Co-optimized analysis of electric and natural gas infrastructures

by

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ABSTRACT

This dissertation proposes and implements a long-term capacity expansion model for the co-optimization of electric and natural gas infrastructures. It allows to determine the required investments in generation units, transmission lines and pipelines for meeting future demands, while representing electricity and natural gas flows using steady state equations. A Mixed Integer Nonlinear Programming (MINLP) problem is developed, from which a linearized version is derived. A twenty six node integrated electric-gas system for the Eastern Region of the United States is used to demonstrate the model's capabilities. Results show that the model provides an accurate operational representation of the integrated system, and therefore, enhances the expansion planning process.

CHAPTER 1. OVERVIEW

1.1 Motivation

For many decades, natural gas has had an important role in the global energy landscape. The situation has not been very different in the United States, where the natural gas share of total energy use has moved from approximately 21% in 1980 to 27% in 2012, and it is expected to be 30% in 2040 (26), i.e., almost a third part of the primary energy consumption.

Natural gas has traditionally been used within industrial processes and as a heating alternative for residential and commercial sectors. However over the years, its participation as a fuel for generating electricity has increased considerably as shown in Figure 1.1, and even more important, this trend seems to remain in the coming decades.

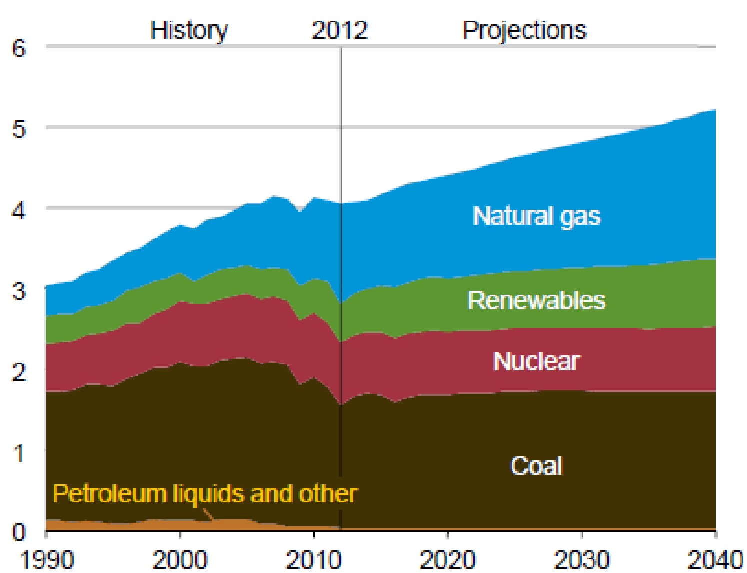

Figure 1.1 U.S. Electricity generation by fuel (26)

Electricity generation capacity seems to have a similar behavior according to Figures 1.2

and 1.3, from which new gas-fired generation capacity additions have played an important role since 1998 and they will continue growing until 2040, where natural gas is by far the major contributor to the *Natural gas/oil* category.

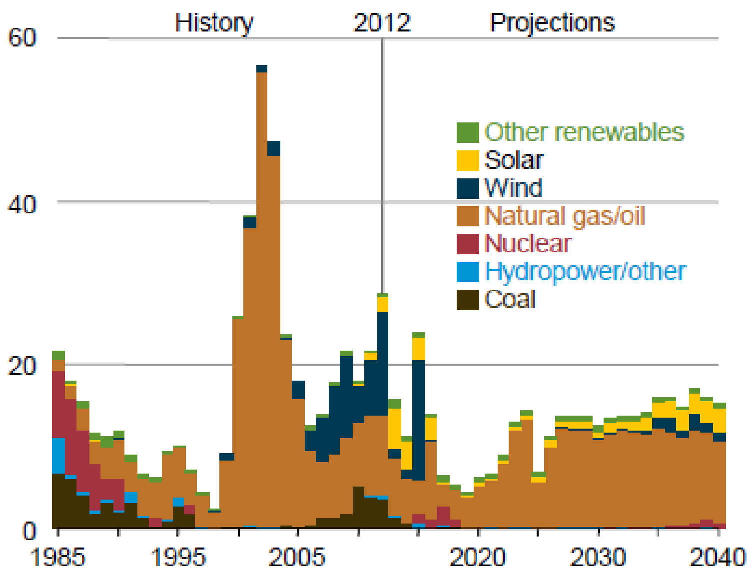

Figure 1.2 U.S. Electricity generation capacity additions (26)

There are multiple reasons associated with this phenomenon among which are: i) the shale gas boom, i.e., the significant increase of gas production due to technological developments in the extraction techniques of non-conventional resources, ii) a reduction in the market prices as the result of the growth in the supply, iii) the environmental benefits that combined cycle units have demonstrated when compared against other fossil-fired units, and iv) the operational support that gas-fired units can provide for renewable integration (26), (56), (57). Thus, it is clear that the electric sector has become an important player within the natural gas industry, which results in strong interactions between them, not only physically but also economically (76), (79).

However, there has been little coordination for the development or planning of operational activities for both systems in the past, and much less for determining the combined infrastructure expansion requirements. Only recently, NERC has begun to develop efforts to facilitate the coordination of activities between the two industries, assess the risks associated with the

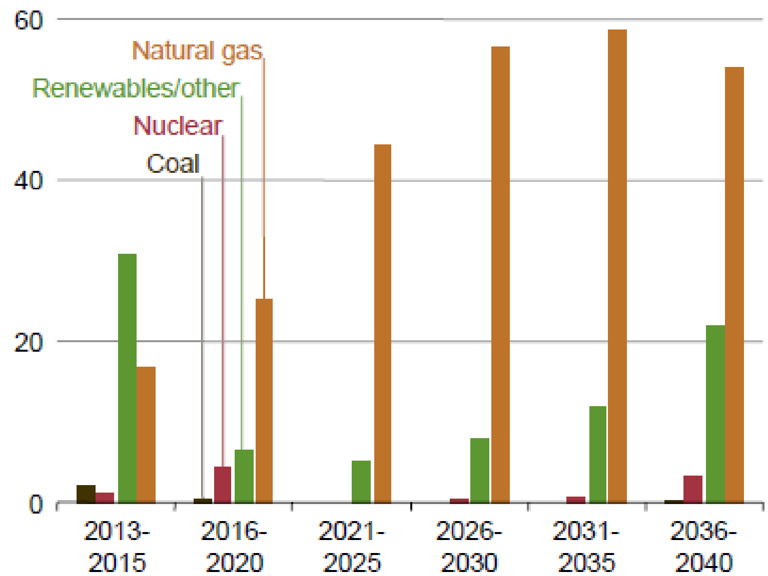

Figure 1.3 U.S. Electricity generation capacity additions by fuel type (26)

increasing dependence between them, and to consider further actions for minimizing them (56) and (57).

1.2 Description of the problem

The increasing interdependance between electric and natural gas systems worldwide, both technically and economically, appears to raise the need for designing new models, procedures and simulation tools to develop planning studies that provide for the identification of new infrastructure requirements, and to explore the uncertainties and the risks related with long-term and large-scale investments in both sectors (47), (63).

Multi-sector models using network theory have enabled the first steps towards this purpose (64), (65). However, although transportation models can give a good approximation under normal operation conditions, they can either overestimate or underestimate the transmission capacity under stressed conditions, because they do not consider the physical relations governing the energy flows (70). On the other hand, steady state equations can be used to improve the accuracy of the models for the transmission networks, however, their nonlinear characteristics have limited their inclusion within optimization problems (45), (52).

This dissertation proposes and implements a long-term capacity expansion model for the co-optimization of electric and natural gas infrastructures. It enables identification of the required investments in generation units, transmission lines and pipelines for meeting future demands, while representing electricity and natural gas flows using steady state equations. A twenty six node integrated electric-gas system for the Eastern Region of the United States is used to demonstrate the model's capabilities.

1.3 Objectives

1.3.1 General objective

The general objective of this dissertation is to design a model for assessing co-optimized analysis of electric and natural gas infrastructures in long-term expansion planning studies.

1.3.2 Specific objectives

There are five specific objectives to the work of this dissertation. They are:

1. Identify the different physical phenomena associated with natural gas flows in a pipeline network under steady state and transient conditions, and determine the required assumptions to propose an adequate representation in a long-term capacity expansion problem.

2. Identify different models to represent electricity and natural gas flows in a transmission network inside an optimization problem, understand their differences, their rationales, and the advantages/disadvantages introduced in a long-term expansion problem.

3. Develop a MILP model for the capacity expansion planning problem of an integrated system considering the steady state representation of the electricity and gas flows in the transmission network.

4. Analyze the impact of the pressure in new pipeline investments, and propose a simplified model for compression/reduction stations to improve the transmission network representation.

5. Propose a method for performing co-optimized analysis of electric and natural gas infrastructures in large-scale systems considering the mathematical formulations proposed in this dissertation.

1.4 Contributions

Contributions are summarized here against the backdrop of a detailed literature review of the state of the art, presented in Chapter 2. This literature review summarized previous work in natural gas flows under steady state and transient conditions in pipeline networks; optimization problems for natural gas systems; and co-optimization of operation and planning activities for an integrated electric-gas system.

The contributions of this dissertation are as follows:

1. *Analytical modeling*: Modeling of natural gas and electric systems for co-optimized expansion planning.
   - Steady state equations for natural gas pipeline
   - Linearized representation of gas flow using SOS2 variables
   - Disjunctive representation of gas and electric investment options
2. *System representation*: Development of an aggregated representation of the natural gas and electric systems within the Eastern US.
   - Adaptation of aggregated EI electric systems representation from EE project
   - Development of an aggregated EI natural gas representation
3. *Solution algorithm*: A solution procedure for a computationally intense co-optimized expansion planning problem modeled as a mixed-integer linear program.
   - Sequential/Quasi-feasible solution procedure
4. *Investment insights*: Use of the analytical modeling, system representation, and solution algorithm developed within this dissertation to identify insights into gas/electric invest-

ments necessary to achieve an economically attractive low-carbon future for the Eastern US.

- Very large electric transmission investments are required to move wind power from the Midwest to the East coast population centers;
- Significant natural gas pipeline investments are required to move natural gas from the shale gas plays in the northern Appalachian mountains throughout the US.

1.5 Thesis organization

This dissertation is structured as follows. Chapter 2 presents a literature review of natural gas flow under steady state and transient conditions in pipeline networks, optimization problems for natural gas systems, and co-optimization of operation and planning activities for an integrated electric-gas system. Chapter 3 summarizes organizational structures and related investment procedures of the natural gas industry, and a mathematical model to represent the gas flows in a pipeline is presented. Chapter 4 introduces two disjunctive models (a linear and a non-linear one), to analyze long-term capacity expansion in pipeline networks. Chapter 5 modifies these models to include them in a co-optimization problem for an integrated electric-gas system. Results for the Eastern Interconnection of the United States are shown in Chapter 6, while appendices summarize the acronyms, the mathematical nomenclature and the input data and basic parameters for the simulation models. Chapter 7 provides conclusions and identifies future work.

CHAPTER 2. LITERATURE REVIEW

2.1 Natural gas flows in pipelines

Natural gas flows in pipelines are a complex phenomena requiring the use of a set of partial differential equations (PDEs) to adequately represent the physical interactions that occur between the fluid, the pipeline and its external environment. A highly accurate representation should even consider multi-phase models, given that a little percentage of the gas could condensate while being transmitted across the pipeline (10), (11), (51). Usually these PDEs are derived from the application of the laws of conservation of energy, mass and momentum as described in (30), (33), (58). Advanced mathematical algorithms combined with large computational capacity are required to solve this group of equations.

Different assumptions are considered in order to simplify this complex problem, resulting in different types of models used for either steady state or transient simulations. Usually transient representations intend to analyze the effect of the heat exchange in the gas flows, while isentropic (no heat exchange with the outside) or isothermal conditions (constant temperature) are considered when deriving steady state expressions.

Regarding the study of transient models, a comparison between isothermal and non-isothermal transient flow models is presented in (59); (1), (12) and (77) derived non-isothermal representations to determine the effect of temperature and heat exchange in gas flows; (3) proposed a state space formulation for transient flows; and finally, (31) focused on the implementation of solution algorithms based on Runge-Kutta methods.

A detailed analysis of the various steady state equations that result from considering different flow regimes is presented in (15). Reference (58) in turn develops mathematical algorithms to address the set of algebraic equations representing the flows in a pipeline network. Finally, different case studies are solved in (10) by using steady state formulations.

These papers provide important background of the equations studied before to represent the gas flows, the complexities introduced by them when considered in large-scale systems, the assumptions beneath them, and they build the basis for developing a model of gas flows that has sufficient fidelity without overwhelming computational burden.

2.2 Modeling of natural gas systems in optimization problems

Pipeline networks have been frequently represented using *transportation models* in planning optimization problems, mainly due to the advantages of linear formulations in terms of computational burden. However, this representation does not allow to model different technical characteristics, because of their nonlinear nature, that could suboptimize the simulation results. Because of this, different research projects have been conducted in recent years to improve these formulations, either linearizing the nonlinear expressions or developing solution algorithms based on metaheuristics (69). This section presents a review of the different models found in the literature.

A dynamic programming approach is used in (84) to minimize the cost of operating a long pipeline including multiple compression stations. Of course, the applicability of this formulation is limited to a restricted number of transmission elements.

When considering linear strategies, a MILP problem to find an optimal investment plan that guarantees an adequate supply of the future natural gas demand in the UK was formulated in (66). In addition, a methodology for the optimization of the design of pipeline networks assuming a continuous range of diameters is proposed in (60). For this particular case, the final solution for the continuous variables that represent the pipeline's diameters is approximated to the closest integer value. Reference (34) works in a successive linear programming algorithm to determine the optimal diameters of a given pipeline network, in order to minimize the operational and investment costs.

From a nonlinear perspective, references (9), (13), (67) and (85) derived MINLP problems to minimize fuel consumptions in compressor stations when considering steady state flows in a transmission network. Due to the nonconvex nature of these formulations, in (85) a lower bounding procedure is implemented for approximating the optimal solution, while in (9), (13) and (67) heuristic algorithms are used for finding local optimal solutions. Reference (21) shows how to minimize the fuel consumption of the compressor stations considering transient network flows.

Additionally, five different mathematical formulations are presented in references (4), (32), (36), (38) and (82) to determine optimal expansion plans in pipeline networks. A two step relaxation approach for solving a MINLP is studied in (4) to determine optimal locations and diameters of the pipeline segments required to reinforce an existing transmission network. A MINLP problem is proposed in (32) to determine an optimal design for the Turkish natural gas pipeline network. A branch and bound algorithm combined with a nonlinear algorithm is used to determine a local optimal solution for the problem. Long-term planning analysis of natural gas networks are developed in (36). An optimization procedure is proposed using Genetic Algorithms to find cost efficient network structures for distribution systems. In (38), an heuristic algorithm is developed as the optimization strategy to solve a MINLP model for identifying required investments in pipelines and compressor stations within the simulation horizon. A disjunctive approach for the MINLP problem is formulated in (82) to find the required investments in the natural gas network in Turkey. A reduction technique that combines graph theory and nonlinear functional analysis to reduce the size of pipeline optimization problems is presented in (68).

However, the majority of these models were either low fidelity because of the simplified expressions used to represent gas flows in pipelines, or they could not necessarily guarantee a global optimal solution because of the algorithms implemented for solving the problem.

2.3 Co-optimized analysis of electric and natural gas infrastructures

Transmission networks play an important role in the future development of electric and natural gas systems, because of their ability to take advantage of the geographical diversity of natural resources, which translates into economic and operational improvements (39), (47). However, an accurate representation of transmission networks in optimization problems can be computationally demanding, and therefore a reasonable tradeoff between fidelity and complexity is always desirable.

Different representations for the electric transmission network can be found in the literature (70), ranging from simple transportation models using network flows, to more detailed formulations considering electric laws. Under steady state conditions, AC Power Flow equations provide an accurate representation of the flows across the transmission network in planning studies. However, this will also entail the need for considering a set of nonlinear/nonconvex equations in the optimization problem, resulting in a considerable increase in their complexity. On the other hand, it is possible to use a transportation model in which Kirchhoff's Voltage Law will be likely violated, possibly causing an overestimation/underestimation of the transmission capabilities under some scenarios.

Gas transmission systems can also be modeled using different representations according to the assumptions considered (21), (69). The simplest approach would represent the pipeline network using a transportation model, especially when considered in long-term planning problems. Although this representation can overestimate/underestimate the capability of the transmission network, it has been frequently used because it can be easily implemented, and because it can provide acceptable aproximations when dealing with uncongested networks. More detailed representations can be developed by considering steady state natural gas flow equations or transient flow equations.

References (37), (64), (65), (80) present examples of different optimization problems considering integrated energy systems represented as transportations models. Production costs analysis and co-optimized expansion plans are reported in (37) for an integrated electric-gas system that represents the Eastern Region of the United States. A network flow model for evaluating the interdependencies between coal, natural gas, and electricity systems is developed in (64) and (65). A MILP formulation for studying the capacity expansion problem of an integrated electric-gas system is proposed in (80).

However, multiple research efforts have been developed in the recent years to improve the modelling of the transmission networks in electric-gas analisys. An energy flow analysis for the steady state operation of an integrated electric-gas system considering the effect of the temperature in the gas flows is presented in (46). An optimal power and natural gas flow is studied in (17) and (78). The former develops an iterative methodology based on solving a MILP problem considering transport outage distribution factors and pressure shift factors for the pipeline network; the latter solves the optimization problem using a sequential-hybrid approach combining heuristics and an interior point algorithm.

References (14), (18), (19), (44) and (81) analize the short-term planning problem of an integrated electric-gas system. Reference (14) presents an operational planning model for an electric system considering a detailed representation of the pipeline network and the hydroelectric power plant reservoirs. The security constrained unit commitment problem is studied in (18) including dynamic gas constraints and line packing in pipelines. In (19), a MILP formulation for the production cost problem is proposed including different technical characteristics for generation units, spinning reserve requirements for the power system, line packing, and steady state equations for the electricity and natural gas flows. In (44), a bilevel optimization problem is proposed to implement a coordinated scheme for the scheduling of electricity and natural gas infrastructure, while considering a transient model for the natural gas flow. Reference (81) formulates a MILP problem for analyzing the operational interdependencies of electric and natural gas systems.

From a long-term planning point of view, a sequential solution algorithm is implemented in (6) to find an optimal expansion plan for an integrated electric-gas system while considering the steady state natural gas flow equations. Because of the procedure followed to evaluate the natural gas load flow, its applicability is reduced to radial configurations. The expansion of distributed generation, transmission lines and pipelines for a subtransmission system considering the steady state equations for pipelines and compression stations is studied in (7), and solved using a metaheuristic approach. The implications of considering natural gas supply and transmission constraints in reliability studies for power systems is discussed in (53), (54).

As observed above, several research efforts have been developed to study the operational planning problem of integrated energy systems; however, just a few ones to perform co-optimized analyzes of long-term capacity expansion. The latters usually consider transportation models to represent the energy flows across the transmission networks, or they resort to heuristic algorithms to solve the problem. This dissertation intends to develop a co-optimization model for the long-term capacity expansion problem considering the steady state equations for the flows of electricity and natural gas, while retaining a mixed integer-linear structure in order to find optimal global solutions.

CHAPTER 3. INDUSTRY, ORGANIZATIONS, AND MODELING

3.1 Natural gas industry in the U.S.

In the early days of the industry, natural gas was produced in each municipality just to satisfy its local demand, i.e., the service was provided under an open competition scheme between multiple utilities, resulting in a price war with a single winner that defined the rates for the area. As the cities began to grow, the largest companies identified the transportation of gas between municipalities and states as a business opportunity, leading to the construction of the first pipelines. This is a common evolution for companies that develop into natural monopolies, and therefore, an inmediate action from the local governors was to require that each municipality had to own and operate its local gas company, or at least regulate the private ones, in order to protect the public interest (55).

The Natural Gas Act of 1938 gave control to the Federal Power Commission to regulate the interstate commerce of natural gas by setting rates, determining the requirements to file for a Certification of Public Convenience and Necessity for the new transmission projects, verifying discriminatory conduct, among other activities. The regulation of the sale prices for the interstate commerce at the wellheads was also assigned as a responsability of the Federal Power Commission by the Supreme Court in 1954. The decade of the seventies was characterized by the occurrence of severe shortages of natural gas, due to a series of events occurring in the U.S. energy sector, leading to the publication of the Natural Gas Policy Act of 1978, which started the process of deregulation in the entire industry (55).

Natural gas was purchased by the transmission companies from the producers and then re-sold to the distributers as a bundled commodity for a regulated price until 1984. In 1985, the Federal Energy Regulatory Commission (FERC) released the *Open Access Order* or *Order*

436, which set a voluntary framework for pipeline companies to offer just the transportation service, at a first come first serve basis and for a price agreed between both parties within regulated boundaries. Later, in 1989, the Natural Gas Wellhead Decontrol Act amended the Natural Gas Policy Act of 1978 to eliminate the ceiling prices on the wellhead sales (55).

Finally, FERC Order 636 (issued in 1992), forced all pipeline companies to separate their sales and transportation, i.e., transmission companies could not sell gas anymore, while all sellers would have open access to the pipeline network (55).

3.1.1 Natural gas chain value

3.1.1.1 Reservoirs and production

According to (75), gas reservoirs are usually located between 3,000 and 25,000 feet below the Earth's surface. Traditionally, they have been classified as conventional and unconventional, and their difference can be fundamentally attributed to the ease and cost of extracting the resource. A precise definition of what is conventional or unconventional gas is difficult to state. In this dissertation, we define conventional gas as gas trapped in a geologic formation caused by folding and/or faulting of sedimentary layers that permits its extraction using conventional techniques. And therefore, unconventional gas is gas trapped in the source rock from which it is generated or gas that migrates to a formation of impermeable rock and therefore is not trapped in a conventional deposit; thus, it requires unconventional extraction techniques. Figure 3.1. provides a visual description for this classification (75). An attribute of this definition is that as technology and geological knowledge advance, what was unconventional yesterday can become conventional tomorrow.

During the last few decades, tight gas reserves (which contain primarily dry gas) has been the most important unconventional source for producing natural gas in the U.S. However, the recent advances reached in horizontal drilling and induced hydraulic fracturing techniques have enabled the economical production of shale gas and tight oil, where drillers are mainly looking wet natural gas wells (those with both gas and oil) because of the difference between gas and oil prices.

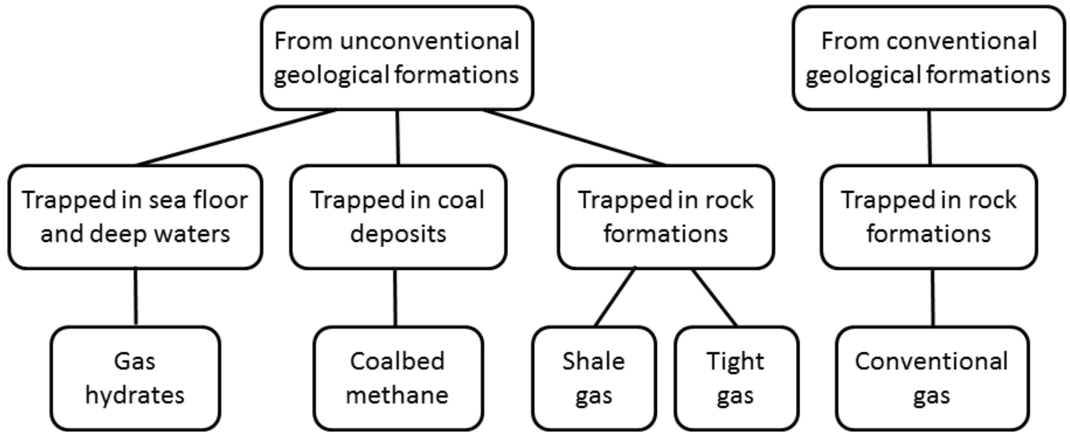

Figure 3.1 Conventional and unconventional gas

Fracking, as it commonly known, consists of injecting a high pressure fluid into the wellbore for fracturing the deep-rock formations where the resources are allocated. Although these advances have demonstrated that is possible to extract a vast amount of natural gas reserves worldwide, growing concerns about the environmental impacts that these technologies can generate have created a strong opposition against them.

Raw natural gas produced from different types of wells will have different chemical compositions and therefore will require different processing activities and will allow producing different amount of sub-products. Its composition will depend on different factors such as the type, depth, and location of the underground reserves as well as the geological characteristics of the area. Based on the type of reserves in which the natural gas reserves are trapped, an alternative classification of types of natural gas is: natural gas from crude oil, dry gas, or condensate wells (75).

Proved reserves are the natural gas volumes expected to be recoverable in the future with a certain degree of certainty, when considering the actual economic and operational conditions; unproved reserves, on the other hand, are the estimated volumes that can be recovered based only on the application of the current technologies.

The U.S. had 2,203 and 322.7 Tcf of natural gas unproved and proved reserves, respectively, for the year 2012 (25). Considering an annual rate of consumption of about 25.5 Tcf (which is what was reported for the year 2012 (25)), these reserves are enough to last 86.4 and 12.7 years, respectively. Also, from the 322.7 Tcf of natural gas proved reserves, 129.4 Tcf correspond to shale gas reserves.

3.1.1.2 Processing

Raw natural gas must be purified before being transported across the pipeline network. The process begins at the wellheads, when a system of small pipelines is used for gathering different streams of gas which are then delivered to a lease separation facility, in which liquid water and lease condensate are extracted. The lease condensate is a mix of pentanes and some other heavy hydrocarbons that can be extracted from the gas stream as a liquid at normal pressures and temperatures. Although they represent a small percentage of the oil industry, they are highly priced because of the ease of refining them (75).

The gas is then moved to a processing plant, where some impurities, natural gas plant liquids and other fluids are separated for finally obtaining dry quality natural gas, i.e., gas that satisfies the quality standards defined by the pipeline companies. Natural gas plant liquids are the hydrocarbons, that are not methane, extracted from the gas stream as a gas, that can be turned into a liquid in a processing plant by increasing its pressure or reducing its temperature. They usually include ethane (used in the chemical industry), propane (used for heating and cooking), butane (used as a gasoline additive) and pentane and other heavier hydrocarbons (75). Each pipeline company defines its own quality standards, based on the pipelines design and the market requirements. In general terms, these standards define the acceptable ranges of values for the main gas properties, and they control the amount of impurities present in the gas stream.

3.1.1.3 Transportation

Natural gas has a relatively low energy density in its gaseous state when compared with other fossil fuels, like coal and crude oil. This property makes its storage as a gas uneconomical; therefore its development as a global market is difficult, because of the problems that this would cause when using sea transport systems (75).

It is possible to compress the natural gas at normal temperatures in order to reduce its volume, and in this way, increase its energy density. This is known as compressed natural gas (CNG); it is used for low storage requirements.

Natural gas can be condensed to a liquid by significantly reducing its temperature (depending on its composition the temperature range will change between -184°F and -274°F) at almost normal pressure conditions. This is called liquified natural gas (LNG), and it provides a form of natural gas that has significantly increased energy density. And these are precisely the advances that have made possible a growing global market (75). Natural gas is first condensed in a liquefaction terminal at the exporting country, and then it is transported using LNG carriers across the seas, and finally it is delivered to regasification plants at the importing country. From there, natural gas can be transported to the final users as a liquid in special containers by railway or trucks, or as a gas using the pipeline network.

LNG imports grew considerably during the first decade of the 21st century. However, the growth of shale gas production during the recent years have dramatically changed the picture: the country is not only reducing significantly the imported amounts, but it also initiated the process for constructing a significant amount of liquefaction terminals, moving from a importing country to a exporting one. At the end of 2013, there were 11 existing importing terminals and just one exporting terminal in the U.S. And there were 15 proposed projects for constructing exporting terminals, and 8 importing projects (between approved and proposed), which probably will not be built.

Natural gas is mainly transported in the U.S. using a highly integrated pipeline transmission and distribution network. The U.S. pipeline network consisted of more than 200 different pipelines systems, comprising more than 300,000 miles of transmission pipelines, and more than 11,000 delivering points, 5,000 receipt points and 1,400 interconnection points for the year 2008 (24).

Pipelines can be classified as interstate or intrastate in accordance with the geographic area in which they provide their services. An interstate pipeline is engaged in the transportation of natural gas across state boundaries; while an intrastate pipeline operates within state borders linking producers with local markets or interstate pipelines companies within the state they serve. The former is subject to FERC regulation, while the latter is regulated by the respective state. An intrastate pipeline that is supplied from interstate pipelines sources, but that delivers all the gas within the state in which it operates is called a Hinshaw pipeline, and it is regulated by the state despite the fact that it participates in interstate commerce (75).

This work will focus primarily on the interstate transmission network, which allows transporting natural gas between different states across the country. Although each interstate transmission system has its own particular characteristics, some general aspects can be highlighted (75).

- A typical system is comprised by the following elements: pipelines, compressors, block valves and regulator stations, and protection, monitoring and metering equipment.
- The transmission capacity of the system is determined as a function of the diameter of the pipelines, their maximum allowable operating pressure (MAOP), the number, capacity and location of compressors stations, and different ambient conditions. The MAOP for a pipeline refers to the value of pressure that its walls can safely hold under normal operating conditions.
- Interstate systems are typically built using pipelines with diameters between 24 and 42 inches; it usually operates at pressures levels between 600 and 1200 psi. They are also comprised by lateral pipelines (with diameters from 6 to 16 inches) used for connecting the main lines with the local distribution systems.
- Compressor stations are usually located every 50 to 150 miles along the course of the pipeline. A typical station has one or more compressors, scrubbers and filters, and bypass piping and valves for routing the gas around the station when it is required.
- Block valves and regulator stations are used to restrict the flows in the pipeline or to isolate a portion of it. They are typically installed 5 to 20 miles apart.
- Metering stations are installed at different locations of the pipeline for measuring the volumes of gas (Mcf) that enters or leaves the system at these points. These stations

are usually provided with pressure regulation equipment to guarantee that end users' pressure requirements are satisfied.

- Natural gas travels inside the pipeline system with a speed ranging between 15 and 30 miles per hour, which is very slow when compared to electricity.

3.1.1.4 Distribution

Natural gas is delivered from the transmission system to the final users through a distribution network. Typically, distribution systems consists of a group of pipes (with diameters from 2 to 24 inches, and operated at pressures from 60 psi to 0.25 psi), small compressors, regulators and block valves stations and protection and metering equipment. Sometimes they are also equipped with monitoring systems (75).

3.1.1.5 Storage

Natural gas storage principally enables the meeting of market demand while maintaining production and transportation activities at normal operational levels. However, it is also used for many different secondary purposes, such as: balancing the flow in pipeline systems, leveling production, ensuring the reliability of gas supply, and reducing gas price volatility (75).

There are different ways for storing natural gas. Underground facilities are the most commonly used alternative for long-term storage purposes in the U.S. They are usually located in depleted gas or oil reservoirs; however they can also be located in depleted aquifers and salt domes. They used to have a yearly cycle, with the gas being injected in the summer months (low demand) and withdrawn during the winter term (high demand). However, a considerable increase in the capacity of natural gas fired plants in the electric sector has modified this cycle due to the needs of gas during the summer to cover the electricity peak's demand (75).

For local distribution companies that are not located close to any underground storage facilities, LNG tanks and propane-air plants are the most common options to meet demand peaks. They were essentially short-term storage facilities, but technology advances have made possible significant increases in their capacity over the years.

Natural gas line packing is a different storage alternative commonly used for short term storage. It uses the pipeline network for holding an inventory of gas. In this form, transmission companies are able to balance the pipeline network when there is a difference between the gas supplied and the demand consumption, and of course, it also allows increases in the demand.

3.2 Organizations for the U.S. Natural Gas Industry

Multiple companies and organizations are involved in the natural gas value chain. This is mainly due to the geographic diversity where the resource is available, the complexity of the processes required to transform it into a usable product, and the different services that this fuel can provide to the final users. Below is a list of different government organizations and natural gas trade associations participating in this industry.

- The natural gas industry is regulated depending of the geographic scope of the services provided. Local government authorities usually regulate municipal utilities; the state's Public Utilities Commission (also known as state's Public Services Commission) regulates services provided within state borders; and the FERC regulates pipelines and storage facilities participating in interstate commerce.

- The Office of Pipeline Safety (OPS) associated to the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA) ensures the safety in the transportation of natural gas through the pipeline network.

- The U.S. Coast Guard (USCG) and the Maritime Administration (MARAD) are the agencies dealing with the licensing, design and operation of deepwater ports under the Deepwater Port Act (DWPA) of 1974.

- The U.S. Environmental Protection Agency writes and enforces regulations (some of them apply directly or indirectly to the natural gas industry) to protect human health and environment.

- The U.S. Energy Information Administration is the section of the Department of Energy that collects, analyzes and disseminates energy information, including the gas industry.

- America's Natural Gas Alliance (ANGA). Represents some natural gas exploration and production companies in North America.
- Natural Gas Supply Association (NGSA). Represents suppliers that produce and market natural gas in the U.S.
- American Gas Association (AGA). Represents companies delivering natural gas worldwide.
- Interstate Natural Gas Association of America (INGAA). Represents interstate natural gas transmission pipeline companies in U.S. and Canada.
- Gas Technology Institute (GTI). Perfoms research for the natural gas industry.

Finally, from a market dimension, natural gas system participants can be divided into three major groups (75):

- Upstream (production activities). Producers, gathering pipelines, aggregators, and financial services companies.
- Midstream (transmission activities). Marketers, brokers, shippers, interstate pipelines, storage providers, hub operators, financial services companies, and electronic trading exchanges
- Downstream (distribution activities). Local distribution companies, retail marketers and end users are associated with the downstream sector.

3.3 Pipelines modeling

This section uses mathematical nomenclature that is defined in Appendix B. Assuming one-dimensional flows, natural gas through a pipeline can be modeled as the set of partial differential equations (PDE) described by Equations 3.1 - 3.3, which relates the rate of change of density, velocity, pressure and energy with respect to time and position (10), (11), (51), (58). The one-dimensional flow assumption is accepted to give satisfactory results when the cross sectional area in the pipeline does not change at all or change slowly, and the radius of curvature of the pipeline is large enough when it is compared with the diameter of its cross section (51).

$$\frac{\partial \rho}{\partial t} + \frac{\partial \rho v}{\partial x} = 0 \tag{3.1}$$

$$\frac{\partial}{\partial t}\left[\rho\left(e_{in} + \frac{v^2}{2} + gz\right)\right] + \frac{\partial}{\partial x}\left[\rho v\left(e_{in} + \frac{p}{\rho} + \frac{v^2}{2} + gz\right)\right] - q - w = 0 \tag{3.2}$$

$$\rho\frac{\partial v}{\partial t} + \rho v\frac{\partial v}{\partial x} + \frac{\partial p}{\partial x} + \frac{f\rho}{2d}v\left|v\right| + \rho g sin(\alpha) = 0 \tag{3.3}$$

Equation 3.1 is obtained from the law of conservation of mass and establishes that the net mass flow rate into (out of) any differential volume of gas in the pipeline is equal to the rate of increase (decrease) of mass within this differential volume. The law of conservation of energy is presented in Equation 3.2 and states that the change in the total energy of a system must be equal to the addition of the exchange of heat from the surroundings to the system and the work done by external forces to the system. Finally, Equation 3.3 describes the law of conservation of momentum, in which the rate of change of momentum of the differential volume of gas is equal to the algebraic sum of the forces acting on this volume (23), (51), (58), (77), (83).

This set of equations by itself is not close, and it would require advanced simulation algorithms to solve it as a whole. However, if a steady state isothermal process is assumed for an horizontal gas flow through the transmission network, it is possible to derive a set of nonlinear algebraic equations relating the flows with the pressures at the terminal nodes of the pipelines, that can be used to improve the representation of natural gas systems in optimization problems (3), (10), (12), (15), (21). Under this assumption, Equation 3.1 transforms into Equation 3.4, meaning that the mass flow (defined in Equation 3.5) is constant though all cross-sections of the pipeline; Equation 3.2 becomes redundant (44); and Equation 3.3 reduces 3.6 (10), (44).

$$\frac{\partial \rho v}{\partial x} = 0 \tag{3.4}$$

$$\dot{m}_{\bar{p}} = \rho\ G_{\bar{p}}^{pl} = \rho v A \tag{3.5}$$

$$\rho v \frac{dv}{dx} + \frac{dp}{dx} + \frac{f\rho}{2d} v^2 = 0 \tag{3.6}$$

Given that for large pipelines (such as interstate links) pressure losses occur primarily by friction and not by the acceleration of the gas, Relation 3.7 is reasonable, and therefore Equation 3.6 reduces to 3.8 (10).

$$\rho v \frac{dv}{dx} << \frac{dp}{dx} \tag{3.7}$$

$$\frac{dp}{dx} + \frac{f\rho}{2d} v^2 = 0 \tag{3.8}$$

In order to find a relation between the density and the pressure of a gas in a pipeline, the gas law for real gases is defined in Equation 3.9 (10).

$$\rho = \frac{M_g}{\bar{Z}RT} p \tag{3.9}$$

Equation 3.10 is derived by substituting Equations 3.5 and 3.9 in 3.8.

$$-p\frac{dp}{dx} = \frac{f\bar{Z}RT}{2dA^2M_g} \dot{m}_{\bar{p}}^2 \tag{3.10}$$

Equation 3.10 is integrated over the length of the pipeline to obtain Equation 3.11.

$$\dot{m}_{\bar{p}}^2 = \frac{dA^2M_g}{f\bar{Z}RTl} \left(p_1^2 - p_2^2\right) \tag{3.11}$$

Finally, Equation 3.12 is derived by substituting Equation 3.5 in 3.11, and assuming that the gas density remains constant inside the pipeline at an average value $\bar{\rho}$.

$$G_{\bar{p}}^{pl^2} = K\left(p_1^2 - p_2^2\right) \text{ where } K = \frac{dA^2M_g}{\bar{\rho}^2 f\bar{Z}RTl} \tag{3.12}$$

This is a general expression to represent the steady state gas flows through a pipeline. As it can be seen, K is an important factor that mainly depends on the design and construction process of the pipeline and on the physical properties of the gas transported. An interesting discussion of the different equations used in the industry as a function of flow regimes and pipeline characteristics, as well as their impact on the transmission capacity can be found in (15).

CHAPTER 4. EXPANSION PLANNING OF NATURAL GAS SYSTEMS

4.1 Introduction

Natural gas has had an important role in the global energy landscape, and more recently it has become an attractive area for mathematical modeling and optimization. This section formulates the capacity expansion problem for a pipeline network, going from a typical formulation based on network flows to more complex ones including steady state relations between gas flows and pressure variables in the transmission system.

An initial representation considering a Pipes and Bubbles model is developed and used to pave the way to develop a more complex MINLP problem. However, because of the nonconvex nature of the latter, linear approximations for the nonlinear constraints are constructed using SOS2 variables, in order to find optimal global solutions. This chapter uses mathematical nomenclature that is defined in Appendix B.

4.2 P&B model for the pipeline network expansion problem

A P&B integer approach is developed in this section to compute the expansion of the pipeline network in a natural gas system, i.e., it determines the capacity and the location of the pipelines (from a set of candidates) required to meet the forecast of gas demand.

Equation 4.1 represents the total cost for the system, and it is determined as the sum of the gas production cost, the O&M costs for the pipeline network, the investment cost in new elements, and the transmission network, the cost of the necessary investments and the load shedding costs; a gas balance equation for each node of the system is imposed using Equation 4.2; the expansion plan for the pipeline network is determined using Equation 4.3; while Equations 4.4 - 4.7 are used to restrict the transmission capacity of the existing and candidate elements respectively. Equation 4.8 limits the maximum gas production by area; finally Equation 4.9 establishes nonnegativity conditions for the decision variables in the problem.

$$
\begin{aligned}
min\ \zeta = & \sum_{j,t,m,s} \xi^t \tau^{gas}\ G^{\,ls}_{jtms} h_s + \sum_{j,k,t,m,s,f} \xi^t c^{\,op,f=\text{gas}}_{jkftm} \eta\ G^{\,p}_{jktms} h_s + \sum_{j,t,m,s} \xi^t c^{\,d,gas}_{jtm}\ G^{\,d}_{jtms} h_s \\
& + \sum_{\substack{\bar{p},t \\ p \in P_c}} \xi^t c^{\,in,pl}_{\bar{p}t} Z_{\bar{p}t} + \sum_{\bar{p},t,m,s} \xi^t \left(c^{\,op,pl}_{\bar{p}t} G^{\,pl}_{\bar{p}tms} + c^{\,op,plo}_{\bar{p}t} G'^{\,pl}_{\bar{p}tms} \right) h_s
\end{aligned} \tag{4.1}
$$

subject to

$$
\begin{aligned}
& \sum_{\bar{d}:B_d=j} - \left(G^{\,pl}_{\bar{p}tms} - G'^{\,pl}_{\bar{p}tms} \right) + \sum_{\bar{d}:E_d=j} \left(G^{\,pl}_{\bar{p}tms} - G'^{\,pl}_{\bar{p}tms} \right) = G^{\,d}_{jtms} + \sum_{k \in K_g} G^{\,p}_{jktms} \\
& - G^{\,p,t}_{jtms} - G^{\,ls}_{jtms}\ ,\ \forall j \in J_a, t, m, s
\end{aligned} \tag{4.2}
$$

$$
S_{\bar{p}t} = \sum_{i=1}^{t} Z_{\bar{p}i}\ ,\ \forall \bar{p} \in P_c, t \tag{4.3}
$$

$$
G^{\,pl,min}_{\bar{p}tms} \leq -G'^{\,pl}_{\bar{p}tms}\ ,\ \forall \bar{p} \in P_e, t, m, s \tag{4.4}
$$

$$
G^{\,pl}_{\bar{p}tms} \leq G^{\,pl,max}_{\bar{p}tms}\ ,\ \forall \bar{p} \in P_e, t, m, s \tag{4.5}
$$

$$
S_{\bar{p}t} G^{\,pl,min}_{\bar{p}tms} \leq -G'^{\,pl}_{\bar{p}tms}\ ,\ \forall \bar{p} \in P_c, t, m, s \tag{4.6}
$$

$$
G^{\,pl}_{\bar{p}tms} \leq S_{\bar{p}t} G^{\,pl,max}_{\bar{p}tms}\ ,\ \forall \bar{p} \in P_c, t, m, s \tag{4.7}
$$

$$
G^{\,p,t}_{jtms} \leq G^{\,p,max}_{jtms}\ ,\ \forall j \in J_a, t, m, s \tag{4.8}
$$

$$
G^{\,ls}_{jtms}, G^{\,p}_{jktms}, G^{\,p,t}_{jtms}, G^{\,pl}_{\bar{p}tms}, G'^{\,pl}_{\bar{p}tms} \geq 0 \tag{4.9}
$$

4.3 MINLP model for the pipeline network expansion problem

The set of nonlinear constraints defined by Equations 4.10 - 4.12 represent the steady state equations that relates the gas flows inside a pipeline and the pressure values measured on its terminal points, which in conjunction with Equations 4.1 - 4.9 define a disjunctive model for the pipeline network expansion problem.

$$\pi_{B_p tms} - \pi_{E_p tms} - Y_{\bar{p}} G^{pl}_{\bar{p}tms} |G^{pl}_{\bar{p}tms}| = 0 \ , \ \forall \bar{p} \in P_e, t, m, s \tag{4.10}$$

$$-(1 - S_{\bar{p}t}) M^{pl} \leq \pi_{B_p tms} - \pi_{E_p tms} - Y_{\bar{p}} G^{pl}_{\bar{p}tms} |G^{pl}_{\bar{p}tms}| \leq (1 - S_{\bar{p}t}) M^{pl}, \forall \bar{p} \in P_c, t, m, s \tag{4.11}$$

$$\pi^{min}_{jtms} \leq \pi_{jtms} \leq \pi^{max}_{jtms} \ , \ \forall j, t, m, s \tag{4.12}$$

4.4 MILP model for the pipeline network expansion problem using piecewise linear functions

The MINLP problem described in the previous section is challenging to solve. We do so by replacing its nonlinear functions with piecewise linear ones that reasonably capture the nonlinearities associated with the original problem. This enables us to take advantage of the maturity of the algorithms developed to solve MILP problems. There are multiple approaches for linearizing bivariate nonlinear functions, one of which is presented below.

Consider a bivariate nonlinear function h, defined as: $h : \Omega \subseteq \Re^2 \rightarrow \Re$ with $\Omega = \{(x, y) \setminus x_a \leq x \leq x_b, y_a \leq y \leq y_b\}$. Partitioning Ω as $i \in \Lambda_x = \{1, ..., k_x\}$, and $j \in \Lambda_y = \{1, ..., k_y\}$, it is possible to represent the value of any point (x, y) enclosed inside the rectangle $\Delta_{ij} = \{(x, y)/x_i \leq x \leq x_{i+1}, y_j \leq y \leq y_{j+1}\}$ using a convex combination of the coordinates associated with its corners. Moreover, it is also possible to approximate h using piecewise linear functions defined for each of multiple rectangles in the domain Ω. Following this procedure, the surface defined by the equation $h(x, y) = 0$ is approximated using a set of rectangular planes joined together by their corners.

In general, Equations 4.13 - 4.21 can be used to approximate constraints of the form $h(x, y) = 0$ (where h is a nonlinear function), in optimization problems using Special Ordered Set (SOS) of type 2 variables (45).

$$x = \sum_{j \in \Lambda_x} \lambda^x_i x_i \tag{4.13}$$

$$y = \sum_{j \in \Lambda_y} \lambda_j^y y_j \tag{4.14}$$

$$h(x,y) \approx \sum_{i \in \Lambda_x} \sum_{j \in \Lambda_y} \lambda_{ij}^h h_{ij} \tag{4.15}$$

$$\sum_{i \in \Lambda_x} \lambda_i^x = 1 \tag{4.16}$$

$$\sum_{j \in \Lambda_y} \lambda_j^y = 1 \tag{4.17}$$

$$\sum_{i \in \Lambda_x} \lambda_{ij}^h = \lambda_i^y ... \forall j \in \Lambda_y \tag{4.18}$$

$$\sum_{j \in \Lambda_y} \lambda_{ij}^h = \lambda_i^x ... \forall i \in \Lambda_x \tag{4.19}$$

$$\lambda_i^x, \lambda_j^y, \lambda_{ij}^h \geq 0 \tag{4.20}$$

$$\lambda_i^x, \lambda_j^y \ \textit{SOS2 variables} \tag{4.21}$$

We applied this approach to approximate the Weymouth equations, which are bivariate non-linear functions relating gas flows to pressure values at the terminals of a pipeline. The MINLP problem presented before can be reformulated as a MILP model by replacing Equations 4.10 - 4.11 with Equations 4.22 - 4.30.

$$\pi_{jtms} = \sum_{i} \lambda\pi_{jtmsi} \Pi_{ji} \ , \ \forall j, t, m, s \tag{4.22}$$

$$G_{\bar{p}tms}^{pl} - G_{\bar{p}tms}^{\prime\, pl} = \sum_{i} \sum_{i'} \lambda g_{\bar{p}tmsii'}^{pl} \ g_{\bar{p}tmsii'}^{val} \ , \ \forall \bar{p}, t, m, s \tag{4.23}$$

$$\sum_{i} \lambda\pi_{jtmsi} = 1 \ , \ \forall j, t, m, s \tag{4.24}$$

$$\sum_{i'} \lambda g_{\bar{p}tmsii'}^{pl} = \lambda\pi_{jtmsi} \ , \ \forall \bar{p} \in P_e, t, m, s, i \tag{4.25}$$

$$\sum_{i} \lambda g_{\bar{p}tmsii'}^{pl} = \lambda\pi_{jtmsi'} \ , \ \forall \bar{p} \in P_e, t, m, s, i' \tag{4.26}$$

$$-(1-S_{\bar{p}t})M^{pl}+\lambda\pi_{jtmsi} \leq \sum_{i'} \lambda g^{pl}_{\bar{p}tmsii'} \leq \lambda\pi_{jtmsi}+(1-S_{\bar{p}t})M^{pl}, \forall \bar{p} \in P_c, t, m, s, i \tag{4.27}$$

$$-(1-S_{\bar{p}t})M^{pl}+\lambda\pi_{jtmsi'} \leq \sum_{i} \lambda g^{pl}_{\bar{p}tmsii'} \leq \lambda\pi_{jtmsi'}+(1-S_{\bar{p}t})M^{pl}, \forall \bar{p} \in P_c, t, m, s, i' \tag{4.28}$$

$$\lambda\pi_{jtmsi}, \lambda g^{pl}_{\bar{p}tmsii'} \geq 0 \tag{4.29}$$

$$\lambda\pi_{jtmsi} \ \textit{SOS2 variables} \tag{4.30}$$

Equations 4.22 - 4.30 constitute a disjunctive MILP capacity expansion model, representing the natural gas flows using piecewise linear functions via a partition of the pressure variables in the pipeline network. Equations 4.22 - 4.23 correspond with Equations 4.13 - 4.15 which are linear combinations for calculating pressures and gas flows in the pipeline network, once provided the unknown coefficients $\lambda\pi_{jtmsi}$ and $\lambda g^{pl}_{\bar{p}tmsii'}$. Equations 4.24 - 4.26 correspond with Equations 4.16 - 4.19 and establish a set of relations that parameters $\lambda\pi_{jtmsi}$ and $\lambda g^{pl}_{\bar{p}tmsii'}$ must satisfy in order to be able to adequately define the set of piecewise linear functions.

Equations 4.27 - 4.28 enforce Weymouth Equations for candidate pipelines. $S_{\bar{p}t}$ is a binary variable used to track if candidate pipeline $\bar{p}$ has or has not been installed until period t, therefore, when $S_{\bar{p}t} = 1$, Equations 4.27 - 4.28 reduce to Equations 4.25 - 4.26, and enforce Weymouth equation for $\bar{p}$. However, if $S_{\bar{p}t} = 0$, Equations 4.27 - 4.28 reduce to Equations 4.31 - 4.32, which in conjunction with Equations 4.6, 4.7 and 4.23 will set variables $\lambda g^{pl}_{\bar{p}tmsii'}$ to zero for $\bar{p}$, while $\lambda\pi_{jtmsi}$ and $\lambda\pi_{jtmsi'}$ still can take nonzero values.

$$-M^{pl}+\lambda\pi_{jtmsi} \leq \sum_{i'} \lambda g^{pl}_{dtmsii'} \leq \lambda\pi_{jtmsi}+M^{pl} \tag{4.31}$$

$$-M^{pl}+\lambda\pi_{jtmsi'} \leq \sum_{i} \lambda g^{pl}_{dtmsii'} \leq \lambda\pi_{jtmsi'}+M^{pl} \tag{4.32}$$

Therefore, it is possible to approximate the MINLP problem developed in Section 4.3. by a MILP one by using Equations 4.22 - 4.30 instead of Equations 4.10 - 4.11.

4.5 Alternative MILP model for the pipeline network expansion problem using piecewise linear functions

Although the MILP formulation presented in the previous section is a novel approximation for solving the co-optimized expansion planning problem for an integrated electric-gas system, it is also a computationally intensive one (it requires a SOS2 variable for each $\lambda\pi_{jtmsi}$ coefficient), and therefore for large co-optimization problems, particularly ones with large number of candidate transmission lines (and therefore large number of integer variables), it requires significant computation just to find a feasible solution. We address this by developing a different MILP approximation.

It is possible to reduce the number of SOS2 variables required by representing the gas flow terms in the Weymouth equations directly as piecewise linear functions (81), as presented in Equations 4.33 - 4.35. This means that Equations 4.3 - 4.7 in conjunction with Equations 4.33 - 4.39 will constitute an alternative disjunctive formulation for a pipeline network; however it is also a less accurate representation, because of the linear approximation used in Equation 4.34.

$$G^{pl}_{\bar{p}tms} - G'^{pl}_{\bar{p}tms} = \sum_i \lambda g^{pl}_{\bar{p}tmsi}\ g^{val}_{\bar{p}tmsi}\ ,\ \forall \bar{p}, t, m, s \tag{4.33}$$

$$\Gamma^{pl}_{\bar{p}tms} = \sum_i \lambda g^{pl}_{\bar{p}tmsi}\ (g^{val}_{\bar{p}tmsi})^2\ ,\ \forall \bar{p}, t, m, s \tag{4.34}$$

$$\sum_i \lambda g^{pl}_{\bar{p}tmsi} = 1\ ,\ \forall \bar{p}, t, m, s \tag{4.35}$$

$$\pi_{B_p tms} - \pi_{E_p tms} = Y_{\bar{p}} \Gamma^{pl}_{\bar{p}tms}\ ,\ \forall \bar{p} \in P_e, t, m, s \tag{4.36}$$

$$-(1 - S_{\bar{p}t})M^{pl} \leq \pi_{B_p tms} - \pi_{E_p tms} - Y_{\bar{p}} \Gamma^{pl}_{\bar{p}tms} \leq (1 - S_{\bar{p}t})M^{pl}\ ,\ \forall \bar{p} \in P_c, t, m, s \tag{4.37}$$

$$\lambda g^{pl}_{\bar{p}tmsi} \geq 0\ ,\ \forall \bar{p}, t, m, s \tag{4.38}$$

$$\lambda g^{pl}_{\bar{p}tmsi}\ \textit{SOS2 variables} \tag{4.39}$$

4.6 Results

A natural gas system consisting of five nodes is simulated over twenty years to test the three different formulations developed in this chapter. Figure 4.1 presents its network topology, and Tables 4.2 - 4.3 summarize its main parameters.

Production fields are modeled in two of the five nodes of the system, while natural gas loads are associated to four of them. A load duration curve consisting of three different seasons over the year (summer, shoulder and winter), each of which is disaggregated into three different periods (maximum, medium and minimum) are used to model the demands in the optimization problem. Additionally, three different pipeline candidates are proposed for each of the network links, which differ from each other in their maximum transmission capacity and, of course, in their investment costs. Detailed information for production, demand, and pipelines can be found in Tables 4.1, 4.2 and 4.3 respectively.

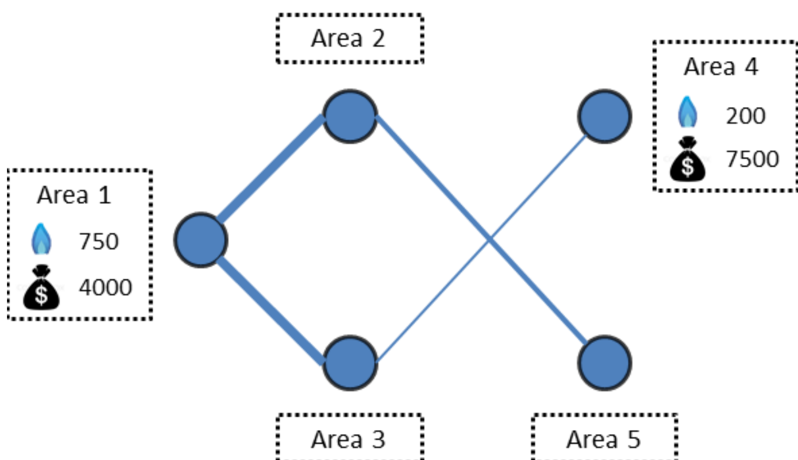

Figure 4.1 Natural gas system

Table 4.1 Natural gas production parameters

Area	Max. production (MMcf/h)	Production cost (USD/MMcf)
Area 1	750	4000
Area 4	200	7500

Table 4.2 Natural gas demand (MMcf/h)

Area	Summer			Shoulder			Winter			Growth
	p1	p2	p3	p1	p2	p3	p1	p2	p3	rate (%)
Area 1	-	-	-	-	-	-	-	-	-	-
Area 2	95	60	35	80	45	20	100	70	40	1.5
Area 3	185	135	110	170	115	90	200	155	135	1.0
Area 4	105	90	45	95	65	30	120	100	50	1.0
Area 5	200	160	140	185	140	135	220	175	150	1.0
Duration (h)	25	685	2962	25	800	2103	35	490	1635	

Table 4.3 Pipeline network parameters

Pipe	Status	From	To	Capacity (MMcf/h)	Investment cost (Millions USD)	Constant $(psi/MMcf/h)^2)$
1	Existing	Area 1	Area 2	350	-	34
2	Existing	Area 1	Area 3	350	-	34
3	Existing	Area 2	Area 5	250	-	48
4	Existing	Area 3	Area 4	125	-	95
5	Candidate	Area 1	Area 2	10	4	1190
6	Candidate	Area 1	Area 3	10	4	1190
7	Candidate	Area 2	Area 4	10	4	1190
8	Candidate	Area 2	Area 5	10	4	1190
9	Candidate	Area 3	Area 4	10	4	1190
10	Candidate	Area 1	Area 2	20	8	595
11	Candidate	Area 1	Area 3	20	8	595
12	Candidate	Area 2	Area 4	20	8	595
13	Candidate	Area 2	Area 5	20	8	595
14	Candidate	Area 3	Area 4	20	8	595
15	Candidate	Area 1	Area 2	30	12	397
16	Candidate	Area 1	Area 3	30	12	397
17	Candidate	Area 2	Area 4	30	12	397
18	Candidate	Area 2	Area 5	30	12	397
19	Candidate	Area 3	Area 4	30	12	397

The simulation results for the five nodes system considering the three mathematical formulations are presented and compared in Tables 4.4 and 4.5. The investment plan for the pipeline network is identical for the three models; similarly, gas production values are equal between the two linear models (P&B and MILP) and almost the same when compared to the nonlinear model (MINLP), demonstrating the advantages of the proposed representations for this particular dataset.

Table 4.4 Investment plan for candidate pipelines

Pipeline	From	To	P&B	MINLP	MILP
5	Area 1	Area 2	9	9	9
6	Area 1	Area 3	14	14	14
7	Area 2	Area 4	7	7	7
13	Area 2	Area 5	13	13	13
15	Area 1	Area 2	11	11	11

Table 4.5 Gas production per year (Thousands of MMcf)

Year	P&B	MINLP	MILP	P&B	MINLP	MILP
		Area 1			Area 4	
2011	3061.01	3061.01	3061.01	0.00	0.00	0.00
2012	3093.27	3093.27	3093.27	0.00	0.00	0.00
2013	3133.97	3133.97	3133.97	0.00	0.00	0.00
2014	3158.84	3158.84	3158.84	0.00	0.00	0.00
2015	3192.16	3192.16	3192.16	0.00	0.00	0.00
2016	3225.79	3225.78	3225.79	0.04	0.05	0.04
2017	3268.31	3268.30	3268.31	0.00	0.01	0.00
2018	3294.26	3294.25	3294.26	0.02	0.03	0.02
2019	3329.05	3329.03	3329.05	0.00	0.02	0.00
2020	3364.16	3364.15	3364.16	0.04	0.05	0.04
2021	3408.53	3408.52	3408.53	0.00	0.01	0.00
2022	3435.65	3435.63	3435.65	0.00	0.02	0.00
2023	3471.93	3471.92	3471.93	0.02	0.03	0.02
2024	3508.59	3508.58	3508.59	0.05	0.06	0.05
2025	3554.81	3554.80	3554.81	0.10	0.11	0.10
2026	3583.06	3583.05	3583.06	0.17	0.18	0.17
2027	3620.76	3620.73	3620.76	0.37	0.40	0.37
2028	3658.79	3658.78	3658.79	0.64	0.65	0.64
2029	3706.79	3706.78	3706.79	0.93	0.94	0.93
2030	3736.07	3736.06	3736.07	1.23	1.24	1.23

4.7 Conclusions

The three formulations developed in this chapter reported similar results for the proposed natural gas system. Thus, this work provides some evidence of the proper performance of the nonlinear model and its linear approximation for this particular dataset, and therefore, it constitutes a first step to develop a computationally efficient way to solve the problem. However, simulation scenarios considering a stressed pipeline network may provide different results between the three formulations, thus highlighting the differences between the nonlinear model and the two linear approximations. More complex scenarios will be simulated in the following chapters to analyze this situation.

CHAPTER 5. CO-OPTIMIZED ANALYSIS OF ELECTRIC AND GAS INFRASTRUCTURES

5.1 Introduction

A co-optimized expansion planning formulation provides simultaneous identification of two or more classes of related infrastructure decisions within a single optimization (39). In this chapter, we study the co-optimization expansion planning problem for an integrated electric-gas system. Hence, the model to be developed will aim to find the type, capacity, location, and timing of the required investments in generation units, transmission lines and pipelines that satisfy the future demands for both systems, while considering different operational, security and reliability criteria.

A disjunctive MINLP formulation of the co-optimization expansion planning problem for an integrated electric-gas system is presented in the next section, where electricity and gas flows are represented using the DC power flow equations and the Weymouth equations, respectively. The mathematical nomenclature used in this chapter is defined in Appendix B.

5.2 Co-optimized expansion planning problem

The co-optimized expansion planning problem for an integrated electric-gas system is formulated below. Equation 5.1 presents the objective function, which expresses the net present value of the sum of operational costs (electricity generation and transmission as well as natural gas production, transmission and storage), investment costs (for new generation units, transmission lines and pipelines) and penalties (unserved demand). Equations 5.2 - 5.3 are used to update the generation capacity in each of the areas and for each type of technology, by considering additions and retirements at each time step; based on the calculated capacities, Equations 5.4 - 5.5 constraint the power and electricity outputs for each generation unit by means of a capacity credit and a capacity factor respectively. Equation 5.6 enforces a reliability criterion by requiring a minimum amount of capacity reserves in the power system.

Equations 5.7 - 5.14 represent the electric system transmission network using a disjunctive approach as proposed in (5). Equation 5.7 enforces power balance in each area. Equations 5.8 - 5.9 represent the DC power flow equations for the existing and candidate transmission lines, respectively. Equation 5.10 tracks the investments in transmission lines in every time step. Equations 5.11 - 5.14 constrain the amount of power that can be transferred across each transmission line in the electric system. A sufficiently large parameter M^{tl} is required in Equation 5.9. Although not essential, computational benefit can result from choosing this parameter according to rationale given in (8) as explained in (41).

Equations 5.15 - 5.23 represent the gas transmission network using a disjunctive approach as proposed in Chapter 4. Equation 5.15 enforces gas balances in area nodes, while Equations 5.17 - 5.18 represent Weymouth equations for existing and candidate pipelines. Similar to the disjunctive model proposed for the electric transmission system, Equation 5.19 tracks the investments in pipelines, while Equations 5.20 - 5.23 limit the amount of the gas that can bed transferred using the pipeline network. Once again, a large parameter M^{pl} must be used in Equation 5.18 to relax the pressure differences across the candidates pipelines when these have not been built yet.

Equation 5.15 plays a significant role in the co-optimization problem: it links both systems, by modeling the amount of gas required by the combustion turbine units and the combined cycle plants to generate electricity.

Equations 5.24 - 5.29 represent the storage system in the co-optimization problem. The initial values of the gas stored for each of the areas are defined through Equations 5.24 - 5.25. Equations 5.26 - 5.27 are used to calculate the gas stored at every time step, based on its initial value, and the amount of gas being injected or withdrawn. Upper bounds on injections and withdrawals of natural gas are considered using Equations 5.28 - 5.29.

Equations 5.30 - 5.37 establish upper and lower limits for some of the decision variables, impose non-negativity requirements, and define the required binary and the integer variables.

$$
\begin{aligned}
min\ \zeta = & \sum_{\bar{g},t} \xi^t \left(c_{\bar{g}t}^{fx,g} C_{\bar{g}}^{max} C_{\bar{g}t} + \sum_{m,s} c_{\bar{g}t}^{op,g} P_{\bar{g}tms}^{g} h_s \right) + \sum_{\bar{g},t,m,s,f} \xi^t c_{jkftm}^{op,f\neq \text{gas}} \gamma_{\bar{g}} P_{\bar{g}tms}^{g} h_s \\
& + \sum_{j,k,t,m,s,f} \xi^t c_{jkftm}^{op,f=\text{gas}} \eta\ G_{jktms}^{p} h_s + \sum_{\substack{\bar{g},t \\ g\in G_c}} \xi^t c_{\bar{g}t}^{in,g} C_{\bar{g}}^{max} C_{\bar{g}t}^{a} + \sum_{j,t,m,s} \xi^t \tau\ P_{jtms}^{ls} h_s \\
& + \sum_{j,t,m,s} \xi^t c_{jtm}^{d,gas}\ G_{jtms}^{d} h_s + \sum_{\substack{\bar{l},t \\ l\in L_c}} \xi^t c_{\bar{l}t}^{in,tl} Z_{\bar{l}t} + \sum_{\substack{\bar{p},t \\ p\in P_c}} \xi^t c_{\bar{p}t}^{in,pl} Z_{\bar{p}t} + \sum_{j,t,m} \xi^t c_{jtm}^{op,s} G_{jtm}^{s} \\
& + \sum_{\bar{l},t,m,s} \xi^t \left(c_{\bar{l}t}^{op,tl} P_{\bar{l}tms}^{tl} + c_{\bar{l}t}^{op,tlo} P_{\bar{l}tms}^{\prime\, tl} \right) h_s + \sum_{\bar{p},t,m,s} \xi^t \left(c_{\bar{p}t}^{op,pl} G_{\bar{p}tms}^{pl} + c_{\bar{p}t}^{op,plo} G_{\bar{p}tms}^{\prime\, pl} \right) h_s \\
& + \sum_{j,t,m,s} \xi^t \left(c_{jtm}^{op,i} G_{jtms}^{i} + c_{jtm}^{op,w} G_{jtms}^{w} \right) h_s
\end{aligned}
\tag{5.1}
$$

subject to

$$C_{\bar{g}t} = C_{\bar{g}}^{e} + \sum_{i=1}^{t} \left(C_{\bar{g}i}^{a} - C_{\bar{g}i}^{r} \right)\ ,\ \forall \bar{g}, t \tag{5.2}$$

$$C_{\bar{g}t}^{a} \leq C_{\bar{g}t}^{a,max}\ ,\ \forall \bar{g}, g\in g_c, t \tag{5.3}$$

$$P_{\bar{g}tms}^{g} \leq CC_{\bar{g}tms}\ C_{\bar{g}}^{max}\ C_{\bar{g}t}\ ,\ \forall \bar{g}, t, m, s \tag{5.4}$$

$$\sum_{m,s} \left(P_{\bar{g}tms}^{g} h_s \right) \leq CF_{\bar{g}t}\ C_{\bar{g}}^{max}\ C_{\bar{g}t} \sum_{m,s} h_s\ ,\ \forall \bar{g}, t \tag{5.5}$$

$$\sum_{\bar{g}} FC_{\bar{g}t}\ C_{\bar{g}t} \geq (1+r_j) P_{jt}^{d,peak}\ ,\ \forall j\in J_a, t \tag{5.6}$$

$$\sum_{\bar{l}:B_l=j} - \left(P_{\bar{l}tms}^{tl} - P_{\bar{l}tms}^{\prime\, tl} \right) + \sum_{\bar{l}:E_l=j} \left(P_{\bar{l}tms}^{tl} - P_{\bar{l}tms}^{\prime\, tl} \right) = P_{jtms}^{d} - P_{jtms}^{ls} - \sum_{\bar{g}} P_{\bar{g}tms}^{g}\ , \quad \forall j\in J_a, t, m, s \tag{5.7}$$

$$\theta_{B_l tms} - \theta_{E_l tms} = X_{\bar{l}} \left(P_{\bar{l}tms}^{tl} - P_{\bar{l}tms}^{\prime\, tl} \right),\ \forall \bar{l}\in L_e, t, m, s \tag{5.8}$$

$$-(1-S_{\bar{l}t}) M^{tl} \leq \theta_{B_l tms} - \theta_{E_l tms} - X_{\bar{l}} \left(P_{\bar{l}tms}^{tl} - P_{\bar{l}tms}^{\prime\, tl} \right) \leq (1-S_{\bar{l}t}) M^{tl}\ ,\ \forall \bar{l}\in L_c, t, m, s \tag{5.9}$$

$$S_{\bar{l}t} = \sum_{i=1}^{t} Z_{\bar{l}i} \ , \ \forall \bar{l} \in L_c, t \tag{5.10}$$

$$P^{tl,min}_{\bar{l}tms} \leq -P'^{\,tl}_{\bar{l}tms} \ , \ \forall \bar{l} \in L_e, t, m, s \tag{5.11}$$

$$P^{tl}_{\bar{l}tms} \leq P^{tl,max}_{\bar{l}tms} \ , \ \forall \bar{l} \in L_e, t, m, s \tag{5.12}$$

$$S_{\bar{l}t} P^{tl,min}_{\bar{l}tms} \leq -P'^{\,tl}_{\bar{l}tms}, \forall \bar{l} \in L_c, t, m, s \tag{5.13}$$

$$P^{tl}_{\bar{l}tms} \leq S_{\bar{l}t} P^{tl,max}_{\bar{l}tms}, \forall \bar{l} \in L_c, t, m, s \tag{5.14}$$

$$\sum_{\bar{p}:B_p=j} -\left(G^{pl}_{\bar{p}tms} - G'^{\,pl}_{\bar{p}tms}\right) + \sum_{\bar{p}:E_p=j} \left(G^{pl}_{\bar{p}tms} - G'^{\,pl}_{\bar{p}tms}\right) = G^{d}_{jtms} + \sum_{k \in K_g} G^{p}_{jktms}$$
$$- G^{p,t}_{jtms} + G^{i}_{jtms} - G^{w}_{jtms} \ , \ \forall j \in J_a, t, m, s \tag{5.15}$$

$$\sum_{j \in J_a} G^{p}_{jktms} = \sum_{\bar{g}} \left(\frac{\gamma_{\bar{g}}}{\eta}\right) P^{g}_{\bar{g}tms} \ , \ \forall k \in K_g, t, m, s \tag{5.16}$$

$$\pi_{B_p tms} - \pi_{E_p tms} - Y_{\bar{p}} G^{pl}_{\bar{p}tms} |G^{pl}_{\bar{p}tms}| = 0 \ , \ \forall \bar{p} \in P_e, t, m, s \tag{5.17}$$

$$-(1 - S_{\bar{p}t}) M^{pl} \leq \pi_{B_p tms} - \pi_{E_p tms} - Y_{\bar{p}} G^{pl}_{\bar{p}tms} |G^{pl}_{\bar{p}tms}| \leq (1 - S_{\bar{p}t}) M^{pl} \ , \ \forall \bar{p} \in P_c, t, m, s \tag{5.18}$$

$$S_{\bar{p}t} = \sum_{i=1}^{t} Z_{\bar{p}i} \ , \ \forall \bar{p} \in P_c, t \tag{5.19}$$

$$G^{pl,min}_{\bar{p}tms} \leq -G'^{\,pl}_{\bar{p}tms} \ , \ \forall \bar{p} \in P_e, t, m, s \tag{5.20}$$

$$G^{pl}_{\bar{p}tms} \leq G^{pl,max}_{\bar{p}tms} \ , \ \forall \bar{p} \in P_e, t, m, s \tag{5.21}$$

$$S_{\bar{p}t} G^{pl,min}_{\bar{p}tms} \leq -G'^{\,pl}_{\bar{p}tms} \ , \ \forall \bar{p} \in P_c, t, m, s \tag{5.22}$$

$$G^{pl}_{\bar{p}tms} \leq S_{\bar{p}t} G^{pl,max}_{\bar{p}tms} \ , \ \forall \bar{p} \in P_c, t, m, s \tag{5.23}$$

$$G_{j,t=1}^{s,in} = G_j^{s,ex} \ , \ \forall j \tag{5.24}$$

$$G_{jt}^{s,in} = G_{j(t-1)m}^{s} \ , \ \forall j, t \neq 1, m = last \tag{5.25}$$

$$G_{jtm}^{s} = G_{jt}^{s,in} + \sum_{s}(G_{jtms}^{i} - G_{jtms}^{w})h_s \ , \ \forall j, t, m = 1 \tag{5.26}$$

$$G_{jtm}^{s} = G_{jt(m-1)}^{s} + \sum_{s}(G_{jtms}^{i} - G_{jtms}^{w})h_s \ , \ \forall j, t, m \neq 1 \tag{5.27}$$

$$G_{jtms}^{i} \leq G_{jtm}^{i,max} \ , \ \forall j, t, m, s \tag{5.28}$$

$$G_{jtms}^{w} \leq G_{jtm}^{w,max} \ , \ \forall j, t, m, s \tag{5.29}$$

$$-1.57 \leq \theta_{jtms} \leq 1.57 \ , \ \forall j \in J_a, t, m, s \tag{5.30}$$

$$G_{jtms}^{p,t} \leq G_{jtms}^{p,max} \ , \ \forall j, t, m, s \tag{5.31}$$

$$G_j^{s,min} \leq G_{jtm}^{s} \leq G_j^{s,max} \ , \ \forall j, t, m \tag{5.32}$$

$$\pi_{jtms}^{min} \leq \pi_{jtms} \leq \pi_{jtms}^{max} \ , \ \forall j, t, m, s \tag{5.33}$$

$$C_{\bar{g}t}, P_{\bar{g}tms}^{g}, P_{jtms}^{ls}, P_{\bar{l}tms}^{tl}, P_{\bar{l}tms}^{\prime\, tl} \geq 0 \tag{5.34}$$

$$G_{jtms}^{i}, G_{jktms}^{p}, G_{jtms}^{p,t}, G_{\bar{p}tms}^{pl}, G_{\bar{p}tms}^{\prime\, pl}, G_{jt}^{s,in}, G_{jtm}^{s}, G_{jtms}^{w} \geq 0 \tag{5.35}$$

$$\textit{Integer variables: } C_{\bar{g}t}^{a}, C_{\bar{g}t}^{r} \tag{5.36}$$

$$\textit{Binary variables: } S_{\bar{l}t}, Z_{\bar{l}t}, S_{\bar{p}t}, Z_{\bar{p}t} \tag{5.37}$$

Equations 5.1 - 5.37 define a MINLP formulation for the co-optimization problem, particularly difficult to solve when considering a large number of decision variables and constraints. This formulation can be transformed into a MILP one by using the piecewise linear approximation developed in Chapter 4, i.e., by substituting Equations 5.18 - 5.19 with Equations. 4.33 - 4.39.

5.3 Results

Three different scenarios are used to demonstrate the capabilities of the proposed formulations for the integrated electric - gas system presented in Figure 5.1. Simulations are run under the following assumptions:

- Natural gas combined cycle and wind are the only two generation technologies considered.
- Values for the capacity factor and the capacity credit of the wind generation plants are lower than 1.
- Gas produced in Area 2 is much more expensive than gas produced in Area 1.
- All the existing and candidate transmission lines are modeled using the same parameters.
- All the existing and candidate pipelines are modeled using the same parameters.

Tables 5.1 and 5.2 summarize additional data for each of the nodes and scenarios; from this information, nodes 1, 2, and 4 are characterized as exporting areas, and node 3 as an importing one.

Table 5.1 Supply and demand data by area

Parameter	Unit	Area 1	Area 2	Area 3	Area 4
NGCC existing capacity	GW	5	10	3	3
Wind existing capacity	GW	0	0	3	5
Demand	GW	0	8	6	3
Gas supply	MMcf/h	200	40	0	0

Table 5.2 Maximum investment capacity by generation technology (GW)

Scenario	Technology	Area 1	Area 2	Area 3	Area 4
High gas	NGCC	3	3	3	3
	Wind	0	0	0	0
High wind	NGCC	0	0	0	0
	Wind	10	10	10	10
Mixed	NGCC	0	0	3	3
	Wind	0	3	5	5

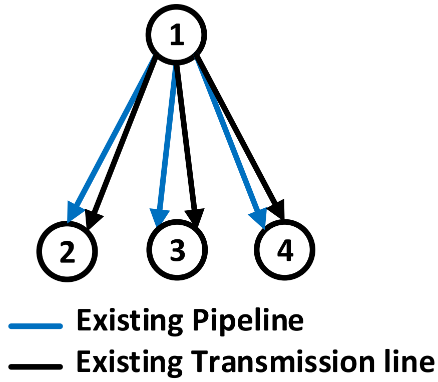

Figure 5.1 Integrated electric - gas network

Simulations for a thirty years horizon are carried out for the proposed system under the scenarios described in Table 5.2, considering the two disjunctive formulations developed. These results are compared in Table 5.3 against a *Best Bound*, which is obtained as the value of the objective funcion for the linear relaxation of the MILP problem.

Table 5.3 Total cost per scenario (Million USD)

Scenario	High gas	High wind	Mixed
MINLP - Cold start	539,691.11	559,407.42	580,203.96
MINLP - Hot start	539,426.62	559,407.42	580,145.14
MILP	539,428.95	559,407.71	580,160.11
Best bound	539,426.55	539,407.35	580,102.66

Additionally, expansion plans of the electric and gas transmission networks for each of the scenarios are depicted in Figure 5.2. A *cold start* for the MINLP problem refers to the default initial solution selected by the optimization solver. Conversely, a *hot start* is an initial solution obtained after solving the MILP problem.

It is possible to find an optimal solution (not necessarily a global one) for the three scenarios considered when using the MINLP formulation for this small system. However, for the *High gas* and *Mixed* simulations, different investment plans are obtained when starting from a cold or from a hot initial point. When the *hot start* initial point is used for the MINLP formulation, its optimal solution is always located in the interval defined by the *Best Bound* value and the optimal solution of the MILP problem, which provide evidence that the proposed linear approximation captures with some precision the nonlinearities of the Weymouth equations for this small system. Finally, these results provide evidence supporting a clear and consistent investment policy: under the *High gas* scenario, the pipeline network is strongly reinforced; multiple investments in transmission lines are required for the *High wind* scenario; and a combined investment plan considering transmission lines and pipelines is estimated under the *Mixed* scenario.

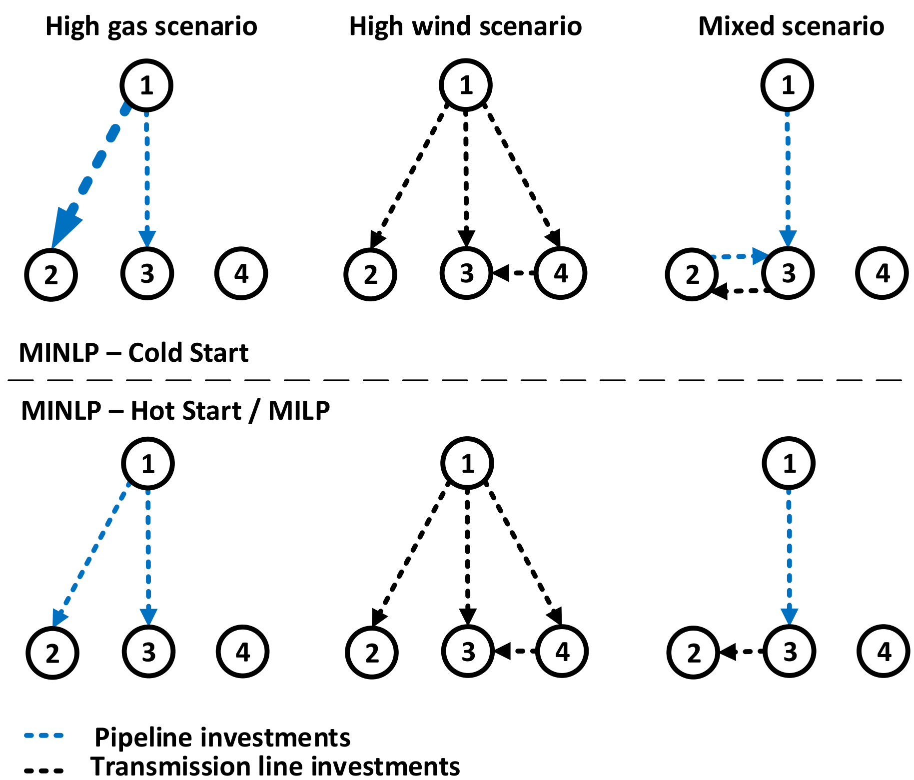

Figure 5.2 Expansion plans for the proposed scenarios

5.4 Conclusions

Two different approaches have been presented in this chapter to co-optimize a long term capacity expansion planning problem for an integrated electric - gas system. Both of them find the same investment plan when the MINLP problem begins the optimization process from a *hot start* point, which gives a reference of the goodness of the linear approximation proposed to represent the nonlinearities of Weymouth equations. Furthermore, the MILP problem solution is at least as good as the one found using the MINLP formulation when starting from a *cold initial* point, which also gives an idea of the accuracy of the MILP model to solve the problem when considering this small system. Finally, it is important to notice that, although the MINLP formulation is able to find an optimal solution for all the scenarios studied in this chapter, the results are strongly dependent on the initial solution considered.

CHAPTER 6. CO-OPTIMIZATION OF TRANSMISSION AND OTHER RESOURCES

6.1 Introduction

In Chapter 5, a MINLP model was applied to a small test system. It was observed that the model works adequately for this particular database. However, a MINLP model does not guarantee an obtained solution is a global optimal solution, and the increase in the model size will increase the simulation time significantly. Therefore, it is clear that the MINLP model will not be effective for application to larger systems, and it is unlikely to be implemented today in long-term expansion planning processes. In this chapter we address this issue by developing two linear formulations to approximate the MINLP problem.

Initially, a co-optimized simulation considering an electric-only system is run to validate that the model behaves adequately when tested against a reference software (27), (37). The electric-only system is then extended to include the natural gas network, and this dataset is used in conjunction with the proposed linear formulations (a pipes and bubbles model, and a disjunctive model) to solve the co-optimized capacity expansion problem. The differences between the two formulations are established along the chapter. The simulation results for the three models are compared to assess their consistency, and highlight the differences between them. In the last section, a comparison between the sequential optimization planning process and the proposed co-optimization process is developed.

The capacity expansion studies developed in this chapter consider a database for an Eastern Interconnection (EI) system (see Appendix A), to verify the applicability of the proposed co-optimization problem in large-scale systems and validate its benefits when doing expansion planning.

6.2 Co-optimization of transmission and generation in the Eastern Interconnection

In this section, a MILP problem is used to co-optimize the investments in generation and transmission for the EI electric system described in Appendix A. The mathematical formulation presented below consider the nomenclature defined in Appendix B. Unlike the models developed later in this chapter, this co-optimization problem does not consider any element from the natural gas network other than the gas-fired generating units, and it constitutes the basis for the two integrated electric-gas models developed in Section 6.3.

6.2.1 Mathematical formulation

The mathematical formulation of the co-optimized electric-only expansion planning problem is provided below.

$$
\begin{aligned}
&min\ \zeta = \sum_{\bar{g},t} \xi^t \left(c_{\bar{g}t}^{fx,g} C_{\bar{g}}^{max} C_{\bar{g}t} + \sum_{m,s} c_{\bar{g}t}^{op,g} P_{\bar{g}tms}^{g} h_s \right) + \sum_{\bar{g},t,m,s,f} \xi^t \left(c_t^{cc}\ \upsilon_{k,f}\ \gamma_{\bar{g}} P_{\bar{g}tms}^{g} h_s \right) \\
&+ \sum_{\bar{g},t,m,s,f} \xi^t c_{jkftm}^{op,f} \gamma_{\bar{g}} P_{\bar{g}tms}^{g} h_s + \sum_{\bar{l},t,m,s} \xi^t \left(c_{\bar{l}t}^{op,tl} P_{\bar{l}tms}^{tl} + c_{\bar{l}t}^{op,tlo} P_{\bar{l}tms}^{\prime\, tl} \right) h_s + \sum_{j,t,m,s} \xi^t \tau\ P_{jtms}^{ls} h_s \\
&+ \sum_{\substack{\bar{g},t \\ g \in G_c}} \xi^t c_{\bar{g}t}^{in,g} C_{\bar{g}}^{max} C_{\bar{g}t}^{a} - \sum_{\bar{g},t} \xi^\iota c_{\bar{g}t}^{in,g} \left(\delta_k{}^g - (\iota - (t-1))/\delta_k{}^g \right) C_{\bar{g}}^{max} C_{\bar{g}t}^{a} \\
&+ \sum_{\substack{\bar{l},t \\ l \in L_e}} \xi^t c_{\bar{l}t}^{in,tl} P_{\bar{l}t}^{tl,a} - \sum_{\bar{l},t} \xi^\iota c_{\bar{l}t}^{in,tl} \left(\delta^{tl} - (\iota - (t-1)) \big/ \delta^{tl} \right) P_{\bar{l}t}^{tl,a}
\end{aligned}
\tag{6.1}
$$

subject to

$$C_{\bar{g}t} = C_{\bar{g}}^{e} + \sum_{i=1}^{t} \left(C_{\bar{g}i}^{a} - C_{\bar{g}i}^{r} \right)\ ,\ \forall \bar{g}, t \tag{6.2}$$

$$C_{\bar{g}t}^{a} \leq C_{\bar{g}t}^{a,max}\ ,\ \forall \bar{g}, g \in g_c, t \tag{6.3}$$

$$\sum_{t} C_{\bar{g}t}^{a} \leq C_{\bar{g}}^{a,tot}\ ,\ \forall \bar{g}, g \in g_c \tag{6.4}$$

$$\sum_{g \in g_c, j} C_{\bar{g}}^{max}\ C_{\bar{g}t}^{a} \leq C_{kt}^{a,max}\ ,\ \forall k, t \tag{6.5}$$

$$C_{\bar{g}t}^{r} \leq C_{\bar{g}t}^{r,max}\ ,\ \forall \bar{g}, t \tag{6.6}$$

$$P^{g}_{\bar{g}tms} \leq (1-\mu_{\bar{g}})\,(1-\nu_{\bar{g}tms})\;\; C^{max}_{\bar{g}}\; C_{\bar{g}t}\;,\; \forall \bar{g}, t, m, s \tag{6.7}$$

$$\sum_{m,s} P^{g}_{\bar{g}tms} h_s \leq CF_{\bar{g}t}\; C^{max}_{\bar{g}}\; C_{\bar{g}t} \sum_{m,s} h_s\;,\; \forall \bar{g}, t \tag{6.8}$$

$$\sum_{\bar{g}} FC_{\bar{g}t}\; C_{\bar{g}t} \geq (1+r_j) P^{d,peak}_{jt}\;,\; \forall j \in J_a, t \tag{6.9}$$

$$\sum_{i=1}^{t} \sum_{g \in g_c} C^{max}_{\bar{g}}\; C^{a}_{\bar{g}i} \geq C^{anom}_{jt},\; \forall\; j \in J_a, t \tag{6.10}$$

$$\sum_{\bar{g},m,s} P^{g}_{\bar{g}tms}\; h_s \leq \sum_{j,m,s} \Phi_j\; P^{d}_{jtms} h_s\; , \forall k = \{wind, solar\}, t \tag{6.11}$$

$$\sum_{\bar{g},m,s} P^{g}_{\bar{g}tms}\; h_s \geq \sum_{j,m,s} \Psi_t\; P^{d}_{jtms} h_s\; , \forall k = renewables, t \tag{6.12}$$

$$\sum_{\bar{g},m,s} P^{g}_{\bar{g}tms}\; h_s \geq \sum_{m,s} \psi_{jt}\; P^{d}_{jtms} h_s\; , \forall j \in J_a, k = renewables, t \tag{6.13}$$

$$\sum_{\bar{l}:B_l=j} -\left(P^{tl}_{\bar{l}tms} - P'^{\,tl}_{\bar{l}tms}\right) + \sum_{\bar{l}:E_l=j} \left(P^{tl}_{\bar{l}tms} - P'^{\,tl}_{\bar{l}tms}\right) = P^{d}_{jtms} - P^{ls}_{jtms} - \sum_{\bar{g}} P^{g}_{\bar{g}tms}\;,$$

$$\forall j \in J_a, t, m, s \tag{6.14}$$

$$P^{tl,c-min}_{\bar{l}t} = P^{tl,c-min}_{\bar{l}(t-1)} - P^{tl,a}_{\bar{l}t}\;,\; \forall \bar{l} \in L_e, t \; where \; P^{tl,c-min}_{\bar{l}(t=0)} = P^{tl,c-min}_{\bar{l},exi} \tag{6.15}$$

$$P^{tl,c-max}_{\bar{l}t} = P^{tl,c-max}_{\bar{l}(t-1)} + P^{tl,a}_{\bar{l}t}\;,\; \forall \bar{l} \in L_e, t \; where \; P^{tl,c-max}_{\bar{l}(t=0)} = P^{tl,c-max}_{\bar{l},exi} \tag{6.16}$$

$$\sum_{t} P^{tl,a}_{\bar{l}t} \leq P^{tl,a,max}_{\bar{l}}\;,\; \forall\; \bar{l} \tag{6.17}$$

$$P^{tl,c-min}_{\bar{l}t} \leq -P'^{\,tl}_{\bar{l}tms}\;,\; \forall \bar{l} \in L_e, t, m, s \tag{6.18}$$

$$P^{tl}_{\bar{l}tms} \leq P^{tl,c-max}_{\bar{l}t}\;,\; \forall \bar{l} \in L_e, t, m, s \tag{6.19}$$

$$C_{\bar{g}t}, P^{g}_{\bar{g}tms}, P^{ls}_{jtms}, P^{tl}_{\bar{l}tms}, P'^{\,tl}_{\bar{l}tms}, P^{tl,a}_{\bar{l}t}, P^{tl,c-max}_{\bar{l}t}, P^{tl,c-min}_{\bar{l}t} \geq 0 \tag{6.20}$$

$$\textit{Integer variables: } C^{a}_{\bar{g}t}, C^{r}_{\bar{g}t} \tag{6.21}$$

The objective function, presented as Equation 6.1, expresses the net present value of the sum of operational costs (electricity generation and transmission as well as natural gas production and transmission), investment costs (for new generation units, transmission lines and pipelines), penalties (carbon emissions and unserved demand) and salvage values (for mitigating end horizon effects in long-term planning simulations).

When simulating a capacity expansion problem, the optimization algorithm will invest in elements with the lowest capital cost in the last years, regardless of the value of their operating costs over time unless corrective logic is provided. This is due to the fact that for the optimizer, the world ends once the simulation ends, and therefore, it is necessary to implement actions to avoid this bias.

There are multiple approachs to mitigate end horizon effects (48). The most common one is to model the last year's operational cost repeated over some 30 or 40 years and only report the results for the first m years; however, because of the amount of time that this problem requires to be solved, this alternative has been discarded in this dissertation. Instead expressions of salvage value are included to reduce the investment costs of the new assests as a function of their remaining lifetime at the end of the simulation. This improvement will be considered for all the candidate elements in each of the formulations developed hereafter.

Integer variables are used for modeling generation additions and retirements. Equation 6.2 allows determination of the number of units available at every time step. Equations 6.3 - 6.5 impose upper bounds for generation investments, and Equation 6.6 constraints unit retirements. Equations 6.7 - 6.8 limit power and electricity outputs from the units using capacity credit and capacity factor parameters, respectively. Equation 6.9 enforces a reliability criterion by requiring a minimum amount of capacity reserves in each region using a peak power demand value.

Additional constraints are considered for this co-optimization problem. Equation 6.10 distributes the generation investments between the different areas. Equation 6.11 limits the amount of electricity generated from intermittent resources. This is an operational constraint in order to ensure a secure operation of the power system. On the other hand, Equations 6.12 - 6.13 impose a national and some regional Renewable Portfolio Standards (RPS) requirements respectively, forcing the investments in renewable generation units across the EI. For this particular case, these expressions are modeled as hard constraints; however, it is possible to include them as soft constraints by modeling a penalty term in the objective function.

The expansion problem for the transmission network is considered using a P&B model (see Equations 6.15 - 6.19) instead of a disjunctive one, which is a common alternative to reduce the simulation time, by aggregating the lines into interfaces. In this dissertation, an interface is understood as a group of multiple parallel transmission lines connecting the same pair of nodes. Under this approach, the integer variables used before to represent each of the transmission lines are replaced by continuous variables modeling the capacity of each interface. Finally, Equations 6.20 and 6.21 establish non-negativity requirements, and define the required integer variables.

6.2.2 Results

Tables 6.1 - 6.4 summarize the results of the expansion for the electric assets across the EI. The simulation is over 20 years with an electric demand represented using three different load duration curves (summer, shoulder and winter) divided into ten, five and five load blocks, respectively. RPS requirements are imposed at the national and regional levels, and carbon emission penalties are also considered.

A brief summary of the main simulation results are presented in Table 6.1. The results exhibit high investments requirements in generation and transmission, which is mainly due to the aggressive environmental assumptions. Table 6.2 shows the changes in generation capacity grouped by technology. In terms of investments, new wind farms and natural gas plants represent 71% and 23% of the total investment cost, respectively, which can be explained as the result of environmental regulations represented within the problem by penalties for the carbon dioxide emissions, the RPS assumptions, the significant increase in the domestic production of shale gas, and the technological advances in wind generation.

The ratio of the capacity change (the difference between the final and the initial capacities) and the corresponding initial capacity is reported under the row tagged as *Dif* (%) in Table 6.2. In turn, 56% of the new wind farms are distributed across the Midwest region according to Table 6.3, and therefore, significant investments in transmission are required to move this electricity to the East coast, where the main load centers are located (see Table 6.4). There is a total of 120 GW in new lines, which means that according to this result, it will be necessary to double the transmission capacity over the next 20 years in order to support the large penetration of renewable resources.

Table 6.1 Costs (dollars)

Element	Fuel + O&M	Investment
Generation	9.850E+11	7.953E+11
Transmission lines	2.147E+10	4.536E+10
Effect of the end of the horizon	-4,56E+11	
Total cost	1,535E+12	

Table 6.2 Generation capacity by technologies (GW)

Year	BM	Coal	Gas	Geo	HY	LFG	NU	PV	ST	Wind	Total
2011	0.3	229.4	264.3	0.04	68.4	3.5	98.3	0.2	30.8	27.4	722.6
2030	1.1	8.7	396.6	0.04	75.3	8.1	122.4	1.5	0.4	441.5	1055.4
Dif	0.8	-220.7	132.3	0.0	6.9	4.6	24.1	1.3	-30.4	414.1	332.9
Dif (%)	275	-96	50	0	10	130	24	771	-99	1512	46

Table 6.3 Generation expansion by areas and technologies (GW)

	BM	Coal	Gas	HY	LFG	NU	PV	ST	Wind	Total
ENT	0.0	-8.5	7.5	1.1	0.1	0.0	0.0	-3.2	4.8	1.9
FRCC	0.0	-9.5	-8.5	0.0	0.2	25.5	0.0	-4.7	0.0	3.0
HQ	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.9
IESO	0.3	-3.6	4.4	0.3	0.0	-4.6	1.0	-0.4	1.8	-0.7
MAPP_CA	0.0	-1.7	1.3	1.3	0.0	0.0	0.0	0.0	0.0	0.9
MAPP_US	0.0	-2.9	1.5	0.0	0.0	0.0	0.3	0.0	8.2	7.0
MISO_IN	0.0	-12.8	3.6	0.0	0.1	0.0	0.0	-0.3	11.0	1.6
MISO_MI	0.0	-7.2	5.3	0.0	0.1	0.0	0.0	-3.0	9.2	4.4
MISO_MO-IL	0.0	-11.2	5.0	0.3	0.4	-2.2	0.0	-0.6	31.7	23.4
MISO_W	0.0	-11.7	3.0	0.0	0.0	0.0	0.0	-0.2	178.9	169.9
MISO_WUMS	0.0	-6.4	8.0	0.0	0.2	-0.5	0.0	-0.5	2.4	3.2
NB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NE	0.0	-3.9	11.8	0.0	0.1	-1.3	0.0	-0.3	13.4	19.9
NEISO	0.3	-2.6	-2.4	0.0	0.8	0.0	0.0	0.0	8.1	4.2
NonRTO_Midwest	0.0	-10.2	8.2	0.7	0.1	0.0	0.0	0.0	0.0	-1.1
NYISO_A-F	0.0	-1.6	0.0	0.0	0.5	0.0	0.0	-0.1	4.9	3.7
NYISO_G-I	0.0	-0.4	-0.3	0.0	0.2	0.0	0.0	-0.2	0.2	-0.5
NYISO_J-K	0.0	0.0	4.2	0.0	0.5	0.0	0.0	-6.4	0.0	0.3
PJM_E	0.0	-2.5	5.6	0.0	0.1	0.0	0.0	-0.9	1.2	3.5
PJM_ROM	0.0	-15.0	1.5	0.7	0.3	0.0	0.0	-0.6	3.3	-9.9

Table 6.3 (Continued)

	BM	Coal	Gas	HY	LFG	NU	PV	ST	Wind	Total
PJM_ROR	0.1	-43.8	42.7	0.5	0.4	0.0	0.0	-1.5	3.4	3.4
SOCO	0.1	-20.2	9.7	0.9	0.1	3.7	0.0	-0.5	0.0	-6.3
SPP_N	0.0	-7.9	5.5	0.0	0.1	-0.6	0.0	-1.7	37.4	32.8
SPP_S	0.0	-12.4	-6.4	0.1	0.1	0.0	0.0	-4.0	87.1	64.4
TVA	0.0	-11.7	9.3	0.0	0.1	1.2	0.0	0.0	0.4	-0.6
VACAR	0.0	-16.8	14.4	0.1	0.1	2.8	0.0	-0.4	6.8	7.0
Total	0.8	-224.3	134.9	6.9	4.6	24.1	1.3	-29.4	414.1	332.9

Table 6.4 Initial capacity and investments for the transmission network (GW)

Element	Transmission Lines	
	Initial	Investments
ENT to MISO_MO-IL	2.5	0.0
ENT to SOCO	2.4	18.9
ENT to SPP_N	7.3	0.0
ENT to SPP_S	4.3	19.1
ENT to TVA	3.0	0.0
FRCC to SOCO	3.7	2.4
HQ to NEISO	NA	NA
IESO to MAPP_CA	0.3	0.0
IESO to MISO_MI	3.1	2.0
IESO to MISO_W	0.2	0.0
IESO to NEISO	NA	NA
IESO to NYISO_A-F	2.2	0.0
MAPP_CA to MAPP_US	0.4	0.0
MAPP_CA to MISO_W	2.0	0.0
MAPP_US to MISO_W	2.6	0.0
MAPP_US to NE	2.0	0.0
MISO_IN to MISO_MI	5.5	3.4
MISO_IN to MISO_MO-IL	5.0	13.6
MISO_IN to NonRTO_Midwest	4.8	2.0
MISO_IN to PJM_ROR	1.0	0.0
MISO_MI to MISO_MO-IL	NA	NA
MISO_MI to MISO_WUMS	0.3	0.1
MISO_MI to PJM_ROR	1.4	0.0
MISO_MO-IL to MISO_W	4.0	9.4

Table 6.4 (Continued)

Element	Transmission Lines	
	Initial	Investments
MISO_MO-IL to MISO_WUMS	NA	NA
MISO_MO-IL to NE	NA	NA
MISO_MO-IL to PJM_ROR	1.2	0.0
MISO_MO-IL to SPP_N	4.0	0.0
MISO_MO-IL to TVA	4.0	4.9
MISO_W to MISO_WUMS	1.7	4.9
MISO_W to NE	3.6	0.0
MISO_W to PJM_ROR	19.8	27.1
MISO_W to SPP_N	3.2	0.0
MISO_WUMS to PJM_ROR	1.6	0.0
NE to SPP_N	1.9	0.0
NEISO to NYISO_A-F	0.6	0.0
NEISO to NYISO_G-I	0.6	0.0
NEISO to NYISO_J-K	1.0	0.9
NonRTO_Midwest to PJM_ROR	NA	NA
NonRTO_Midwest to TVA	2.4	0.0
NYISO_A-F to NYISO_G-I	5.3	1.7
NYISO_A-F to NYISO_J-K	NA	NA
NYISO_A-F to PJM_ROM	2.0	0.0
NYISO_G-I to NYISO_J-K	6.1	0.8
NYISO_G-I to PJM_E	1.5	0.0
NYISO_J-K to PJM_E	0.3	0.0
PJM_E to PJM_ROM	8.0	0.0
PJM_ROM to PJM_ROR	8.0	1.6
PJM_ROR to TVA	2.5	0.0
PJM_ROR to VACAR	3.0	7.3
SOCO to TVA	3.2	0.0
SOCO to VACAR	3.0	0.0
SPP_N to SPP_S	4.0	0.0
TVA to VACAR	0.9	0.0
Total	151.6	120.0

A high level design for the electric transmission network is depicted in Figure 6.1. The results show that strong reinforcements are required in the transmission grid to move the electricity from the Midwest area to the East coast, which is consistent with the information reported in (27) and (37), and makes a lot of sense considering that 66% of the new installed generation capacity corresponds to wind farms located in the Midwest area (the area with the best capacity factors). Final generation capacities aggregated by super regions for three of the six generation technologies (coal, gas and wind) as described in Table 6.5 are also displayed in Figure 6.1.

Table 6.5 Description of the super regions

Super Regions	Areas
Canada	HQ, IESO, MAPP_CA
MISO	MISO (IN, MI, MO-IL, W, WUMS)
North	NEISO, NYISO (A-F, G-I, J-K)
PJM	PJM (E, ROM, ROR)
West	MAPP_US, NE, SPP (N, S)
South	ENT, FRCC, NonRTO Midwest, SOCO, TVA, VACAR

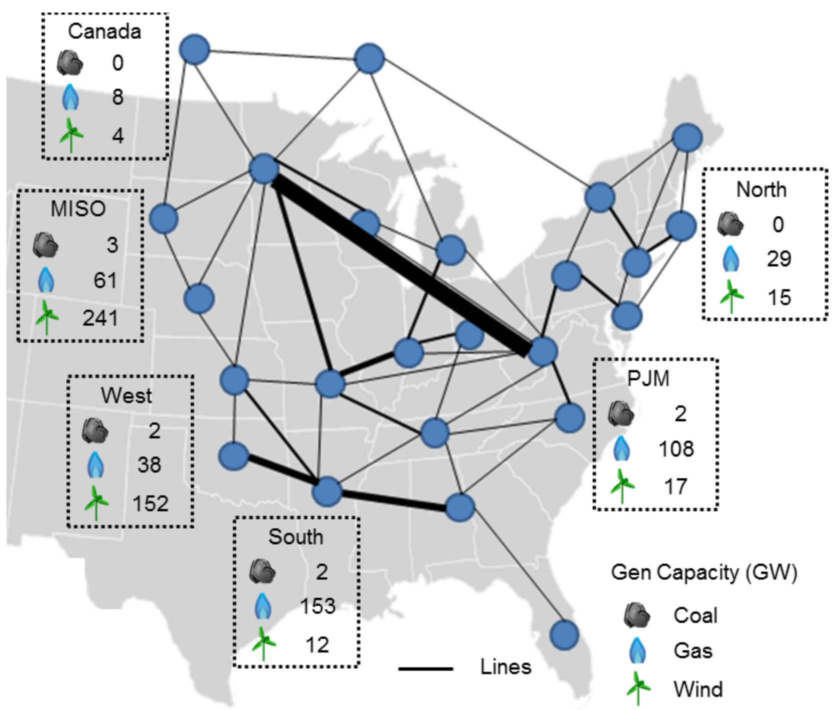

Figure 6.1 EI electric transmission network

6.3 Co-optimization of electric and natural gas infrastructures

6.3.1 Introduction

In Chapter 5, a MINLP problem was presented to co-optimize a small electric-gas integrated system. Then in Section 6.2, a MILP problem considering an electric-only model for the EI was formulated and used to co-optimized generation and transmission assets. In this section, the mathematical formulation developed so far is extended to represent an integrated electric-gas system, and corresponding results are presented for application to the EI.

For this purpose, two main tasks need to be done: extend the database that represents the electric grid of the EI to include the natural gas system, and extend the co-optimization problem by adding the equations that model the expansion and operation of it.

Two different models will be developed in the remaining sections of this chapter: a *P&B model* considering transmission links for electricity and natural gas as interfaces, and a *disjunctive model* for candidate transmission lines (and thus representing the DC power flow equations), and for candidate gas pipelines (and thus representing the Weymouth equations). In all two of these formulations, generation capacity decision variables are represented using integers.

6.3.2 P&B model

6.3.2.1 Mathematical formulation

The mathematical formulation for the P&B model is initially presented in this section, which is similar to the one developed in the previous section but includes the required equations to represent the gas system.

Equation 6.22 represents the objective function, but it includes not only the costs and the penalties associated with the electric system, but also those for the natural gas system. Equation 6.23 imposes a gas balance for each of the nodes. Equation 6.24 connects both systems by calculating the gas consumed in the gas-fired units. An upper bound for the gas production is established by Equation 6.25. Equations 6.26 - 6.30 model the operation and the expansion of the pipeline network as linear equations. Finally, Equation 6.31 sets the nonnegativity requirements for the decision variables.

$$
\begin{aligned}
&min\ \zeta = \sum_{\bar{g},t} \xi^t \left(c_{\bar{g}t}^{fx,g} C_{\bar{g}}^{max} C_{\bar{g}t} + \sum_{m,s} c_{\bar{g}t}^{op,g} P_{\bar{g}tms}^{g} h_s \right) + \sum_{j,t,m,s} \xi^t \tau\ P_{jtms}^{ls} h_s \\
&+ \sum_{\bar{g},t,m,s,f} \xi^t \left(c_t^{cc}\ \upsilon_{k,f}\ \gamma_{\bar{g}} P_{\bar{g}tms}^{g} h_s + c_{jkftm}^{op,f\neq\text{gas}} \gamma_{\bar{g}} P_{\bar{g}tms}^{g} h_s \right) \\
&+ \sum_{j,k,t,m,s,f} \xi^t c_{jkftm}^{op,f=\text{gas}} \eta\ G_{jktms}^{p} h_s + \sum_{j,t,m,s} \xi^t c_{jtm}^{d,gas}\ G_{jtms}^{d} h_s \\
&+ \sum_{\bar{l},t,m,s} \xi^t \left(c_{\bar{l}t}^{op,tl} P_{\bar{l}tms}^{tl} + c_{\bar{l}t}^{op,tlo} P_{\bar{l}tms}^{\prime\, tl} \right) h_s + \sum_{\bar{p},t,m,s} \xi^t \left(c_{\bar{p}t}^{op,pl} G_{\bar{p}tms}^{pl} + c_{\bar{p}t}^{op,plo} G_{\bar{p}tms}^{\prime\, pl} \right) h_s \\
&+ \sum_{\substack{\bar{g},t \\ g\in G_c}} \xi^t c_{\bar{g}t}^{in,g} C_{\bar{g}}^{max} C_{\bar{g}t}^{a} - \sum_{\bar{g},t} \xi^{\iota} c_{\bar{g}t}^{in,g} \left(\delta_k{}^g - (\iota - (t-1))/\delta_k{}^g\right) C_{\bar{g}}^{max} C_{\bar{g}t}^{a} \\
&+ \sum_{\substack{\bar{l},t \\ l\in L_e}} \xi^t c_{\bar{l}t}^{in,tl} P_{\bar{l}t}^{tl,a} - \sum_{\bar{l},t} \xi^{\iota} c_{\bar{l}t}^{in,tl} \left(\delta^{tl} - (\iota - (t-1)) \big/ \delta^{tl} \right) P_{\bar{l}t}^{tl,a} \\
&+ \sum_{\substack{\bar{p},t \\ p\in P_e}} \xi^t c_{\bar{p}t}^{in,pl} G_{\bar{p}t}^{pl,a} - \sum_{\bar{p},t} \xi^{\iota} c_{\bar{p}t}^{in,pl} \left(\delta^{pl} - (\iota - (t-1)) \big/ \delta^{pl} \right) G_{\bar{p}t}^{pl,a}
\end{aligned}
\tag{6.22}
$$

subject to

Equations 6.2 - 6.21

$$
\sum_{\bar{p}:B_p=j} -\left(G_{\bar{p}tms}^{pl} - G_{\bar{p}tms}^{\prime\, pl} \right) + \sum_{\bar{p}:E_p=j} \left(G_{\bar{p}tms}^{pl} - G_{\bar{p}tms}^{\prime\, pl} \right) = G_{jtms}^{d} + \sum_{k\in K_g} G_{jktms}^{p} - G_{jtms}^{p,t}\ ,
$$

$$
\forall j \in J_a, t, m, s \tag{6.23}
$$

$$
\sum_{j\in J_a} G_{jktms}^{p} = \sum_{\bar{g}} \left(\frac{\gamma_{\bar{g}}}{\eta} \right) P_{\bar{g}tms}^{g}\ ,\ \forall k \in K_g, t, m, s \tag{6.24}
$$

$$
G_{jtms}^{p,t} \le G_{jtms}^{p,max}\ ,\ \forall j, t, m, s \tag{6.25}
$$

$$
G_{\bar{p}t}^{pl,c-min} = G_{\bar{p}(t-1)}^{pl,c-min} - G_{\bar{p}t}^{pl,a}\ ,\ \forall \bar{p} \in P_e, t\ where\ G_{\bar{p}(t=0)}^{pl,c-min} = G_{\bar{p},exi}^{pl,c-min} \tag{6.26}
$$

$$
G_{\bar{p}t}^{pl,c-max} = G_{\bar{p}(t-1)}^{pl,c-max} + G_{\bar{p}t}^{pl,a}\ ,\ \forall \bar{p} \in P_e, t\ where\ G_{\bar{p}(t=0)}^{pl,c-max} = G_{\bar{p},exi}^{pl,c-max} \tag{6.27}
$$

$$
\sum_{t} G_{\bar{p}t}^{pl,a} \le G_{\bar{p}}^{pl,a,max}\ ,\ \forall\ \bar{p} \tag{6.28}
$$

$$
G_{\bar{p}t}^{pl,c-min} \le -G_{\bar{p}tms}^{\prime\, pl}\ ,\ \forall \bar{p} \in P_e, t, m, s \tag{6.29}
$$

$$
G_{\bar{p}tms}^{pl} \le G_{\bar{p}t}^{pl,c-max}\ ,\ \forall \bar{p} \in P_e, t, m, s \tag{6.30}
$$

$$
G_{jktms}^{p}, G_{jtms}^{p,t}, G_{\bar{p}tms}^{pl}, G_{\bar{p}tms}^{\prime\, pl}, G_{\bar{p}t}^{pl,a}, G_{\bar{p}t}^{pl,c-max}, G_{\bar{p}t}^{pl,c-min} \ge 0 \tag{6.31}
$$

6.3.2.2 Results

Tables 6.6 - 6.9 summarize the results for the co-optimization problem. Table 6.6 presents the costs of the simulation for each of the different types of elements. It can be observed from it, that the most significant costs are related to generation, followed by that for the transmission lines, and lastly, that for the pipelines.

Table 6.6 Costs (dollars)

Element	Fuel + O&M	Investment
Generation	9.684E+11	7.815E+11
Transmission lines	2.008E+10	4.677E+10
Pipelines	5.318E+09	4.382E+09
Effect of the end of the horizon	-4,52E+11	
Total cost	1,521E+12	

Generation capacity expansion results are reported in Tables 6.7 and 6.8. There is a significant reduction in the capacity from coal and other fossil fuels plants, mainly compensated by large investments in wind farms and gas-fired plants. Investments in wind generation take place around the Midwest area, which is the zone with the greatest wind potential; on the other hand, gas-fired generation is built in regions close to the shale gas resources, or highly connected to them through pipelines. According to Table 6.7, the installed generation capacity increases across the simulation horizon. This is mainly due to an annual growth rate for the electric demand, and to the differences in capacity factor between wind farms and fossil fuel based units.

Table 6.7 Generation capacity by technologies (GW)

Year	BM	Coal	Gas	Geo	HY	LFG	NU	PV	ST	Wind	Total
2011	0.3	229.4	264.3	0.04	68.4	3.5	98.3	0.2	30.8	27.4	722.6
2030	1.3	8.7	394.2	0.04	74.6	8.1	124.0	1.2	0.7	436.4	1049.1
Dif	1.0	-220.7	129.9	0.0	6.2	4.6	25.7	1.1	-30.1	409.0	326.5
Dif (%)	345	-96	49	0	9	131	26	618	-98	1493	45

Table 6.8 Generation expansion by areas and technologies (GW)

	BM	Coal	Gas	HY	LFG	NU	PV	ST	Wind	Total
ENT	0.0	-8.5	8.0	1.1	0.1	0.0	0.0	-3.2	1.2	-1.2
FRCC	0.1	-9.5	-10.0	0.0	0.2	26.0	0.0	-5.5	0.0	1.3
HQ	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.2
IESO	0.3	-3.5	4.3	0.3	0.0	-5.2	1.0	-0.2	1.8	-1.0
MAPP_CA	0.0	-1.7	1.4	1.3	0.0	0.0	0.0	0.0	0.0	1.0
MAPP_US	0.0	-2.4	1.0	0.0	0.0	0.0	0.0	0.0	8.2	6.9
MISO_IN	0.0	-13.0	4.2	0.0	0.1	0.0	0.0	-0.3	11.0	2.0
MISO_MI	0.0	-6.4	3.8	0.0	0.1	0.0	0.0	-3.0	9.2	3.7
MISO_MO-IL	0.0	-10.8	5.1	0.3	0.4	0.0	0.0	-0.6	31.1	25.6
MISO_W	0.0	-11.7	2.2	0.0	0.0	0.0	0.0	-0.5	184.9	174.8
MISO_WUMS	0.0	-6.4	5.7	0.0	0.2	0.0	0.0	-0.4	2.4	1.4
NB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NE	0.1	-3.9	3.5	0.0	0.1	-1.3	0.0	-0.3	13.2	11.5
NEISO	0.3	-2.6	-3.2	0.0	0.8	0.0	0.0	-0.5	7.5	2.3
NonRTO_Midwest	0.0	-9.2	8.2	0.7	0.1	0.0	0.0	0.0	0.0	-0.2
NYISO_A-F	0.0	-1.3	0.0	0.0	0.5	0.0	0.0	-0.1	4.9	4.0
NYISO_G-I	0.0	-0.4	-0.2	0.0	0.2	0.0	0.0	0.0	0.2	-0.1
NYISO_J-K	0.0	0.0	3.8	0.0	0.5	0.0	0.0	-6.5	0.2	-2.3
PJM_E	0.0	-2.6	4.0	0.0	0.1	0.0	0.0	-0.4	1.2	2.4
PJM_ROM	0.0	-15.0	0.7	0.7	0.3	0.0	0.0	-1.2	0.1	-14.5
PJM_ROR	0.1	-41.5	45.7	0.5	0.4	0.0	0.0	-1.9	3.0	6.3
SOCO	0.1	-20.9	10.3	0.9	0.1	2.7	0.0	-0.5	0.0	-7.3
SPP_N	0.0	-7.9	9.9	0.0	0.1	-1.2	0.0	-1.7	37.8	37.0
SPP_S	0.0	-12.4	-1.6	0.1	0.1	0.0	0.0	-3.7	84.3	66.7
TVA	0.0	-12.0	10.1	0.0	0.1	1.2	0.0	0.0	0.0	-0.6
VACAR	0.1	-16.8	13.1	0.1	0.1	3.3	0.0	-0.1	6.8	6.6
Total	1.0	-220.3	130.0	6.2	4.6	25.7	1.1	-30.6	409.0	326.5

From Table 6.6, transmission lines represent the second most costly investment category, because the resulting expansion plan performs large transmission investments throughout the simulation horizon. According to Table 6.9, there is 120 GW of transmission investment across the simulation horizon, which is almost four fifths of the initial capacity. The new infrastructure is required to connect the new wind generation farms to the large demand centers in the East coast.

Table 6.9 Initial capacity and investments for the transmission network

Element	Transmission Lines (GW)		Pipelines (MMcf/h)	
	Initial	Investments	Initial	Investments
ENT to MISO_MO-IL	2.5	0.0	265.6	0.0
ENT to SOCO	2.4	14.7	312.5	101.0
ENT to SPP_N	7.3	0.0	NA	NA
ENT to SPP_S	4.3	17.8	208.3	0.0
ENT to TVA	3.0	0.0	265.6	0.0
FRCC to SOCO	3.7	0.8	215.0	0.0
HQ to NEISO	NA	NA	8.3	0.0
IESO to MAPP_CA	0.3	0.0	187.5	0.0
IESO to MISO_MI	3.1	2.4	125.0	0.0
IESO to MISO_W	0.2	0.0	NA	NA
IESO to NEISO	NA	NA	31.3	0.0
IESO to NYISO_A-F	2.2	0.0	NA	NA
MAPP_CA to MAPP_US	0.4	0.0	156.3	0.0
MAPP_CA to MISO_W	2.0	0.0	93.8	0.0
MAPP_US to MISO_W	2.6	0.0	156.3	0.0
MAPP_US to NE	2.0	0.0	NA	NA
MISO_IN to MISO_MI	5.5	2.2	41.7	0.0
MISO_IN to MISO_MO-IL	5.0	13.5	156.3	0.0
MISO_IN to NonRTO_Midwest	4.8	1.9	NA	NA
MISO_IN to PJM_ROR	1.0	0.0	187.5	0.0
MISO_MI to MISO_MO-IL	NA	NA	104.2	0.0
MISO_MI to MISO_WUMS	0.3	0.4	NA	NA
MISO_MI to PJM_ROR	1.4	0.0	41.7	0.0
MISO_MO-IL to MISO_W	4.0	10.4	NA	NA
MISO_MO-IL to MISO_WUMS	NA	NA	62.5	0.0
MISO_MO-IL to NE	NA	NA	62.5	0.0
MISO_MO-IL to PJM_ROR	1.2	0.0	NA	NA
MISO_MO-IL to SPP_N	4.0	0.0	114.6	0.0
MISO_MO-IL to TVA	4.0	7.9	NA	NA
MISO_W to MISO_WUMS	1.7	5.3	93.8	0.0
MISO_W to NE	3.6	0.0	133.3	0.0
MISO_W to PJM_ROR	19.8	27.7	NA	NA
MISO_W to SPP_N	3.2	0.0	NA	NA
MISO_WUMS to PJM_ROR	1.6	0.0	NA	NA
NE to SPP_N	1.9	0.5	NA	NA

Table 6.9 (Continued)

Element	Transmission Lines (GW)		Pipelines (MMcf/h)	
	Initial	Investments	Initial	Investments
NEISO to NYISO_A-F	0.6	0.0	93.8	0.0
NEISO to NYISO_G-I	0.6	0.0	NA	NA
NEISO to NYISO_J-K	1.0	1.5	NA	NA
NonRTO_Midwest to PJM_ROR	NA	NA	156.3	0.0
NonRTO_Midwest to TVA	2.4	0.0	166.7	0.0
NYISO_A-F to NYISO_G-I	5.3	0.9	20.8	0.0
NYISO_A-F to NYISO_J-K	NA	NA	20.8	29.8
NYISO_A-F to PJM_ROM	2.0	0.0	187.5	0.0
NYISO_G-I to NYISO_J-K	6.1	0.0	NA	NA
NYISO_G-I to PJM_E	1.5	0.0	NA	NA
NYISO_J-K to PJM_E	0.3	0.0	NA	NA
PJM_E to PJM_ROM	8.0	0.0	125.0	0.0
PJM_ROM to PJM_ROR	8.0	3.1	250.0	0.0
PJM_ROR to TVA	2.5	0.0	NA	NA
PJM_ROR to VACAR	3.0	6.6	125.0	0.0
SOCO to TVA	3.2	2.4	NA	NA
SOCO to VACAR	3.0	0.0	156.0	0.0
SPP_N to SPP_S	4.0	0.0	NA	NA
TVA to VACAR	0.9	0.0	NA	NA
Total	151.6	120.0	4325.2	130.8

The pipeline network represents only a small portion of the total cost (see Table 6.6). This is due to the fact that most of the electricity produced in the system is obtained from wind farms, and therefore, investments in gas-fired units are mainly needed to guarantee the reliability requirements in the areas with massive retirements of coal-fired units. Finally, a high level design for the integrated electric-gas transmission network is depicted in Figure 6.2. Final generation capacities are aggregated by super regions (as described in Table 6.5) for three of the six generation technologies (coal, gas and wind).

If we compare the results for the first two models, the total cost for the integrated electric-gas system is lower than the one for the electric-only system, which means that a combined model optimizes the long-term operation. The difference in the total capacity of the new

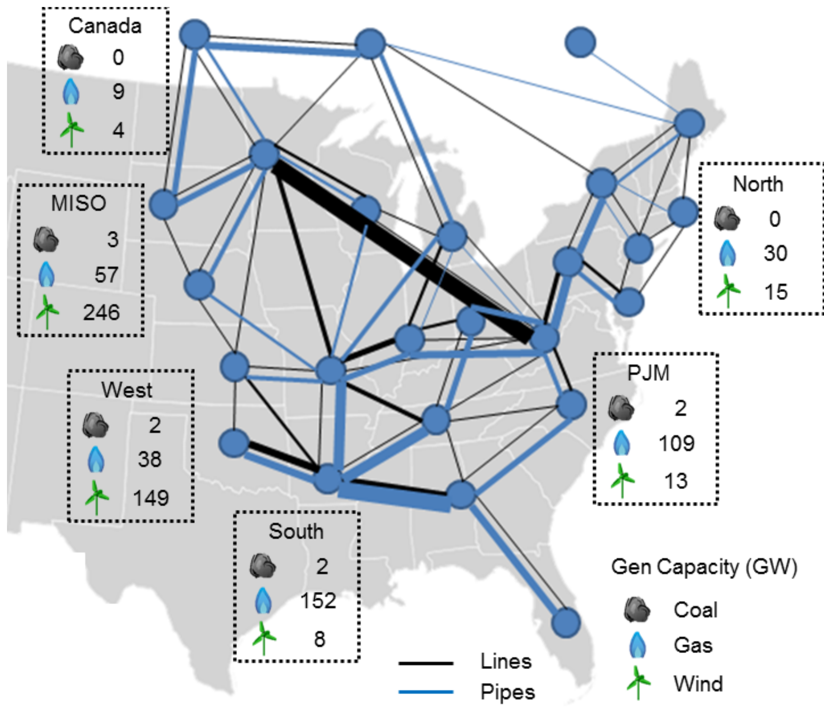

Figure 6.2 P&B model - EI integrated electric-gas transmission network

investments in transmission lines is almost 0 (this is because the constraint limiting this value is binding), however there are significant differences in the locations and timings for the new investments. For example:

- Almost 11 GW of new lines (9% of the total investments) are built in different locations.
- 92% of the total investments in transmission lines are built in the last 10 years for the electric-only system; this value decreases to 80% for the integrated gas-electric system.
- In a particular case, the new pipelines connecting the areas ENT and SOCO decrease the investments in transmission lines between the same areas by 4.2 GW.

6.3.3 Disjunctive model

6.3.3.1 DC power flow equations

Different representations for the electric transmission network can be found in the literature (70), ranging from simple transportation models using network flows to more detailed formulations considering electric laws. When using a transportation model, Kirchhoff's Voltage Law will be violated, possibly causing an overestimation/underestimation of the transmission capabilities under some scenarios, and therefore, in this section, we impose the DC power flow equations. However, imposing the DC power flow equations requires the implementation of a disjunctive model for the expansion of the electric transmission network.

6.3.3.2 Compression and reduction elements in a pipeline network

As mentioned before, it is possible to consider the operational effect of pressure in gas flows throughout the pipeline network by including Weymouth equations in the co-optimization problem. In order to properly represent the operational behavior of pressure variables within the network, the pipeline model considered so far has to be modified in order to include elements of compression and reduction as presented in Figure 6.3.

Initial simulations considering a simplified representation of the pipeline illustrated an inadequate behavior as a result of a poor control of the pressure in the system. For example, in some simulations, the gas transported by some pipelines was far below their nominal capacity, just to ensure that the pressure at their terminal node was the adequate to allow an additional transference of a portion of this gas to an adjacent area. This effect causes the model to inappropriately compensate the small pressure differentials between areas by investing in multiple unwanted parallel pipelines.

Given these benefits of the new model, it is necessary to analyze the additional requirements imposed by it. It is addressed by, for each pipeline considered, increasing the number of nodes with two additional nodes, and increasing the number of arcs to model the compression/reduction elements.

In terms of the analytical model, the formulation needs to be modified as follows: change the objective function in order to include the additional costs, modify the gas balance equation for each of the areas, include a gas balance equation for each pipeline terminal node, and add operational constraints to characterize the compression/reduction elements. These changes are illustrated in Figure 6.3 and fully described in the next section.

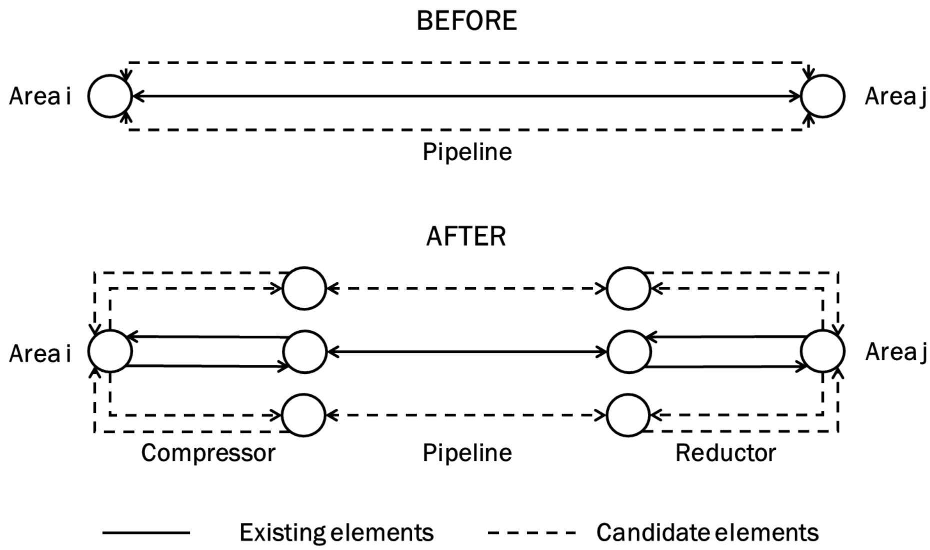

Figure 6.3 Pipeline model considering compression/reduction elements

6.3.3.3 Candidate selection

To move from a continuous model to an integer one, representation of the transmission elements in the co-optimization problem requires the definition of the existing and candidate lines in the dataset. Each interface can be substituted by a set of parallel lines whose total capacity is equivalent to the original one. However, the *a priori* definition of the candidate lines is not a trivial exercise since a narrow definition of the set could modify the optimal investment plan, but a large one might require a significant simulation time. The following iterative procedure is proposed to address this issue.

- Determine an initial set of candidate lines for each interface based on the simulation results for the *P&B continuous model.*
- Run a simulation and determine the interfaces for which all the candidates are selected.
- Increase the number of parallel candidates by one for the interfaces found in the item above, and run a new simulation for the new dataset.
- Iterate until none of the interfaces has all their candidates selected.

6.3.3.4 Mathematical formulation

A disjunctive model is developed in this section to include the operational effects of the steady state natural gas flows in the pipeline network. At first glance, it can be seen that a new set of continuous variables has been included to represent the pressure in each of the nodes of the system. They initially appear in the objective function (Equation 6.32) to represent the operational cost of the compression/reduction elements as a function of the pressure differential created in them. The constraints associated with the electric system present no change in the optimization problem, unlike those related with the pipeline network. For the latter, it is required to impose two balance equations: one for the pipelines nodes (Equation 6.33), and another one for the area nodes (Equation 6.34).

The disjunctive model for the pipeline network while considering steady state natural gas flows is implemented through Equations 4.33 - 4.38. In addition, the constraints governing the behavoir of the new compression/reduction elements are included (Equations 6.35 - 6.38), as well as the operational bounds for the pressure variables (Equation 6.40). The complete mathematical formulation, including all the aforementioned changes, is presented below.

$$
\begin{aligned}
min\ \zeta = & \sum_{\bar{g},t} \xi^t \left(c_{\bar{g}t}^{fx,g} C_{\bar{g}}^{max} C_{\bar{g}t} + \sum_{m,s} c_{\bar{g}t}^{op,g} P_{\bar{g}tms}^{g} h_s \right) + \sum_{\bar{g},t,m,s,f} \xi^t c_t^{cc}\ \upsilon_{k,f}\ \gamma_{\bar{g}} P_{\bar{g}tms}^{g} h_s \\
& + \sum_{\bar{g},t,m,s,f} \xi^t c_{jkftm}^{op,f\neq \text{gas}} \gamma_{\bar{g}} P_{\bar{g}tms}^{g} h_s + \sum_{j,k,t,m,s,f} \xi^t c_{jkftm}^{op,f=\text{gas}} \eta\ G_{jktms}^{p} h_s + \sum_{j,t,m,s} \xi^t c_{jtm}^{d,gas}\ G_{jtms}^{d} h_s \\
& + \sum_{\bar{l},t,m,s} \xi^t \left(c_{\bar{l}t}^{op,tl} P_{\bar{l}tms}^{tl} + c_{\bar{l}t}^{op,tlo} P_{\bar{l}tms}^{\prime\ tl} \right) h_s + \sum_{\bar{p},t,m,s} \xi^t \left(c_{\bar{p}t}^{op,pl} G_{\bar{p}tms}^{pl} + c_{\bar{p}t}^{op,plo} G_{\bar{p}tms}^{\prime\ pl} \right) h_s \\
& + \sum_{\substack{\bar{d},t,m,s \\ d\in D_c}} \xi^t c_{\bar{d}t}^{op,cr} \left(\pi_{j'tms} - \pi_{jtms} \right) h_s + \sum_{\substack{\bar{d},t,m,s \\ d\in D_r}} \xi^t c_{\bar{d}t}^{op,cr} \left(\pi_{jtms} - \pi_{j'tms} \right) h_s + \sum_{j,t,m,s} \xi^t \tau\ P_{jtms}^{ls} h_s \\
& + \sum_{\substack{\bar{g},t \\ g\in G_c}} \xi^t c_{\bar{g}t}^{in,g} C_{\bar{g}}^{max} C_{\bar{g}t}^{a} - \sum_{\bar{g},t} \xi^\iota c_{\bar{g}t}^{in,g} \left(\delta_k{}^g - (\iota - (t-1))/\delta_k{}^g \right) C_{\bar{g}}^{max} C_{\bar{g}t}^{a} \\
& + \sum_{\substack{\bar{l},t \\ l\in L_c}} \xi^t c_{\bar{l}t}^{in,tl} Z_{\bar{l}t} - \sum_{\bar{l},t} \xi^\iota c_{\bar{l}t}^{in,tl} \left(\delta^{tl} - (\iota - (t-1)) \Big/ \delta^{tl} \right) Z_{\bar{l}t} \\
& + \sum_{\substack{\bar{p},t \\ p\in P_c}} \xi^t c_{\bar{p}t}^{in,pl} Z_{\bar{p}t} - \sum_{\bar{p},t} \xi^\iota c_{\bar{p}t}^{in,pl} \left(\delta^{pl} - (\iota - (t-1)) \Big/ \delta^{pl} \right) Z_{\bar{p}t}
\end{aligned}
\tag{6.32}
$$

subject to

Equations 6.2 - 6.14, 5.8 - 5.14

$$\sum_{\bar{d}:B_d=j} -\left(G^{cr}_{\bar{d}tms} - G'^{cr}_{\bar{d}tms}\right) + \sum_{\bar{d}:E_d=j}\left(G^{cr}_{\bar{d}tms} - G'^{cr}_{\bar{d}tms}\right) = G^{d}_{jtms} + \sum_{k\in K_g} G^{p}_{jktms} - G^{p,t}_{jtms}\ ,$$

$$\forall j \in J_a, t, m, s \tag{6.33}$$

$$\sum_{\bar{d}:B_d=j} -\left(G^{cr}_{\bar{d}tms} - G'^{cr}_{\bar{d}tms}\right) + \sum_{\bar{d}:E_d=j}\left(G^{cr}_{\bar{d}tms} - G'^{cr}_{\bar{d}tms}\right) - \sum_{\bar{p}:B_p=j}\left(G^{pl}_{\bar{p}tms} - G'^{pl}_{\bar{p}tms}\right)$$

$$+\sum_{\bar{p}:E_p=j}\left(G^{pl}_{\bar{p}tms} - G'^{pl}_{\bar{p}tms}\right) = 0\ ,\ \forall j \in J_p, t, m, s \tag{6.34}$$

Equations 6.24 - 6.25, 4.33 - 4.38, 5.19 - 5.23

$$\pi_{jtms} \leq \pi_{j'tms}\ ,\ \forall \bar{d} \in D_c, t, m, s \tag{6.35}$$

$$\pi_{j'tms} \leq W_{\bar{d}}\ \pi_{jtms}\ ,\ \forall \bar{d} \in D_c, t, m, s \tag{6.36}$$

$$\pi_{j'tms} \leq \pi_{jtms}\ ,\ \forall \bar{d} \in D_r, t, m, s \tag{6.37}$$

$$\pi_{jtms} \leq W_{\bar{d}}\ \pi_{j'tms}\ ,\ \forall \bar{d} \in D_r, t, m, s \tag{6.38}$$

$$-1.57 \leq \theta_{jtms} \leq 1.57\ ,\ \forall j \in J_a, t, m, s \tag{6.39}$$

$$\pi^{min}_{jtms} \leq \pi_{jtms} \leq \pi^{max}_{jtms}\ ,\ \forall j, t, m, s \tag{6.40}$$

$$C_{\bar{g}t}, P^{g}_{\bar{g}tms}, P^{ls}_{jtms}, P^{tl}_{\bar{l}tms}, P'^{tl}_{\bar{l}tms} \geq 0 \tag{6.41}$$

$$G^{p,t}_{jtms}, G^{p}_{jktms}, G^{pl}_{\bar{p}tms}, G'^{pl}_{\bar{p}tms}, G^{cr}_{\bar{d}tms}, G'^{cr}_{\bar{d}tms} \geq 0 \tag{6.42}$$

Integer variables: $C^{a}_{\bar{g}t}, C^{r}_{\bar{g}t}$ (6.43)

Binary variables: $S_{\bar{l}t}, Z_{\bar{l}t}, S_{\bar{p}t}, Z_{\bar{p}t}$ (6.44)

SOS2 variables: $\lambda g^{pl}_{\bar{p}tmsi}$ (6.45)

6.3.3.5 Disaggregated solution procedure

It is necessary to develop a disaggregated solution procedure to reduce the simulation time of the proposed co-optimization problem, given that CPLEX was not able to find an optimal solution within a reasonable time due to the large number of SOS2 variables needed to represent the steady state gas flows in the pipeline network, and the size of the system considered.

The procedure is based on the construction of a quasi-feasible solution for a large optimization problem, from the optimal solutions of a set of smaller instances, as summarized below.

- Solve the co-optimization problem for years 2011 to 2015.
- Solve the co-optimization problem for years 2016 to 2020.
- Build a quasi-feasible solution for the co-optimization problem for years 2011 to 2020.
- Solve the co-optimization problem for years 2011 to 2020.
- Solve the co-optimization problem for years 2021 to 2025.
- Build a quasi-feasible solution for the co-optimization problem for years 2011 to 2025.
- Solve the co-optimization problem for years 2011 to 2025.
- Solve the co-optimization problem for years 2026 to 2030.
- Build a quasi-feasible solution for the co-optimization problem for years 2011 to 2030.
- Solve the co-optimization problem for years 2011 to 2030.

The GAMS Data eXchange module is used to construct quasi-feasible solutions according to the procedure depicted in Figure 6.4. In this context, a quasi-feasible solution is a solution that although not being feasible, could be close to be it, because just a few constraints are being unsatisfied. The *Infeasibility procedure* is designed with external code to reduce the number of infesibilities found in the *Aggregated solution*. This procedure uses the inequalities stated in Equations 6.46 - 6.48 to compare the values of the integer/binary variables representing the investments in generation units, transmission lines and pipelines in all the partial solutions. If the inequality is satisfied, the procedure modifies the values for the variables $C_{\bar{g}t}$, $S_{\bar{l}t}$, $Z_{\bar{l}t}$, $S_{\bar{p}t}$, and $Z_{\bar{p}t}$ according to the Equations 6.46 - 6.48, and in this way, it reduces the number of infeasibilities in the aggregated solution. In this case, superscripts i and j refer to *Partial solution* i and *Partial solution* j.

$$\text{if } C_{\bar{g}t}^{(i)} > C_{\bar{g}t}^{(j)}, \text{ then } \forall t \in j, C_{\bar{g}t}^{(j)} = C_{\bar{g}t}^{(i)} \text{ until } C_{\bar{g}t}^{(i)} \leq C_{\bar{g}t}^{(j)} \tag{6.46}$$

$$\text{if } S_{\bar{l}t}^{(i)} > S_{\bar{l}t}^{(j)}, \text{ then } \forall t \in j, S_{\bar{l}t}^{(j)} = 1 \text{ and } Z_{\bar{l}t}^{(j)} = 0 \tag{6.47}$$

$$\text{if } S_{\bar{p}t}^{(i)} > S_{\bar{p}t}^{(j)}, \text{ then } \forall t \in j, S_{\bar{p}t}^{(j)} = 1 \text{ and } Z_{\bar{p}t}^{(j)} = 0 \tag{6.48}$$

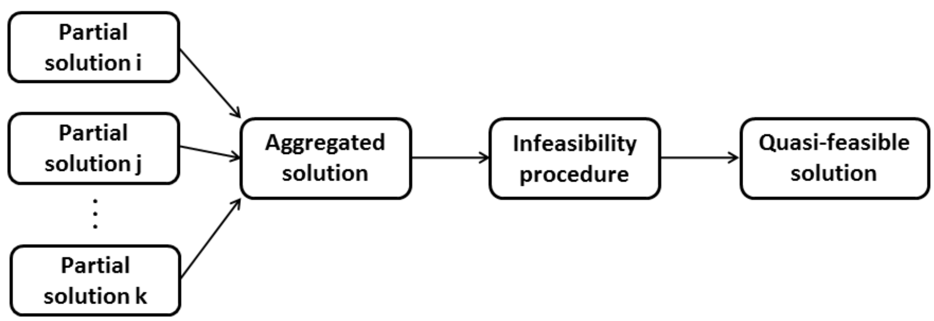

Figure 6.4 Disaggregated solution procedure

Table 6.10 summarizes the simulation parameters reported by CPLEX for each of the instances solved. It can be observed in Table 6.10 that this procedure was able to find an optimal solution for the complete co-optimization problem with a relative gap lower than 1.5% in less than 19 days.

Table 6.10 CPLEX simulation parameters

Time interval solved	Reduced MIP size (binaries, generals, SOSs)	Simulation time (hh:mm:ss)	Relative gap
2011-2015	3339, 3191, 5440	10:45:07	0.001563
2016-2020	3438, 3191, 6000	11:29:49	0.002565
2021-2025	3241, 3391, 5440	16:03:34	0.006518
2026-2030	3339, 3391, 6000	32:11:19	0.011993
2011-2020	6941, 4932, 12000	47:25:55	0.004604
2011-2025	6456, 4473, 18000	137:08:37	0.023840
2011-2030	8697, 6339, 24000	197:54:10	0.014033

6.3.3.6 Results

Tables 6.11 - 6.14 summarize the results obtained in this section. A high renewable scenario is created by imposing carbon emission costs to fossil fuel generation, restricting new investments in nuclear plants and allowing significant developments of wind farms. Simulation costs are presented in Table 6.11. Consistent with what was observed in Table 6.6, in a study reported earlier in this chapter, the total cost of the integrated system is dominated by the cost of generation, followed by transmission lines and then pipelines.

Large investments in gas and wind technologies can be observed in the simulation results, as observed in Tables 6.12 and 6.13. New gas plants are built close to the new shale areas or to areas connected to them using pipelines. Wind generation is developed strongly in the Midwest region, mainly due to the high capacity factor values of the technology in this area.

Initial transmission capacities and new investments in lines and and pipelines are presented in Table 6.14. Large investments in transmission lines to move the electricity produced by the new wind farms from the Midwest region to the main load centers located in the East coast are reported in the results, as well as significant builds on new pipelines to move shale gas resources to regions with high gas generation capacities.

Table 6.11 Costs (dollars)

Element	Fuel + O&M	Investment
Generation	1.008E+12	7.834E+11
Transmission lines	1.562E+10	1.994E+10
Pipelines	1.075E+10	1.341E+10
Effect of the end of the horizon	-4.58E+11	
Total cost	1.568E+12	

Table 6.12 Generation capacity by technologies (GW)

Year	BM	Coal	Gas	Geo	HY	LFG	NU	PV	ST	Wind	Total
2011	0.3	229.4	264.3	0.04	68.4	3.5	98.3	0.2	30.8	27.4	722.6
2030	1.3	10.9	384.2	0.04	73.1	8.1	131.5	1.3	1.6	401.6	1013.5
Dif	1.0	-218.5	119.9	0.0	4.7	4.6	33.2	1.1	-29.2	374.2	291.0
Dif (%)	363	-95	45	0	7	131	34	635	-95	1366	40

Table 6.13 Generation expansion by areas and technologies (GW)

	BM	Coal	Gas	HY	LFG	NU	PV	ST	Wind	Total
ENT	0.0	-8.5	7.8	1.1	0.1	0.0	0.0	-2.2	0.0	-1.7
FRCC	0.0	-9.0	-1.1	0.0	0.2	20.5	0.0	-8.3	0.0	2.4
HQ	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.3
IESO	0.3	-3.5	2.3	0.2	0.0	0.0	1.0	0.0	3.4	3.9
MAPP_CA	0.0	-1.6	1.4	1.3	0.0	0.0	0.0	-0.1	0.0	0.9
MAPP_US	0.1	-2.7	0.8	0.0	0.0	0.5	0.0	0.0	8.2	6.9
MISO_IN	0.0	-12.6	1.6	0.0	0.1	0.0	0.0	-0.3	11.0	-0.1
MISO_MI	0.0	-6.4	12.0	0.0	0.1	0.0	0.0	-2.9	15.8	18.7
MISO_MO-IL	0.0	-8.6	0.5	0.3	0.4	0.0	0.0	-0.5	27.9	20.0
MISO_W	0.0	-11.7	6.9	0.0	0.0	0.0	0.0	-0.2	130.3	125.2
MISO_WUMS	0.0	-5.8	3.8	0.0	0.2	0.0	0.0	-0.4	2.4	0.1
NB	0.0	0.0	0.0	-1.5	0.0	0.0	0.0	0.0	0.0	-1.5
NE	0.0	-3.9	5.1	0.0	0.1	0.0	0.0	-0.3	17.6	18.7
NEISO	0.3	-2.6	-1.4	0.0	0.8	0.0	0.0	-0.5	4.5	1.1
NonRTO_Midwest	0.0	-9.3	8.1	0.7	0.1	0.0	0.0	0.0	0.0	-0.3
NYISO_A-F	0.0	-1.6	-2.0	0.0	0.5	0.0	0.0	0.0	4.9	1.8
NYISO_G-I	0.0	-0.4	1.4	0.0	0.2	0.0	0.0	0.0	0.2	1.4
NYISO_J-K	0.0	0.0	5.0	0.0	0.5	0.0	0.0	-6.5	0.0	0.7
PJM_E	0.0	-1.9	3.0	0.0	0.1	0.0	0.0	-0.9	8.6	9.0
PJM_ROM	0.0	-14.5	-0.3	0.7	0.3	0.0	0.0	-0.7	16.9	2.4
PJM_ROR	0.1	-45.2	30.7	0.5	0.4	0.0	0.0	0.0	11.2	6.2
SOCO	0.1	-20.4	8.8	0.9	0.1	8.7	0.0	-1.1	0.0	-2.9
SPP_N	0.0	-7.9	4.4	0.0	0.1	0.0	0.0	-1.7	40.4	35.2
SPP_S	0.0	-12.4	5.5	0.1	0.1	0.0	0.0	-3.2	40.9	30.9
TVA	0.2	-11.5	8.7	0.0	0.1	1.2	0.0	0.0	0.0	-1.3
VACAR	0.0	-16.3	7.0	0.1	0.1	2.3	0.0	-0.1	30.0	23.1
Total	1.0	-218.0	119.9	4.7	4.6	33.2	1.1	-29.7	374.2	291.0

Table 6.14 Initial capacity and investments for the transmission network

Element	Transmission Lines (GW)		Pipelines (MMcf/h)	
	Initial	Investments	Initial	Investments
ENT to MISO_MO-IL	2.5	0.0	265.6	63.0
ENT to SOCO	2.4	0.0	312.5	0.0
ENT to SPP_N	7.3	0.0	NA	NA
ENT to SPP_S	4.3	2.0	208.3	0.0

Table 6.14 (Continued)

Element	Transmission Lines (GW)		Pipelines (MMcf/h)	
	Initial	Investments	Initial	Investments
ENT to TVA	3.0	0.0	265.6	0.0
FRCC to SOCO	3.7	0.0	215.0	0.0
HQ to NEISO	NA	NA	8.3	0.0
IESO to MAPP_CA	0.3	0.0	187.5	0.0
IESO to MISO_MI	3.1	4.0	125.0	63.0
IESO to MISO_W	0.2	0.0	NA	NA
IESO to NEISO	NA	NA	31.3	21.0
IESO to NYISO_A-F	2.2	0.0	NA	NA
MAPP_CA to MAPP_US	0.4	0.0	156.3	0.0
MAPP_CA to MISO_W	2.0	0.0	93.8	0.0
MAPP_US to MISO_W	2.6	0.0	156.3	0.0
MAPP_US to NE	2.0	0.0	NA	NA
MISO_IN to MISO_MI	5.5	0.0	41.7	0.0
MISO_IN to MISO_MO-IL	5.0	24.0	156.3	0.0
MISO_IN to NonRTO_Midwest	4.8	0.0	NA	NA
MISO_IN to PJM_ROR	1.0	12.0	187.5	0.0
MISO_MI to MISO_MO-IL	NA	NA	104.2	0.0
MISO_MI to MISO_WUMS	0.3	0.0	NA	NA
MISO_MI to PJM_ROR	1.4	2.0	41.7	0.0
MISO_MO-IL to MISO_W	4.0	34.0	NA	NA
MISO_MO-IL to MISO_WUMS	NA	NA	62.5	0.0
MISO_MO-IL to NE	NA	NA	62.5	0.0
MISO_MO-IL to PJM_ROR	1.2	0.0	NA	NA
MISO_MO-IL to SPP_N	4.0	2.0	114.6	0.0
MISO_MO-IL to TVA	4.0	10.0	NA	NA
MISO_W to MISO_WUMS	1.7	6.0	93.8	0.0
MISO_W to NE	3.6	0.0	133.3	0.0
MISO_W to PJM_ROR	19.8	0.0	NA	NA
MISO_W to SPP_N	3.2	0.0	NA	NA
MISO_WUMS to PJM_ROR	1.6	0.0	NA	NA
NE to SPP_N	1.9	2.0	NA	NA
NEISO to NYISO_A-F	0.6	0.0	93.8	0.0
NEISO to NYISO_G-I	0.6	0.0	NA	NA
NEISO to NYISO_J-K	1.0	0.0	NA	NA
NonRTO_Midwest to PJM_ROR	NA	NA	156.3	42.0

Table 6.14 (Continued)

Element	Transmission Lines (GW)		Pipelines (MMcf/h)	
	Initial	Investments	Initial	Investments
NonRTO_Midwest to TVA	2.4	0.0	166.7	0.0
NYISO_A-F to NYISO_G-I	5.3	2.0	20.8	0.0
NYISO_A-F to NYISO_J-K	NA	NA	20.8	42.0
NYISO_A-F to PJM_ROM	2.0	0.0	187.5	0.0
NYISO_G-I to NYISO_J-K	6.1	2.0	NA	NA
NYISO_G-I to PJM_E	1.5	0.0	NA	NA
NYISO_J-K to PJM_E	0.3	0.0	NA	NA
PJM_E to PJM_ROM	8.0	0.0	125.0	0.0
PJM_ROM to PJM_ROR	8.0	0.0	250.0	0.0
PJM_ROR to TVA	2.5	0.0	NA	NA
PJM_ROR to VACAR	3.0	0.0	125.0	189.0
SOCO to TVA	3.2	10.0	NA	NA
SOCO to VACAR	3.0	0.0	156.0	126.0
SPP_N to SPP_S	4.0	2.0	NA	NA
TVA to VACAR	0.9	0.0	NA	NA
Total	151.4	114.0	4325.2	546.0

A high level and aggregated design for an integrated electric-gas transmission network according to the co-optimization results is depicted in Figure 6.5. Final generation capacities aggregated by super regions (as described in Table 6.5) for three of the six generation group technologies (coal, gas and wind) are also presented. The figure illustrates strong correspondence between the required investments in generation, transmission lines and pipelines. This design proposes a robust electric transmission grid configured as a ring between MISO and PJM to move the large amounts of electricity produced in the new wind farms. It also requires a robust pipeline network connecting the regions South, PJM and North to transport the shale gas in the south-north direction.

6.4 Conclusions

Tables 6.15 - 6.20 compare the results from three different long-term capacity expansion models. A *Pipes and Bubbles* approach (also known as a transportation model) for an electric

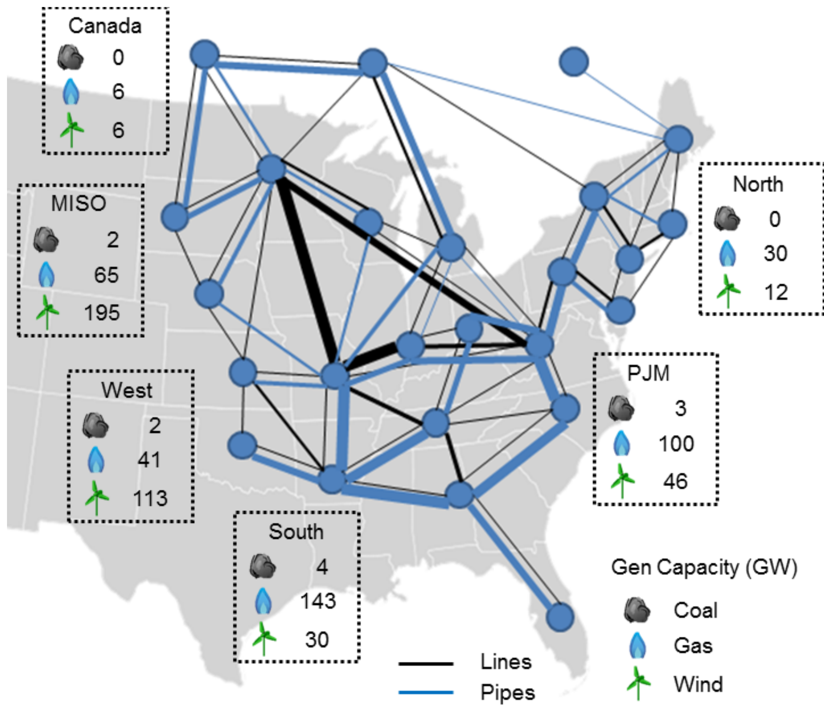

Figure 6.5 Disjunctive model - EI integrated electric-gas transmission network

system (Model 1); a *Pipes and Bubbles* approach for an integrated electric-gas system (Model 2); and the *disjunctive model* for an integrated electric-gas system developed throughout this dissertation (Model 3). The comparison between the results obtained for models 1 and 2 illustrates the impact of considering the pipeline network in the co-optimization problem; and the variations due to the change of the optimization algorithm, the selection of the set of transmission elements and the effect of modeling the steady state flow equations for electricity and natural gas is indicated by comparing models 2 and 3.

The inclusion of the pipeline network in Model 2 allows the decrease of the total cost of the co-optimization problem when compared with Model 1. This reduction is mainly due to a better utilization of the available gas resources between areas, and to the decrease of the fuel costs for the generation plants because of a more economical selection of the investments. This is not necessarily the best environmental choice. Under this investment plan, some wind farms are replaced by gas-fired units, which marginally increases the penalties associated with carbon dioxide emissions.

Table 6.15 Costs comparison (dollars)

Costs		Model 1	Model 2	Model 3
Fuel	Generation	9.850E+11	9.684E+11	1.008E+12
+	Lines	2.147E+10	2.008E+10	1.562E+10
O&M	Pipes	–	5.318E+09	1.075E+10
	Generation	7.953E+11	7.815E+11	7.834E+11
Invest.	Lines	4.536E+10	4.677E+10	1.994E+10
	Pipes	–	4.382E+09	1.341E+10
Other	Emissions	1.438E+11	1.458+11	1.745E+11
	End Horizon	-4.56E+11	-4.52E+11	-4.58E+11
Total Cost		1.535E+12	1.521E+12	1.568E+12

Table 6.16 Final capacity comparison

Capacity	Units	Model 1	Model 2	Model 3
Lines	GW	272	272	266
Pipes	MMcf/h	–	4456	4871
Generation	GW	1055	1049	1014
Coal	GW	9	9	11
Gas	GW	397	395	384
Hydro	GW	75	75	73
Nuclear	GW	122	124	132
Offshore Wind	GW	–	–	55
Onshore Wind	GW	442	436	347
Others	GW	11	11	12

Table 6.17 Simulation parameters comparison

Parameter	Model 1	Model 2	Model 3
Sim. time (hh:mm:ss)	1:35:06	1:57:57	197:54:10
Relative gap	0.001757	0.001871	0.014033

As expected, Model 3 has the highest total cost. From a mathematical point of view this phenomenon is explained by the increased number of constraints. From an operational point of view, the addition of the steady state flow equations limits the amount of electricity and natural gas that can be sent through the transmission links, requiring more investments in generation and transmission assets, and increasing the fuel and O&M costs. Therefore, in order to optimize system operation under the new constraints, some of the investments in new wind farms and gas-fired plants must be replaced by other generation technologies, and some new transmission lines are replaced by new pipelines.

6.5 Sequential optimization vs Co-optimization

Utilities are responsible for the secure, reliable and economic planning and operation of their electric grid in the U.S. To this end, they run production cost simulations and capacity expansion analysis using commercial or proprietary tools, based on NERC's guidelines. However, planning expansion studies have always been computationally intensive because of the large number of infrastructure alternatives to consider, and the extension of the simulation horizons. Therefore, sequential optimizations of generation and transmission were a comon practice in the recent decades.

With the growth of the electricity markets, a better economic performance was achieved, but power systems were also more stressed. In response to this situation, new organizations were created (such as Regional Transmission Operators and Independent System Operators), to satisfy the new interregional coordination requirements and procedures. New planning tools were also required with higher spatio-time resolution than the existing ones. Multi-sector models, as NEMS and MARKAL, initially appear as an alternative to analyze the impact of different energy policies at the national level. However these models had a coarse representation of the electric grid, and therefore, a second generation of computational programs were developed, such as ReEDS and SWITCH, considering an improved representation of the power system.

A third generation of planning tools, such as RPM and Plexos, takes advantage of the new computational efficiencies to co-optimize highly interdependent systems. Long-term capacity expansion studies integrating generation and transmission, or integrating electric and natural gas systems are being developed now. In this section, a comparison between the sequential optimization results and the co-optimization results obtained from our model is presented for the electric-gas integrated system of the Eastern Region of the United States.

For the P&B representation, the results were as expected. Simulation times were almost the same for the two models (a little lower for the sequential approach), however, the total costs have a significant reduction for the co-optimization problem, due to the reduction in the investments in new generation units and pipelines, which highlights the benefits of considering both systems in an integrated way, because of a better utilization of the natural resources.

Table 6.18 Costs comparison (dollars)

Costs		Continuous P&B Sequential	Continuous P&B Co-optimization
Fuel + O&M	Generation	9.850E+11	9.684E+11
	Lines	2.147E+10	2.008E+10
	Pipes	5.478E+09	5.318E+09
Invest.	Generation	7.953E+11	7.815E+11
	Lines	4.536E+10	4.677E+10
	Pipes	1.396E+10	4.382E+09
Other	Emissions	1.438E+11	1.458+11
	End Horizon	-4.67E+11	-4.52E+11
Total Cost		1.544E+12	1.521E+12

Table 6.19 Final capacity comparison

Capacity	Units	Continuous P&B Sequential	Continuous P&B Co-optimization
Lines	GW	272	272
Pipes	MMcf/h	4732	4456
Generation	GW	1055	1049
Coal	GW	9	9
Gas	GW	397	395
Hydro	GW	75	75
Nuclear	GW	122	124
Offshore Wind	GW	–	–
Onshore Wind	GW	442	436
Others	GW	11	11

Table 6.20 Simulation parameters comparison

Parameter	Continuous P&B Sequential	Continuous P&B Co-optimization
Sim. time (hh:mm:ss)	1:57:32	1:57:57
Relative gap	0.001996	0.001871

CHAPTER 7. CONTRIBUTIONS, CONCLUSIONS AND FUTURE WORK

7.1 Contributions

The contributions of this dissertation are summarized as follows:

- *Analytical modeling*: Modeling of natural gas and electric systems for co-optimized expansion planning.
- *System representation*: Development of an aggregated representation of the natural gas and electric systems within the Eastern US.
- *Solution algorithm*: A solution procedure for a computationally intense co-optimized expansion planning problem modeled as a mixed-integer linear program.
- *Investment insights*: Use of the analytical modeling, system representation, and solution algorithm developed within this dissertation to identify insights into gas/electric investments necessary to achieve an economically attractive low-carbon future for the Eastern US.

7.2 Conclusions

The conclusions of this dissertation are as follows:

- The co-optimized analysis and design of electric and natural gas infrastructures enables identification of less costly investment alternatives, highlighting the relevance of developing new planning procedures and tools that guarantee a systematic approach for the integrated system. This issue is particularly important during a time of major expansions and even more, considering the longevity of the infrastructure to be built.

- In our work, we have developed the computational tools to facilitate gas-electric expansion planning. However, there will also need to be coordinating bodies and procedures developed, because at this point in time, the organizations that plan and build natural gas infrastructure are completely different from the organizations that plan and build electric infrastructure. Finally, because these infrastructures are interregional, decision-making processes will benefit from coordination at the national level.

- In this dissertation, a disjunctive MILP model for the capacity expansion problem of a pipeline network is derived to develop co-optimized analysis and design of integrated electric-gas systems. It is also stated a solution procedure, which constitutes a first step to develop a computationally efficient procedure to solve large-scale instances. Finally, the methodology is applied to an aggregated representation of the electric and natural gas system for the Eastern Region of the United States to validate its proper performance.

7.3 Future work

- *Improvements to the disjunctive model:* the proposed formulation can require a significant amount of time to find an optimal solution for large-scale systems with large number of candidate pipelines. Although significant improvements toward computational efficiency were made in this dissertation, it is necessary to continue studying the formulation and alternative solution techniques to reduce the simulation times.

- *Improvements to the integrated electric-gas system of the Eastern Region of the United States:* the model used in this dissertation for the Eastern Interconnection provides the basis to start a co-optimization analysis; however, its aggregation level inhibits representation of some operational constraints that can influence expansion planning results.

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APPENDIX A. EASTERN INTERCONNECTION PLANNING COLLABORATIVE INTEGRATED ELECTRIC-GAS SYSTEM

The Eastern Interconnection Planning Collaborative (EIPC) is a coalition between the majority of the regional Planning Authorities of the Eastern Interconnection to develop different electric analysis in order to understand the impact on the grid of different policies. The thirty nodes model elaborated by the EIPC (27) to represent the electric system of the Eastern Interconnection has been modified in this dissertation to construct an integrated electric-gas system that is used to demonstrate the capabilities of the proposed co-optimization problem in a twenty years simulation. This appendix presents a general description of the modified system, as well as the values used for the main parameters.

A.1 Electric-Gas System Overview

The proposed system consists of twenty five node, as listed in Table A.1, in which the first twenty two represent areas belonging to the Eastern Interconnection, while the remaining three (marked with an asterisk) allow modeling interactions with some of the Canadian provinces. The different areas are connected via transmission links for transporting electricity and natural

Table A.1 List of areas modeled

ENT	MISO_MO-IL	NonRTO_Midwest	PJM_ROM	TVA
FRCC	MISO_W	NYISO_A-F	PJM_ROR	VACAR
MAPP_US	MISO_WUMS	NYISO_G-I	SOCO	HQ (*)
MISO_IN	NE	NYISO_J-K	SPP_N	IESO (*)
MISO_MI	NEISO	PJM_E	SPP_S	MAPP_CA (*)

gas; eighteen different technologies for generation and gas production fields are represented within the areas according to the availability of natural resources in order to meet the end users demand. Finally, gas and electricity loads are represented using load duration curves considering three seasonal periods in a year (summer, shoulder and winter), each of them divided into several blocks of demand (ten, five and five respectively).

A.2 Additional Parameters for the Electric-Gas System

This section describes the additional parameters required to complete the EIPC system in order to formulate the co-optimization problem. Tables A.2 and A.3 summarize the impedances for the existing and candidate transmission links considering a S_{base} of 1 MW. These values allow to consider the characteristics of the electric transmission network by formulating the DC power flow equations.

Table A.2 Impedances for existing transmission links (p.u.)

Transmission link	Impedance	Transmission link	Impedance
ENT to MISO_MO-IL	0.0003138	MISO_W to MISO_WUMS	0.0003288
ENT to SOCO	0.0002969	MISO_W to NE	0.0001830
ENT to SPP_N	0.0000965	MISO_W to PJM_ROR	0.0000425
ENT to SPP_S	0.0001569	MISO_W to SPP_N	0.0002481
ENT to TVA	0.0002511	MISO_WUMS to PJM_ROR	0.0004614
FRCC to SOCO	0.0001890	NE to SPP_N	0.0003225
IESO to MAPP_CA	0.0040827	NEISO to NYISO_A-F	0.0013150
IESO to MISO_MI	0.0001878	NEISO to NYISO_G-I	0.0006947
IESO to MISO_W	0.0062354	NEISO to NYISO_J-K	0.0004962
IESO to NYISO_A-F	0.0002855	NonRTO_Midwest to TVA	0.0002357
MAPP_CA to MAPP_US	0.0020413	NYISO_A-F to NYISO_G-I	0.0000919
MAPP_CA to MISO_W	0.0003821	NYISO_A-F to PJM_ROM	0.0002772
MAPP_US to MISO_W	0.0002729	NYISO_G-I to NYISO_J-K	0.0000802
MAPP_US to NE	0.0003722	NYISO_G-I to PJM_E	0.0003712
MISO_IN to MISO_MI	0.0001128	NYISO_J-K to PJM_E	0.0012619
MISO_IN to MISO_MO-IL	0.0001268	PJM_E to PJM_ROM	0.0000564
MISO_IN to NonRTO_Midwest	0.0000951	PJM_ROM to PJM_ROR	0.0000900
MISO_IN to PJM_ROR	0.0004949	PJM_ROR to TVA	0.0002354
MISO_MI to MISO_WUMS	0.0023074	PJM_ROR to VACAR	0.0002371
MISO_MI to PJM_ROR	0.0003970	SOCO to TVA	0.0001674
MISO_MO-IL to MISO_W	0.0001794	SOCO to VACAR	0.0002134
MISO_MO-IL to PJM_ROR	0.0002805	SPP_N to SPP_S	0.0001282
MISO_MO-IL to SPP_N	0.0001804	TVA to VACAR	0.0006866
MISO_MO-IL to TVA	0.0001653		

Table A.3 Impedances for candidate transmission links (p.u.)

Transmission link	Impedance	Transmission link	Impedance
ENT to MISO_MO-IL	0.0002714	MISO_W to MISO_WUMS	0.0002398
ENT to SOCO	0.0004162	MISO_W to NE	0.0002669
ENT to SPP_N	0.0003167	MISO_W to PJM_ROR	0.0005519
ENT to SPP_S	0.0002714	MISO_W to SPP_N	0.0004976
ENT to TVA	0.0004343	MISO_WUMS to PJM_ROR	0.0004614
FRCC to SOCO	0.0003800	NE to SPP_N	0.0002352
IESO to MAPP_CA	0.0009952	NEISO to NYISO_A-F	0.0002398
IESO to MISO_MI	0.0001945	NEISO to NYISO_G-I	0.0001267
IESO to MISO_W	0.0007600	NEISO to NYISO_J-K	0.0001810
IESO to NYISO_A-F	0.0002262	NonRTO_Midwest to TVA	0.0001719
MAPP_CA to MAPP_US	0.0002488	NYISO_A-F to NYISO_G-I	0.0001176
MAPP_CA to MISO_W	0.0003483	NYISO_A-F to PJM_ROM	0.0002398
MAPP_US to MISO_W	0.0003483	NYISO_G-I to NYISO_J-K	0.0001221
MAPP_US to NE	0.0004071	NYISO_G-I to PJM_E	0.0001810
MISO_IN to MISO_MI	0.0002262	NYISO_J-K to PJM_E	0.0000769
MISO_IN to MISO_MO-IL	0.0002081	PJM_E to PJM_ROM	0.0000860
MISO_IN to NonRTO_Midwest	0.0001040	PJM_ROM to PJM_ROR	0.0003890
MISO_IN to PJM_ROR	0.0000905	PJM_ROR to TVA	0.0002036
MISO_MI to MISO_WUMS	0.0004207	PJM_ROR to VACAR	0.0003076
MISO_MI to PJM_ROR	0.0002171	SOCO to TVA	0.0001448
MISO_MO-IL to MISO_W	0.0004252	SOCO to VACAR	0.0002081
MISO_MO-IL to PJM_ROR	0.0002805	SPP_N to SPP_S	0.0001402
MISO_MO-IL to SPP_N	0.0003619	TVA to VACAR	0.0001674
MISO_MO-IL to TVA	0.0003574		

Compression and reduction stations are incorporated into the system to improve the modeling of pressures in the pipeline network. The main parameters considered for these elements are presented in Table A.4.

Table A.4 Technical parameters for compression - reduction elements

Element	Parameter	Unit	Value
Compressor	Compression Factor	-	3
	Operational Cost	USD/psig^2/h	0.001
Reductor	Reduction Factor	-	3
	Operational Cost	USD/psig^2/h	0.00001

The technical characteristics of the pipelines represented as a constant value in Weymouth equations are summarized in Tables A.5 and A.6; besides, the maximum production capacity of gas for each of the areas is presented in Table A.7.

Table A.5 Technical constant for existing pipeline links ($(\text{psi}/\text{MMcf/h})^2$)

Pipeline link	Constant	Pipeline link	Constant
ENT to MISO_MO-IL	3.54	MISO_MI to PJM_ROR	143.98
ENT to SOCO	2.55	MISO_MO-IL to MISO_WUMS	64.00
ENT to SPP_S	5.76	MISO_MO-IL to NE	64.00
ENT to TVA	3.54	MISO_MO-IL to SPP_N	19.04
FRCC to SOCO	5.41	MISO_W to MISO_WUMS	28.44
HQ to NEISO	3602.88	MISO_W to NE	14.06
IESO to MAPP_CA	7.11	NEISO to NYISO_A-F	28.44
IESO to MISO_MI	16.00	NonRTO_Midwest to PJM_ROR	10.24
IESO to NEISO	256.00	NonRTO_Midwest to TVA	9.00
MAPP_CA to MAPP_US	10.24	NYISO_A-F to NYISO_G-I	576.18
MAPP_CA to MISO_W	28.44	NYISO_A-F to NYISO_J-K	576.18
MAPP_US to MISO_W	10.24	NYISO_A-F to PJM_ROM	7.11
MISO_IN to MISO_MI	143.98	PJM_E to PJM_ROM	16.00
MISO_IN to MISO_MO-IL	10.24	PJM_ROM to PJM_ROR	4.00
MISO_IN to PJM_ROR	7.11	PJM_ROR to VACAR	16.00
MISO_MI to MISO_MO-IL	23.04	SOCO to VACAR	10.27

Table A.6 Technical constant for candidate pipeline links ($(\text{psi}/\text{MMcf/h})^2$)

Pipeline link	Constant	Pipeline link	Constant
ENT to MISO_MO-IL	566.89	NonRTO_Midwest to PJM_ROR	566.89
IESO to MISO_MI	566.89	NYISO_A-F to NYISO_J-K	566.89
IESO to NEISO	566.89	PJM_ROR to VACAR	566.89
PJM_ROR to VACAR	566.89	SOCO to VACAR	566.89
SOCO to VACAR	566.89		

Table A.7 Maximum capacities for gas production (MMcf/h)

Pipeline link	Constant	Pipeline link	Constant
ENT	822	NEISO	15
HQ	8	PJM_ROM	162
IESO	25	PJM_ROR	162
MAPP_CA	225	SPP_N	77
NE	146	SPP_S	197

Finally, Table A.8 summarizes the financial parameters considered in the simulations for the candidate elements.

Table A.8 Economic parameters for candidate elements

Element	Parameter	Unit	Value
Transmission Line	WACC	%	10
	Economic Life	Years	40
	Capacity	GW	2
	Expansion Cost	MillionUSD/GW	0.18 - 0.89
Pipeline	WACC	%	10
	Economic Life	Years	80
	Capacity	MMcf/h	21
	Expansion Cost	MillionUSD/MMcf/h	10.41 - 57.27

APPENDIX B. NOMENCLATURE

B.1 Sets (indices)

D_c	compression stations	(d)
D_r	reduction stations	(d)
F	fuels	(f)
G	generation units	(g)
G_c	candidate generation units	(g)
G_e	existing generation units	(g)
I, I'	partitions for the squared pressure variables	(i, i')
J	nodes	(j)
J_a	area nodes	(j)
J_p	pipeline nodes	(j)
K	generation technologies	(k)
K_g	gas-fired generation technologies	(k)
L	transmission lines	(l)
L_c	candidate transmission lines	(l)
L_e	existing transmission lines	(l)
M	months	(m)
P	pipelines	(p)
P_c	candidate pipelines	(p)
P_e	existing pipelines	(p)
S	load blocks	(s)
T	years	(t)

B.2 Symbols

ι	last year
B_d	compression/reduction station start node
B_l	transmission line start node
B_p	pipeline start node
E_d	compression/reduction station end node
E_l	transmission line end node
E_p	pipeline end node

B.3 Tuples (set of indices)

$\bar{D}$	compression/reduction station tuple	$\bar{d}(d, B_d, E_d)$
$\bar{G}$	generation units tuple	$\bar{g}(g, j, k)$
$\bar{L}$	transmission lines tuple	$\bar{l}(l, B_l, E_l)$
$\bar{P}$	pipelines tuple	$\bar{p}(p, B_p, E_p)$

B.4 Parameters

$\gamma_{\bar{g}}$	heat rate value for generator $\bar{g}$
η	natural gas heat value
δ_k^g	generator type k lifetime
δ^{tl}	transmission line lifetime
δ^{pl}	pipeline lifetime
ξ	discount rate
π_{jtms}^{max}	maximum squared pressure in node j, year t, month m and block s
π_{jtms}^{min}	minimum squared pressure in node j, year t, month m and block s
τ	electricity load shedding cost
τ^{gas}	natural gas load shedding cost
$\upsilon_{k,f}$	carbon emissions for generator type k and fuel f
$\mu_{\bar{g}}$	forced outage rate for generator $\bar{g}$
$\nu_{\bar{g}tms}$	planned outage rate for generator $\bar{g}$, in year t, month m and block s

Parameters (Continuation)

Φ_j	intermittency limits for area j
Π_{ji}	theoretical squared pressure for partition i and node j
ψ_{jt}	regional RPS requirements in area j and year t
Ψ_t	national RPS requirements in year t
A_d	PDE - area of the pipeline cross section
$c_{jtm}^{d,gas}$	non-electric natural gas cost in area j, year t and month m
$c_{\bar{l}t}^{in,tl}$	transmission line $\bar{l}$ investment cost in year t
$c_{\bar{p}t}^{in,pl}$	pipeline $\bar{p}$ investment cost in year t
c_t^{cc}	carbon emissions cost in year t
$c_{\bar{g}t}^{fx,g}$	fixed oper. cost for generator $\bar{g}$, node j and year t
$c_{\bar{g}t}^{in,g}$	investment cost for generator $\bar{g}$, node j and year t
$c_{\bar{d}t}^{op,cr}$	operational cost for compressor/reductor $\bar{d}$ in year t
$c_{\bar{l}t}^{op,tl}$	operational cost for transmission line $\bar{l}$ in year t
$c_{\bar{l}t}^{op,tlo}$	operational cost for transmission line $\bar{l}$ (opposite direction) in year t
$c_{\bar{p}t}^{op,pl}$	operational cost for pipeline $\bar{p}$ in year t
$c_{\bar{p}t}^{op,plo}$	operational cost for pipeline $\bar{p}$ (opposite direction) in year t
$c_{\bar{g}ftm}^{op,f}$	fuel cost for generator $\bar{g}$, fuel f, year t and month m
$c_{\bar{g}t}^{op,g}$	variable oper. cost for generator $\bar{g}$, area j and year t
$c_{jtm}^{op,i}$	gas injection cost in area j, year t and month m
$c_{jtm}^{op,p}$	gas production cost in area j, year t and month m
$c_{jtm}^{op,s}$	gas storage cost in area j, year t and month m
$c_{jtm}^{op,w}$	gas withdrawal cost in area j, year t and month m
C_{jt}^{anom}	anomalies investment requirements for area j in year t
$C_{kt}^{a,max}$	maximum investment value for generation technology k in year t
$C_{\bar{g}}^{a,tot}$	maximum investment value for generator $\bar{g}$ along the simulation horizon
$C_{\bar{g}t}^{a,max}$	maximum investment value for generator $\bar{g}$ in year t
$C_{\bar{g}t}^{r,max}$	maximum retirement value for generator $\bar{g}$ in year t
$C_{\bar{g}}^{e}$	existing units of generator $\bar{g}$ in area j

Parameters (Continuation)

$C_{\bar{g}}^{max}$	maximum capacity for generator $\bar{g}$
$CC_{\bar{g}tms}$	capacity credit for generator $\bar{g}$ in year t, month m and block s
$CF_{\bar{g}t}$	capacity factor for generator $\bar{g}$ in year t
d	PDE - pipeline diameter
f	PDE - pipeline friction factor
$FC_{\bar{g}t}$	firm capacity for generator $\bar{g}$ in year t
g	PDE - gravitational acceleration
$g_{\bar{p}tmsi}^{val}$	theoretical gas flow for pipe $\bar{p}$ in year t, month m, block s, and partition i
$g_{\bar{p}tmsii'}^{val}$	theoretical gas flow for pipe $\bar{p}$ in year t, month m, block s, and partition (i, i')
$G_{\bar{p}tmsii'}$	gas across pipeline $\bar{p}$, in year t, month m, block s and partition (i, i')
G_{jtms}^{d}	non-electric gas demand in area j , year t, month m, and block s
$G_{jtm}^{i,max}$	maximum gas injection rate in area j, year t and month m
$G_{jtms}^{p,max}$	maximum gas production rate in area j, year t, month m, and block s
$G_{jtm}^{w,max}$	maximum gas withdrawal rate in area j, year t and month m
$G_{j}^{s,max}$	maximum storage capacity for area j
$G_{j}^{s,min}$	minimum storage capacity for area j
$G_{\bar{p}}^{pl,a,max}$	maximum investment value for pipeline $\bar{p}$ along the simulation horizon
$G_{\bar{p},exi}^{pl,c-max}$	initial maximum capacity for pipeline $\bar{p}$
$G_{\bar{p},exi}^{pl,c-min}$	initial minimum capacity for pipeline $\bar{p}$
$G_{\bar{p}tms}^{pl,max}$	maximum capacity for pipeline $\bar{p}$, year t, month m and block s
$G_{\bar{p}tms}^{pl,min}$	minimum capacity for pipeline $\bar{p}$, year t, month m and block s
$G_{\bar{p}tmsii'}^{val}$	theoretical gas flow for pipe $\bar{p}$, year t, month m, block s and partition (i,i')
$G_{j}^{s,ex}$	existing stored gas in area j
h_s	block duration
l	PDE - pipeline length
M_g	PDE - natural gas molar mass
M^{pl}	pipelines large constant
M^{tl}	transmission lines large constant

Parameters (Continuation)

P_{jtms}^{d}	power demand in area j, year t, month m and block s
$P_{jt}^{d,peak}$	power peak demand in area j and year t
$P_{\bar{l}}^{tl,a,max}$	maximum investment value for line $\bar{l}$ along the simulation horizon
$P_{\bar{l},exi}^{tl,c-max}$	initial maximum capacity for transmission line $\bar{l}$
$P_{\bar{l},exi}^{tl,c-min}$	initial minimum capacity for transmission line $\bar{l}$
$P_{\bar{l}tms}^{tl,max}$	maximum capacity for transmission line $\bar{l}$ in year t, month m and block s
$P_{\bar{l}tms}^{tl,min}$	minimum capacity for transmission line $\bar{l}$ in year t, month m and block s
r_j	generation reserves in area j
R	PDE - universal natural gas constant
T	PDE - natural gas absolute temperature
$W_{\bar{d}}$	technical coefficient for compressor/reductor $\bar{d}$
$X_{\bar{l}}$	reactance for transmission line $\bar{l}$
$Y_{\bar{p}}$	technical coefficient for pipeline $\bar{p}$
$\bar{Z}$	PDE - natural gas compressibility factor

B.5 Continuous decision variables

α	PDE - pipeline inclination angle from a reference level
$\Gamma_{\bar{p}tms}^{pl}$	squared gas flow across pipeline $\bar{p}$ in year t, month m and block s
$\lambda g_{\bar{p}tmsii'}^{pl}$	linear combination coefficients for gas flow across pipeline $\bar{p}$ in year t, month m, block s and partition (i,i')
π_{jtms}	squared pressure in node j, year t, month m and block s
$\pi_{j'tms}$	squared pressure in node j', year t, month m and block s
ρ	PDE - natural gas density
θ_{jtms}	voltage angle in area j, year t, month m and block s
ζ	total cost net present value
$C_{\bar{g}t}$	number of units for generator $\bar{g}$ in year t
$G_{\bar{d}tms}^{cr}$	gas flow across compressor/reductor $\bar{d}$ in year t, month m and block s

Continuous decision variables (Continuation)

$G'^{cr}_{\bar{d}tms}$	gas flow across compressor/reductor $\bar{d}$ (opposite direction) in year t, month m and block s
$G^{s,in}_{jt}$	initial stored gas in area j and year t
G^{i}_{jtms}	natural gas injected in area j, year t, month m and block s
G^{ls}_{jtms}	natural gas load shedding in area j, year t, month m and block s
G^{p}_{jktms}	gas production rate for area j, technology type k, year t, month m and block s
$G^{p,t}_{jtms}$	total gas production rate for area j, year t, month m and block s
G^{s}_{jtm}	natural gas stored in area j, year t and month m
G^{w}_{jtms}	natural gas withdrawed in area j, year t, month m and block s
$G^{pl,a}_{\bar{p}t}$	transmission capacity additions for pipeline $\bar{p}$ in year t
$G^{pl,c-max}_{\bar{p}t}$	maximum transmission capacity for pipeline $\bar{p}$ in year t
$G^{pl,c-min}_{\bar{p}t}$	minimum transmission capacity for pipeline $\bar{p}$ in year t
$G^{pl}_{\bar{p}tms}$	gas flow across pipeline $\bar{p}$ in year t, month m and block s
$G'^{pl}_{\bar{p}tms}$	gas flow across pipeline $\bar{p}$ (opposite direction) in year t, month m and block s
$G^{pl}_{\bar{p}}$	PDE - gas volumetric flow across pipeline $\bar{p}$
$\dot{m}_{\bar{p}}$	PDE - gas mass flow across pipeline $\bar{p}$
$P^{g}_{\bar{g}tms}$	power level for generator $\bar{g}$, in year t, month m and block s
P^{ls}_{jtms}	electric load shedding in area j, year t, month m and block s
$P^{tl}_{\bar{l}tms}$	power across line $\bar{l}$ in year t, month m and block s
$P'^{tl}_{\bar{l}tms}$	power across line $\bar{l}$ (opposite direction) in year t, month m, and block s
p	PDE - natural gas pressure
$P^{g}_{\bar{g}tms}$	power level for generator $\bar{g}$, in year t, month m and block s
P^{ls}_{jtms}	load shedding in area j, year t, month m and block s
$P^{tl,a}_{\bar{l}t}$	transmission capacity additions for line $\bar{l}$ in year t
$P^{tl,c-max}_{\bar{l}t}$	maximum transmission capacity for line $\bar{l}$ in year t
$P^{tl,c-min}_{\bar{l}t}$	minimum transmission capacity for line $\bar{l}$ in year t
$P^{tl}_{\bar{l}tms}$	power across line $\bar{l}$ in year t, month m and block s

Continuous decision variables (Continuation)

$P'^{tl}_{\bar{l}tms}$	power across line $\bar{l}$ (opposite direction) in year t, month m, and block s
q	PDE - heat per unit volume of pipeline
v	PDE - natural gas flow average velocity
w	PDE - power added to the gas flow from other sources
z	PDE - elevation from a reference level

B.6 Integer decision variables

$C^{a}_{\bar{g}t}$	investments for generator $\bar{g}$ in year t
$C^{r}_{\bar{g}t}$	retirements for generator $\bar{g}$ in year t

B.7 Binary decision variables

$S_{\bar{l}t}$	set to 1 if line $\bar{l}$ has been installed until period t, 0 otherwise, for l $\in L_c$
$S_{\bar{p}t}$	set to 1 if pipeline $\bar{p}$ has been installed until period t, 0 otherwise, for p $\in P_c$
$Z_{\bar{l}t}$	set to 1 if line $\bar{l}$ is installed in period t, 0 otherwise, for l $\in L_c$
$Z_{\bar{p}t}$	set to 1 if pipeline $\bar{p}$ is installed in period t, 0 otherwise, for p $\in P_c$

B.8 SOS2 decision variables

$\lambda\pi_{jtmsi}$	linear combination coefficients for squared pressure in area j, year t, month m, block s and partition i
$\lambda g^{pl}_{\bar{p}tmsi}$	linear combination coefficients for gas flow across pipe $\bar{p}$ in year t, month m, block s and partition i

APPENDIX C. ACRONYMS

BM	Biomass Generation Technology
CNG	Compressed Natural Gas
DOE	Department of Energy
EIA	U.S. Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
FERC	Federal Energy Regulatory Commission
Geo	Geothermal Generation Technology
HY	Hydro Generation Technologies
LDC	Load Duration Curve
LFG	Landfill Gas Generation Technology
LNG	Liquefied Natural Gas
LP	Linear Programming
MAOP	Maximum Allowable Operating Pressure
MILP	Mixed Integer Linear Programming
MINLP	Mixed Integer NonLinear Programming
MMcf	Million of cubic feet
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NLP	NonLinear Programming
NU	Nuclear Generation Technology
O&M	Operation and Maintenance
PDE	Partial Differential Equations
psi	Pounds per square inch

P&B	Pipes and Bubbles
PV	Solar Photovoltaic Generation Technology
RPS	Renewable Portfolio Standard
SOS2	Special Ordered Set of type 2
ST	Steam Turbine Generation Technologies
Tcf	Trillion of cubic feet
WACC	Weighted Average Cost of Capital