different supply locations.

5.3 Deterministic problem: mathematical formulation

5.3.1 Objective function

From a centralized perspective, the aim of the combined NG&E operational planning is the minimization of the total operating and shortages costs over the considered time horizon. This can be formulated as an optimization problem whose objective function is stated as:

$$OF:\ \min\left\{\sum_{t}\sum_{k}B^{k}\begin{pmatrix}\sum_{i}C_i\left(pg_i^{k,t}\right)+\sum_{j}CSE\left(ps_j^{k,t}\right)+COM_i(pgn_i)\\ \sum_{g}C_g\left(w_g^{k,t}\right)+\sum_{j}CSG\left(ws_j^{k,t}\right)\end{pmatrix}\right\} \tag{51}$$

where $C_i(pg_i)$ is the production cost of a thermal generating unit i which does not use NG as fuel, $CSE(ps_j)$ is the electricity shortage cost related to a fictitious unit whose output power ps_j is equal to the load shedding at node j, and $COM(pgn_i)$ is the variable operation and maintenance cost of NGFPP i. $C_g(w_g)$ is the NG supply cost of the supplier g and $CSG(ws_j)$ is the NG shortage costs related to a fictitious NG injection ws_j which value equals the NG load shedding at node j.

5.3.2 Electric power systems constraints

This optimization is subject to a set of electrical system constraints at each block k of the stage t:

$$\sum_{i}\left(pg_i^{k,t}+pgn_i^{k,t}+pgh_i^{k,t}\right)+\sum_{j}Pgw_j^{k,t}+\sum_{j}ps_j^{k,t}=\sum_{j}De_j^{k,t} \tag{52}$$

$$-F_m^{max}\le\sum_{j}\left[H_{mj}\left(\sum_{i\in G_j}\left(pg_i^{k,t}+pgn_i^{k,t}+pgh_i^{k,t}\right)+Pgw_j^{k,t}+ps_j^{k,t}-De_j^{k,t}\right)\right]\le F_m^{max}\quad\forall m \tag{53}$$

$$0\le pg_i^{k,t},pgn_i^{k,t},pgh_i^{k,t}\le P_i^{dmax}\qquad\forall i \tag{54}$$

where the subset Γ_j includes all the generating units connected to node j. Equation (52) represents the electric power balance and (53) shows the maximum transmission capacity limits F_m^{max} for each line m. It is important to note that although each H_{mj} factor depends on the choice of slack node, the result of the optimization problem is indifferent to this choice. Equations (52) and (53) represent the dc model of electric power flows. Finally, constraint (54) models the maximum capacity of power plants.

5.3.3 Natural gas systems constraints

Also there are a set of NG system's constraints for each block k of stage t:

$$\begin{pmatrix} \sum_{g \in W_j} w_g^{k,t} + ws_j^{k,t} + \sum_{m \in I_j} Qg_m^{k,t} - \sum_{m \in O_j} Qg_m^{k,t} + \\ \sum_{p \in P_j} QO_p^{k,t} - \sum_{p \in P_j} QI_p^{k,t} - \sum_{i \in G_j} HR_i\left(pgn_i\right) \end{pmatrix} = Dg_j^{k,t} \tag{55}$$

$$W_g^{min} \le w_g^{k,t} \le W_g^{max} \qquad \forall g \tag{56}$$

$$-Qg_m^{max} \le Qg_m^{k,t} \le Qg_m^{max} \qquad \forall m \tag{57}$$

Equation (55) represents the nodal NG flow balance at each node j including storage injection/withdrawal flow rates, $QIW_p^{k,t}$ and the NG consumption of the NGFPPs, $HR_i(pgn_i)$, where Π_j is the subset of NG reservoirs located at node j. Constraints (56) shows the limits of NG production capacities of each NG supplier and Equation (57) sets the maximum transport capacities of each pipeline.

5.3.4 Storage constraints

The operational conditions outlined above are augmented with restrictions that couple the stages. These restrictions are the inventory equation of NG storages (58) and the inventory equation of water reservoirs (59):

$$Vg_p^t = Vg_p^{t-1} - \sum_k B_k \, QIW_p^{k,t} \qquad \forall p \tag{58}$$

$$V_i^t = V_i^{t-1} + A_i^t \, ST - \sum_k B_k \, Qw_i^{k,t} - S_i^t \, ST \qquad \forall i \in G_h \tag{59}$$

where Γ_h is the subset of hydro power generating units with an associated water reservoir.

There are other set of constraints that couple the decision at different time slices within a certain stage. The equivalent hydro power plants introduce this type of constraints:

$$\sum_k pgh_{i,o}^{k,t} = HE_i^t \, RF_i \qquad \forall i \in G_{he} \tag{60}$$

$$pgh_{i,b}^{k,t} = \frac{HE_i^t \left(1 - RF_i\right)}{ST} \qquad \forall k, \forall i \in G_{he} \tag{61}$$

$$pgh_i^{k,t} = pgh_{i,b}^t + pgh_{i,o}^{k,t} \qquad \forall i \in G_{he} \tag{62}$$

where Γ_{he} is the subset of equivalent hydro power generating units.

Natural gas line-pack also introduces time coupling constraints within each stage:

$$\sum_k B_k \, QWIL_m^{k,t} = 0 \qquad \forall m \in M_{LP} \tag{63}$$

$$-QWIL_m^{max} \le QWIL_m^{k,t} \le QWIL_m^{max} \qquad \forall m \in M_{LP} \tag{64}$$

$$Qg_{jm}^{max} = Qg_{mk}^{max} = Qg_{m}^{max} \qquad \forall m \in M_{LP} \tag{65}$$

$$Qg_{jm}^{k,t} + QWIL_{m}^{k,t} - Qg_{mk}^{k,t} = 0 \qquad \forall m \in M_{LP} \tag{66}$$

where M_{LP} is the subset of pipelines for which their line-pack have been modeled.

Finally, other constraints related to the storage facilities must be taken into account:

$$Vg_{p}^{min} \leq Vg_{p}^{t} \leq Vg_{p}^{max} \qquad \forall p \tag{67}$$

$$-QI_{p}^{max} \leq QIW_{p}^{k,t} \leq QW_{p}^{max} \qquad \forall p \tag{68}$$

$$V_{i}^{min} \leq V_{i}^{t} \leq V_{i}^{max} \qquad \forall i \in G_{h} \tag{69}$$

$$pgh_{i}^{k,t} = \rho_{i}\left(Qw, H\right) Qw_{i}^{k,t} \qquad \forall i \in G_{h} \tag{70}$$

Constraints (67) and (69) set the capacity limits of the systems' energy storages. Equation (68) establishes the limits for the injection/withdrawal flow rates of NG storage *p*, and Equation (70) is the power output function of the hydro plant *i*.

5.3.5 Time horizon coupling constraints

The difference between the initial and the final (last stage) volumes of NG and water at each storage facility can affect significantly the total NG&E supply cost in the considered time horizon. If the final volumes of NG and water are not constrained at specific values, these volumes match the storage minimum volumes, since the opportunity cost of use the energy (FCF) beyond the time horizon is unknown, and thus not modeled. In order to cope with the problem's characteristics explained before, and for the sake of simplicity, the combined NG&E operational planning take into account a time horizon of one year and the following constraint are imposed:

$$Vg_{p}^{\text{ini}} = Vg_{p}^{T} \qquad \forall p \tag{71}$$

$$V_{i}^{\text{ini}} = V_{i}^{T} \qquad \forall i \in G_{h} \tag{72}$$

where Vg_{p}^{ini} and V_{i}^{ini} are the initial volumes and Vg_{p}^{T} and V_{i}^{T} are the volumes at the final stage *T*.

5.4 Probabilistic problem: application of the Monte Carlo method

The presented mathematical formulation in the previous section address the so-called deterministic problem, since all the inputs parameters (NG&E demands, water inflows, fuel prices, wind power productions, etc.) are known values. However, these parameters are uncertain. This means that the medium-term NG&E operational planning is, in fact, a stochastic optimization problem. Among other methodologies, the simulative Monte Carlo method can be implemented to deal with these uncertainties. This simulative method is based on statistical sampling experiments which are performed on mathematical model of the system to estimate its stochastic behavior. The results obtained by simulating a finite number of times the stochastic behavior of the system are, by the very nature of the method, inexact [64]. Thus, simulative techniques usually require a large number of simulations to obtain sufficiently accurate results. However, the simulative procedures allow formulating mathematical models very close to reality, its most important advantage. In practice, these methods can provide results even more representative of real behavior of the studied system as analytical methods under restrictive assumptions. Another important advantage is that the Monte Carlo method obtains the probability distribution of the variables studied within the procedure without extra calculation effort. This feature distinguishes a significant improvement over the analytical methods, which usually provide only the expected value of the variables analyzed.

Therefore, the deterministic medium-term NG&E operational planning problem is solved a finite quantity of realizations representing different possible values of the uncertain input parameters. The number of Monte Carlo realizations is determined according the selected stopping criterion. Further details about the different stopping criteria can be found in Appendix A.2.

Figure 5.10 shows the general flowchart of the procedure that has been developed to carrying out an stochastic NG&E operational planning and to obtain the probabilistic results applying the Monte Carlo simulation method.

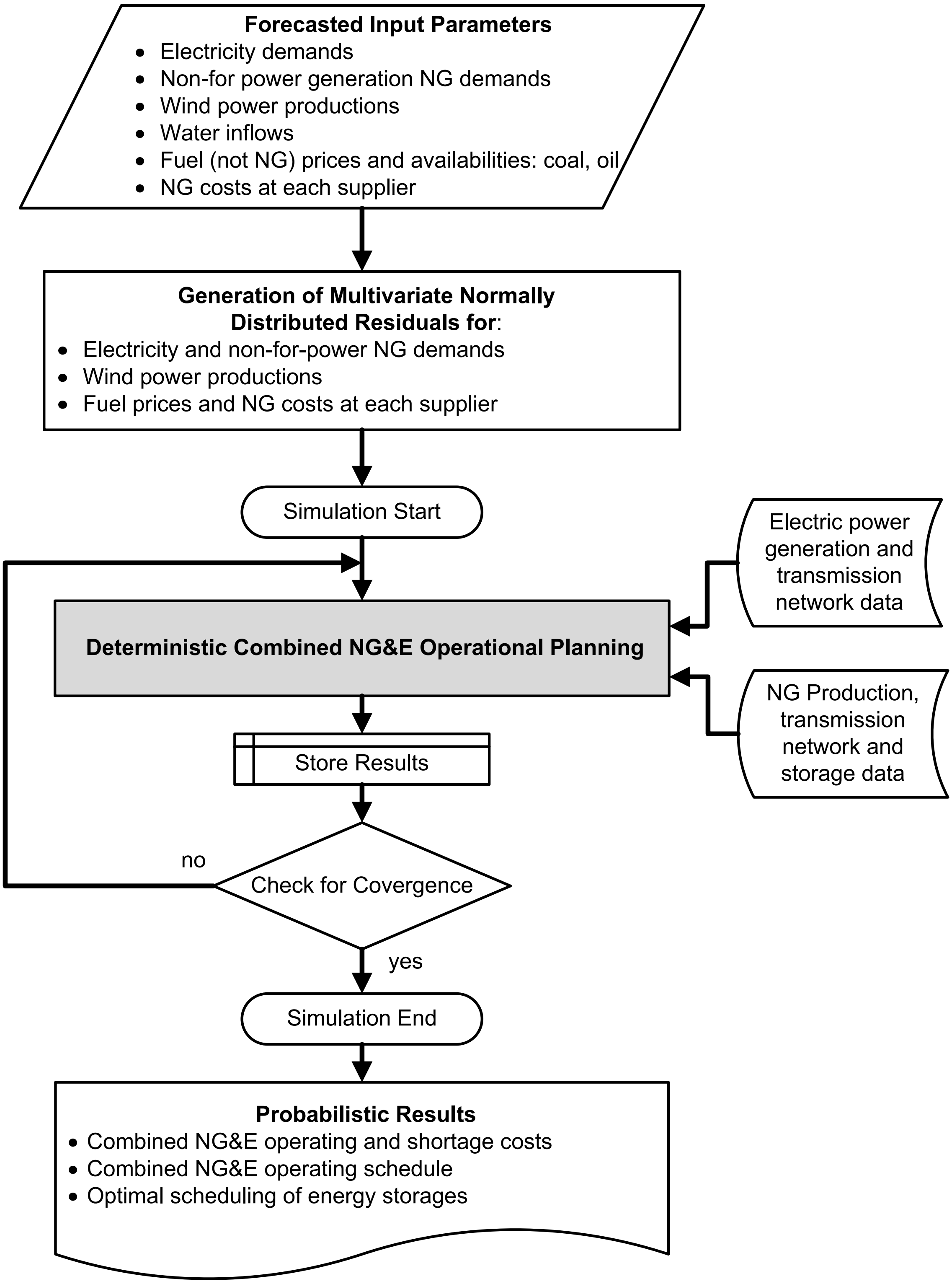

Figure 5.10: Flowchart of the probabilistic NG&E operational planning procedure

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APPENDIX

A.1 Normal multivariate distribution - Residuals

This appendix describes the mathematical procedure for generating multivariate normally distributed random variables from a vector of non-correlated and independent random numbers with mean values equal to zero and unitary variances [64]. This method is applied to generate the random residuals associated with some uncertain input parameters of the NG&E operational model.

Let $\overline{Z} = \left(Z_1,...,Z_r\right)^T$ denote a random vector with a multivariate normal probability distribution function (pdf) that can be mathematically expressed as

$$f\left(\overline{z}\right) = \left(2\pi\right)^{-r/2} \left|\Sigma\right|^{-1/2} e^{-\left(\overline{z}-\overline{\mu}\right)^T \Sigma^{-1}\left(\overline{z}-\overline{\mu}\right)} \qquad -\infty \le z_i \le \infty \qquad i = 1,...,r \qquad \text{(A.1.1)}$$

where $\overline{\boldsymbol{\mu}}$ denotes a r x 1 column vector of means $\mu_1,\ldots,\mu_r$, y $\boldsymbol{\Sigma}$ denotes and $r{\times}r$ a posituve definte, symmetric matrix of covariances. Hereafter, the expresion A.1.1 is denoted by $N\ (\boldsymbol{\mu},\Sigma)$. If $\overline{X} = \left(X_1,...,X_r\right)^T$ is a vector with $N\ (\overline{\mathbf{0}},\overline{\mathbf{I}})$ where $\overline{\mathbf{0}}$ is a column vector of zeros and $\overline{\mathbf{I}}$ is the $r{\times}r$ identity matrix, then it can be stated $\overline{\mathbf{Z}}$ as

$$\overline{Z} = \overline{c}\,\overline{X} + \overline{\mu} \qquad \text{(A.1.2}$$

where $\overline{\mathbf{c}}$ is a unique lower triangular matrix satisfying [65]

$$\Sigma = \overline{c}\,\overline{c}^T \qquad \text{(A.1.3)}$$

In this way, $\overline{\mathbf{Z}}$ represents a vector of correlated random variables with mean values $\overline{\boldsymbol{\mu}}$ and a covariance matrix $\boldsymbol{\Sigma}$. Due to the residuals generated following this procedure are used in a Monte Carlo simulation, then $\overline{\mathbf{X}}$ is an arrange of independent pseudo random numbers with mean values equal to zero and unitary variances.

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A.2 Stopping criteria for Monte Carlo simulations

Since the computing time often is a crucial constraint, a very important procedural concern within the Monte Carlo method is related to the number of independent trials or simulations that should be performed in order to achieve a satisfactory level of confidence in the resulting probability distribution functions. This number depends on the predefined error which greatly depends on the characteristics of the problem. Although for the assessment of investments, which is a long-term planning task, time is not an urgent constraint, the confidence degree of the results is an important objective to be achieved.

According to the reviewed literature, there are diverse stop criteria for determining the number of Monte Carlo realizations. An alternative is to control the error either on the expected value of the objective function (OF) as stated in Equation A.2.1 or on the standard deviation of the OF as it is expressed in Equation A.2.2., where *n* is the number of simulations.

$$\varepsilon_{E[OF]} = \frac{E\left[OF_n\right] - E\left[OF_{n-1}\right]}{E\left[OF_n\right]} \tag{A.2.1}$$

$$\varepsilon_{E[\sigma_{OF}]} = \frac{E\left[\sigma_n\right] - E\left[\sigma_{n-1}\right]}{E\left[\sigma_n\right]} \tag{A.2.2}$$

Under this perspective, error must be assessed after each realization in order to determine if the specified confidence degree has been reached. However, in some problems this error's control criteria are not a suitable method for assuring confidence in the obtained results. Indeed, momentary confidence intervals could take place with the consequence of stopping the statistical sampling before a definitive confidence is reached.

Based on the theory for computing confidence intervals, Equation A.2.3 has been deduced to determine the sample size required to obtain a probability density function which meets a specified error. A detailed explanation of this deduction can be found in [69]. This Equation considers the above stated criteria (A.2.1) and (A.2.2) and can be successfully applied for controlling the relative uncertainty existing in the Monte Carlo simulations. In fact, when the assessed error is lower than or at least equal to the specified error, the statistical sampling is stopped.

$$\varepsilon\left(E\left[OF\right],\sigma\right) = \frac{\Phi^{-1}\left(1-\delta/2, 0, 1\right)\sigma_n}{E\left[OF_n\right]\sqrt{N}} \tag{A.2.3}$$

where

Φ^{-1}	Inverse of the standard normal distribution
$1-\delta/2$	Predefined confidence level
σ_n	Expected standard deviation (volatility) of the OF at the simulation *n*
$\varepsilon\left(E\left[OF\right],\sigma_{OF}\right)$	Control of the relative uncertainty at the simulation *n*

$\Phi\left(1-\delta/2, 0, 1\right)$	Critical value of the standard normal distribution with mean value 0 and unitary standard deviation
$E[OF_n]$	Expected value of the OF at the simulation n
N	Total number of simulations
n	Number of simulation

In the proposed approach, the control of the relative uncertainty (A.2.3) is the adopted as the stopping criterion of the Monte Carlo simulations.