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Integrated Planning of Natural Gas Transportation System and Natural Gas-Fired Electric Power Generators

by

Babatunde Oluwaseyi Odetayo

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE

DEGREE OF DOCTOR OF PHILOSOPHY

GRADUATE PROGRAM IN ELECTRICAL AND COMPUTER ENGINEERING

CALGARY, ALBERTA

NOVEMBER, 2017

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Abstract

This thesis focuses on the long-term integrated planning of electric power and natural gas transportation systems in the presence of uncertain electricity and natural gas demand. The first part of this thesis proposes a sequential approach to planning the natural gas and electricity distribution system in the presence of uncertain electricity demand. This planning approach is effective in regions where there are minimum and predictable non-electricity demand for natural gas. The second part of this thesis accommodates the uncertainties of the electricity and natural gas demand by proposing an integrated approach towards solving the long-term natural gas and electricity distribution systems. In the third part of this thesis, a real option assessment of the managerial investment flexibilities presented by future uncertain electricity demand at the distribution level was presented.

The fourth part of this thesis concentrate on the integrated planning of the electricity and natural gas system at the transmission level. The fourth part proposes a model for planning the location and sizing of the natural gas-fired generators, natural gas pipeline, and the natural gas compressor. This model exploits a combination of investments and natural gas supply contract reviews for meeting future electricity and natural gas demand.

Acknowledgements

First, I sincerely thank my supervisor Dr. William D. Rosehart for his immeasurable help, guidance, and support during my Ph.D. studies. I will also like to extend my sincere gratitude to Dr. Hamidreza Zareipour, my co-supervisor for his constant support and advice. I will also like to thank Dr. Maccormack for his support and advice.

Special thanks to my friends for their support and encouragement. I will also like to thank Dr. Ehsan Nasrolahpour, Dr. Payam Zamanidehkordi, Dr. Soroush Shafiee, Dr. Ali Seifi, Dr. Hamid Sakar, Dr. Ali Jahanbini, Dr. Mostafa Kazemi, Mrs Yasaman Mozafari, Mrs Madhu and Mrs Tasnim Hossain, Mr. Juan Arteaga, Mr. Edmond Chic, Mr. Hamed Chitsaz, Miss Sara Awara, and Mr. Shubhrajit Bhattacharjee, for their support.

My warmest acknowledgment to my loving mother who sacrificed a lot to give my siblings and I quality education. My special thanks to my beautiful, understanding and loving wife, Adesewa, whose encouragement and tolerance allowed for this accomplishment. Finally, as a recipient of the Werner Graupe International Fellowships in Engineering and the Professor Om P Malik Family Graduate Scholarship in Electrical Machines and Power Systems, I would like to express my sincere gratitude to the Antje Graupe Pryor Foundation and the Professor Om P Malik Family for the tremendous support that was afforded me through this scholarship.

To the memory of my father, **Abiodun** *and my mother*, **Ayodele**, *whose love, guidance and support have shaped my life*

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List of Symbols and Abbreviations

Abbreviation

Symbol	Definition
NG	Natural Gas
NGDG	Natural Gas Distributed Generators
NGG	Natural Gas Generators
CCP	Chance Constrained Programming
RP	Reliability Programming
GAMS	Generalized Algebraic Modeling Systems

Chapter 1

Introduction

1.1 Research Motivation

The worldwide electricity generation capacity is expected to grow by 69% from 21.6 trillion kilowatt-hours (kWh) in 2012 to 36.5 trillion kWh in 2040 and Non-Organization for Economic Co-oporation and Development (Non-OECD) economies are expected to account for 61% of this growth [1]. In consequence to this, in the past two decades, a number of non-OECD and OECD economies have restructured their electricity systems in order to attract private capital and increase efficiencies via competition.

The objective of restructuring electricity markets differs significantly across countries and as expected, the post-restructuring realities also differ. In OECD countries, for instance, restructuring of the electricity system was motivated by the need to increase the level of performance and commercial standards of the electric power system via competition. The narrative differs in developing countries where the main objective of restructuring is to attract investment for sufficient power supply, expand access to public electricity supply and reduce the expenditure of public funds in supporting the power sector [2]. These in addition to other factors such as environmental requirements, technological advancement, and financial constraints have shaped the choice of fuel and technology for electric power generation across the world. A technology that has enjoyed significant growth is Natural Gas-fired Generators (NGG).

Global electricity generation from Natural Gas (NG) is expected to grow by 110% from 4.8 trillion kWh to 10.1 trillion kWh between now and 2040 [1]. In Alberta for instance, NG-fired generation accounted for 40% of the 81,621GWh of net electricity generation in comparison to 51% from coal in 2015. NG is expected to account for 70% of net electricity generation by 2030 [3]. This increase is driven by the availability of relatively cheap NG supply, environmental regulations

such as the Alberta Climate Leadership Act [3], improvement in the efficiencies of NG-fuel generators (NGG), competitive investment cost of NGG and the relative cleanliness of NG as a fuel for electric power generation [4–6].

It is estimated that 42% of the annual global NGG capacity additions by 2020 will be Natural Gas-fired Distributed Generators (NGDG) [7]. This growth is motivated by the relatively short installation times, modularity, scalability, fast ramp rates, and competitive capital and operating costs. In addition to these, NGDGs are enjoying appreciable growth in developing countries partly due to environmental policies, the constraint on transmission infrastructure and the relative ease of financing them in the light of budgetary constraints [8]. NGDGs include reciprocating engines, gas turbines, microturbines, and fuel cells connected to the electricity distribution grid.

The increasing utilization of NG fired generators implies an increasing dependency of the reliability of the electric power system on that of the NG transportation system. Unlike coal which is traditionally employed for meeting base-load power demand, NG needs to be transported via a complex network of pipelines, compressors and NG storage over great distance. In consequence to this, the increased dependency of the electric power system on the NG transportation system exposes the reliability of the electric power systems to disruptions in NG supply, transportation, delivery and competing NG-demand for heating, transportation, manufacturing, and export. These reliability concerns have necessitated advanced modeling and analysis approaches to the integrated planning of both systems. The main motivation behind this thesis is the development of computational tools for the long-term integrated planning of the electric power and NG transportation at the distribution and transmission systems.

1.2 Background

1.2.1 Electric Power System

The electric power system comprises of electric power generators, electric current transportation grid, and the electric power demand. The electric power system can be divided into electric distri-

bution and transmission systems.

1.2.1.1 Electric distribution System

The electric distribution system is an interconnected grid through which electric energy flows from the point of supply on the transmission system and from locally distributed generators to the end users at low voltages. The distribution system consists of one or more distribution substations, distribution feeders, distribution network transformers, various switches and local generators connected to the distribution system [9, 10]. Typically distribution systems in Canada are operated at 69kV or less. Electric distribution systems are mostly operated in a radial configuration and are reconfigurable using switches in the presence of faults [11].

1.2.1.2 Electric Transmission System

The electric transmission system transport bulk electrical energy at high voltage from the electric power generator to the distribution substations. In Canada, the electric transmission system involves the transportation of electrical energy at voltage levels that are $\geq$ 69kV.

1.2.2 Natural gas transportation system

The natural gas transportation system is a complex network of pipelines, compressor stations and valves designed to quickly and efficiently transport natural gas from its sources to points of demand. There are three major types of pipelines along the NG transportation route: gathering pipelines, interstate/transmission pipelines and distribution pipelines [12, 13]. Gathering pipelines are not considered in this thesis.

1.2.2.1 Natural gas distribution System

The natural gas distribution system is a network of small diameter distribution pipelines that transport natural gas from delivery point/city gates along major pipelines to the customer at low-pressure [14]. According to the Canadian Energy Pipelines Association, the outside diameter of NG distribution pipelines in Canada ranges from 12.7 millimeters(mm) to 152.4mm and transport

odorized NG at a pressure range of 0.14bar to 13.8bar. There are about 450,000 kilometers of distribution NG pipeline in Canada [15].

1.2.2.2 Natural gas Transmission System

The natural gas transmission comprises of NG transmission pipelines, compression stations, metering stations, and valves. The diameters of the NG pipelines at the transmission level are any between 6 and 48 inches. The compression stations ensure that the NG flowing through the pipeline remains pressurized. Compressors are typically placed at 40 to 100 miles interval along a pipeline [12]. NG metering stations and valves are not accommodated in the model proposed in this thesis.

1.2.2.3 Natural Gas Fired Distributed Generator (NGDG)

Natural Gas-fired Distributed Generator (NGDG) are thermal electric generators connected to the local electricity distribution system [16]. Typical NGDG technologies are reciprocating engines, gas turbines, microturbines, and fuel cells with sizes ranging from 500 kilowatts (kW) to 50 Megawatt (MW) depending on the technology and local regulation [7].

1.2.2.4 Natural Gas Fired Generator (NGG)

Natural Gas Fired Generators (NGGs) are large natural gas-fired electric power generators connected to the electric power systems. In this thesis, NGGs are assumed to have a nameplate capacity of 50MW and above. Typical NGG technologies include open cycle, combined cycle and combined heat and power NG-fired generators.

1.2.3 Definitions

The following definitions and assumptions were employed in this thesis

1.2.3.1 Reliability/Confidence level

The term confidence level and reliability are used interchangeably in this thesis and is defined as the level to which the nodal balance constraint is satisfied. In other words, the level to which

the sum of local electric power generation and the net inflow of electric power satisfies the local electric power demand [17]. Similarly, the reliability/confidence level of the NG system is the level to which the sum of local NG supply and the net NG inflow satisfies the local NG demand.

1.2.3.2 Real options

A real option is the right to expand, delay or abandon the integration of the underlining tangible asset of a project in response to changing economic, technical or market conditions. In the context of this thesis, Real options are the right to expand, delay or abandon the integration of NGDGs and NG pipeline in response to change electricity demand forecast.

1.2.3.3 Steady state NG system model

The NG flows in the NG distribution and transmission systems are assumed to be in steady states in the models proposed in this thesis. Therefore, the frictional factor and compressibility factor are assumed to be constant [18, 19].

1.2.3.4 Long-term planning philospphy

In long-term adequacy based planning of electricity and NG systems, the objective is to ensure the annual peak demands are met with the desired confidence level. Therefore, it is typical to ignore the daily dynamics of the power flow and NG hydraulics in the development of the long-term investment plan. This approach was employed in this thesis.

1.3 Research Objectives and Scope

The main objective of this research is to develop mathematical tools and models for the long-term integrated planning of natural gas transportation systems and electric power generators. The objective of this Ph.D. studies is divided into four sub-objectives

1. To develop mathematical models for the long-term reliability based planning of the electric and NG distribution system when NG demand for electricity and non-electricity purposes are independent

2. To develop mathematical models for the long-term reliability based planning of the electric and NG distribution system when NG demand for electricity and non-electricity purposes are dependent

3. To establish the real option presented by the adaptability and flexibility of NGDGs and NG distribution pipelines on the long-term integrated planning of the electric and NG distribution systems

4. To develop probabilistic long-term planning models for the integrated planning of NG and electric power generation systems at the transmission level

1.2.1 Reliability-based long-term planning of the electric and NG distribution system when NG demand for electricity and non-electricity purposes are independent: Natural gas distributed generators are expected to play a significant role in bridging the gap between electricity demand and supply in a number of developing countries with access to cheap NG supply but a constrained electric power transmission infrastructure and financial capital. This is due to the relatively short installation times, modularity, scalability, fast ramp rate, competitive capital and operating costs of NGDGs. Harnessing the potential of NGDG requires extending the existing or building an entirely new, natural gas distribution infrastructure. In temperate developing countries such as Nigeria, where electric power generation and predictable industrial process accounts for most NG demands, a sequential planning approach offers an effective tool for the joint planning of the electric power and NG distribution system. In the sequential planning approach, the NG demand is first computed by calculating the optimum location and size of NGDGs then the NG distribution route is determined. The overall objective of the joint long-term planning problem is the minimization of the investment and operation cost of NGDGs and NG distribution system required to meet the long-term electric power demand. This objective is addressed in Chapter 2.

1.2.2 Reliability-based planning of the electric and NG distribution system when NG demand for electricity and non-electricity purposes are interdependent: The increased integration of dis-

tributed electric power generators means the reliability of electricity distribution systems will increasingly depend on the reliability of natural gas distribution system. This concern is heightened by the cascaded relationship between these systems allowing easy propagation of reliability violations between them. Factors that affect the reliability of the NG distribution system includes the failure rate of NG distribution pipelines, NG distribution pressure, NG flow rate and competing demands for other purposes such as heating and transportation. A utility interested in harnessing the potentials of NGDGs will, therefore, have to develop a long-term investment plan that optimizes the integration of NGDGs and NG distribution infrastructure for meeting both electricity and non-electricity NG demands. The objective of the integrated planning approach is to compute the optimum location and size of NGDGs, the optimum route of NG pipelines required to ensure the stochastic electricity and NG demand are met in the long-term. This objective is addressed in Chapter 3.

1.2.3 Real option presented by the adaptability and flexibility of NGDGs and NG distribution pipelines on the long-term integrated planning of the electric and NG distribution systems: The infrastructure gap in developing environments can sometimes make the utilization of NGDG financially nonviable when assessed using traditional financial assessment tools such as discounted cash flow, internal rate of return and net present value. This is because these tools fail to value the options presented by the scalability, modularity, and adaptability of natural gas distributed generators (NGDGs) and NG distribution system. These scalability, modularity, and adaptability of NGDGs offer the management of a distribution utility the flexibility to adapt its expansion plans to new realities by delaying, canceling or executing its expansion plans. The real options analysis planning approach to the long-term integrated planning of electricity and NG distribution system presents a tool that allows a utility assess current investment in the light of future opportunities it provides. The management flexibilities allow the management of a utility to improve profitability, reduce exposure to financial risk and make well-informed decisions on future investments, especially where access to capital is limited. The proposed model develops a long-term plan in two stages: the

identification of NGDG and NG pipeline expansion options and the assessment of these options. This long-term planning approach is presented in Chapter 4.

1.2.4 Probabilistic long-term planning models for the integrated planning of NG and electric power generation systems at the transmission level: Finally, environmental policies such as the Alberta Climate Leadership Act [20] and the availability of relatively cheap NG are expected to stimulate increased connection of NG-fired Generators (NGGs). NGGs differ from NGDGs mainly because they generate a large amount of electric power at high voltages and are connected to the electric transmission network. In addition, they also require a large amount of NG that needs to be transported over long distances at high pressure thus the need for compression stations. The objective of the planning problem at the transmission level is therefore, to determine the optimum size and location of NGGs, NG compressor station and the optimum route of the NG pipelines. Similar to the challenges at the distribution system level, the complex nature of the cascade interactions between these systems raises reliability concerns since the reliability of the entire system is the product of the reliability of the individual systems. The reliability of a series connected system increases exponentially with an increase in the higher reliability percentile, hence, the cost of achieving a perfectly reliability system can be enormous and financially nonviable. A Probabilistic planning approach equips the utility planner with a tool to strategically minimize its investment cost while accommodating acceptable reliability violations. Two probabilistic planning approaches to solving the integrated planning problem at the transmission level in the presence of uncertain electricity and NG demand are presented in Chapter 5.

1.4 Thesis Contributions and Importance

The main contributions of this thesis are described in the paragraphs below.

The first contribution of this thesis is to extend previous research [19, 21] on the planning of NG and electricity distribution systems by proposing a reliability-based analytical approach to the long-term planning of both systems. The integrated planning problem was modeled as a

chance constrained optimization problem and solved sequentially. The output of the model is the location and size of the NGDGs and NG pipeline that ensures the desired level of system reliability while considering the uncertainties in electricity demand. Since system reliability is related to the investment cost of a system, the expansion plans are assessed for different levels of reliabilities. This solution algorithm proposed is suitable for the joint planning of the electricity and NG system in temperate developing environments where NG demand for non-electricity purposes are either absent or predictable, access to capital is limited and the electricity supply from the transmission system is constrained. The proposed analytical model differs from the models proposed in [19, 21] which are based on heuristic approaches that do not guarantee repeatability of a result. In addition, the proposed model provides a framework for developing a reliable long-term energy supply plan in the presence of a constrained transmission system.

The second contribution of this thesis is the extension of the sequential probabilistic long-term planning approach presented in Chapter 2 [22] and previous research [19, 21] by proposing and solving an integrated adequacy-based model for the long-term planning of NGDGs and NG distribution network in the presence of stochastic real and reactive electricity demand. The integrated planning problem is modeled as a chance constrained optimization problem and solved using the proposed algorithm, which simultaneously accommodates the risk of uncertainty and adequacy requirements in both the electricity and NG distribution system. The output of the proposed model is the optimal location and size of NGDGs and NG distribution pipeline route that ensures a desired level of system reliability. The proposed model is different from the proposed model in Chapter 2 owing to its ability to accommodate the interdependencies between NG demand for electric and non-electric purposes. In addition, it differs from [19, 21, 22] in view of its ability to accommodate the uncertain dynamics of the active and reactive power demand at the electric power distribution level. Furthermore, the solution approach from the proposed model allows for the repeatability of solutions and allows for the consideration of multiple scenarios. The proposed model equips a distribution company with an exclusive right to supply electricity and NG, to adequately plan

the utilization of NGDGs for the purpose of meeting future electricity demand while ensuring reliable NG distribution. In addition, the proposed solution allows an incremental approach towards increasing the adequacy level of electric power system supply. The integrated planning problem is modeled from the perspective of a distribution utility in a developing country or suburban or rural environments with relatively easy access to NG supply, a constrained transmission system, budgetary constraints and a regulatory framework that allows the integration of NGDGs.

The third contribution of this thesis is the extension of the proposed models in Chapter 2 [22], Chapter 3 [23] and the real option approach to electric power generation planning presented in [24, 25] by proposing an approach that values the real options that accompany the flexibilities of NGDGs in the development of a long-term integrated plan. Whereas the previous models treated all expansion options as a cost, the real options approach to long-term planning ascribes values to initial investments that are leveraged on in the future thereby increasing the financial viability of the expansion plan. The output of the proposed model is a contingency plan that allows the utility to adjust i.e. execute, delay or abandon NG pipeline and NGDG integration in response to the future realization of electricity and NG demands. The proposed model differs from [22, 23] and [26–28] which only attributes cost to NGDG and NG pipeline integration. The real option planning approach allows the management of a utility to value the adaptability of an expansion plan to the downstream realization of uncertain parameters. The proposed model develops a long-term plan in two stages: the identification of NGDG and NG pipeline expansion options and the assessment of these options. The real options approach to the integrated planning of the electricity and NG systems provides a tool that allows a utility to assess current investment in the light of future opportunities it provides. This approach is very useful in helping utilities improve profitability, reduce exposure to financial risk and make well-informed decisions on future investments, especially where access to capital is limited.

The fourth contribution of this thesis extends previous research [4–6, 22, 23, 29–32] by proposing probabilistic planning algorithms for the integrated planning of natural gas-fired electric power

generators, natural gas compressor station and natural gas pipelines in the presence of reliability constraints and stochastic electricity and natural gas demand. The proposed planning models minimize the investment and operation cost of the electric power and NG gas systems while ensuring a minimum system-wide reliability is achieved. Two reliability based solution algorithms i.e. a joint chance constrained programming and a reliability-programming framework for modeling and solving the integrated planning problem are proposed. The joint chance constrained programming ensures that desired system reliability levels set a priori is met by the long-term plan while the reliability programming model optimizes the individual system probabilities that ensure a desired overall system reliability. The proposed models differs from previous models in Chapter 2 [22], Chapter 3 [23] and Chapter 4 [33] in that it concentrates on the transmission system and simultaneously accommodated uncertainties in the electric power and NG demands. In addition, it differs from [4–6, 22, 23, 29–32] by accommodating system reliability criteria while allowing reliability cross compensation between the electric and NG system in the presence of uncertain electricity and NG demand uncertainties. The proposed probabilistic long-term planning approaches allow the system operator to ensure an overall system reliability by allowing manageable violations in each of the component systems and cross reliability compensation between the constituent systems via a combination of financial, technical and contractual solution approaches.

1.5 Thesis Organization and Structure

This is a manuscript-based thesis. It consists of an introduction in Chapter 1, and five related research articles presented individually in Chapters 2-5, and a conclusion in Chapter 6.

Chapter 2 focus on a sequential approach to the integrated long-term planning of natural gas-fired distributed generations and natural gas distribution system in the presence of uncertain electricity demand forecast.

In Chapter 3, an integrated approach to the long-term integrated planning of natural gas-fired distributed generations and natural gas distribution system in the presence of uncertain complex

electricity demand forecast is proposed.

A Real Option assessment approach to the long-term integrated planning of natural gas-fired distributed generations and natural gas distribution system in the presence of uncertain electricity demand forecast is proposed in Chapter 4.

Chapter 5 proposes reliability focused approaches to the long-term integrated planning of natural gas-fired generators and natural gas transmission systems in the presence uncertain electric power and natural gas demand.

Finally, concluding remarks is presented in Chapter 6

Chapters 2, 3 and 4 are published papers. Chapters 5 have been submitted for publication and are under review for publication.

This research was carried out under the supervision of my supervisor, Dr. W. Rosehart, and my co-supervisor Dr. H. Zareipour and they are both co-authors of these papers.
Dr. John Maccormack an adjunct professor at the department of electrical and computer engineering, University of Calgary, is also a co-author of these papers, he provided technical and editorial advice in the development of these papers. Dr. Seifi, a visiting professor at the department of electrical and computer engineering, University of Calgary is a co-author of the fourth paper.

1.5.1 Notes on Nomenclature

Some of the nomenclatures are not consistent throughout the thesis. This is because they were updated in subsequent manuscript to improve the presentation and legibility of the research. A nomenclature section is included at the start of chapters that were either published or submitted to journals that allows a nomenclature section. For chapters published in journals where nomenclatures sections are not allowed, nomenclatures are defined in the body of the chapter.

Chapter 2

Sequential Planning of Natural Gas Distribution System and Natural Gas fired Distributed Power Generator [1]

The increasing integration of natural gas-fired distributed power generators at the distribution level of the electric power system presents reliability concerns. We present a comprehensive long-term planning model of natural gas distribution pipelines, natural gas-fired distributed power generators, and capacitor banks. The planning problem is modeled as a chance constrained mixed integer nonlinear optimization problem. Chance constrained programming affords the planner to simultaneously ensure a desired system reliability level while accommodating the risk of uncertain electricity demand. The objective of the planning problem is the minimization of the fixed and operating costs of both natural gas and electricity systems over a planning period of ten years. We solve this problem using a sequential planning approach. The outputs of the planning model are the best location and size of the natural gas-fired generators and the capacitor banks. The minimum acceptable reliability level in our model is set to 96%. We illustrate our approach using a simple radial distribution test system. We show that an energy system with desired reliability can be attained while accommodating the uncertainties of electricity demand in the long-term plan. In addition, we show a relationship between the expansion plans and the reliability policies of a distribution utility.

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2.1 Introduction

There is an increase in the integration of Distributed Generation (DG) across the world, especially in developing economies where there is an urgent need to bridge the gap between electricity demand and supply. This increase is partly due to environmental policies , the constraint on transmission infrastructure and the relative ease of financing smaller electricity generation projects in a part of the world where access to capital if often a challenge. In the developed world, natural gas is seen as a "bridging fuel" from a fossil fuel dominated energy system to a low-carbon energy system [35]

Natural Gas-fired Distributed power Generation (NGDG) has attracted lots of interest in recent times. This is because of the recent lower cost of extracting, transporting and marketing of Natural Gas (NG). In addition, the relatively short installation times, modularity, scalability, fast ramp rate, and competitive capital and operating costs of NGDGs have made them a competitive choice for electricity generation. According to General Electric a world leader in original equipment manufacturing, 42% of the annual NG-fired generation capacity additions by 2020 will be NGDGs [7]. NGDGs include reciprocating engines, gas turbines, microturbines, and fuel cells connected to the electricity distribution grid. The increasing NGDG integration increases the dependency of the electric distribution system on the NG distribution system. As identified by the energy sector management assistance program of the World Bank [36], this increase in dependencies necessitates long-term comprehensive planning of both systems.

Long-term comprehensive planning of electricity and NG transportation systems can be classified into transmission [5] and distribution system planning [37]. Transmission systems differ from distribution system both physically and in the way they are modeled. Transmission system planning involves planning systems at higher electricity voltages and NG transmission pressure [38]. Distribution systems planning, on the other hand, is the planning of electricity and NG systems at lower electric voltages and NG pressure respectively [39]. In addition, there are normally no compressors in the NG distribution system [19], therefore the NG distribution system must be

planned such that an acceptable pressure differential between the NG source and demand node must be maintained always. From a modeling perspective, an approximation that ignores the line resistance and reactive power i.e. direct current (DC) power flow can often provide acceptable results in planning electric transmission system [38]. The reactive power and the resistance of the distribution feeders, however, cannot be ignored in electric distribution planning. The comprehensive planning of NG and electricity systems at the distribution system has yet to receive significant attention [4].

The planning of NGDGs and a NG distribution system were presented in [37]. In that paper, the solution assumed the existence of an adequate NG distribution system. A detailed work on the planning of both distribution systems was provided in [19] where a hybrid of heuristic and analytical methods was employed to solve the planning problem. The heuristic approach involves the selection of the best option from a given set, so the quality of the solution depends on the quality of the options set. There is, however, limited research on the reliability challenges of an electricity distribution system that is dependent on a NG distribution system.

Electricity and NG distribution systems are serially linked. This raises reliability challenges because the reliability of the entire system is equivalent to the product of the reliability of the individual series components [40]. This implies that both systems must be planned to ensure an acceptable combined reliability level. The planning problem is further complicated by the presence of uncertain future real and reactive electricity demand [41] and the normal radiality of both the electric and NG distribution systems. In addition, significant reactive power demand on the distribution system can affect the system reliability of the systems because of its relationship with the system voltages. In the light of this, there is a need for planning approaches that accommodate the risk of uncertain real and reactive electric power demand, and ensure the desired reliability level is met.

We model the planning problem as a chance-constrained programming (CCP) [42] optimization problem. CCP is a stochastic reliability programming approach where the constraint with an

uncertain parameter is formulated in a probabilistic term such that an a priori selected reliability level is attained [43]. CCP has been shown to provide expansion plans that ensure the desired reliability level is met in the presence of uncertain electricity demand [44].

This research extends previous research [19, 37] by modeling the comprehensive long-term planning of a NG and electricity distribution system problem as a CCP optimization. CCP is an analytical modeling approach that accommodates the risk of uncertainties, while ensuring the desired system reliability level is met. The series reliability dependency is accommodated by sequentially optimizing both systems. The significant reactive power demand in the electric distribution system is addressed by including capacitor bank planning in the comprehensive long-term planning problem. The output of the model is the location and size of the NGDGs, capacitor banks, and NG pipeline that ensures the desired level of system reliability while considering the uncertainties in electricity demand. Since system reliability is related to the investment cost of a system, we assessed expansion plans for different levels of reliability. It is important to note that the solution presented in this paper is from the viewpoint of developing environments where access to capital is limited and the electricity supply from the transmission system is constrained.

The rest of this paper is structured as follows. Section II describes the electricity and NG distribution planning problem. Section III presents our solution methodology. Section IV discusses the results from testing this model on a simple test system. Section V provides concluding remarks.

2.2 Electricity and natural gas distribution planning problem

The electricity and NG long-term distribution planning problem for a distribution utility that owns both systems is presented in (2.1). The planning problem minimizes the capital, operating [45] and reliability cost of the electricity and the NG distribution systems subject to the physical and operational constraints of the electricity and NG distribution system and the electricity - NG coupling constraint [19]. The solution to the planning problem is the location and sizing of NGDGs,

capacitor banks, and NG distribution pipelines required to reliably transport NG.

$$
\begin{aligned}
min \;\; z = & \sum_{t}^{T} \Big(\sum_{b}^{\Omega_b} \sum_{\rho}^{\Omega_\rho} \delta_t \lambda_{\rho,b,t} C_{\rho}^{g,I} + \sum_{b}^{\Omega_b} p_{b,t}^{g} C^{g,O} \\
& + \sum_{b}^{\Omega_b} \sum_{\rho}^{\Omega_\rho} \delta_t \pi_{\rho,b,t} C_{\rho}^{c,I} + \sum_{i,j}^{\Omega_p} \delta_t C^{p,I} L_{i,j} (y_{ij,t+1} - y_{ij,t}) \\
& + \sum_{ij}^{\Omega_p} y_{ij,t} F_r L_{ij} \varsigma \big((Q_{i,j,t} \times C^{o}) + \tau_{i,j,t} \big) \Big) \qquad (2.1a)
\end{aligned}
$$

$$
\delta_t = \frac{ir}{1 - (1+ir)^{-t}} \qquad (2.1b)
$$

The first, second, third, fourth and fifth term of (2.1a) are the present value of the capital cost of new NGDGs, the operating cost of energy generation from existing and new generators, the present value of the capital cost of the capacitor banks, the present value of the capital cost of new distribution pipelines between NG nodes i and j, and the annual reliability cost of pipeline outages respectively. $C_{\rho}^{g,I}$ is the capital cost of adding NGDG g of quantized size ρ to bus b at the start of year t. $\lambda_{\rho,b,t}$ is a binary variable that equals one when a new NGDG of size ρ is installed and zero otherwise. Ω_b and Ω_ρ are the set of all electricity bus and NGDG type respectively. $C^{g,O}$ is the fixed and variable operating cost of generating electricity energy from existing generators and new NGDGs and the cost of buying electric energy from the grid. The substation connects the radial distribution system to the grid and is modeled as an existing generator. The capital cost of the substation $C_{s}^{g,I}$ is set to zero because it is assumed to be in existence, while the operating cost of the substation is the cost of buying electricity from the grid which is taken to be a fraction of the operating cost of NGDGs [46].

$\pi_{\rho,b,t}$ is a binary decision variable to install a new capacitor bank of quantized size ρ at electricity node b at the beginning of planning horizon t. $C_{\rho}^{c,I}$ is the capital cost of capacitor bank c of size ρ. Ω_ρ is the set of all type of capacitor banks. $C^{p,I}$ is the present value of the capital cost of adding or extending the length $L_{i,j}$ (miles) of pipe y connecting nodes i and j. y is a unique identifier for each pipe. Ω_p is the set of all pipes. The annual pipeline reliability cost is the sum of the cost to the customer of an NG outage and the cost of repairing the failed pipeline. The total

pipeline reliability cost is a function of the peak NG flow rate $Q_{i,j,t}$ million standard cubic feet per day $(MMscf/day)$ in each section of the pipeline, the length of connected pipeline L_{ij}, the cost of repair $\$\tau_{i,j,t}$, the outage cost $C^o(\$/MMscf)$, and the outage duration ς in days. F_r is the annual pipeline failure rate per mile [47]. The annuity δ_t in (2.1b) is dependent on the payback time t (years) and the interest rate $ir\%$.

2.2.1 Physical and operational constraints on the electric distribution system

The flow of electricity in a radial distribution system such as that shown in Fig. 2.1 is constrained by physical and capacity constraints [48]. V_0 is the voltage at the substation. The feeder and load

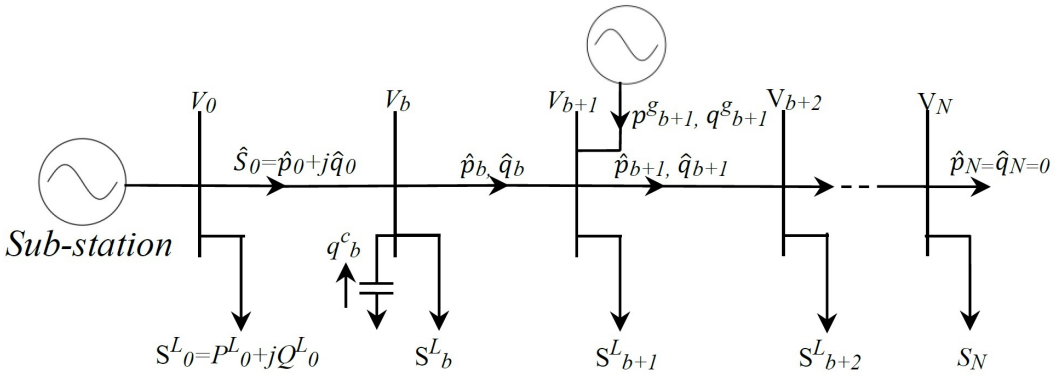


Figure 2.1: Typical N-bus radial distribution system with DG placed at bus i.

are represented by the series impedance $z_b = r_b + jx_b$ and the complex power sink $S_b^L = P_b^L + jQ_b^L$ respectively. The complex power flow in the feeder connecting bus b to $b+1$ is modeled as $\hat{S}_b = \hat{p}_b + j\hat{q}_b$. p_{b+1}^g, q_{b+1}^g and q_b^c are the real power generation, the reactive power generation and the reactive power generation from the capacitor bank respectively [49] . The capacitor bank is a reactive power injector, while the NGDGs can inject or absorb reactive power. The branch flow equations - (2.2) and (2.3) enforce Kirchhoff's flow conservation and ohms law [48].

$$p_{b+1,t}^g + \left[\hat{p}_{b,t} - \frac{r_{b+1}(\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2)}{v_{b,t}^2}\right] = P_{b+1,t}^L + \hat{p}_{b+1,t} \tag{2.2}$$

$$q_{b+1,t}^g + \left[\hat{q}_{b,t} - \frac{x_{b+1}(\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2)}{v_{b,t}^2}\right] = Q_{b+1,t}^L + \hat{q}_{b+1,t} \tag{2.3}$$

(2.2) states that the sum of the local real power generation $p^g_{b+1,t}$ on bus $b+1$ shown in Fig. 2.1 and the real power inflow $\hat{p}_{b,t}$ into bus $b+1$ from bus b less the loss due to the resistance of on the feeder connecting bus b to bus $b+1$ i.e. the third term of (2.2), is equal to the local real power demand $P^L_{b+1,t}$ and the real power outflow $\hat{p}_{b+1,t}$ from bus $b+1$ in time t. r_{b+1} and v_b are the resistance on the feeder connecting bus b to $b+1$ and the bus voltage respectively. The reactive power nodal balance equation similar to (2.2) is presented in (2.3). $\hat{q}_{b,t}$, $q^g_{b+1,t}$, x_{b+1}, $Q^L_{b+1,t}$, and $\hat{q}_{b+1,t}$ are the reactive power inflow from bus b to bus $b+1$, the local reactive power generation from NGDG connected to bus $b+1$, reactance on the feeder connecting bus b to $b+1$, the local reactive power demand, and the reactive power outflow from bus $b+1$. The third term of (2.3) is losses associated with the reactance of the feeder connecting bus b to bus $b+1$. The voltage magnitude at node $b+1$ as a function of the the magnitude of the sending node b and losses on the feeder is presented in (2.4).

$$v^2_{b+1,t} = v^2_{b,t} - 2(r_b\hat{p}_{b,t} + x_b\hat{q}_{b,t}) + \left(r^2_{b,t} + x^2_{b,t}\right)\frac{\hat{p}^2_{b,t} + \hat{q}^2_{b,t}}{v^2_{b,t}} \tag{2.4}$$

The total nodal active and reactive power generation is modeled in (2.5) and (2.6).

$$p^g_{b+1,t} = p^{g,e}_{b+1,t} + p^{g,n}_{b+1,t} + p^{g,s}_{b+1,t} \tag{2.5}$$

$$q^g_{b+1,t} = q^{g,e}_{b+1,t} + q^{g,n}_{b+1,t} + q^{g,s}_{b+1,t} + q^c_{b+1,t} \tag{2.6}$$

(2.5) states that at each bus the total real power generation in time t, $p^g_{b+1,t}$, at buse $b+1$ is equal to the sum of real power generation from existing generators, $p^{g,e}_{b+1,t}$, new NGDG, $p^{g,n}_{b+1,t}$, and power imported from the transmission system via substation, $p^{s,g}_{b,t}$. Similarly, (2.6) states that the total reactive power $q^g_{b+1,t}$ generated on bus $b+1$ is equal to the sum of reactive power generation from existing generators $q^{g,e}_{b+1,t}$, new NGDG, $q^{g,n}_{b+1,t}$, reactive power import from the transmission system substation $p^{g,s}_{b,t}$, and the reactive power generation from capacitor $p^c_{b+1,t}$. The radial network is assumed to have a single connection to the transmission system i.e. bus 0, therefore, $p^{g,s}_{b,t}$ and

$q_{b,t}^{g,s}$ are zero for other buses on the radial distribution network [49].

$$\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2 = |S_{b,t}|^2 \tag{2.7}$$

(2.7) states that the sum of the square of the real $\hat{p}_{b,t}^2$ and reactive power $\hat{q}_{b,t}^2$ flow is equal to the square of the absolute value of the complex power $S_{b,t}$ flow from bus b to bus $b+1$. Constraints (2.8)–(2.10) imposes capacity limits on the active and reactive power flow on feeder connecting bus b and $b+1$ and the bus voltages in time t.

$$\hat{p}_b^{min} \leq \hat{p}_{b,t} \leq \hat{p}_b^{max} \tag{2.8}$$

$$\hat{q}_b^{min} \leq \hat{q}_{b,t} \leq \hat{q}_{g_b}^{max} \tag{2.9}$$

$$v_b^{min} \leq v_{b,t} \leq v_b^{max} \tag{2.10}$$

$\hat{p}_b^{min}$ and $\hat{p}_b^{max}$ are the minimum and maximum limits on real power flow in the feeder connecting nodes b to $b+1$ respectively. Similarly, $\hat{q}_b^{min}$ and $\hat{q}_b^{max}$ are the minimum and maximum capacity limits on the reactive power flow in the feeder connecting nodes b to $b+1$ respectively. (2.10) ensures that the nodal voltage remain within acceptable limits. v_b^{min} and v_b^{max} are the maximum and minimum voltage limit at each bus b. These consequently limits the size of NGDG that can be installed on each bus. Constraints (2.11)–(2.13) ensure that the newly connected capacitors and the NGDGs are of the desired quantized sizes and types.

$$0 \leq p_{b,t}^{g,n} \leq \lambda_{b,t,\rho} PG^{\rho} \tag{2.11}$$

$$0 \leq q_{b,t}^{g,n} \leq \lambda_{b,t,\rho} QG_{\rho} \tag{2.12}$$

$$q_{b,t}^{c} = \pi_{b,t,\rho} QC_{\rho} \tag{2.13}$$

$\lambda_{b,t,\rho}$ is a binary variable i.e. $\lambda, \pi \in 0,1$ that represents NGDG type ρ with maximum real and reactive power generation capacity of PG_ρ and QG_ρ respectively. π is binary decision variable that represents capacitor types ρ with a size of QC_ρ. (2.14) ensures that the capacitors and NGDGs are not co-located on the same bus.

$$\lambda_b^\rho + \pi_b^\rho = 1 \tag{2.14}$$

The constraints (2.4) can be further simplified by eliminating the quadratic terms that represent the losses on the branches. Power losses in the feeder are typically much smaller than the power flow in the feeder. (2.2), (2.3) and (2.4) are rewritten as (2.15a), (2.15b), and (2.15c) [48].

$$p^g_{b+1,t} + \hat{p}_{b,t} = P^L_{b+1,t} + \hat{p}_{b+1,t} \tag{2.15a}$$

$$q^g_{b+1,t} + \hat{q}_{b,t} = Q^L_{b+1,t} + \hat{q}_{b+1,t} \tag{2.15b}$$

$$v^2_{b+1} = v^2_b - 2(r_b\hat{p}_b + x_b\hat{q}_b) \tag{2.15c}$$

2.2.2 Electricity and natural gas coupling constraints

The peak annual NG demand $D^e_{i,t}$ required by the NGDG as a function of the complex peak electric power generation $S^g_{b,t}$ injected into the electricity distribution system assuming a constant non-electricity NG demand is modeled as (2.16) [19]. (2.16) relaxes the electricity -NG coupling equality constraint which is non-convex [6]. The electricity buses b are assumed to be co-located with non-NG source nodes i. a_i, b_i, and c_i are the gas fuel rate coefficients for converting electricity to NG demand [37].

$$D^e_{i,t} \geq a_i + b_i S^g_{b,t} + c_i (S^g_{b,t})^2 \tag{2.16}$$

2.2.3 Physical and operational constraints on Natural gas distribution

NG distribution systems are typically networks of small-diameter (12.7–152.4 mm) pipes that transport NG at low pressure (0.14–13.8 bar) [15]. These pipes are required to transport NG from the NG source to the NG demand nodes. The constraints that inhibit the seamless flow of NG in the distribution pipes [50] are discussed next. Constraint (2.17) ensures that the NG pressure $\Gamma_{i,t}$

at the start of time t is equal to the maximum pressure Γ_i^{max} for all set of NG source nodes Ω_s.

$$\Gamma_{i,t} = \Gamma_i^{max} \qquad \forall i \in \Omega_s \tag{2.17}$$

$$\Gamma_i^{min} \leq \Gamma_{i,t} \leq \Gamma_i^{max} \qquad \forall i \notin \Omega_d \tag{2.18}$$

Constraint (2.18) ensures that the NG pressures are within limits to NG pressure acceptable for seamless operation of the NGDGs for all sets of NG demand nodes Ω_d. $\Gamma_{i,t}$ and $\Gamma_{j,t}$ are the pressures at the source i and demand j nodes of pipe $y_{i,j}$ in time t. Constraint (2.19) limits the NG flow in the NG distribution system. $B_{i,j,t}$ in is a binary decision variable that is 1 when NG flows between nodes i and j in year t and zero otherwise. Since the NG flow rate $Q_{i,j,t}$ between nodes i and j is usually greater than 1, a large value $M_{1,t}$ set to the maximum NG flow in the network is used to limit $Q_{i,j,t}$ in each pipeline [50].

$$Q_{i,j,t} \leq M_{1t} B_{i,j,t} \tag{2.19}$$

$$S_{i,t} + \sum_{j}^{\Omega_p} Q_{j,i,t} = \sum_{j}^{\Omega_p} Q_{i,j,t} + D_{i,t}^{e} \tag{2.20}$$

Constraints (2.20) ensures that the difference between the NG inflow and outflow at nodes i is equal to the local NG demand for electricity generation $D_{i,t}^{e}$. $S_{i,t}$ indicates NG source, Ω_p is the set of all pipes. NG demands for non-electricity generation purposes are assumed to be constant. This assumption is practical since the NG demand for other purposes such as heat generation and industrial processes are more predictable. Constraints (2.21), (2.22) and (2.23) enforce the general steady-state flow in a gas pipeline assuming isothermal flow through a horizontal pipeline segment with pipeline length such that the effect of kinetic energy is negligible [51].

$$(\Gamma_{i,t}^2 - \Gamma_{j,t}^2) - \Psi_{ij} Q_{i,j,t}^2 \geq M_2 (B_{i,j,t} - 1) \tag{2.21}$$

$$(\Gamma_{i,t}^2 - \Gamma_{j,t}^2) - \Psi_{ij} Q_{i,j,t}^2 \leq M_2 (1 - B_{i,j,t}) \tag{2.22}$$

$$\Psi_{i,j} = \left(\frac{1}{1.1494 \times 10^{-3}}\right)^2 \frac{GT_f L_{ij} Zf}{\Delta_{ij}^5} \left(\frac{\Gamma_b}{T_b}\right)^2 \tag{2.23}$$

The pressure drop between NG nodes i and j at the start of year t is equal to the product of the flow rate $Q_{i,j,t}$ and the pipeline resistance $\Psi_{i,j}$. (2.21) and (2.22) are formulated such that they limit the peak NG pressure drop between nodes i and j. When NG is flowing between nodes i and j, $B_{ijt} = 1$. This sets the right-hand sides of (2.21) and (2.22) to zero. M_2 is set to a large value close to P_{max}^2 to ensure a zero pressure drop between nodes i and j when $B_{ijt} = 0$. Constraints (2.21) and (2.22) also ensure that NG flows from the higher pressure node to the lower pressure node. The pipeline resistance $\Psi_{i,j}$ is defined in (2.23). $\Delta_{ij}(inch)$, $L_{i,j}(mile)$ are the diameter and the length of the pipe respectively. The frictional factor f, the base pressure Γ_b, the base temperature T_b, the NG gravity G, the gas compressibility factor Z, and the flow temperature T_f are taken to be 0.01, 1 bar, 288^oK, 0.66, 0.805, and 283^oK respectively. Constraint (2.24) ensures the existence of an NG pipe when there is NG flow across nodes i and j at the start year t [50]. Constraint (2.25) states that $B_{i,j,t}$ and $y_{i,j,t}$ are binary decision variables.

$$B_{i,j,t} + B_{j,i,t} \leq y_{ijt} \tag{2.24}$$

$$B_{i,j,t}, y_{j,i,t} \in 0,1 \tag{2.25}$$

Constraints (2.26) ensures that a built pipeline is available for the entire planning period.

$$y_{i,j,t} \leq y_{i,j,t+1} \qquad \forall i < j \tag{2.26}$$

$$y_{ij0} = 0 \qquad \forall i < j \tag{2.27}$$

$$\Gamma_{i,t}^2, Q_{i,j,t} \geq 0 \tag{2.28}$$

Constraint (2.27) models the nonexistence of pipeline(s) between nodes i and j at the beginning of the planning horizon. Constraint (2.28) ensures that the flow rate and the square of the nodal pressure are nonnegative.

The NG distribution pressure drop model is nonlinear: (2.21) and (2.22) contain Γ^2 and Q^2. We replace Γ^2 with Θ to linearize the formulation in terms of the pressure variables, and we replace $\Gamma_i^{max}, \Gamma_i^{min}$ with their squares. As a result, (2.18), (2.21), (2.22) become (2.29a)–(2.29c):

$$\Gamma_i^{min^2} \leq \Theta_{i,t} \leq \Gamma_{it}^{max^2} \tag{2.29a}$$

$$(\Theta_{i,t} - \Theta_{j,t}) - \Psi_{ij} Q_{i,j,t}^2 \geq M_2(B_{i,j,t} - 1) \tag{2.29b}$$

$$(\Theta_{i,t} - \Theta_{j,t}) - \Psi_{ij} Q_{i,j,t}^2 \leq M_2(1 - B_{i,j,t}) \tag{2.29c}$$

The overall formulation remains nonlinear and non-convex because of the flow variable $Q_{i,j,t}^2$. However, [6] has shown that 2.29*b* and 2.29*c* are very often tight in practice for expansion planning problem. In addition, the branch and bound method has been shown to provide acceptable solutions to Mixed Integer Nonlinear Programming (MINLP) problems with non-convex functions such as (2.29b) and (2.29c) [52]. The pipeline layout model differs from the model in [19] because it is formulated as an MINLP pipeline length minimization problem. It also differs from [45] where NG pipelines were assumed to exist, forming constraints of the model. The uncertainty in the total NG demand is assumed to depend only on the uncertainty associated with the NG demand for electricity generation.

2.2.4 Chance constrained formulation of the integrated problem

The CCP approach to solving the planning problem ensures that the expansion plan computed satisfies the constraint with an uncertain variable with the desired level of reliability called the confidence level. In this case, the constraint with the uncertain variable is the nodal balance equations 2.2 and 2.3 and the uncertain parameter is the nodal electricity demand. We formulate the CCP equivalent of the NGDG and capacitor bank sizing and location problem in the presence of uncertain electric demand by replacing the flow conservation equations in (2.2) and (2.3) with the

complex power CCP equivalent in (2.30).

$$Pr\big[\bigcap_{i}\big(S^{g}_{b+1,t}+\hat{S}_{b,t}-\hat{S}_{b+1,t}\geq S^{L}_{b+1,t}\big)\big]\geq\alpha \tag{2.30a}$$

$$\hat{S}_{b/b+1,t}=\hat{p}_{b/b+1,t}+j\hat{q}_{b/b+1,t} \tag{2.30b}$$

$$S^{L}_{b+1,t}=P^{L}_{b+1,t}+jQ^{L}_{b+1,t} \tag{2.30c}$$

Constraint (2.30a) states that the probability that the sum of the local complex power generation, $S^{g}_{b+1,t}$, at bus $b+1$ and complex power inflow $\hat{S}_{b,t}$ from bus b to $b+1$ less complex power outflow $\hat{S}_{b+1,t}$ from bus $b+1$ is greater than the local complex power demand, S^{L}_{Lbt}, with the desired reliability level α. The electricity demand is assumed to follow a Gaussian distribution based on the Central limit theorem and the fact that a non-Gaussian data set could be transformed into Gaussian dataset [53]. Therefore, constraint (2.30a) can be replaced with (2.31), where $\mu^{S^L}_{b,t}$ and $\sigma^{S^L}_{b,t}$ are the mean and standard deviation of the nodal complex electricity demand respectively [17].

$$S^{g}_{b+1,t}+\hat{S}_{b,t}-\hat{S}_{b+1,t}=\mu^{S_L}_{b+1,t}+\sigma^{S_L}_{b+1,t}Z_{\alpha} \tag{2.31}$$

where Z_α is the inverse cumulative distribution of $[1-\frac{1-\alpha}{nb}]$ i.e. $Z_\alpha = \phi^{-1}[1-\frac{1-\alpha}{nb}]$. nb is the number of buses. The CCP solution algorithm is explained in the next section.

2.3 Solution methodology

Solving (2.1) subject to the constraints discussed above is a very challenging problem. Therefore we employ a sequential solution approach. A similar approach has been adopted for solving an integrated planning problem at the transmission level [5]. In the sequential approach, we assumed the non-electricity NG demand is known and certain. Therefore, the uncertainties in NG demand are positively correlated to the uncertainty in electricity demand. In consequence to this, the uncertainty in NG demand is resolved once the uncertainty in electricity demand is resolved. This assumption allows us to, therefore, solve the NGDG location and sizing problem first, then using the coupling constraint determine the peak NG demand. The computed NG demand then serves

as the input into the NG distribution route-planning problem. The algorithm for the sequential approach is presented in Fig. 2.2.

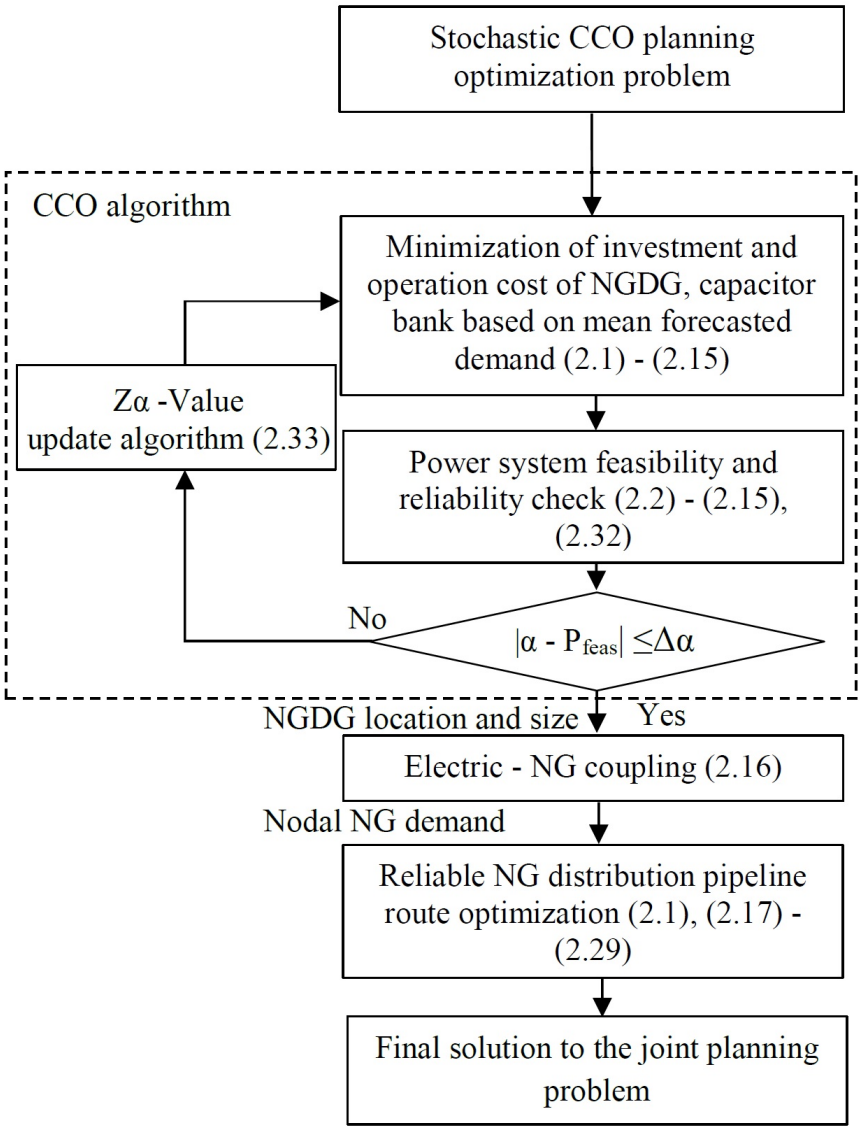


Figure 2.2: Algorithm for sequential integrated planning model.

2.3.1 The chance constrained programming algorithm

The algorithm for the CCP is presented in Fig. 2.2. The CCP algorithm constitutes of a deterministic capital and operational cost minimization component, the power system operational feasibility check component and the $Z-update$ algorithm.

2.3.1.1 The deterministic capital and operation cost minimization expansion problem

In the deterministic model the planning problem is solved for an instance of electricity demand. The output of the deterministic problem is the location and size of the generator and capacity bank that ensure a non-violation of the physical and operational constraints of the electricity network.

2.3.1.2 The power system operational feasibility check

The preferred expansion plan is one that ensures the non-violation of the power system physical and operational constraint with a reliability level of α [43]. Therefore, the deterministic expansion plan is subject to an operation feasibility check i.e. the Optimal Power Flow (OPF) for N_{times} demand scenarios [54]. The objective function (2.32) is the integrated planning objective function without the investment cost. The output of each OPF computation is either feasibility or non-feasibility.

$$min \quad z = \sum_{t}^{T} \sum_{b}^{\Omega_b} p_{b,t}^{g} C^{g,O} \tag{2.32}$$

The OPF determines the feasibility of the expansion plan for each of the demand scenarios. The reliability level P_{feas} of an expansion plan is computed by dividing the sum of the feasible cases by the total number of cases. If P_{feas}, is greater, equal or slightly less than the desired reliability level with an acceptable tolerance level $\triangle\alpha$, the plan is optimal. Otherwise, the demand profile is updated by updating the $Z - value$ values using the algorithm below.

2.3.1.3 Z-value Updating algorithm

The $Z - value$ is updated using Equation (2.33) [43]. In essence, the Z-value update updates the load profile of the system.

$$Z_{\alpha}^{i} = Z^{Lo} + \left[\frac{Z_{\alpha} - Z_2}{Z_1 - Z_2}\left(Z^{Hi} - Z^{Lo}\right)\right] \tag{2.33}$$

Two initial reference reliability levels above and below the desired reliability level α are selected. Z^{Hi} and Z^{Lo} are the inverse distribution of the selected higher P_h and lower P_l reliability level. Z_1 and Z_2 are the updated inverse distribution when the OPF is solved for N_{times} demand scenario for each of Z^{Hi} and Z^{Lo} reliability levels. Z_{α} is the Z value equivalent of the desired probability. Z_1

and Z_2 are updated iteratively until $|\alpha - P_{feas}| \leq \triangle\alpha$ holds. $\triangle\alpha$ is a small tolerance allowed in the target probability. The details of the updating algorithm are presented in [17].

2.4 Results for test system

We illustrate the model presented using a modified nine bus distribution radial system shown in Fig. 2.3 [55] for a planning horizon of ten years. The choice of the simple test system is to allow easy tractability. The network is connected to the grid via a distribution substation located at bus 0. Buses 1 to 9 are load buses pending the integration of NGDGs. A similar configuration was employed in [37]. We assume that the transmission system and the substation expansion are outside the planning scope of the distribution utility. This is a realistic assumption in unbundled electricity systems where the planning of the transmission and distribution systems is done separately.

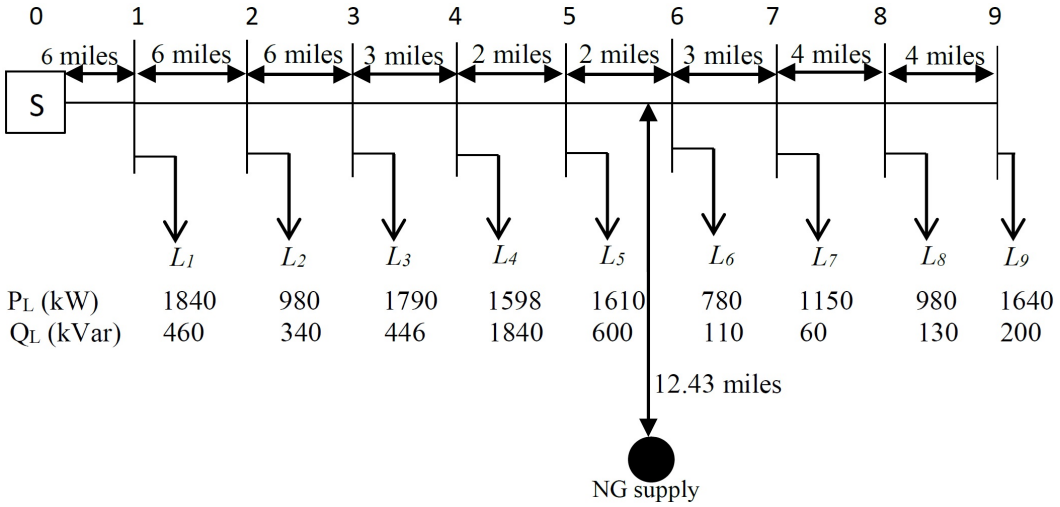


Figure 2.3: Radial distribution network with peak and average demands.

The uncertain electricity demand is assumed to follow a Gaussian distribution. The relationship between the mean μ^{SL} and the standard deviation σ^{S_L} is given as $3\mu^{SL} = 0.25\sigma^{S_L}$ [17]. It is important to note that the net demand at a bus with NGDG could be negative i.e. the bus is a net exporter of power. The mean demands μ^{S_L} are shown in Fig. 2.3. NGDGs and capacitor banks are usually manufactured in discrete sizes. As such, the set of NGDG and capacitor banks employed for this illustration and their associated capital cost is presented in Table 2.1 [55,56] .

Table 2.1: Sizes and costs of capacitors and NGDGs

	Capacitor						NGDG	
Type (ρ/ρ)	1	2	3	4	5	6	1	2
Size (KVar/KVA)	150	300	450	600	900	1200	1000	2000
Cost ($000s)	0.750	0.975	1.140	1.320	1.650	2.040	1,200	2,000

The minimum acceptable NG pressure at each of the NG demand nodes is taken to be 6 bar. This is the minimum NG pressure required by typical 1 MW and 2 MW microturbine NGDGs [57]. The NG pressure at the NG source is set to 13.8 bar, which is the maximum allowable pressure at the NG distribution level in Canada [15]. The annual electrical load growth is assumed to be 3% [58]. The pipelines and NGDGs are assumed to be under the jurisdiction of a single utility company. This is a common occurrence, for example, the ATCO Group, a global energy corporation, has both electricity and NG distribution infrastructure and operations [59]. This assumption puts the integrated approach to planning in context. The expected pipeline repair time (ς) in the event of a failure is assumed to be 48 h, and the annual pipeline failure rate (τ_p) is taken to be $0.2/year.thousand\ miles$ [47]. The cost of a new pipeline is set to \$100,000/inch-mile [60].

In the CCP algorithm, the OPF is solved for 1000 scenarios of complex electricity demand pairs. The scenarios are generated via Monte Carlo Simulation. We use the Branch-and-Reduce Optimization Navigator solver (BARON) [61] available in GAMS 24.2 [62].

The computed NGDG location and sizes required in year with and without the inclusion of capacitor bank sizing and location optimization in the expansion model is represented in Table 2.2.

As expected the inclusion of capacitor sizing and location optimization in the expansion planning problem results in a reduction in the apparent power demand from the NGDG. This is because the integration of capacitor banks reduces the reactive power demand from the NGDGs. This translates to an overall reduction in the capital and operational cost of the entire system. In addition, fewer NGDGs also means fewer NG pipelines are required. For example, as shown in Table 2.2 there is no need to construct NG pipelines for nodes 2, 3, and 6 in year one. The inclusion of

Table 2.2: Optimal location and size of NGDGs and capacitors in year one

	Without capacitor planning		With capacitor planning		
Bus No./ facility location	power generation capacity (KVA)	Reactive power generation (KVAr)	power generation capacity (KVA)	Reactive power generation (KVAr)	Capacitor size (KVAr)
0	1440	-200	1440	0	0
1	1000[a]	489	2000[b]	51	0
2	1000[a]	206	0	0	0
3	1000[a]	1000	0	0	1200[c]
4	2000[b]	2000	2000[b]	112	0
5	2000[b]	704	4000[b]	-400	0
6	1000[a]	-200	0	0	2400[c]
7	1000[a]	748	1000[a]	100	0
8	1000[a]	179	1000[a]	350	0
9	2000[b]	-200	1000[a]	688	
Total	12,000 KVA		11,000 KVA		3600 KVAr
Total investment cost	US$ 13,200,000		US$11,606,120		

[a] 1000 KVA NGDG. [b] 2000 KVA NGDG. [c] Type 6 capacitor

capacitor planning in the system planning ensures that NGDGs are not operated in overexcited or under excited states as required for system stability. This also ensures that the maintenance costs of the NGDGs are within a manageable range

Table 2.3 shows the location and sizes of the NGDGs and capacitor banks for a reliability level of 96% in year one of the planning period when the uncertainties associated with electricity demand are accommodated. In comparison with the previous solution, the size of the NGDGs is 2000 KVA lower. This is because the NGDG locations are optimized to satisfy varying electricity demands. There was also an increase in the capacitor size since the NGDGs meet real rather than reactive power demand.

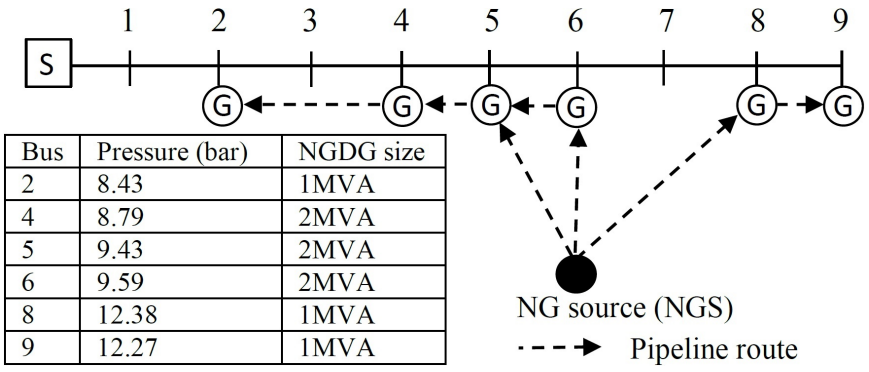
Fig. 2.4 shows the cheapest pipeline route for transporting NG to the NGDGs in year one of the planning period when pipeline layout reliability is not considered.

The pipeline layout with the shortest length is selected when the cost of losing a pipeline is not accommodated in the expansion model. Although the layout ensures that NG is delivered within the acceptable pressure range, the outages of some pipes such as $y_{4,5}$ will result in the

Table 2.3: Optimal location and size of NGDGs and capacitors considering active and reactive power uncertainty in year one

Bus No/ facility location	complex power generation (KVA)	Reactive power generation (KVAr)	Capacitor size (KVAr)
0	1440	0	0
1	0	0	0
2	1000[a]	145.4	1200[d]
3	0	0	0
4	2000[b]	35	0
5	2000[b]	980.3	0
6	2000[b]	200	0
7	0	0	1200[d],450[c]
8	1000[a]	282.7	0
9	1000[a]	131.3	0
Total size (KVA)	9000KVA		2850Kvar

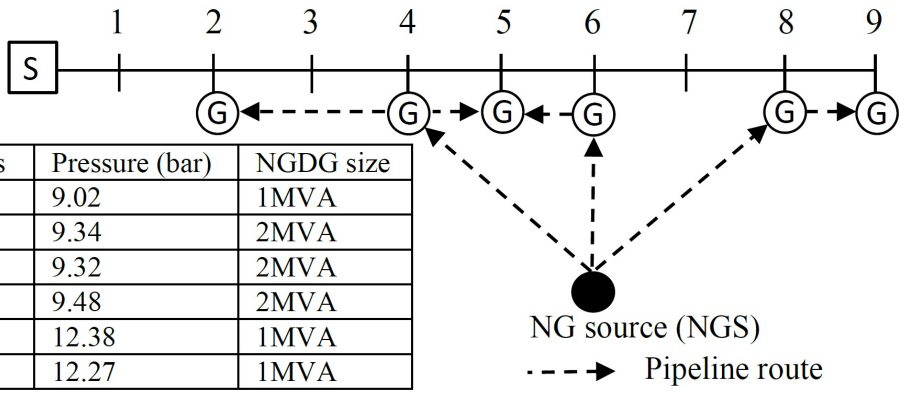
[a] 1000 KVA NGDG. [b] 2000 KVA NGDG. [c] Type 3 capacitor. [d] Type 6 capacitor



Bus	Pressure (bar)	NGDG size
2	8.43	1MVA
4	8.79	2MVA
5	9.43	2MVA
6	9.59	2MVA
8	12.38	1MVA
9	12.27	1MVA

Figure 2.4: NG pipe layout for year one without reliability considerations.

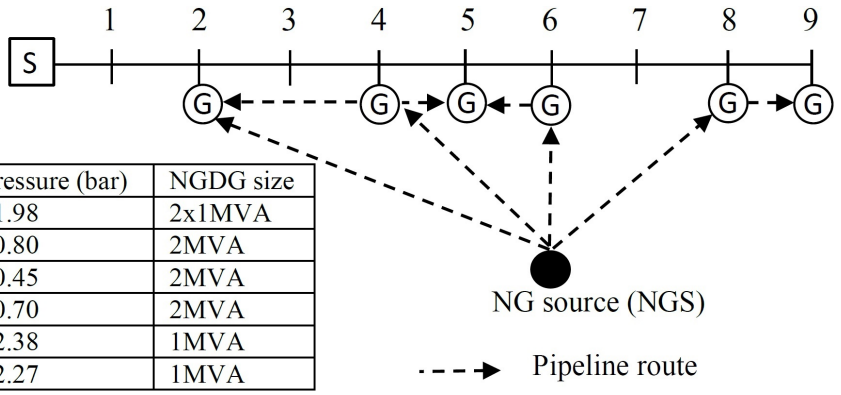
loss of 3000KVA amount of generation. A more reliable layout is presented in Fig. 2.5. Since the reliability cost is a function of the NG flow rate, a lower flow rate is desired to reduce the reliability cost in the event of an outage to any section of the pipeline. Greater reliability usually corresponds to an increase in the capital cost. This is evident in the plan shown in Fig. 2.5 where the pipe $y_{NGS,5}$ is replaced with a longer pipe $y_{NGS,4}$. This increase is justified by the increase in reliability associated with the ring pipeline layout around the combined 6000-KVA NGDGs located at nodes four, five, and six. This layout is, however, less reliable and cheaper than a potential layout where each NG demand node is connected separately to the source and possibly ringed.



Bus	Pressure (bar)	NGDG size
2	9.02	1MVA
4	9.34	2MVA
5	9.32	2MVA
6	9.48	2MVA
8	12.38	1MVA
9	12.27	1MVA

Figure 2.5: NG pipe layout for year 1 with reliability considerations.

Figure 2.6 shows the NGDGs and pipeline required to meet the demand in year four. A 1-MVA NGDG is added to bus two and pipe $y_{NGS,2}$ is required to transport NG to node two. This reduces the flow rate in $y_{NGS,4}$ and $y_{NGS,6}$, and consequently the pressure gradient between NGS and nodes four, five, and six is reduced. This layout assumes that the layout of Fig. 2.5 is built in year one.



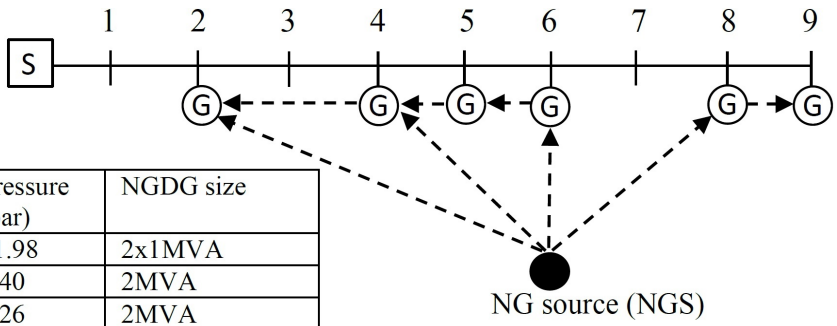
Bus	Pressure (bar)	NGDG size
2	11.98	2x1MVA
4	10.80	2MVA
5	10.45	2MVA
6	10.70	2MVA
8	12.38	1MVA
9	12.27	1MVA

Figure 2.6: NG pipe layout for year 4 with reliability considerations.

Fig. 2.7 shows the NGDGs and pipeline required to meet the demand in year 7. An additional 1-MVA NGDG is proposed for bus 6; the existing pipeline is capable of supplying NG within the acceptable pressure range at nodes four, five, and six.

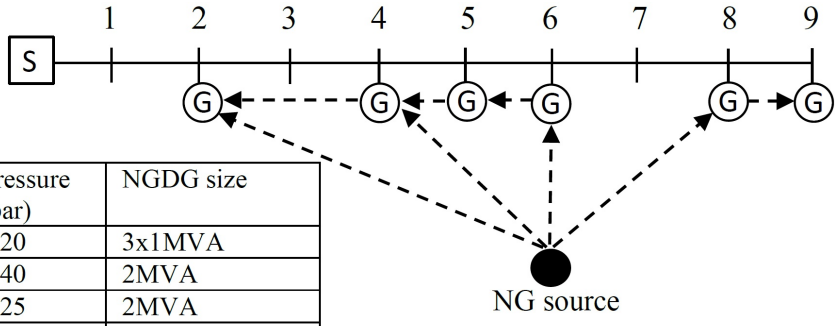
Fig. 2.8 shows the NGDGs and pipeline required to meet the demand in year 9.

The optimal layout remains the same because the pressure constraint is not violated by the addition of a 1-MVA NGDG to bus 2. There is, however, an increase in the pressure gradient between NGS and node 2; this is expected because of the increase the NG flow rate. Over the plan-



Bus	Pressure (bar)	NGDG size
2	11.98	2x1MVA
4	9.40	2MVA
5	9.26	2MVA
6	9.42	1MVA, 2MVA
8	12.37	1MVA
9	12.27	1MVA

Figure 2.7: NG pipe layout for year 7 with reliability considerations.



Bus	Pressure (bar)	NGDG size
2	9.20	3x1MVA
4	9.40	2MVA
5	9.25	2MVA
6	9.42	1MVA, 2MVA
8	12.37	1MVA
9	12.27	1MVA

Figure 2.8: NG pipe layout for year 9 with reliability considerations.

ning period, the NGDG integration at bus 2 has increased from 1 MVA to 3 MVA, indicating the scalability of NGDGs. This ability to add NGDGs when necessary helps to reduce the investment and operating costs.

We are aware of the limitation of the staged expansion solution presented especially in the developed world where issues related to the logistic of continuous construction, right of way, public convenience could be a source of challenge. The staged solution methodology presented is, however, suitable for developing where the foremost goal is to increase access to reliable electricity supply in the presence of limited capital.

Since there is a relationship between the size of NGDG integration and system reliability, we carried out a sensitivity analysis of the NGDG integration requirement and desired reliability level.

Fig. 2.9 shows the NGDGs required to achieve reliability levels of 96%, 97%, and 98%.

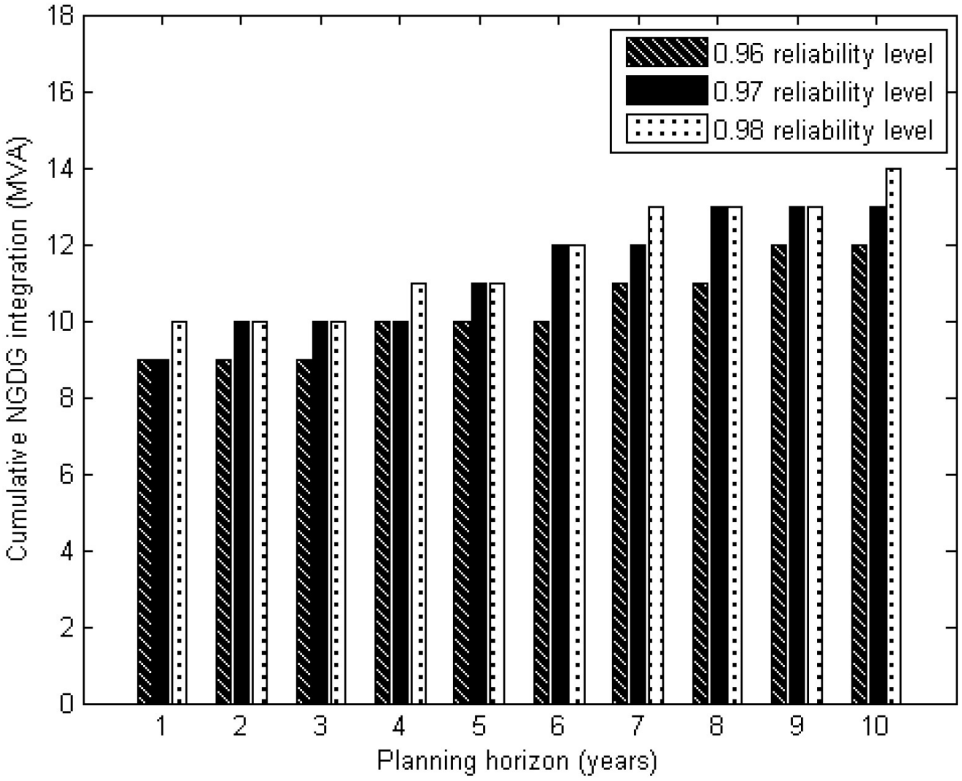


Figure 2.9: NGDG location and sizing for selected reliability levels.

As expected, more NGDGs need to be integrated to ensure increased reliability levels across the planning horizon. The sensitivity of the NGDG integration to the desired system reliability varies in each year of the planning horizon. This is because the candidate NGDGs are of quantized sizes thereby resulting in varying utilization levels across the planning horizon. The CCP based sensitivity analysis is very valuable for utility planner in determining the cost associated with a reliability policy as related to future expansion plans.

2.4.1 Limitation of the sequential solution approach

A potential limitation of the sequential approach to the long-term planning of both systems may not result in a global optimum solution because the solution to the first problem i.e. the optimal sitting and sizing NGDG, is a constraint on the solution of the second problem i.e. the optimal route plan of the NG distribution system.

2.5 Conclusion

This paper presents a reliability based sequential approach to the long-term planning of Natural Gas (NG) distribution system and Natural Gas Distributed power Generators (NGDGs). We ensured the expansion plan meets a desired reliability level by first minimizing the investment cost of the integrating NGDGs in the presence of uncertain electricity demand. This is then followed by the minimization of the investment cost and reliability cost of the NG distribution system. By accommodating the uncertainties of electric power demand, the expansion plan results in a 2000KVA reduction in the size of NGDGs required to ensure 96% reliability in the electric system. On the other hand, the minimization of the outage cost of the NG distribution system results in a 0.56-mile increase in NG pipeline. The longer pipelines, however, results in an increase in the nodal natural gas pressure, a reduction in the natural gas flow rate in each segment of the pipe and consequently increase the reliability of the NG distribution system.

An analysis of the sensitivity of the long-term plan to 96%, 97%, and 98% reliability levels was carried out. Although the required NGDG integration increases with the desired system reliability, its sensitivity to the reliability levels differs across the planning horizon. This is because the quantized NGDG sizes installed provides idle capacity thereby reducing the sensitivity of the expansion plan to the change in the desired reliability levels. The solution presented in this paper provides the basis for further research work on the planning of NG distribution systems and NGDGs.

Chapter 3

A chance constrained programming approach to integrated planning of distributed power generation and natural gas network [1]

The growing integration of distributed electric power generators means the reliability of electricity distribution systems will increasingly depend on the reliability of primary energy resources such as natural gas supply for natural gas-fired distributed power generation. This, therefore, necessitates an integrated approach for planning both the electricity and natural gas distribution systems for the purpose of ensuring reliable natural gas supply for electricity generation. We propose a probabilistic planning approach based on the chance constrained programming method for planning these two systems in the presence of uncertain real and reactive power demand. The proposed model minimizes the investment cost of gas-fired generators, natural gas pipeline and the operation cost of the natural gas-fired distributed generators over a long-term planning horizon. The proposed integrated planning approach is used to develop a 10 years long-term plan for 9 and 33 bus distribution systems. The result shows that the integrated planning approach results in a cheaper and more reliable system in comparison with a traditional sequential planning approach.

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3.1 Nomenclature

A. Abbreviation

NG	Natural Gas
NGDG	Natural Gas-fired Distributed power Generator
CCP	Chance Constrained Programming

B. Identifier

k	Identifier for lateral feeders $k = 0, 1, ...K$

C. Indices

b	Index of electricity bus, $b = 0, 1, ...B$
t	Index of planning time horizon, $t = 0, 1, ...T$
i, j	Index of source and sink NG nodes associated with a pipeline segment
ρ	Index of quantized NGDG sizes
ρ	Index of quantized capacitor bank sizes

D. Binary Variables

$\lambda_{\rho,b,t}$	1 if a new NGDG size ρ is connected to bus b in time t. 0 otherwise
$\pi_{\rho,b,t}$	1 if a new capacitor bank size ρ is connected to bus b in time t. 0 otherwise
y_{ijt}	1 if a pipeline y is installed between NG nodes i, j in time t. 0 otherwise
B_{ijt}	1 if NG flow from NG node i to j in time t. 0 otherwise

E. Random Variables

ξ_1	Uncertain real electric power demand forecast
ξ_2	Uncertain reactive electric power demand forecast

F. Variables

$P_{b,t}$	Real electric power generation connected to bus b in time t
$P_{b,t}^{(e)}$	Real power generation from existing (e) generators connected to bus b in time t

Variables continued

$P_{b,t}^{(n)}$	Real power generation from new (n) NGDGs connected to bus b in time t
$P_{b,t}^{(ip)}$	Real power imported (ip) from the transmission grid via bus b in time t
$Q_{b,t}$	Reactive electric power generation connected to bus b in time t
$Q_{b,t}^{(e)}$	Reactive power generation from existing (e) generators connected to bus b in time t
$Q_{b,t}^{(n)}$	Reactive power generation from new (n) NGDG connected to bus b in time t
$Q_{b,t}^{(ip)}$	Reactive power imported (ip) from the transmission grid via bus b in time t
$Q_{b,t}^{(c)}$	Reactive power generation from capacitor bank (c) connected to bus b in time t
$\Phi_{i,j,t}$	NG flow-rate in the pipe connecting nodes i and j in time t
$\Psi_{i,j}$	The pipeline resistance of the pipe connecting NG nodes i and j
$v_{b,t}$	Bus voltage in time t
$\hat{p}_{b,t}$	Real power flow from sending node b between buses b and $b+1$ in time t
$\hat{q}_{b,t}$	Reactive power flow from sending node b between buses b and $b+1$ in time t
$\hat{s}_{b,t}$	complex power flow between buses b and $b+1$ in time t
δ_t	Annuity payment
$\Gamma_{i,t}$	NG pressure at the source NG node i in time t
$\Gamma_{j,t}$	NG pressure at the sink NG node j in time t
$\Theta_{i,t}$	Square of the NG pressure at source node i in time t
$\Theta_{j,t}$	Square of the nodal NG pressure at sink node j in time t

F Parameters

$C_{\rho}^{(I)}$	Present value of the overnight investment (I) cost of installing NGDG of size ρ
$C_{\rho}^{(I)}$	Present value of the overnight investment (I) cost of installing capacitor bank of size ρ
$C^{(I)}$	Present value of the overnight investment (I) cost of building a pipe of type y
$C^{(o)}$	Operating (o) cost i.e. fixed and variable cost of embedded electric power generation

Parameters continued

$C^{(ip)}$	Cost of importing (ip) electricity from the electric transmission grid
$L_{i,j}$	Length of existing and candidate pipe connecting NG nodes i and j
$\Delta_{i,j}$	Diameter of existing and candidate pipe connecting NG nodes i and j
F_r	Annual failure rates of each segment of pipeline per miles
τ	Cost of repairing a segment of the pipeline
OC	Outage cost of a segment of the pipeline
ς	Average outage duration of a segment of the pipeline
ir	Interest rate %
x_b	Reactance of the feeder connecting bus b to $b+1$
r_b	Resistance of the feeder connecting bus b to $b+1$
$P_{b,t}^{(L)}$	Peak local real power demand at bus b in time t
$Q_{b,t}^{(L)}$	Peak local reactive power demand at bus b in time t
$\underline{\hat{S}_b}$	Lower limit on the complex power flow in the distribution feeder b
$\overline{\hat{S}_b}$	Upper limits on the power flow in the distribution feeder b
$\underline{V_b}$	Lower limit on the bus b voltage
$\overline{V_b}$	Upper limit on the bus b voltage
PG_ρ	Real power nameplate capacity of generator ρ
QG_ρ	Reactive power nameplate capacity of generator ρ
QC_ρ	Nameplate capacity of capacity bank ρ
a_i,b_i, c_i	The gas fuel rates coefficients of the NG-fired generators
$M_{1,t}$	Maximum total possible NG flow-rate in any section of the pipeline in time t
M_2	Maximum possible pressure difference between two nodes
$\underline{\Gamma_i}$	Lower limit on the nodal pressure at source nodes i
$\overline{\Gamma_i}$	Upper limit on the nodal pressure at source nodes i

Parameters continued

$S_{i,t}$	NG supply from NG source node i in time t
$D_{i,t}$	NG demand at node i in time t

G. Chance constraint parameters

α	Desired confidence level of satisfying the uncertain real electric power demand
β	Desired confidence level of satisfying the uncertain reactive electric power demand

H. Sets

Ω_B	Set of electricity buses, indexed by (b,r)
Ω_p	Set of NG distribution pipes, indexed by (i,j)
Ω_ρ	Set of quantized NGDG sizes
Ω_ρ	Set of quantized capacitor bank sizes
Ω_d	Set of NG demand nodes
Ω_s	Set of supply nodes

3.2 Introduction

Natural Gas (NG) fired power generators are expected to serve as a bridging technology in the energy transition from fossil fuels to renewables. This is because Natural Gas-fired Distributed power Generators (NGDG) are flexible with relatively high efficiencies and a competitive investment and operating cost [63]. In consequence to this, the rate at which NG-fired generators are installed continue to increase worldwide. This trend is further encouraged by the availability of cheap NG supply.

By 2020, 42% of new NG-fired generators are expected to be Natural Gas-fired Distributed power Generators (NGDGs) [7]. Typically, NGDGs have relatively short installation time and are usually scalable due to their modularity characteristics. In addition, recent advancements in NGDG technologies have made them competitive cost-wise making them a viable solution for bridging the gap between electricity demand and supply, especially in developing regions [7] where

access to funds, weak physical infrastructure, and market inefficiencies remain a challenge [8]. Examples of NGDGs include reciprocating engines, fuel cells, gas turbines, and microturbines that are connected to the electric power distribution grid.

The efficient utilization of NGDGs depends on the reliability and availability of sufficient NG supply thereby motivating an increased interest in the adoption of integrated planning approach to planning the electric and NG distribution system. Integrated planning of the NG transportation and the electric systems can be broadly divided into operations planning [38, 64–66] and investment planning [4, 19, 21, 39, 67–70]. The objective of operations planning is to ensure the reliability of NG supply for the purpose of meeting the varying electricity demand in the short-term. Investment planning, on the other hand, ensures the availability of adequate infrastructure for reliable long-term energy supply. Long-term planning models can be further classified into integrated transmission [4, 38, 39, 67] and distribution [19, 21, 39] system planning.

Transmission systems planning entails planning at higher electric voltages and NG pressure while the distribution system planning concentrates on planning for NG and electric power transportation at lower pressure and voltages respectively. From a modeling perspective, reactive power is of lesser importance in transmission system planning [38, 39, 67]. However, in the electric power distribution system, real and reactive power plays a significant role in maintaining the bus voltages [19]. NG distribution systems are usually void of compressors, typically resulting in pressure drops across the pipeline segments. Consequently, distribution pipelines must be planned to ensure the NG nodal pressures remain within acceptable limits.

The integrated planning of NG distribution systems and NGDGs is further complicated by the uncertainty of the electricity demand. These uncertainties affects the reliability of both systems considering the cascaded relationship between them. Building a reliable cascaded system can be challenging especially in the presence of budgetary constraints. In consequence to this, a probabilistic planning approach that allows a planner to assess investment cost in terms of reliability levels is of immense benefit. Chance Constrained Programming (CCP), a probabilistic optimization

tool, has been shown to be effective in the development of plans that ensure a prior set confidence or reliability level [42]. This is also useful in developing environments, where planners are likely to adopt an incremental approach toward energy supply and system reliability. System reliability is the adequacy or the level of confidence by which electric power demand is supplied.

The CCP has successfully been used to develop long-term expansion plans in power systems. In [71] and [72] CCP was applied to the power generation expansion problem and optimal power flow problem in the presence of uncertain electric power demand. A CCP approach to reactive power planning in the presence of uncertain economic development, and environmental regulations was presented in [73]. Reference [74] proposed a CCP approach to transmission expansion planning in the presence of the uncertain location and size of new power plants and electricity demand. [75] and [76] proposed a CCP model for optimally siting and sizing distributed generators in the presence of uncertain electricity prices, power output from renewable energy resources and future electric power demand growth.

A hybrid of heuristic and analytical approach for solving the integrated distribution expansion problem was presented in [19]. Also, utilizing a heuristic optimization approach, [21] assumed the existence of an adequate NG distribution system for the transportation of NG to the NGDG whose location and size is computed using an approximate power flow based optimization model. In this paper, we formulate the integrated planning problem as a mixed integer non-linear CCP problem that minimizes the investment and operating cost of both systems over a period of 10 years while maintaining the desired confidence level. This is a non-convex problem, however, because of the approximation possibilities offered by CCP, a convex approximation of the problem is solved. In addition, CCP ensures a robust solution via the maximization of the probability of achieving the desired level of system reliability.

In this paper, we extend our previous work [22] by proposing and solving an adequacy-based model for the long-term integrated planning of NGDGs and NG distribution network in the presence of stochastic real and reactive electricity demand. We model the planning problem as a CCP

optimization problem because of its ability to simultaneously accommodate the risk of uncertainty and adequacy requirements. In addition, the CCP solution algorithm allows repeatability of solutions and accommodates the consideration of multiple scenarios. The proposed planning model allows a distribution company with an exclusive right to supply electricity and NG to utilize NGDGs for the purpose of meeting future electricity demand while ensuring reliable NG distribution.

The integrated planning problem is modeled from the perspective of a distribution utility in a developing country with relatively easy access NG resource, a constrained transmission system, budgetary constraints and the existing regulatory framework allows the integration of NGDGs. The proposed solution allows an incremental approach towards increasing the adequacy level of electric power system supply. That being said, the solution approach is also applicable in developing countries with perhaps an increased confidence level target.

The rest of this paper is structured as follows: Section three describes the CCP integrated electricity and natural gas distribution planning problem. In Section four, the solution methodology for solving this problem is presented. In section five, the proposed model is illustrated on two systems with different levels of complexities, and section six concludes the paper.

3.3 The integrated electricity and natural gas distribution planning problem

The integrated electricity and NG distribution planning problem is a mixed-integer non-linear programming problem subject to physical, operational, design, contractual and electric-NG coupling constraints [69].

3.3.1 Objective model

The objective of the integrated planning problem is to minimize the capital and operation cost of NGDG, capacitor banks and the NG distribution pipeline needed to transport NG from the NG source (NGS) to the NGDG connected to *bus* $b+1$ [19,77] as shown in Fig. 3.1. The mathematical representation of this objective is presented in (3.1).

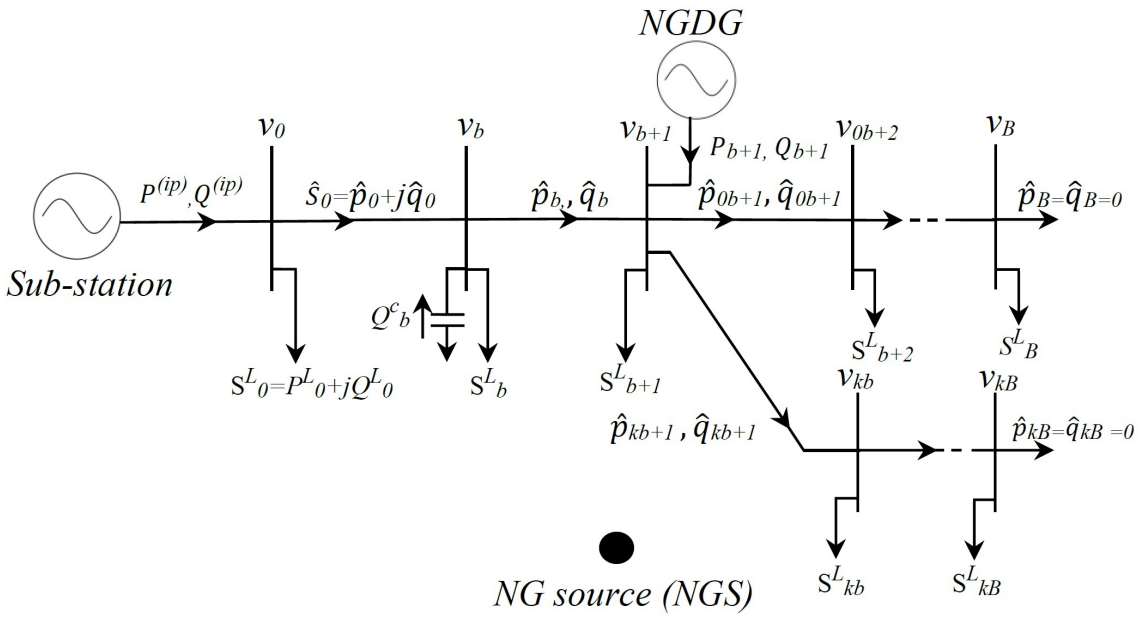


Figure 3.1: Typical N-bus radial distribution system with DG placed at bus_{b+1}

$$min\ z=\sum_{t}^{T}\Big[\underbrace{\sum_{b}^{\Omega_b}\sum_{\rho}^{\Omega_\rho}\delta_t\lambda_{\rho,b,t}C_\rho^{(I)}}_{\text{Present Value (PV) of capital cost of new NGDG}}+\underbrace{\sum_{b}^{\Omega_b}P_{b,t}C^{(o)}}_{\text{Operating cost of generation}}$$

$$+\underbrace{\sum_{b=0}P_{b,t}^{(ip)}C^{(ip)}}_{\text{Operating cost energy imported from the grid}}+\underbrace{\sum_{b}^{\Omega_b}\sum_{\rho}^{\Omega_\rho}\delta_t\pi_{\rho,b,t}C_\rho^{(I)}}_{\text{PV of capital cost of capacitor bank}}$$

$$+\underbrace{\sum_{i,j}^{\Omega_p}\delta_t C^{(I)}L_{i,j}(y_{i,j,t+1}-y_{i,j,t})}_{\text{PV of capital cost of NG pipeline}}+\underbrace{\sum_{i,j}^{\Omega_p}F_rL_{i,j}\varsigma\big((\Phi_{i,j,t}\times OC)+\tau\big)}_{\text{NG supply reliability cost}}\Big]$$

subject to

$$\textit{AC distribution powerflow constraints}$$

$$\textit{NG pipeline distribution constraints}$$

$$\textit{Electricity}-\textit{NG coupling constraint} \tag{3.1a}$$

$$\delta=\frac{ir}{1-(1+ir)^{-t}} \tag{3.1b}$$

The first term of (3.1) is the Present Value (PV) of the overnight investment cost of connecting new NGDGs to bus b. The second term is the operating cost i.e. the fixed and variable cost of new

and existing embedded electric power generation. The third term is the cost of importing electric power from the electric transmission grid. The cost of importing electric energy from the grid is taken to be a fraction of the operating cost of the NGDGs [46]. The fourth term of (3.1) is the PV of the overnight investment cost of connecting capacitor banks to bus b in time t. The fifth term of (3.1) is the PV of the overnight investment cost of installing new NG pipeline segments and the sixth term is the reliability cost of losing a segment of the NG distribution pipeline. The pipeline reliability cost is the sum of the loss of revenue from NG outage and the cost of fixing a failed segment of the pipeline.

3.3.2 Operational and physical constraints on the electricity distribution network

Electric power distribution systems are normally operated in radial configurations [11, 78]. Consider a typical radial distribution system shown in Fig. 3.1. The substation voltage, v_0, is assumed to be constant. The feeders and electricity demand are modelled as series impedances $z_b = r_b + jx_b$ and complex power demands $S_b^{(L)} = P_b^{(L)} + jQ_b^{(L)}$ respectively. The complex power flow in each feeder is modeled as $\hat{S}_b = \hat{p}_b + j\hat{q}_b$. Power flow in the radial distribution network has been described by sets of recursive equations called the forward update DistFlow branch equation [11, 79–81]. Assuming the radial network in Fig. 3.1 without the lateral feeder,

$$P_{b+1,t} + \big[\hat{p}_{b,t} - \frac{r_{b+1}(\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2)}{v_{b,t}^2}\big] = P_{b+1,t}^{(L)}(\xi_1) + \sum_{k:(b+1,k)} \hat{p}_{kb+1,t} \quad b = 0,1,.,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.2a}$$

$$Q_{b+1,t} + \big[\hat{q}_{b,t} - \frac{x_{b+1}(\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2)}{v_{b,t}^2}\big] = Q_{b+1,t}^{(L)}(\xi_2) + \sum_{k:(b+1,k)} \hat{q}_{kb+1,t} \quad b = 0,1,.,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.2b}$$

$$v_{b+1,t}^2 = v_{b,t}^2 - 2(r_b\hat{p}_{b,t} + x_b\hat{q}_{b,t}) + \big(r_{b,t}^2 + x_{b,t}^2\big)\frac{\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2}{v_{b,t}^2} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{3.2c}$$

$$\hat{p}_{kB} = \hat{q}_{kB} = 0 \qquad B \in \Omega_b, k \in \mathbb{N} \tag{3.2d}$$

$$v_{0b,t} = v_{b,t} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{3.2e}$$

$$P_{b,t} = P_{b,t}^{(e)} + P_{b,t}^{(n)} + P_{b,t}^{(ip)} \qquad b \in \Omega_b, t \in T \tag{3.2f}$$

$$Q_{b,t} = Q_{b,t}^{(e)} + Q_{b,t}^{(n)} + Q_{b,t}^{(ip)} + Q_{b,t}^{(c)} \qquad b \in \Omega_b, t \in T \tag{3.2g}$$

$$\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2 = |\hat{s}_{b,t}|^2 \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{3.2h}$$

$$\underline{\hat{S}_b} \leq \hat{s}_{b,t} \leq \overline{S_b} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{3.2i}$$

$$\underline{V_b} \leq v_{b,t} \leq \overline{V_b} \qquad b \in \Omega_b, t \in T \tag{3.2j}$$

$$0 \leq P_{b,t}^{(n)} \leq \lambda_{\rho,b,t} PG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{3.2k}$$

$$0 \leq Q_{b,t}^{(n)} \leq \lambda_{\rho,b,t} QG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{3.2l}$$

$$0 \leq P_{b,t}^{(e)} \leq \lambda_{\rho,b,t} PG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{3.2m}$$

$$0 \leq Q_{b,t}^{(e)} \leq \lambda_{\rho,b,t} QG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{3.2n}$$

$$Q_{b,t}^{(c)} = \pi_{\rho,b,t} Q_\rho^{(c)} \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \tag{3.2o}$$

$$\lambda_{\rho,b,t} + \pi_{\rho,b,t} \leq 1 \qquad \rho \in \Omega_\rho, \rho \in \Omega_\rho b \in \Omega_b, t \in T \tag{3.2p}$$

$$\lambda, \pi \in \{0,1\} \tag{3.2q}$$

The Kirchhoff's flow conservation is modeled in (3.2a) and (3.2b). Constraints (3.2a) ensures that the summation of nodal real power generation and the real power inflow less the resistive power loss on the feeder is equal to the sum of the uncertain nodal real power demand and real power outflow from lateral feeders k connected to bus $b+1$ in time t [78]. Similarly, constraint (3.2b) models the reactive power flow conservation. kb represents the bus identification order for lateral feeders k. $k = 0$ on the main radial feeder i.e. $0b = b$. Constraint (3.2c) models the voltage

drop between buses b and $b+1$ as a function of the losses in the feeder connecting buses b to $b+1$ based on Ohms law [11, 78, 81]. Constraint (3.2d) ensures that for a terminal bus B on the main or branched radial feeder, the active and reactive power outflow is zero. $v_{0b,t}$ in (3.2e), is a dummy notation that represents the source bus of the branched feeder k [11,79]. Constraints (3.2f) and (3.2g) model the total real and reactive power generation connected to bus b in time t. The shunt capacitor is a reactive power injector while NGDG's can serve as reactive power injectors or absorbers.

The relationship between the active $\hat{p}_b$, reactive $\hat{q}_b$ and complex $\hat{s}_b$ power flow in feeder b is presented in (3.2h). Constraints (3.2i) and (3.2j) sets the limits on the complex power flow in the feeders and the bus voltages. Constraints (3.2k) and (3.2l) impose capacity limits on the real and reactive power generation from new NGDGs. Similarly, constraints (3.2m) and (3.2n) ensure the active and reactive nameplate capacity limits of existing generators are not exceeded. Constraints (3.2o) set the capacity limits on the installed and candidate capacitor bank ρ in time t. Constraint (3.2p) ensures that NGDGs and capacitors are not co-located on the same bus.

The power losses in distribution feeders are typically much less than the power flow. In consequence to this, constraints (3.2a), (3.2b) and (3.2c) can be approximated to (3.3a), (3.3b) and (3.3c) by eliminating the quadratic terms as shown in (3.3) [78, 79, 81].

$$P_{b+1,t} + \hat{p}_{b,t} = P^{(L)}_{b+1,t}(\xi_1) + \sum_{k:(b+1,k)} \hat{p}_{kb+1,t} \quad b = 0,1,..,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.3a}$$

$$Q_{b+1,t} + \hat{q}_{b,t} = Q^{(L)}_{b+1,t}(\xi_2) + \sum_{k:(b+1,k)} \hat{q}_{kb+1,t} \quad b = 0,1,..,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.3b}$$

$$v^2_{b+1,t} = v^2_{b,t} - 2(r_b \hat{p}_{b,t} + x_b \hat{q}_{b,t}) \qquad b = 0,1,..,B-1 \in \Omega_b, t \in T \tag{3.3c}$$

3.3.2.1 Chance constrained model of the operational and physical constraints on the electricity distribution system

The stochastic constraints (3.3a) and (3.3b) can be formulated in probabilistic terms as shown in (3.4).

$$Prob\Big(\bigcap_{b} P_{b+1,t} + \hat{p}_{b,t} - \sum_{k:(b+1,k)} \hat{p}_{kb+1,t} \geq P^{(L)}_{b+1,t}\Big] \geq \alpha \quad b = 0,1,..,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.4a}$$

$$Prob\Big(\bigcap_{b} Q_{b+1,t} + \hat{q}_{b,t} - \sum_{k:(b+1,k)} \hat{q}_{kb+1,t} \geq Q^{(L)}_{b+1,t}\Big] \geq \beta \quad b = 0,1,..,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.4b}$$

Constraint (3.4a), states that the probability of the real power balance at bus b must be greater than the desired confidence level α. Similarly, constraint (3.4b) states that the reactive power balance at bus b must be greater than the desired confidence level β. These probabilistic models are very suitable for modeling and solving the long-term expansion planning problem in developing environments where the electricity network is unreliable and the planner must adopt an incremental approach towards bridging the gap between electricity demand and supply in the presence of budgetary constraints.

The electric distribution load is difficult to fit into a particular statistical distribution. While [82] concludes that the electric distribution does not follow any common distribution, [83] has fitted a Gaussian distribution to grouped domestic loads. Similarly, [84] assumed residential, industrial and irrigation load follows a Gaussian distribution. Reference [85] modeled the distribution load as a combination of several Gaussian distributions. Based on the proposition made in [85], the assumption of Normal distribution for peak load values is acceptable. Since the objective of the long-term plan is to ensure reliability of supply especially during periods of peak electricity demand, it is safe to assume the Gaussian distribution around the peak demand will capture the topmost percentile of the demand which tends to create the greatest reliability challenges. Therefore, (3.4a) and (3.4b) can be approximated as (3.5a) and (3.5b)

$$P_{b+1,t} + \hat{p}_{b,t} - \sum_{k:(b+1,k)} \hat{p}_{kb+1,t} = \mu^{P^{(L)}}_{b+1,t} + \sigma^{P^{(L)}}_{b+1,t} Z\alpha \quad b = 0,1,..,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.5a}$$

$$Q_{b+1,t} + \hat{q}_{b,t} - \sum_{k:(b+1,k)} \hat{q}_{kb+1,t} = \mu^{Q^{(L)}}_{b+1,t} + \sigma^{Q^{(L)}}_{b+1,t} Z\beta \quad b = 0,1,..,B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{3.5b}$$

The CCP distribution flow branch equations of the radial distribution network shown in Fig. 3.1 are presented in (3.5). The CCP Kirchhoff's current law/flow conservation equation for the active and reactive power is described in (3.5a) and (3.5b). Constraint (3.5a) states that the sum of the local power real power generation and the net power flow in and out of the bus b is equal to the sum of the mean local nodal real electricity demand $\mu_{b+1,t}^{P(L)}$ and the product of the standard deviation of the nodal electricity demand $\sigma_{b+1,t}^{P(L)}$ and Z_α. Where Z_α is the inverse cumulative distribution of the random real electric power demand $[1-\frac{1-\alpha}{B}]$ i.e. $Z_\alpha = \phi^{-1}[1-\frac{1-\alpha}{B}]$. B is the total number of electric buses and α is the fixed reliability level set a-priori [17, 44]. Similarly, constraint (3.5b) implies that the total reactive power generation less the net reactive power flow on feeders connected to bus b is equal to the the sum of the mean local nodal reactive power demand $\mu_{b+1,t}^{Q(L)}$ and the product of the standard deviation of the nodal reactive power demand $\sigma_{b+1,t}^{Q(L)}$ and the inverse cumulated distribution function $\left(Z_\beta = \phi^{-1}[1-\frac{1-\beta}{B}]\right)$ of the random reactive power demand. β is the desired reliability level of reactive supply.

3.3.3 Operational and physical constraints on the Natural gas distribution system

The NG distribution system is made up of a network of pipes of small diameters between 0.5in - 6in. NG is transported in the distribution pipeline at low pressure (i.e. 0.14bar - 13.8bar) [14, 15].

The NG distribution flow equations is presented in (3.6) [19, 37].

$$\Gamma_{i,t} = \overline{\Gamma}_i \qquad \forall i \in \Omega_s, t \in T \tag{3.6a}$$

$$\underline{\Gamma}_i \leq \Gamma_{i,t} \leq \overline{\Gamma}_i \qquad \forall i \in \Omega_d, t \in T \tag{3.6b}$$

$$\Phi_{i,j,t} \leq M_{1t} B_{i,j,t} \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.6c}$$

$$\sum_{j}^{\Omega_p} \Phi_{i,j,t} = S_{i,t} - D_{i,t} \qquad \forall i \in \Omega_s \cup \Omega_d, t \in T \tag{3.6d}$$

$$(\Gamma_{i,t}^2 - \Gamma_{j,t}^2) - \Psi_{i,j} \Phi_{i,j,t}^2 \geq M_2 (B_{i,j,t} - 1) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.6e}$$

$$(\Gamma_{i,t}^2 - \Gamma_{j,t}^2) - \Psi_{i,j} \Phi_{i,j,t}^2 \leq M_2 (1 - B_{i,j,t}) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.6f}$$

$$\Psi_{i,j} = \left(\frac{1}{1.1494 \times 10^{-3}} \right)^2 \frac{G T_f L_{i,j} Z f}{\Delta_{i,j}^5} \left(\frac{\Gamma_b}{T_b} \right)^2 \tag{3.6g}$$

$$B_{i,j,t} + B_{j,i,t} \leq y_{ijt} \qquad \forall (i,j) \in \Omega_p, i < j, t \in T \tag{3.6h}$$

$$y_{i,j,t} \leq y_{i,j,t+1} \qquad \forall (i,j) \in \Omega_p, t = 1, \ldots |T| - 1 \tag{3.6i}$$

$$y_{i,j,0} = 0 \qquad \forall (i,j) \in \Omega_p, i < j \tag{3.6j}$$

$$\Gamma_{i,t}, \Phi_{i,j,t} \geq 0 \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.6k}$$

$$B_{i,j,t}, y_{i,j,t} \in 0, 1 \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.6l}$$

Constraint (3.6a) ensures NG pressure $\Gamma_{i,t}$ at the NG source node *NGS*, is equal to the maximum pressure $\overline{\Gamma}_i$ possible. Constraint (3.6b) ensures the NG pressures at the NG demand nodes are within the acceptable pressure limits. Constraint (3.6a) sets the limit on NG-flow rate in a segment of the NG pipeline. The NG flow rate $\Phi_{i,j,t}$ between nodes i, j is usually greater than 1, therefore, a large value $M_{1,t}$ equivalent to the maximum possible NG flow in the network sets an upper limit on $\Phi_{i,j,t}$ in any segments of pipeline [18]. Constraint (3.6d) ensures nodal energy conservation i.e. the net NG flow at nodes i should be equal to the difference between NG nodal supply $S_{i,t}$ and demand $D_{i,t}$ in time t. Constraint (3.6e), (3.6f) and (3.6g) enforce the general steady-state flow of NG in a pipe assuming an isothermal flow along a horizontal segment of the pipeline whose length is such that the effect of kinetic energy is negligible [18, 51, 67]. The squared pressure drop between the NG sending and receiving nodes i and j respectively at the beginning of time t is equal to the product of the pipeline resistant $\Psi_{i,j}$ and the squared flow-rate $\Phi_{i,j,t}$.

Constraints (3.6e) and (3.6f) are formulated such that NG pressure drop between nodes i and j is only limited to connected nodes. When NG is flowing between nodes i and j, $B_{i,j,t} = 1$. This sets the right-hand sides of (3.6e) and (3.6f) to zero. M_2 is set to a large pressure value close to $\overline{\Gamma_i^2}$. This is to ensure a zero pressure drop between nodes i and j when $B_{ijt} = 0$. Constraints (3.6e) and (3.6f) also ensure that NG flows from the higher pressure node to the lower pressure node. The pipeline resistance $\Psi_{i,j}$ is defined in (3.6g). $\Delta_{i,j}$, $L_{i,j}$ are the diameter in (in) and the length in $(miles)$ of the pipe respectively. The frictional factor f, the base pressure Γ_b, the base temperature T_b, the NG gravity G, the gas compressibility factor Z, and the flow temperature T_f are taken to be 0.01, 1 bar, 288^oK, 0.66, 0.805, and 283^oK respectively [18]. Constraint (3.6h) ensures the presence of an NG pipe when there is NG flow across nodes i and j at the start of time t [18]. Constraint (3.6i) ensure that once a pipeline is built, it remains in service for the rest of the planning horizon. The non-existence of pipeline(s) between node i and j before the planning horizon is set to zero by constraint (3.6j). Constraint (3.6k) ensures the NG flow rate and the square of the nodal pressure are nonnegative. Constraint (3.6l) ensures $B_{i,j,t}$ and $y_{i,j,t}$ are binary decision variables.

Constraint (3.6e) and (3.6f) introduces non-linearity into the NG planning problem because of the presence of squared variables Γ^2 and Φ^2. The NG planning model is linearized in terms of the pressure by replacing Γ^2 with Θ and setting the limits on the nodal pressure i.e. $\overline{\Gamma_i}$ and $\underline{\Gamma_i}$ to their squares [18, 69]. Therefore, (3.6b), (3.6e), (3.6f) become (3.7a)–(3.7c):

$$\underline{\Gamma_i^2} \leq \Theta_{i,t} \leq \overline{\Gamma_i^2} \qquad \forall i \in \Omega_d, t \in T \tag{3.7a}$$

$$(\Theta_{i,t} - \Theta_{j,t}) - \Psi_{i,j}\Phi_{i,j,t}^2 \geq M_2(B_{i,j,t} - 1) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.7b}$$

$$(\Theta_{i,t} - \Theta_{j,t}) - \Psi_{i,j}\Phi_{i,j,t}^2 \leq M_2(1 - B_{i,j,t}) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.7c}$$

Constraints (3.7b) and (3.7c) remains nonlinear because of the $\Phi_{i,j,t}^2$ variable [69]

3.3.4 Electricity and natural gas coupling constraints

The NG fuel required to meet the peak electricity generation is computed using the relaxed electricity NG coupling constraint presented in (3.8) [19]:

$$D_{i,t} \geq a_i + b_i S_{b,t} + c_i (S_{b,t})^2 \qquad \forall i = b, t \in T \tag{3.8a}$$

$$S_{b,t}^2 = P_{b,t}^2 + Q_{b,t}^2 \quad b \in \Omega_b, t \in T \tag{3.8b}$$

The relaxed coupling constraint modeled in (3.8) is preferred to the equality constraint which is non-convex [69]. $D_{i,t}$ is the NG demand at node i for electricity generation $P_{b,t}$ assuming a constant non-electricity NG demand [39]. NG Demand nodes i and the electricity generation bus b are assumed to be co-located. a_i, b_i, c_i are the fuel rate coefficients of the NGDGs.

3.4 The NGDG and NG pipeline planning solution methodology

Traditionally, the NG and the electric distribution system are planned independently and linked sequentially. For example, the NGDG location and size is determined, then the NG distribution network is planned to meet the NG demand of NGDGs. Similarly, NGDGs can be sized and located base on existing NG distribution infrastructure. In this section, we discuss a sequential and integrated approach to planning NGDGs and NG distribution network.

3.4.1 A sequential solution methodology

In the sequential planning approach, the electric system is first planned, then the NG distribution system is planned based on the output of the NGDG plan. The procedure for the sequential solution methodology is itemized below [22]:

1. The NGDG location and sizing problem are formulated as CCP optimization problem. The objective of the optimization is the minimization of the capital and operating cost of NGDG assuming adequate reactive power compensation. The output of this model is the location and size of the NGDG.

2. The nodal NG demand is computed based on the location of the candidate NGDGs using the NG- electricity coupling constraint. The input to this constraint is the peak NGDG capacity and location. The output is the peak NG nodal demand.

3. The computed nodal NG peak demand is input into the NG route optimization problem. The solution of this step is the cheapest and most reliable NG pipeline layout that ensures adequate NG flow-rate and nodal pressures.

3.4.2 An integrated solution methodology

The integrated solution approach involves a simultaneous planning of the electric and the NG distribution system. The CCP algorithm provides a framework that ensures feasibility and a desired level of reliability. This is achieved by solving the non-convex approximate MINLP integrated planning problem first and then ensuring the feasibility of the solution by solving a convex NG constrained optimal power flow (NGCOPF) problem for multiple scenarios of real and reactive power demand. The CCP algorithm is presented in Fig. 3.2. The algorithm constitutes the deterministic approximate solution, the NGCOPF, the feasibility check and the Z-update algorithm.

3.4.2.1 The deterministic expansion solution

The deterministic expansion planning involves solving the integrated planning problem for an expected real and reactive power demand. The outputs of the deterministic model are the feasible NGDG location and size, the NG pipeline and the flow direction for an expected scenario of electric real and reactive power demand. The deterministic expansion planning problem is however, non-convex because of the presence of (3.7b) and (3.7c) [69, 86]. The branch and bound method was shown to provide feasible solutions for MINLP problem of similar form [18], [87].

3.4.2.2 Natural gas constraint optimal power flow for demand samples

Once the flow direction through passive pipelines is known, the NG planning problem becomes convex [88]. The convex Natural Gas Constrianed Optimal Power Flow (NGCOPF) is modeled

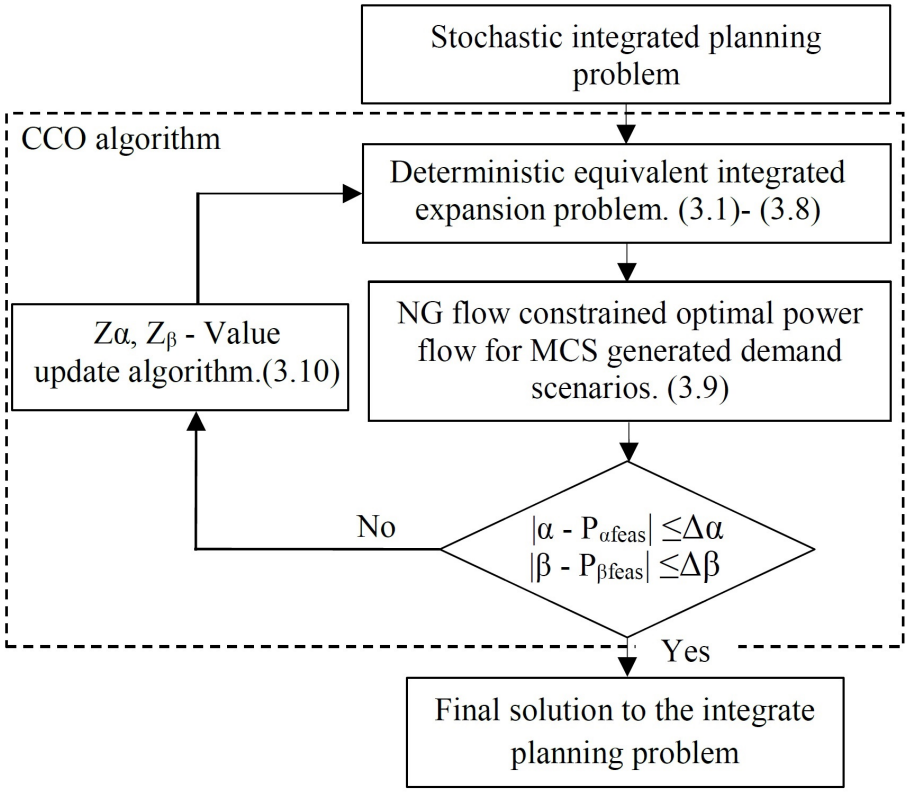


Figure 3.2: Algorithm for the CCP integrated planning model with associated equations/models

in (3.9). (3.9a) minimizes the sum of unserved complex power coefficient $u_{b,t}$ for scenarios of real power $P^{(L)}_{b+1,t}$ and reactive power $Q^{(L)}_{b+1,t}$ demand [86]. These scenarios are generated using Monte Carlo simulation [17, 44]. Loads on the electric distribution system are mainly residential and commercial with different power factors. Therefore, the real and reactive power demand are

taken to be independent random variables [89] and are sampled separately.

$$min \quad \sum_{t}^{T}\sum_{b}^{\Omega_b} u_{b,t} \tag{3.9a}$$

$$s.t \quad P_{b+1,t} + \hat{p}_{b,t} - \hat{p}_{b+1,t} = (1-u_{b+1,t})P^{(L)}_{b+1,t} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{3.9b}$$

$$Q_{b+1,t} + \hat{q}_{b,t} - \hat{q}_{b+1,t} = (1-u_{b+1,t})Q^{(L)}_{b+1,t} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{3.9c}$$

$$0 \leq u_{b,t} \leq 1 \qquad b \in \Omega_b, t \in T \tag{3.9d}$$

$$s_{i,t} + \sum_{j}^{\Omega_p} \Phi_{i,j,t} = D_{i,t} \qquad \forall i \in \Omega_s \cup \Omega_d, t \in T \tag{3.9e}$$

$$(\Theta_{i,t} - \Theta_{j,t}) = \Psi_{i,j}\Phi^2_{i,j,t} \qquad \forall (i,j) \in \Omega_p, t \in T \tag{3.9f}$$

$$\underline{S_b} \leq S_{b,t} \leq min\big[\frac{\Phi_{b,t}}{HR}, \overline{S_b}\big] \qquad b \in \Omega_b, t \in T \tag{3.9g}$$

$$(3.2c), (3.2i) - (3.2p), (3.6a) - (3.6c), (3.6k), (3.8a) \tag{3.9h}$$

The nodal balance constraints on the real and reactive power are modeled in (3.9b) and (3.9c). Equation (3.9d) set the constraint on $u_{b,t}$. The nodal balance equation for the gas network is modeled in (3.9e). Equation (3.9f) constrains the NG flow in a segment of the pipeline as a function of the difference between the square of the source and sink NG node. Equation (3.9g) sets the capacity limit on the complex power generation. The upper limit on the electric generation $\overline{S_{b,t}}$ connected to bus b is set by the lesser of the NGDG capacity and available NG for electricity generation. Electricity generation from NG at bus b depends on the rate of NG inflow $\Phi_{b,t}$ $(MMscf/hr)$ and the heat-rate [90, 91] $(MMscf/kWh)$ of the candidate NGDG. Constants (3.9h) are described in section II. The NGCOPF is computed for N_{times} samples of real and reactive demand. The average of the feasibility cases i.e $P_{\alpha/\beta,feas}$ is computed. P_{feas} must be greater or equal to the desired reliability levels Z_α and Z_β for the optimum integrated expansion plan. In the event that P_{feas} is lesser than the desired reliability levels Z_α and Z_β, the demand profile and consequently the NGDG and pipelines plans are updated using the Z value update algorithm.

3.4.2.3 The Z-value update algorithm

The $Z-value$ which is related to loading level at each bus is updated until the desired reliability level is achieved. The update model is presented in (3.10) [43]. Z^{Hi} and Z^{Lo} correspond to the highest P_h and lowest P_l probabilities of achieving the desired reliability levels α and β. Z_1 and Z_2 are the updated $Z-value$ computed when the operational cost minimization problem in (3.9) is solved for multiple demand scenarios. $Z_{\alpha/\beta}$ is the $Z-value$ equivalent of the desired probability. The iterative $Z-value$ update is repeated until the target probability is reached i.e. the NGDG location and size are updated till $|\alpha - P_{feas}| \leq \triangle\alpha$ and $|\beta - P_{feas}| \leq \triangle\beta$ holds, else $Z_{\alpha/\beta}$ is updated using (3.10). Details of the update algorithm is presented in [44, 54].

$$Z^{i}_{\alpha/\beta} = Z^{Lo} + \big[\frac{Z_{\alpha/\beta} - Z_2}{Z_1 - Z_2}\big(Z^{Hi} - Z^{Lo}\big)\big] \tag{3.10}$$

3.5 Description of Test System and results

The proposed long-term integrated planning model is tested on a standard 9 and 33 bus radial distribution test system for a planning horizon of 10 years. The NGCOPF is tested for 1000 samples i.e. $N_{times} = 1000$ complex power pairs. The Branch-And-Reduce Optimization Navigator (BARON) [61] solver available in GAMS 24.2 [62] is employed in solving the long-term NGDG and NG pipelines planning problem.

3.5.1 Basic assumptions and justifications

Itemized below are assumptions made in illustrating the proposed models and the justification for these assumptions.

1. The uncertain peak instantaneous complex electricity demand is assumed to follow a Gaussian distribution. This is based on similar assumptions made in other scientific literatures [83, 84] and the fact that the peak electricity demand can be fitted into a Gaussain distribution [85]. This assumption was also justified in section (3.3.2.1)

2. We assume a standard deviation of $\sigma^{P^{(L)}} = 0.09\mu^{P^{(L)}}$ and $\sigma^{Q^{(L)}} = 0.09\mu^{Q^{(L)}}$ for the real and reactive peak power demand. This assumption is based on the average of standard deviation of residential 8% and industrial 10% load [84].The real and reactive powers are sampled separately, resulting in an uncertain power factor. It is important to note that net demand on a bus with NGDG can be negative. This is consistent with assumptions made in [17, 44].

3. The minimum acceptable NG pressure at each of the NG demand node is set to 6 *bar*. This is the minimum pressure required to seamlessly operate a sample 1MW and 2MW micro turbine NGDG [57]

4. The NG pressure at the NG source is set to 13.8bar. This is the maximum allowable NG pressure at the NG distribution level in Canada [15]

5. The electrical load is assumed to have an annual growth rate of 3% [58].

6. The pipelines and NGDG are assumed to be under the jurisdiction of a single utility company with an exclusive right to deliver electricity and NG to a particular region. Examples of these utilities are ATCO energy and Enmax both with an exclusive right to distribute NG and electricity in Alberta, Canada [59, 92]. It is envisaged that utilities in a number of developing countries and especially countries rich in NG resources such as Nigeria will adopt a similar business model.

7. The expected pipeline repair time (ς) after a major outage is taken to be 48 hours or two days and the pipeline annual failure rate (τ_p) is assumed to be $0.2/year.thousand\ miles$. Similar assumptions were made in [47, 93].

8. The cost of new pipeline is taken to be $\$100,000/inch-mile$ [60].

9. The candidate NGDGs were assumed to be of quantized size. This is typical as commercially available NGDGs are usually manufactured in discrete sizes. Two discrete sizes of

NGDGs i.e. 1000KVA and 2000KVA costing $\$1,200,000$ and $\$2,000,000$ respectively are employed in this study and adequate reactive power compensation is assumed for the entire planning period.

10. The expansion of the transmission system and the substation is assumed to be out of the jurisdiction of the planner. This is typical in an unbundled power system structure where the transmission and distribution system are normally planned independently.

11. We assumed the NG distribution network is underdeveloped or absent. This is also typical in developing environments.

Some of the assumptions above were based on what is obtainable in a developed country because of the limited access to credible data from a typical developing country.

3.5.2 9 bus distribution test system

The radial 9 bus distribution system is shown in Fig. 3.3 . The rated line voltage of the system is 23 kv. The details of the feeders are available in [94]. The distribution network connects to the grid via a distribution substation located at *bus* 0. Buses 1 to 9 are load buses pending the integration of NGDGs. A similar configuration was utilized in [19, 21].

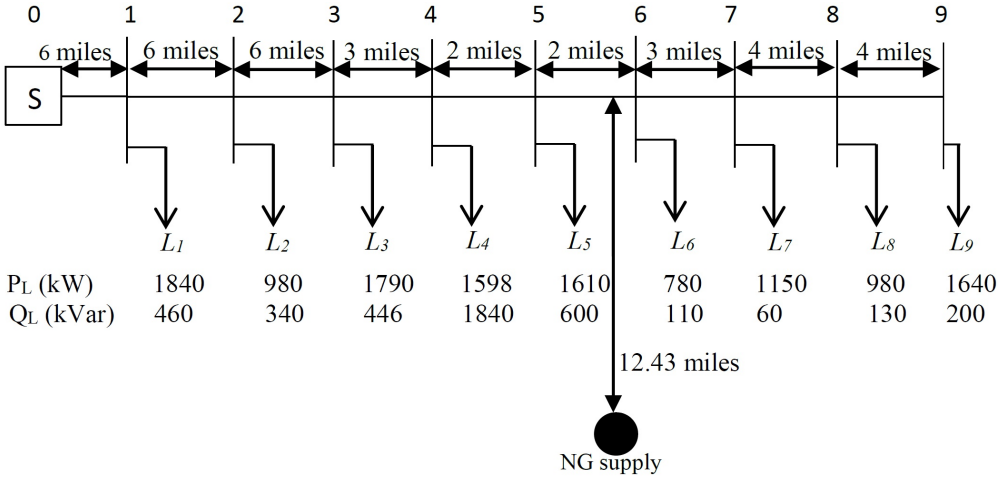


Figure 3.3: Single-line diagram of 9-bus radial distribution system peak and average demand

3.5.3 33 bus distribution test system

It is important to ensure the proposed integrated approach is suitable for planning large and complex distribution systems. Therefore, the proposed model is further tested on a standard $33-bus$ distribution system [80] with two NG source nodes NGS_1 and NGS_2 as shown in Fig. 3.4. The following assumptions were made mostly based on the structure of the $33-bus$ distribution system as presented in the literature and the authors experience:

1. The NG sources are taken to be 5 *miles* south of *bus* 22 and *bus* 25. The length of feeders between the buses was assumed to be 3 *miles* except for $feeders$ 18, 22, and 25 that are taken to be 10, 10 and 6 *miles* respectively from their feeding buses. These assumptions were based on the fact that NG sources are usually located at the outskirts of the city. In consequence to this, the NG sources are likely to be closest to a terminal node. The choice of having the NG sources on the east and west of the distribution network is based on the authors preference. More sources can be present and they can be located anywhere within the geographical location under the jurisdiction of the distribution utility.

2. The candidate pipeline routes are assumed to follow the existing layout of the electric distribution network. This is based on the assumption that the electricity distribution feeders and candidate NG pipeline can be located within the same right of way.

3.5.4 Factual results

The result of testing the proposed model on test cases is presented in this section.

3.5.4.1 A comparison of sequential and integrated planning approach

The expansion plan for the 9 bus test system using a sequential and an integrated planning approach for year one is presented in Fig 3.5 and Fig 3.6 respectively. The plan highlights the location and size of candidate NGDGs and the NG pipeline required to transport NG to the NGDGs. The 10 years systems expansion plan is presented in Table 3.1.

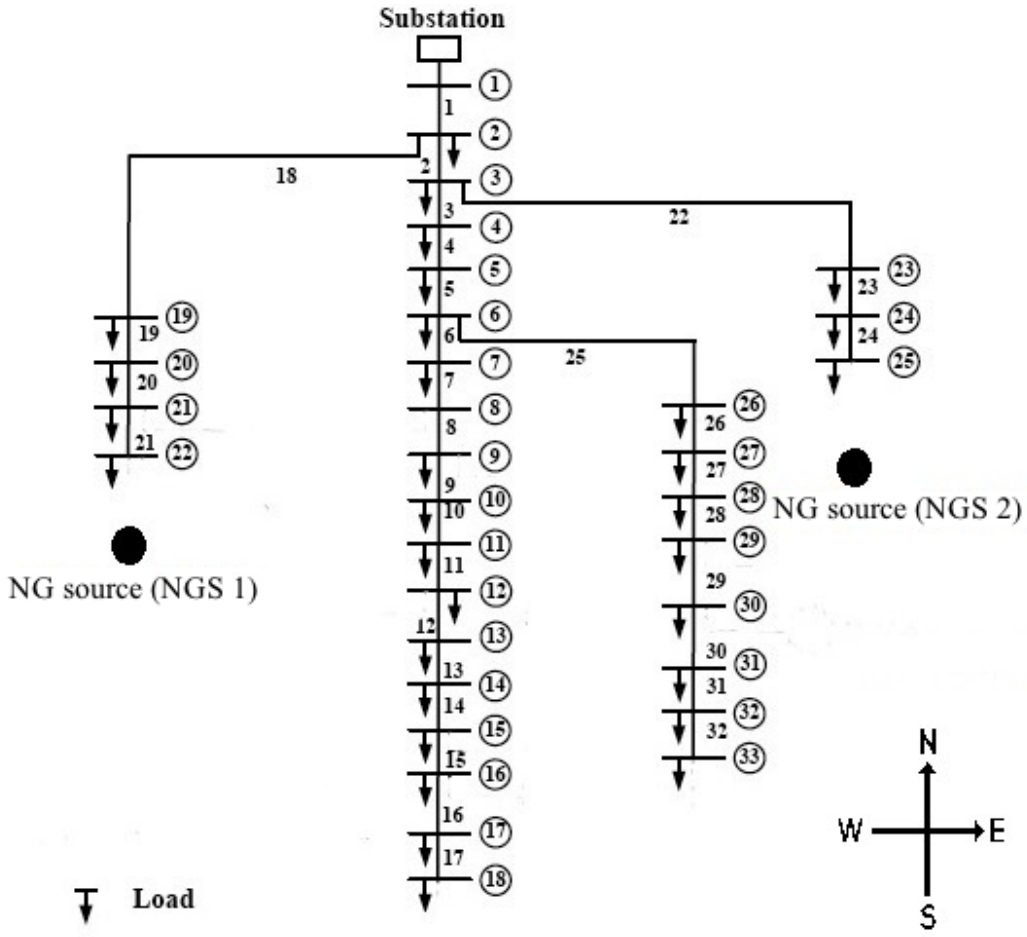
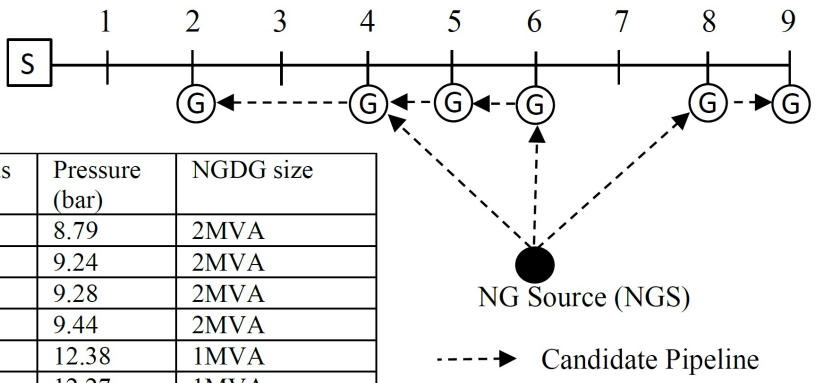


Figure 3.4: Single-line diagram of 33-bus radial distribution system

The computed NGDG size and location from a sequential planning approach and an integrated planning approach to planning the 33 bus system is presented in Table 3.2. The result from the sequential approach suggests the addition of 7 X 1MVA NGDGs at different buses on the network in year one. The results from the integrated planning approach, however; suggest zero NGDG integration across the distribution system in year one. The NGDG and NG pipeline required to ensure power supply reliability in the $33-bus$ distribution system for a planning horizon of 10 years is shown in Table 3.3.



Bus	Pressure (bar)	NGDG size
2	8.79	2MVA
4	9.24	2MVA
5	9.28	2MVA
6	9.44	2MVA
8	12.38	1MVA
9	12.27	1MVA
Total system investment cost		USD16,161,000

Figure 3.5: NGDG sizing, location and NG pipeline layout with reliability consideration for year 1 using a sequential planning approach

Table 3.1: Location and size of NGDGs and NG pipelines

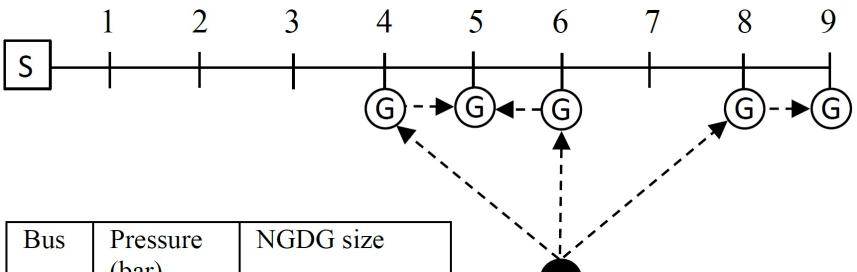
Years in the planning horizon	NGDG location and size (MW_{bus})	NG pipe line route $y_{source\ node \longrightarrow destination\ node}$
1	$1_4, 2_4, 2_5, 2_6, 2_8, 1_9$	$y_{NGS \longrightarrow 4}, y_{NGS \longrightarrow 6}, y_{NGS \longrightarrow 8}$ $y_{4 \longrightarrow 5}, y_{6 \longrightarrow 5}, y_{8 \longrightarrow 9}$
2	1_6	–
5	1_5	–
8	1_3	$y_{NGS \longrightarrow 3}$
9	1_8	–

3.5.5 Interpretation of Results

The advantages and consequence of an integrated approach to planning both systems in comparison to the sequential approach are highlighted in this section.

3.5.5.1 A reduction in capital cost

The integrated planning approach results in a cheaper expansion plan as compared to the output of the sequential approach. This is captured in the detailed expansion plan for year one shown in Fig 3.5 and Fig 3.6. This reduction is attributed to the cost constraint placed on the location and size of the NGDGs by the associated capital cost of building new NG pipelines in the first year. Consequently, the locations of the NGDGs are influenced by the physics of electron flow and the capital cost of extending or adding new NG pipeline. Table 3.2 shows similar results, the



Bus	Pressure (bar)	NGDG size
4	9.32	1MVA, 2MVA
5	9.28	2MVA
6	9.44	2MVA
8	11.54	2MVA
9	11.49	1MVA
Total system investment cost		USD15,261,000

Figure 3.6: NGDG sizing, location and NG pipeline layout with reliability consideration for year 1 using a CCP based integrated planning approach

Table 3.2: Location and size of NGDGs for integrated and non integrated planning of a of 33-bus radial distribution system in year one

Bus Number	Peak real power generation required (MW)	NGDG size for non integrated planning	NGDG size for integrated planning
5	0.492	1	0
11	0.604	1	0
18	0.119	1	0
26	0.647	1	0
28	0.182	1	0
31	0.467	1	0
33	0.276	1	0

integrated approach results in zero NGDG integration and consequently zero pipelines as compared to the result from the sequential planning approach where the addition of 7 X 1MVA NGDGs are recommended in year one.

3.5.5.2 An increase in reliability

The integrated approach results in a plan with shorter pipelines as shown in Fig 3.6. This implies an increase in the reliability of the NG distribution system because the probability of outages on the NG pipeline is directly proportional to the length of the pipeline. The shorter pipelines indicates an increase in the flow rate of NG in each segment of the pipeline. The flow rate is, however,

Table 3.3: Location and size of NGDGs and NG pipelines

Years	NGDG location and size (MW_{bus})	NG pipe line route
1	Nil	Nil
3	$1_5, 1_{25}$	$y_{NGS2 \longrightarrow 25}, y_{25 \longrightarrow 5}$
7	1_{26}	$y_{5 \longrightarrow 26}$
10	1_{22}	$y_{NGS1 \longrightarrow 22}$

maintained at a level that minimizes the outage cost associated with the pipeline. This is achieved via the minimization of the reliability cost which is a function of flow rate in (3.1).

3.5.5.3 The pipeline limits the location of NGDGs

The capital cost of extending the pipeline places an additional constraint on the location of NGDGs. This is evident in the case of the 33 bus system where the integration of NGDGs is less desirable for meeting the energy need in year one as shown in Table 3.2 because of the capital cost of extending the NG pipelines.

3.5.5.4 The flow rate influences the expansion plan

The NG flow significantly affects the choice of a candidate pipeline. This is because it has to justify the capital cost of building the pipeline for it to be selected. For example, no candidate pipeline was selected in the year one expansion plan for the 33 bus system as shown in Table 3.2 because the required local electricity generation and consequently the peak NG flow rate is not large enough to justify the capital cost of building the candidate pipeline. In essence, the NG flow rate in a segment of the pipeline must justify the capital cost of building or extending the pipeline without violating the nodal NG pressure constraints.

The staged expansion solutions presented in Table 3.1 and Table 3.3 may be unattractive in the developed part of the world because of the logistic, legal and perception consequence of continuous infrastructure expansion. This solution methodology is, however, suitable for developing regions of the world where the benefit of reliable electricity supply might outweigh the potential logistic, legal and perception concerns.

In summary, the CCP base integrated planning approach results in a plan that satisfies the

desired reliability level while accommodating uncertainties in the real and reactive power. The integrated model results in an expansion that is less expensive. The integrated model further increases the reliability of the entire system because the NG pipelines are shorter. The integrated approach ensures that the expected flow rate of NG in each segment of the pipeline justifies the capital cost of the pipeline.

3.5.6 Sensitivity of NGDG integration to confidence levels

The confidence level is a major component of the CCP planning algorithm and it influences the size and cost of candidate NGDGs. As expected, the size of candidate NGDGs increases with an increase in the desired adequacy of electric power supply. Fig. 3.7 shows the sensitivity of the

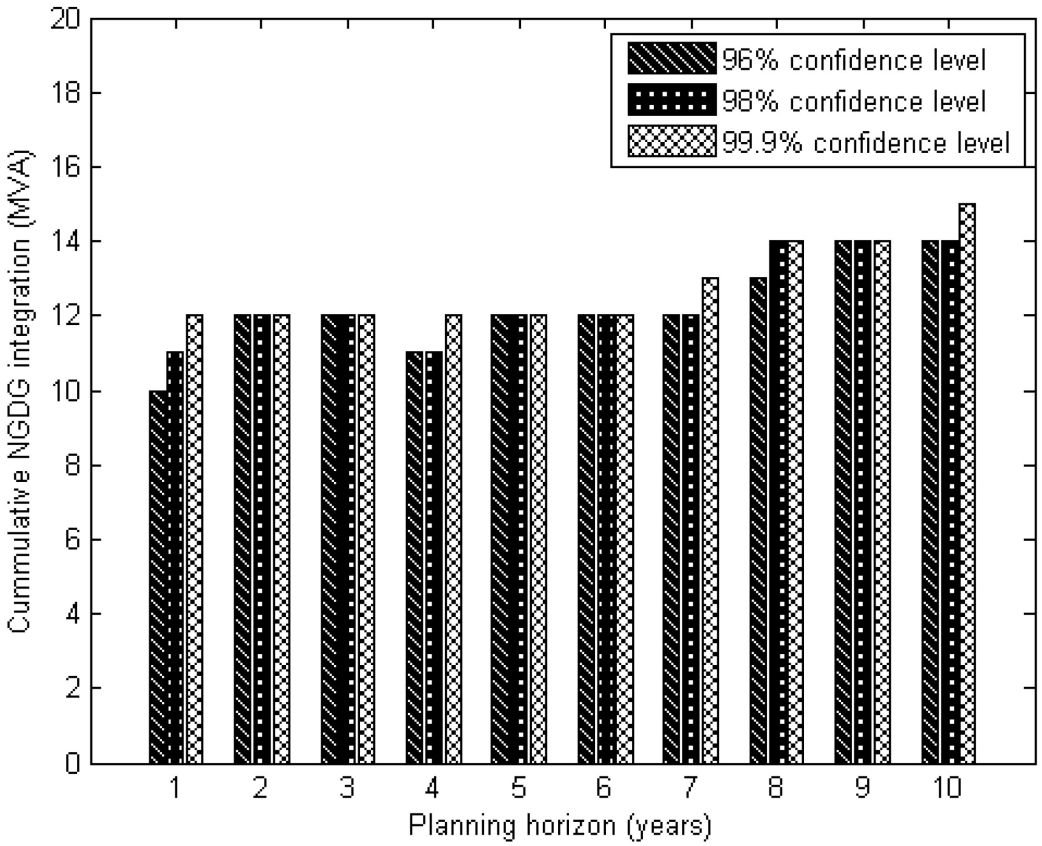


Figure 3.7: Sensitivity of NGDGs integration to confidence-levels on the 9 bus test system

expansion plan for the 9 bus distribution system to different i.e. 96%, 98%, and 99.9% levels of electric power supply adequacy. The annual sensitivity of the NGDG integration to confidence

level varies across the planning horizon. This is because the quantized size of NGDG sometimes doesn't always match the power demand. Consequently, there are idle generation capacities at certain times of the planning horizon. For example in year two, three, five, six and eight, the expansion plan is not sensitive to the change in adequacy level, because there exists enough capacity from previous years to accommodate expected variations in the electricity demand. This sensitivity analysis is important in choosing the optimum confidence level for planning the system. In summary, the sensitivity of the integrated plan to the confidence level is dependent on the quantized size of the candidate NGDGs and the overall size of the electric power demand.

3.6 Conclusion

We present a reliability-focused model of the integrated planning of NGDG and NG distribution problem. The problem was solved using a CCP algorithm, a stochastic optimization technique that ensures the solution to the integrated problem meets a predefined desired level of reliability. The output of the integrated planning approach is less expensive and more reliable than the output of a sequential planning approach for the same sets of nodal electricity demand and system characteristics. In addition, the integrated planning approach ensures that the expected NG flow rate minimizes the reliability cost and justifies the capital cost of building the pipeline. To ensure the model is utilizable for practical systems with a large number of electricity nodes and multiple NG sources, we tested the model on a standard 9 and 33 bus test distribution system with single and multiple NG sources. The results show that the model provides an acceptable result when employed in planning simple and complex distribution systems.

Chapter 4

A Real Option Assessment of Flexibilities in the Integrated Planning of Natural Gas distribution Network and Distributed Natural Gas-fired Power Generations [1]

There is an increasing integration of distributed natural gas-fired electric power generations across the globe. The natural gas-fired power generators are dependent on the availability of reliable natural gas distribution systems. This interdependency coupled with the scalability of the natural gas-fired distributed power generators presents the management of an energy utility with real options to execute, delay or abandon long-term expansion plans based on new realities of electric power demand. A real options analysis of these flexibilities is carried out in this paper. The assessment of these options includes the identification and valuation of the identified options. The value of flexibilities and options is illustrated by assessing the options to implement, delay or abandon expansion plans in the presence of uncertain electric power demand on 9 and 33 bus electricity distribution systems.

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Nomenclature

A. Abbreviation

NG	Natural Gas
NGDG	Natural Gas-fired Distributed power Generator
CCP	Chance Constraint Programming

B. Identifier

k	Identifier for lateral feeders $k = 0, 1, ...K$

C. Indices

b	Index of electricity bus, $b = 0, 1, ...B$
t	Index of planning time horizon, $t = 0, 1, ...T$
i	Index of the source NG nodes associated with a pipeline segment
j	Index of the sink NG nodes associated with a pipeline segment
ρ	Index of quantized NGDG sizes
ρ	Index of quantized capacitor bank sizes
s	Future electricity demand scenarios
η	Expansion plans options
u	up factors of uncertain electric demand realisation
d	down factors of uncertain electric demand realisation

D. Binary Variables

$\lambda_{\rho,b,\eta,t}$	1 if NGDG of size ρ is required in expansion plan η at electric bus b in time t
$\pi_{\rho,b,\eta,t}$	1 if a new capacitor bank of size ρ is required in expansion plan η at electric bus b in time t
$\lambda_{\rho,b,t}$	1 if a new NGDG size ρ is connected to bus b in time t. 0 otherwise
$\pi_{\rho,b,t}$	1 if a new capacitor bank size ρ is connected to bus b in time t. 0 otherwise
$y_{i,j,\eta,t}$	1 if a pipeline y is required in expansion plan η NG nodes i, j in time t. 0 otherwise
$y_{i,j,t}$	1 if a pipeline y is installed between NG nodes i, j in time t. 0 otherwise

Binary Variables continued

$z_{i,j,t}$ 1 if NG flow from NG node i to j in time t. 0 otherwise

$\gamma^{s}_{t,\eta}$ 1 if expansion plan η is built in the short planning horizon t for demand scenario s. 0 otherwise

E. Random Variables

ξ_1 Uncertain real electric power demand forecast

ξ_2 Uncertain reactive electric power demand forecast

F. Variables

$P_{b,t}$ Real electric power generation connected to bus b in time t

$P^{(e)}_{b,t}$ Real power generation from existing (e) generators connected to bus b in time t

$P^{(n)}_{b,t}$ Real power generation from new (n) NGDGs connected to bus b in time t

$P^{(ip)}_{b,t}$ Real power imported (ip) from the transmission grid via bus b in time t

$Q_{b,t}$ Reactive electric power generation connected to bus b in time t

$Q^{(e)}_{b,t}$ Reactive power generation from existing (e) generators connected to bus b in time t

$Q^{(n)}_{b,t}$ Reactive power generation from new (n) NGDG connected to bus b in time t

$Q^{(ip)}_{b,t}$ Reactive power imported (ip) from the transmission grid via bus b in time t

$Q^{(c)}_{b,t}$ Reactive power generation from capacitor bank (c) connected to bus b in time t

$S_{i,t}$ NG supply from NG source node i in time t

$D_{i,t}$ NG demand at node i in time t

$\Phi_{i,j,t}$ NG flow-rate in the pipe connecting nodes i and j in time t

$\Psi_{i,j}$ The pipeline resistance of the pipe connecting NG nodes i and j

$v_{b,t}$ Bus voltage in time t

$\hat{p}_{b,t}$ Real power flow from sending node b between buses b and $b+1$ in time t

$\hat{q}_{b,t}$ Reactive power flow from sending node b between buses b and $b+1$ in time t

$\hat{s}_{b,t}$ Complex power flow between buses b and $b+1$ in time t

Variables continued

$\Theta_{i,t}$	Square of the NG pressure at source node i in time t
$\Theta_{j,t}$	Square of the nodal NG pressure at sink node j in time t
$O_t^{u,d}$	Real call option created by expansion plan in time t base on upward (u) or downward (d) realization of electric power demand
$O_{y_{i,j,t}}^{u,d}$	Real call option presented by pipeline y between nodes i and j in time t base on upward (u) or downward (d) realization of electric power demand

G Parameters

$\mathbb{P}^s$	The probability associated with scenario s
$C_{\eta,t}$	Investment cost of each expansion plan η
δ	Risk-free drift rate
ΔT	Time interval between two short time planning horizon
$C_\rho^{(I)}$	Present value of the overnight investment (I) cost of installing NGDG of size ρ
$C_\rho^{(I)}$	Present value of the overnight investment (I) cost of installing capacitor bank of size ρ
$C_p^{(I)}$	Present value of the overnight investment (I) cost of building a pipe of type y
$C^{(o)}$	Operating (o) cost i.e. fixed and variable cost of embedded electric power generation
$L_{i,j}$	Length of existing and candidate pipe connecting NG nodes i and j
$\Delta_{i,j}$	Diameter of existing and candidate pipe connecting NG nodes i and j
F_r	Annual failure rates of each segment of pipeline per km
τ	Cost of repairing a segment of the pipeline
OC	Outage cost of a segment of the pipeline
ς	Average outage duration of a segment of the pipeline
x_b	Reactance of the feeder connecting bus b to $b+1$
r_b	Resistance of the feeder connecting bus b to $b+1$
$P_{b,t}^{(L)}$	Peak local real power demand at bus b in time t
$Q_{b,t}^{(L)}$	Peak local reactive power demand at bus b in time t

Parameter continued

$\underline{\hat{S}_b}$	Lower limit on the complex power flow in the distribution feeder b
$\overline{\hat{S}_b}$	Upper limits on the power flow in the distribution feeder b
$\mathbb{P}^u$	Probabilities of upward realization of uncertain electric demand
$\mathbb{P}^d$	Probabilities of downward realization of uncertain electric demand
$\underline{V_b}$	Lower limit on the bus b voltage
$\overline{V_b}$	Upper limit on the bus b voltage
PG_ρ	Real power nameplate capacity of generator ρ
QG_ρ	Reactive power nameplate capacity of generator ρ
QC_ρ	Nameplate capacity of capacity bank ρ
a_i,b_i, c_i	The gas fuel rates coefficients of the NG-fired generators
M_1	Maximum total possible NG flow-rate in any section of the pipeline in time t
M_2	Maximum possible pressure difference between two nodes
$\Gamma_{i,t}$	NG pressure at the source NG node i in time t
$\underline{\Gamma_i}$	Lower limit on the nodal pressure at source nodes i
$\overline{\Gamma_i}$	Upper limit on the nodal pressure at source nodes i
$\underline{\Theta_{i,t}}$	Lower limit on the square of the nodal pressure at source nodes i
$\overline{\Theta_{i,t}}$	Upper limit on the square of the nodal pressure at source nodes i

H. Sets

Ω_B	Set of electricity buses, indexed by (b,r)
Ω_p	Set of NG distribution pipes, indexed by (i,j)
Ω_ρ	Set of quantized NGDG sizes
Ω_ρ	Set of quantized capacitor bank sizes
Ω_d	Set of NG demand nodes
Ω_s	Set of supply nodes

4.1 Introduction

The global electric power generation capacity is forecasted to increase by 69% from 21.6 trillion kilowatt-hours (kWh) in 2012 to 36.5 trillion kWh in 2040 with non-Organization for Economic Co-operation and Development (non-OECD) economies accounting for 61% of this growth [95]. In this period, the share of electricity generation from Natural Gas (NG) is also expected to increase by 6% from the current 22% of total global electric power generation capacity and 42% of these capacity additions are expected to be Natural Gas-fired Distributed electric Generators (NGDGs) such as microturbines, fuel cells, gas turbines and reciprocating engines [7]. Some of the drivers for the increasing interest in the integration of NGDGs includes its modularity, scalability, short installation time, ease of deployability, relatively high efficiencies, fast ramp rate, relatively low sunk cost, competitive investment and operational cost and the relative ease of financing [19, 70, 96]. These make them attractive to power utilities in developing regions of the world where existing infrastructure is limited, regulatory institutions are weak and significant budgetary constraints exists.

The effective operation of NGDGs depends on the availability of reliable and adequate NG supply thereby necessitating better coordination between the planning of the electric and NG distribution systems. Traditionally, these systems are planned separately, however, with the increasing interest of energy utilities around the world in the integration of NGDGs, there is a growing interest in the integrated planning of the electric and NG distribution systems [19, 39]. Integrated planning of both systems involves planning the NG and electric power generation and distribution at lower pressure and voltages respectively. Whereas distribution transformers help ensure acceptable voltage ranges are not violated in the electricity distribution network, the NG distribution must be properly planned to avoid nodal pressure violations because of the normal absence of NG compressors at this level of NG distribution. In most of the existing models for the integrated planning of both systems, the objective is the minimization of the present value of the investment and operational cost [19, 22, 23, 39, 97].

Planning both systems is however not that straightforward due to the difference in economies of scale, irreversibility, adaptability to changes in technology, economic and market conditions. For example, whereas NGDGs such as the aero-derivative gas turbines placed on wheels [98] provide great size and location flexibilities, investment in NG pipelines are often less flexible to changes in economic and market conditions. Similarly, the reversibility and sunk cost of investments in these two systems differs, while NGDGs can be relocated or sold in the presence of a change in market condition, NG pipelines do not provide this flexibility because adjustments are usually less economical. That being said, in the presence of favorable market and economic condition, a carefully planned NG distribution system provides valuable real options to extend existing pipelines or quickly scale-up of the integration of NGDGs down the line in the future. The ability to assess the value of these options is a valuable tool for a planner.

The scalability, modularity, and deployability of NGDGs are specifically of interest to distribution utilities especially in a climate where the regulatory framework allows the integration of distributed generation because of the managerial flexibilities they offer. This is because they offer the management of the utility options to adapt investment decisions such as the decision to expand, defer, scale up/down or abandon investments to new economic, technological and market conditions. This differs from the traditional planning methodologies where long-term plans are developed based on present assumptions and goals. The value of the managerial flexibilities increases with the complexity of the systems being planned and the planning horizon of interest.

The increasing integration of NGDGs translates to an increasing cascaded interdependency between the electric power and NG distribution system and presents some reliability challenges because of the ease of propagation of reliability concerns between both systems [22]. For example, an outage on the NG distribution system can lead to outages of NGDGs and consequently electric power outages. In addition, the interdependencies between these systems can result in expansion management complications because of the difference in their expansion flexibilities. For example, while NGDGs are relatively easy to scale up, natural gas pipelines do not offer similar

flexibilities. Similarly, the investment reversibility, life cycle, planning and investment horizon of the electric and NG distribution systems differs significantly especially in regions with weak existing infrastructure, thereby increasing the financial and managerial risk associated with planning these systems and consequently the financial viability.

Despite the advantages of NGDGs, it is not unusual for traditional financial planning tools such as Discounted Cash Flow (DCF), Net Present Value (NPV) and Internal Rate of Return (IRR) to return unfavourable outcomes especially in locations where infrastructure deficits necessitate extensive infrastructure additions or in situations where the economies of scale are unable to support the investment of interest [24]. However, the inability of these traditional planning tools to value flexibilities, adaptability and potential downstream opportunities arising from the exploitation of earlier investments, means sometimes these tools can be limited in their assessment of long-term investment plans. Real Options Analysis (ROA) provides a framework for valuing flexibilities created by uncertain parameters in a long-term multi-stage investment plan [99].

Recent research has applied ROA to energy system related problems, for instance, in [100], ROA was used to evaluate the flexibility in delaying irreversible investments associated with the learning curve information on the prospect of integrating renewable power generation. In [101], a ROA framework for assessing the effects of uncertain government climate policies on private investor's decision to invest in electricity generation from coal, NG, and nuclear power was presented. Reference [24] proposed a ROA based model that utilities can employ to access the managerial and financial flexibilities of multiple interrelated generation planning projects.

In this paper, we extend previous research [19,22,23,37] on the integrated planning of NGDGs and NG distribution networks and the real option approach to electric power generation planning presented in [24,25] by incorporating the evaluation of the real options presented by the flexibilities of NGDG and NG pipeline in the planning algorithm. The proposed model differs from [24, 25] in that it concentrates on the integrated planning of two interdependent system as opposed to a single system. The proposed model differs from [26–28] in that it concentrates on the integrated

planning at the distribution level. Furthermore, it differs from [22, 23, 26–28] by evaluating and ascribing values to initial investments based on the options they present in light of uncertain future parameters such as electric power demand. This increase the financial viability of the expansion plan as expansion options are selected based on the values they present. The proposed model develops a long-term plan in mainly two stages: the identification of NGDG and NG pipeline expansion options and the assessment of the options they present. These options include the option to execute, delay or abandon each of the components of the expansion plan.

Long-term expansion options are often assessed by carrying out decision analysis under uncertainties and risk management [102]. For example, Chance constrained programming (CCP) is a decision analysis approach that satisfies an "a priori" selected reliability level while accommodating uncertainties in planning parameters [42]. Leveraging on the computed sizes and locations of NGDGs and the route of NG distribution pipelines in [23], the values of the real options to expand, delay or abandon either of the identified potential NGDG or NG pipeline expansion options was incorporated into the development of a long-term integrated expansion plan. The proposed methodology is tested on a modified simple 9 and 33-test bus system for a long planning horizon of 10 years. The real option assessment of the flexibilities presented by NGDGs and NG distribution system is from the viewpoint of developing environments where access to capital is limited and the electricity supply from the transmission system is constrained.

The rest of this paper is structured as follows. The long-term planning real option-based model is discussed in section 2. The proposed real option solution methodology is presented in section 3, and illustrated on two test systems with different levels of complexities in section 4. Section 6 concludes the paper.

4.2 Mathematical model of the Real Option analysis in the joint planning of NGDG and NG distribution system

The Real Option in the joint planning of NGDG and NG distribution considers the options to expand, delay or abandon investment in the long-term integrated planning problem by incorporating the probabilities associated with the realization of potential scenarios of the random parameters [25, 103].

4.2.1 Objective of the Real option analysis

The layout of the modeling structure of the real options analysis approach to developing an integrated long-term plan of the NGDGs and NG distribution pipeline is shown in Fig. 4.1. The inputs into the model are the technical specifications of the NG and electric distribution systems, candidate NGDGs and NG pipelines, and the electricity and NG demand forecast. The planning model includes the identification of strategic options, development of the scenario lattice process and the real option assessment. The output of the model is the contingency development plan for NG and NGDG expansion. The mathematic model of the planning model is presented in this section.

The objective of the real options analysis is to optimize the long-term investments while considering the values of each stage of investment, the scenarios of uncertain parameters and its associated probabilities. The mathematical representation of the Real Option in the expansion of NG distribution system and NGDG is formulated in (4.1).

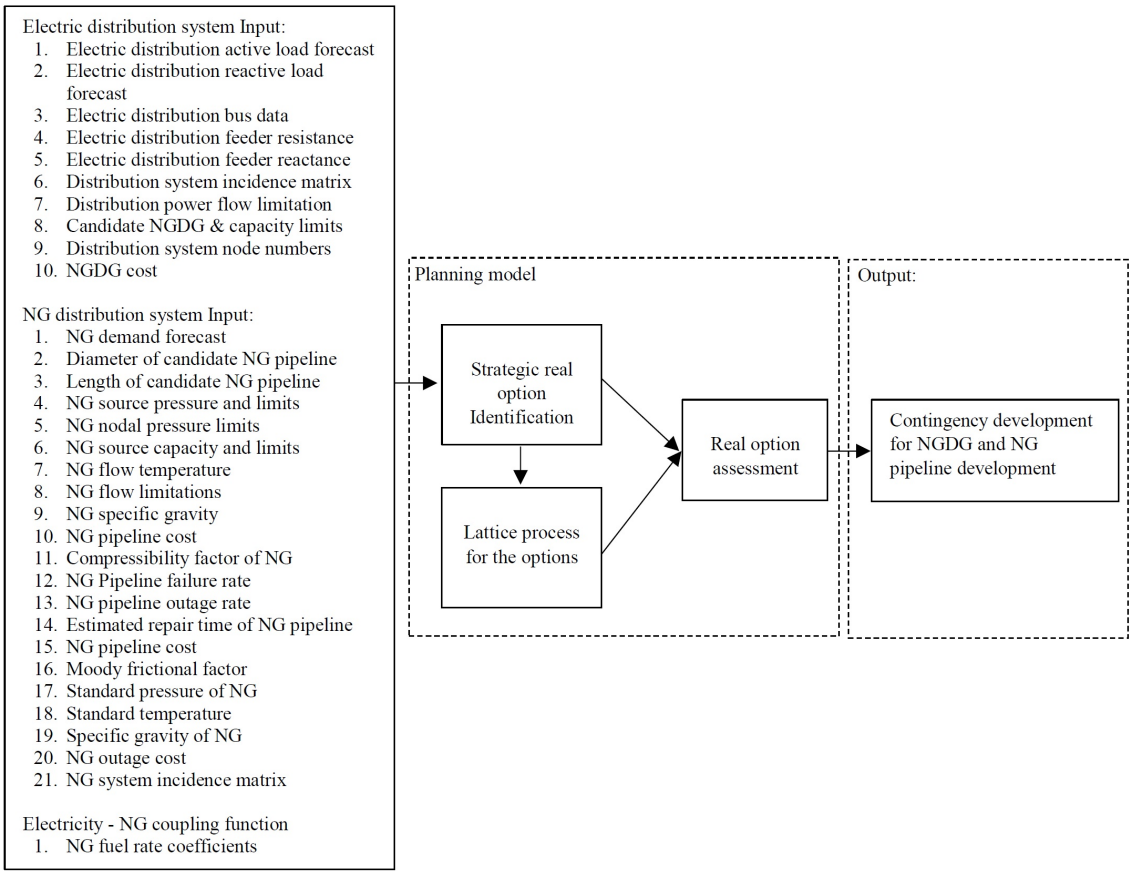


Figure 4.1: Layout of the long-term planning model

$$min \;\; z = \sum_{s} \mathbb{P}^{(s)} \sum_{t}^{T} \Big(\sum_{\eta} C_{\eta,t} \gamma_{\eta,t}^{(s)} (1+\delta)^{(\Delta T(1-t))} \Big) \tag{4.1a}$$

$$C_{\eta,t} = \Big(\sum_{b}^{\Omega_b} \Big(\sum_{\rho}^{\Omega_\rho} \lambda_{\rho,b,\eta,t} C_{\rho}^{(I)} + P_{b,\eta,t} C^{(o)} \Big) + \sum_{b}^{\Omega_b} \sum_{\rho}^{\Omega_\rho} \pi_{\rho,b,\eta,t} C_{\rho}^{(I)} + \sum_{i,j}^{\Omega_p} \Big(C_{p}^{(I)} L_{i,j} (y_{i,j,\eta,t+1} - y_{i,j,\eta,t}) + F_r L_{i,j} \varsigma (\Phi_{i,j,t} \times OC) + \tau \Big) \Big) \quad \forall \rho \in \Omega_\rho, \rho \in \Omega_\rho, b \in \Omega_b, (i,j) \in \Omega_p, t \in T \tag{4.1b}$$

Subject to :

$$\gamma_{t,\eta-1}^{(s)} \leq \gamma_{t,\eta}^{(s)} \quad \forall t \in T \tag{4.1c}$$

$$\gamma_{t,\eta}^{(s)} \in 0,1 \qquad \forall s, \eta, t \tag{4.1d}$$

The physical and operational constrains on the electric distribution system (4.1e)

Electricity – NG coupling constraint (4.1f)

The physical and operational constrains on the NG distribution system (4.1g)

The objective of the ROA model presented in (4.1a) is the maximization of the value of the expansion plan. This is partly achieved by minimizing expected investment, operational, cost of expanding the electricity and NG network to meet electricity and NG demand under various scenarios when a staged and flexible expansion plan strategy is adopted. The cost associated with the probability $\mathbb{P}^{(s)}$ of each of the scenario under consideration are expanded in equation (4.1b).

The first two-term of (4.1b) are the investment and operational costs associated with the NGDG respectively. The investment cost is incurred when a new NGDG is integrated i.e. when $\lambda_{\rho,b,\eta,t} = 1$ while, the operational cost i.e. fixed and variable operational cost is dependent on electricity generation $P_{b,\eta,t}$ from new and existing NGDG. The third term is the investment cost of capacitor banks required for reactive power compensation. The fourth term of (4.1b) is the investment cost of adding new or extending existing NG pipeline as a function of the length of the pipeline. The fifth term is the cost of losing a segment of the pipeline [22]. This cost is dependent on the failure rate, pipeline length, outage duration, flow-rate of NG, the average cost of an outage to the utility and the average repair time of a segment of the pipeline. The operational cost i.e. cost of maintenance of the pipeline is ignored because it is negligible in comparison to the cost of NG which makes up a large portion of the variable cost of electric power generation.

Constraint (4.1c) ensures expansion stages are not skipped [103] while (4.1d) is a binary variable that indicates the implementation of an expansion plan in each scenario. The ROA assessment is constrained by the physical and operational constraints of the electric power distribution system (4.1e), the coupling constraints (4.1f) between the electric and the NG distribution systems (4.1g). These constraints are modeled and explained in the next three subsections.

4.2.2 Physical and operational constraints on the electric distribution system

Consider the simplified primary circuit of an electric power distribution system with sectionalizing switches CB1 - CB5 represented in Fig. 4.2.

The dots represent load points, NGDG connection points or distribution connection points. CB1 - CB5 are opened or closed to reconfiguration the distribution system to reduced the system

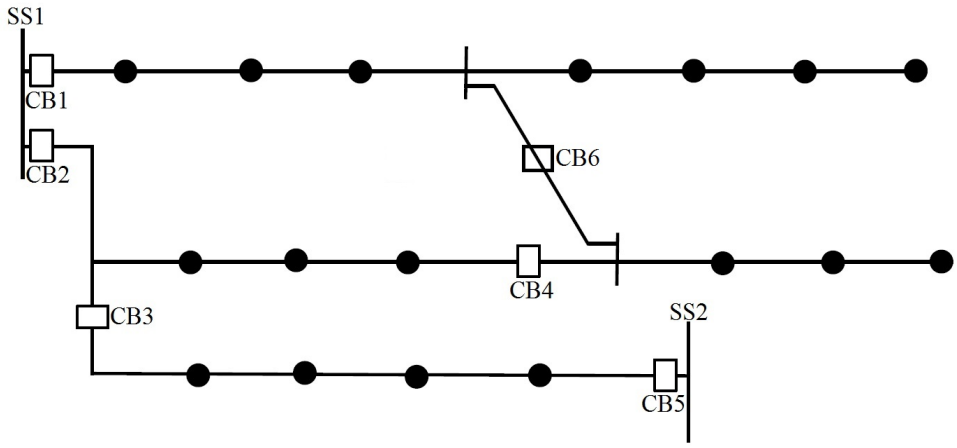


Figure 4.2: Schematic diagram of a primary circuit of a distribution system

loss and relieve overload in the network [11, 79]. The distribution system is normally operated as a set of radial networks [11, 78, 79, 81], consequently the system in Fig. 4.2 can be assessed as radial distribution system assuming a configuration where CB4 and CB5 are open. The system can be analyzed in a similar manner under different combination of switches. Let Fig. 4.3 represent a radial distribution network, the physical and capacity constraints are modeled in (2)- (18). The

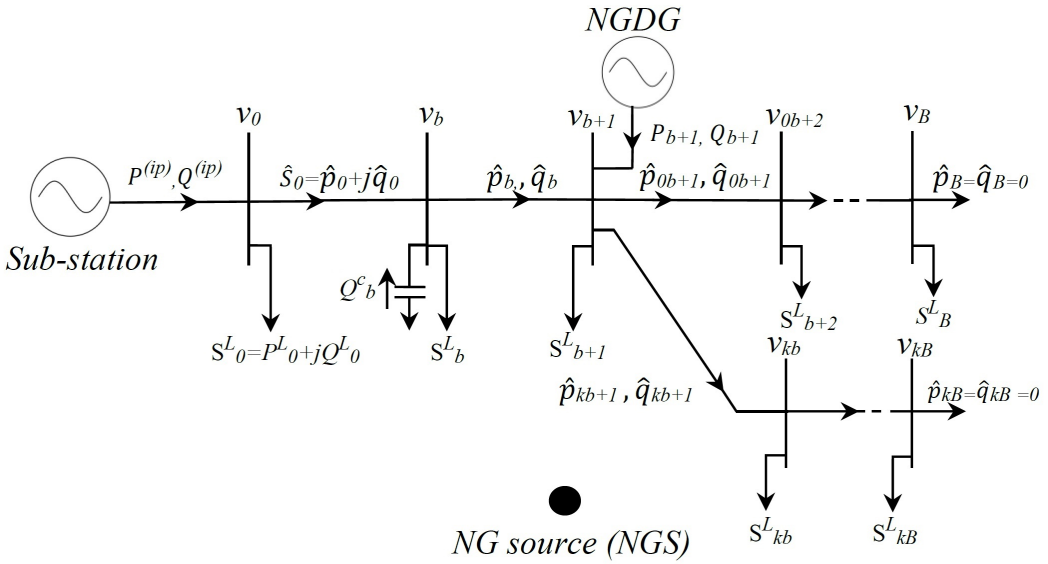


Figure 4.3: Typical N-bus radial distribution system with DG placed at bus_{b+1}

following assumptions were made in modeling the physical and capacity constraints of the electric distribution system.

- The distribution system is connected to the transmission systems via a substation and, the substation voltage, v_0 is assumed to be constant
- New and existing generators to be of quantized real and reactive power size PG_ρ and QG_ρ. This assumption aligns with the common practice of original power equipment manufacturers
- The transmission system to which the distribution system is connected is assumed to be constrained and its expansion is outside the jurisdiction of the distribution utility. This is typical of developing or suburban/rural environments
- The candidate generators i.e. new generators are assumed to natural gas fired-distributed generators i.e. NGDGs

The power flow in the radial feeders is modeled as a set of recursive equations i.e. the forward update DistFlow branch equations [11, 23, 78, 79, 81]. Given the series impedances of feeder $z_b = r_b + jx_b$, the complex nodal power demands $S_b^{(L)} = P_b^{(L)} + jQ_b^{(L)}$ and the complex power flow in each feeder $\hat{S}_b = \hat{p}_b + j\hat{q}_b$, the Kirchhoff's nodal flow conservation for real and reactive power in a typical radial system shown in Fig. 4.3 are modeled in (4.2) and (4.3) [78, 81]. Equation (4.2) states that the real nodal power generation less the real power loss on the feeder is equal to the stochastic real nodal power demand and the real power outflow. Where kb is the bus identification order for lateral feeders k and $k = 0$ on the main radial feeder i.e. $0b = b$. A similar relationship for reactive power nodal balance is modeled in (4.3).

$$P_{b+1,t} + \big[\hat{p}_{b,t} - \frac{r_{b+1}(\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2)}{v_{b,t}^2}\big] = P_{b+1,t}^{(L)}(\xi_1) + \sum_{k:(b+1,k)} \hat{p}_{kb+1,t} \quad b = 0, 1, ., B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{4.2}$$

$$Q_{b+1,t} + \big[\hat{q}_{b,t} - \frac{x_{b+1}(\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2)}{v_{b,t}^2}\big] = Q_{b+1,t}^{(L)}(\xi_2) + \sum_{k:(b+1,k)} \hat{q}_{kb+1,t} \quad b = 0, 1, ., B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{4.3}$$

The resistance and reactance of distribution feeders give rise to real and reactive energy losses and consequently voltage differences between connected electricity buses. The voltage drop in the feeder connecting buses b to $b+1$ as shown in Fig. 4.3 is modeled in constraint (4.4) based on Ohms law [11].

$$v_{b+1,t}^2 = v_{b,t}^2 - 2(r_b\hat{p}_{b,t} + x_b\hat{q}_{b,t}) + \left(r_{b,t}^2 + x_{b,t}^2\right)\frac{\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2}{v_{b,t}^2} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{4.4}$$

The outward real and reactive power flow from the terminal electric power bus **B** connected to the main or branched radial feeder is constrained to zero by (4.5).

$$\hat{p}_{kB} = \hat{q}_{kB} = 0 \qquad B \in \Omega_b, k \in \mathbb{N} \tag{4.5}$$

The lateral distribution feeders from a particular bus all equal reference bus voltage. $v_{0b,t}$ in (4.6), is a dummy notation representing the voltage of the source bus to which the lateral branched feeder k is connected [11, 79].

$$v_{0b,t} = v_{b,t} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{4.6}$$

The real power generation modeled in constraint (4.7), constitute real power generation from existing and new generators i.e. NGDGs and power import from the transmission system via the transmission substation.

$$P_{b,t} = P_{b,t}^{(e)} + P_{b,t}^{(n)} + P_{b,t}^{(ip)} \qquad b \in \Omega_b, t \in T \tag{4.7}$$

The total reactive power supply in the distribution system constitute reactive power generation from new NGDGs and existing power generators, reactive power import from the grid and reactive power compensation from capacitor banks as shown in constraint (4.8). NGDGs can be reactive power injectors or absorbers, while shunt capacitors are reactive power injector.

$$Q_{b,t} = Q_{b,t}^{(e)} + Q_{b,t}^{(n)} + Q_{b,t}^{(ip)} + Q_{b,t}^{(c)} \qquad b \in \Omega_b, t \in T \tag{4.8}$$

The capacity limit on the complex power flow in the feeders is modeled in (4.9). The relationship between the active, reactive and complex power flow in a feeder b at time t is modeled in (4.10).

$$\underline{\hat{S}_b} \leq \hat{s}_{b,t} \leq \overline{S_b} \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{4.9}$$

$$\hat{p}_{b,t}^2 + \hat{q}_{b,t}^2 = |\hat{s}_{b,t}|^2 \quad b = 0,1,...,B-1 \in \Omega_b, t \in T \tag{4.10}$$

The bus voltages is constrained within the acceptable standard voltage range by (4.11)

$$\underline{V_b} \leq v_{b,t} \leq \overline{V_b} \qquad b \in \Omega_b, t \in T \tag{4.11}$$

At any point in time, the real and reactive power output from new and existing power generators can range from zero to a maximum of the nameplate capacity of the generators. Constraints (4.12) and (4.13) imposes the capacity limits on the real and reactive power generation from new NGDGs while constraints (4.14) and (4.15) ensures that the nameplate capacity limits of existing generators are not exceeded.

$$0 \leq P_{b,t}^{(n)} \leq \lambda_{\rho,b,t} PG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{4.12}$$

$$0 \leq Q_{b,t}^{(n)} \leq \lambda_{\rho,b,t} QG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{4.13}$$

$$0 \leq P_{b,t}^{(e)} \leq \lambda_{\rho,b,t} PG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{4.14}$$

$$0 \leq Q_{b,t}^{(e)} \leq \lambda_{\rho,b,t} QG_\rho \qquad \rho \in \Omega_\rho, b \in \Omega_b, t \in T \tag{4.15}$$

Constraints (4.12) - (4.15) are only active when these generators are connected i.e. when the binary variable $\lambda_{\rho,b,t} = 1$. Constraint (4.16) ensures the reactive power output for a connected

capacitor bank i.e. when $\pi_{\rho,b,t} = 1$ does not exceed the nameplate capacity of the capacitor bank.

$$Q_{b,t}^{(c)} = \pi_{\rho,b,t} Q_{\rho}^{(c)} \qquad \rho \in \Omega_{\rho}, b \in \Omega_b, t \tag{4.16}$$

The co-connections of capacitor banks and electricity generators can cause undesired instability and voltage fluctuations especially in the presence of a sudden reduction of inductive load. In consequence to this, constraint (4.17) ensures that capacitor banks and NGDGs are not co-located at a given bus b.

$$\lambda_{\rho,b,t} + \pi_{\rho,b,t} \leq 1 \qquad \rho \in \Omega_{\rho}, \rho \in \Omega_{\rho} b \in \Omega_b, t \in T \tag{4.17}$$

Constraint (4.18) ensures that for a terminal bus B on the main or branched radial feeder, the active and reactive power outflow is zero.

$$\hat{p}_{kB} = \hat{q}_{kB} = 0 \qquad (b = 0, 1, .., B-1; k) \in \Omega_b \tag{4.18}$$

The typical power losses in distribution feeders are much less than the power flow. As a result, constraints (4.2), (4.3) and (4.4) can be approximated to (4.19a), (4.19b) and (4.19c) by eliminating the quadratic terms as shown in (4.19) [79].

$$P_{b+1,t} + \hat{p}_{b,t} = P_{b+1,t}^{(L)}(\xi_1) + \sum_{k:(b+1,k)} \hat{p}_{kb+1,t} \quad b = 0, 1, .., B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{4.19a}$$

$$Q_{b+1,t}^{s} + \hat{q}_{b,t} = Q_{b+1,t}^{(L)}(\xi_2) + \sum_{k:(b+1,k)} \hat{q}_{kb+1,t} \quad b = 0, 1, .., B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{4.19b}$$

$$v_{b+1,t}^2 = v_{b,t}^2 - 2(r_b \hat{p}_{b,t} + x_b \hat{q}_{b,t}) \qquad b = 0, 1, .., B-1 \in \Omega_b, t \in T \tag{4.19c}$$

The approximate nodal balance equations for each scenarios evolution of the real and reactive power demand is modeled as (4.20a) and (4.20b)

$$P_{b+1,t}^{s} + \hat{p}_{b,t}^{s} = P_{b+1,t}^{(s,L)} + \sum_{k:(b+1,k)} \hat{p}_{kb+1,t}^{s} \quad b = 0, 1, .., B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{4.20a}$$

$$Q_{b+1,t}^{s} + \hat{q}_{b,t}^{s} = Q_{b+1,t}^{(s,L)} + \sum_{k:(b+1,k)} \hat{q}_{kb+1,t}^{s} \quad b = 0, 1, .., B-1 \in \Omega_b, k \in \mathbb{N}, t \in T \tag{4.20b}$$

4.2.3 Electricity and natural gas coupling constraint

The NG demand $D_{i,t}$ by NGDG connected to bus b and node i in time t assuming a constant non-electricity NG demand is computed from the electricity-NG coupling constraint modeled in (4.21) [19, 69].

$$D_{i,t} \geq a_i + b_i S^g_{b,t} + c_i (S^g_{b,t})^2 \tag{4.21}$$

a_i, b_i and c_i are the gas fuel rate coefficients for converting electricity to NG demand and electricity buses b and NG nodes i are assumed to be co-located.

4.2.4 Physical and operational constraints on Natural gas distribution

NG distribution system involves moving smaller volumes of NG over a relatively shorter distance [14, 15, 104], therefore they comprise networks of small diameter (12.7mm - 153.4mm) pipes used to transport NG at low pressure (i.e. 14kPa- 1380kpa). The NG distribution flow equations, physical and operational constraints assuming isothermal flow along a horizontal segment of the NG distribution pipeline such that the effect of kinetic energy is negligible are presented in (4.22) - (4.32) [18, 19, 23]. An adequate pressure differential is required for NG flow from the source to the demand nodes. In consequent to this, constraint (4.22) ensures the NG pressure at the NG source node is set to the maximum.

$$\Gamma_{i,t} = \overline{\Gamma_i} \qquad \forall i \in \Omega_s, t \in T \tag{4.22}$$

Constraint (4.23) ensures the NG pressure at any NG demand nodes remains within the acceptable range of NG pressure. While constraint (4.24) limits the maximum possible NG-flow rate in any segment of the NG distribution pipeline.

$$\underline{\Gamma_i} \leq \Gamma_{i,t} \leq \overline{\Gamma_i} \qquad \forall i \in \Omega_d, t \in T \tag{4.23}$$

$$\Phi_{i,j,t} \leq M_1 z_{i,j,t} \qquad \forall (i,j) \in \Omega_p, t \in T \tag{4.24}$$

Constraint (4.24) limits the possible NG-flow rate in any segment of the NG distribution pipeline. Constraint (4.24) is formulated such that it only applies when there is NG flow in the particular segment of the pipeline i.e. when $z_{i,j,t} = 1$. M_1 is set to the maximum possible NG flow in the network. Constraint (4.25) is the NG nodal balance equation and it ensures that the net NG flow in and out of a node equals the difference between NG demand and supply.

$$\sum_{j}^{\Omega_p} \Phi_{i,j,t} - \sum_{j}^{\Omega_p} \Phi_{j,i,t} = S_{i,t} - D_{i,t} \qquad \forall i \in \Omega_s \cup \Omega_d, t \in T \tag{4.25}$$

The general steady-state NG flow is modeled in constraints (4.26), (4.27) and (4.28) [18, 23].

$$(\Gamma_{i,t}^2 - \Gamma_{j,t}^2) - \Psi_{i,j}\Phi_{i,j,t}^2 \geq M_2(z_{i,j,t} - 1) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{4.26}$$

$$(\Gamma_{i,t}^2 - \Gamma_{j,t}^2) - \Psi_{i,j}\Phi_{i,j,t}^2 \leq M_2(1 - z_{i,j,t}) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{4.27}$$

$$\Psi_{i,j} = \left(\frac{1}{1.1494 \times 10^{-3}}\right)^2 \frac{GT_f L_{i,j} Zf}{\Delta_{i,j}^5} \left(\frac{\Gamma_b}{T_b}\right)^2 \tag{4.28}$$

The difference of the squared pressure between the NG source i and demand nodes j in time t is equivalent to the product of the squared flow-rate $\Phi_{i,j,t}$ and the pipeline resistance $\Psi_{i,j}$. The presence of $z_{i,j,t}$ in (4.26) and (4.27) ensures that there is only a pressure drop between connected NG nodes i.e. when $z_{i,j,t} = 1$. A large number M_2 is selected, usually around the square of the largest possible nodal NG pressure such that when $z_{i,j,t} = 0$, constraints 4.26) and (4.27) are not violated. Constraints (4.26) and (4.27) ensures that NG flows only from high to low pressures nodes. The pipeline resistance $\Psi_{i,j}$ is defined in (4.28). $\Delta_{i,j}$ is the diameter of the pipeline and $L_{i,j}$ is the length of the pipe. f is the frictional factor , Γ_b is the base pressure, T_b is the base temperature , G is the NG gravity , Z is the gas compressibility factor, and T_f is the flow temperature.

Constraint (4.29) accommodates NG to flow in either direction between two nodes connected by pipelines [18].

$$z_{i,j,t} + z_{j,i,t} \leq y_{i,j,t} \qquad \forall (i,j) \in \Omega_p, i < j, t \in T \tag{4.29}$$

Constraint (4.30) ensures that existing and new pipeline once installed, remains installed for the entire planning horizon.

$$y_{i,j,t} \leq y_{i,j,t+1} \qquad \forall (i,j) \in \Omega_p, t = 1, ...|T| - 1 \tag{4.30}$$

Constraint (4.31) sets the existing pipeline before the planning horizon to zero. Initializing the existing pipelines increases the manageability of the expansion problem.

$$y_{i,j,0} = 0 \qquad \forall (i,j) \in \Omega_p, i < j \tag{4.31}$$

Constraint (4.32) ensures the NG flow and nodal pressure are always positive.

$$\Phi_{i,j,t}, \Gamma_{i,t} \geq 0 \qquad \forall (i,j) \in \Omega_p, t \in T \tag{4.32}$$

The squared nodal pressure and NG flow rate in (4.26) and (4.27) introduce non-linearity in the NG planning model. In order to improve the linearity of (4.26) and (4.27), Γ^2 is replaced with a new variable Θ [18]. (4.26) and (4.27) is consequently modified to (4.33) and (4.34)

$$(\Theta_{i,t} - \Theta_{j,t}) - \Psi_{i,j}\Phi^2_{i,j,t} \geq M_2(z_{i,j,t} - 1) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{4.33}$$

$$(\Theta_{i,t} - \Theta_{j,t}) - \Psi_{i,j}\Phi^2_{i,j,t} \leq M_2(1 - z_{i,j,t}) \qquad \forall (i,j) \in \Omega_p, t \in T \tag{4.34}$$

$$\underline{\Gamma_i}^2 \leq \Theta_i \leq \overline{\Gamma}_i^2 \qquad \forall i \in \Omega_d, t \in T \tag{4.35}$$

Although the expansion model remains non-linear as result of the squared variables Φ^2 in (4.26) and (4.27), the recent improvement in computational methods has shown acceptable solutions to Mixed Integer Nonlinear Programming (MINLP) problems [18, 52].

4.3 Real Option Solution methodology

The Real option approach to the long-term planning of NGDGs and NG distribution systems is complicated by the path-interdependencies of the different components of the plan [103]. For example, the ability to exercise a downstream option to connect NGDGs of a particular size to any of the electric buses is dependent on the evolutionary path of NG distribution pipelines expansion. Similarly, the ability to exercise a downstream option to extend existing NG pipeline or build a new one can be dependent on the location and size of existing or proposed NGDG connection or expansion. The managerial flexibility to call, delay or abandon investment options in the integrated long-term planning problem can be based on the timing, sizing or location of NG pipeline and NGDG integrations. In this paper, we assess the options associated with the timing of NG distribution pipeline and the integration of NGDG. The option associated with the timing of the NG pipeline is valued by the downstream option to; extend the pipeline or integrate a new generator or expand an existing one. While the option created by the integration of NGDG is valued by the downstream options of extending the pipeline due to the expansion of electric power generation capacity. For illustrative purposes, we assess options generated by investment in NG distribution pipelines.

The solution algorithm for the real options analysis of the integrated long-term planning of the NG and electric power distribution system is presented in Fig. 4.4.

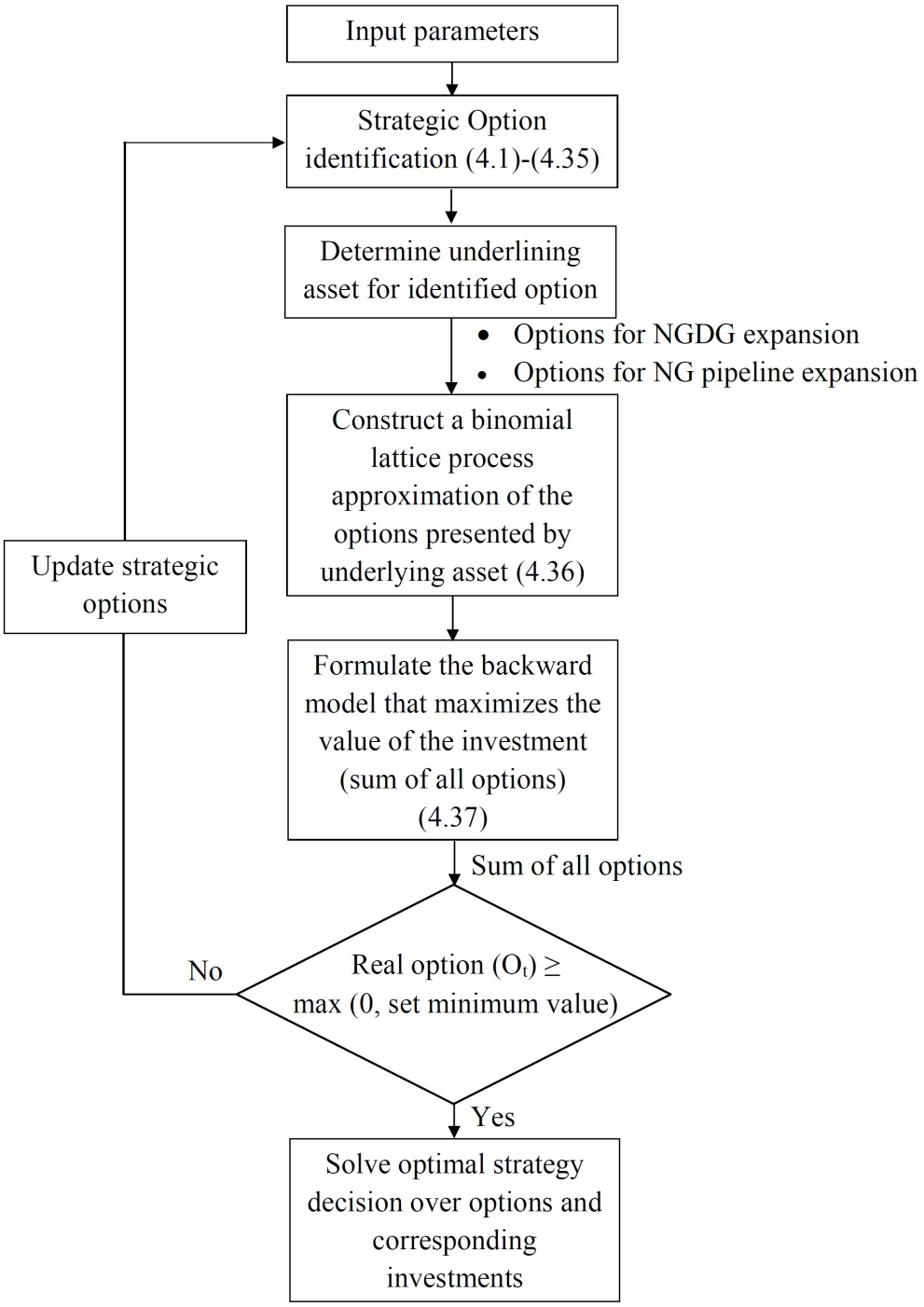


Figure 4.4: Flow chart of the solution algorithm

4.3.1 Input parameters

The input parameters into the solution algorithm include the electricity and natural gas demand forecast, and the technical specifications of the electricity and NG distribution systems.

4.3.2 Strategic option and underlining asset identification

Energy utilities can often modify its long-term expansion plan in response to current realities. The extent of these flexibilities is dependent on the existing underling assets and the level of uncertainties in the planning parameters. As pointed out in [105], the natural gas location marginal price and the electricity location marginal price affects the integrated operation and planning of the electricity and NG system. The extent to which these prices affects the planning of these systems is dependent on the level of coupling between them and the expected operational and physical constraint on the systems. In this paper, the expansion plan is solved via the CCP approach such that the electricity and NG demand are always meet with a desired level of confidence, thereby minimizing potential operational and physical constraints. Consequently, the contingency plan is developed to exploit the uncertainties in the electricity demand. The following steps are employed in the identification of the strategic options and underlining asset:

4.3.2.1 Chance constrained programming planning approach to options identification

The chance constrained programming approach in [23] is summarized below:

- A deterministic integrated planning problem is solved for the location and size of NGDG and NG pipeline
- Using the output of the deterministic model, an NG flow constrained optimal power flow is solved for 1000 samples of complex electric power demand and the average feasibility is computed
- The average feasibility is compared with the desired confidence level

- Where the average feasibility is lesser than the desired confidence level, the inverse cumulative distribution of the real and reactive power demand is updated using an update algorithm. However, if average feasibility is greater or equal to the desired confidence level, an optimal solution is found

4.3.3 Binomial lattice process approximation construction

Considering a set of electricity demand scenarios based on the binomial lattice framework [106], the value of the underlying NG distribution pipeline $v_{y_{i,j},t}$ follows a random walk taking on either of two values i.e. $v^{u}_{y_{i,j},t}$ or $v^{d}_{y_{i,j},t}$ based on the volatility σ of the complex electric power demand [25]. u and d defined in (4.36a) and (4.36b) are the up and down factors with associated upward probability $\mathbb{P}^{u}$ defined in (4.36c). and downward probability $\mathbb{P}^{d}$, where $\mathbb{P}^{d} = 1 - \mathbb{P}^{u}$. ΔT represents the long-term planning time discretization i.e. time between two consecutive stages which must at a minimum accommodate the time-frame required for executing each of the expansion options. ΔT is selected based on the desired accuracy of the expansion plan, the complexity of the system and the minimum time required to implement each of the expansion options.

$$u = e^{\sigma\sqrt{\Delta T}} \tag{4.36a}$$

$$d = e^{-\sigma\sqrt{\Delta T}} \tag{4.36b}$$

$$\mathbb{P}^{u} = \frac{e^{\delta\Delta T} - d}{u - d} \tag{4.36c}$$

4.3.4 Formulating the backward value maximization model

The investment cost $(C^{(p,I)})$ of building a segment of pipeline y provides a real call option for the integration of NGDG $P_{b+1,t}$ at bus b or the extension of pipe y without violating the NG pressure and flow-rate requirement across the NG distribution system. $v^{u,d}_{t}$ is the maximum values of the option presented by an investment evaluated backward in time. The framework for evaluating the values of the real options is presented in (4.37a) and (4.37b)

$$O_t^{u,d} = max[v_t^{u,d} - (C_{\eta,t}), 0] \tag{4.37a}$$

$$O_{y_{i,j,t}}^{u,d} = max[v_{y_{i,j},t}^{u,d} - C_{y_{i,j},t}^{p,I}, 0] \tag{4.37b}$$

Equation (4.37a) is the generalized model for the real options evaluation of the entire system in equation (4.1) and its objective is to maximize the values of the option presented by an investment cost. $O_{y_{i,j},t}^{u,d}$ is the maximum of the difference between the values and investment cost of a particular investment plan. From equation (4.37a), the minimum value of $O_{y_{i,j,t}}^{u,d}$ is zero i.e. the investments does not present an option. A good example of an investment having zero real option is an investment executed in the last year of the planning horizon or an investment implemented base on a forecast that was never realized. The real call option created by a particular pipeline y connecting nodes i, j in time t is modeled in (4.37b).

4.3.5 Convergence criteria

Managerial investment decisions are typically based on the estimated attractiveness of an investment opportunity. Traditional tools such as DCF, NPV, IRR are employed in estimating the investment opportunity with the management favoring that which returns an estimated value that exceeds a set benchmark. In similar fashion, an investment opportunity is attractive if the computed real option value is greater than a maximum of zero and a minimum set value. This value is usually dependent on the investing organization investing philosophy and appetite to risk. The attractiveness of an investment opportunity is directly proportional to the value of the estimated real option.

4.3.6 Update expansion options

Should the real option analysis return a negative real option value, the sets of options is updated or replaced.

4.3.7 Optimal strategy solution

The investments with the largest options are then selected in developing a contingency expansion plan that allows the utility to exploit opportunities or manage risk.

4.4 Description of test system and results

The proposed ROA of the flexibility in the planning of NGDGs and NG distribution system is illustrated with the 9 and 33 bus radial distribution systems with different complexities and layout for a planning horizon of 10 years. The following assumptions were employed in these illustrations.

4.4.1 Basic assumptions and justifications

Itemized below are the assumptions made and associated justifications in the illustration of the proposed model.

1. In the context of this paper, NGDGs are assumed to be all-radial, single-shafted single-stage radial turbine, single stage centrifugal compression, 4-can combustion system, and integral epicyclical gear [57, 107]. In addition, they are often fitted with recuperator allowing them to recover exhaust energy to preheat compressed inlet air [108].

2. Equivalent synchronous 4- pole, 3 phase generators with 0.8 power factor are assumed to be connected to each of the candidate the NGDGs

3. The lower pressure limit at each of the NG demand node is set to 600 kPa in accordance with the minimum pressure required to optimally operate a sample 1MW and 2MW micro turbine NGDG [57, 107]

4. Candidate NGDGs are assumed to be of a quantized size, which is typical of commercially available NGDGs. Two candidate NDGGs of sizes 1.0MVA and 2MVA and an associated capital cost of $\$1,200,000$ and $\$2,000,000$ are considered

5. The NG pressure at the NG source(s) is set to 1380kPa which is the maximum allowable pressure allowed at the NG distribution level in Canada [15].

6. The distribution electric power demand is assumed to grow at 3% per annum [58]

7. The planning of the NG pipelines and NGDG are assumed to be the prerogative of a single utility company with an exclusive right to deliver electric power and NG to a particular location. Utilities such as ATCO energy and Enmax both in Alberta, Canada [59, 92] currently have an exclusive right to distribute NG and electricity in Alberta. Similar trends are expected in a number of developing countries, especially countries rich in NG resources such as Nigeria

8. The expected time of repair for a damaged pipeline (ς) after a major outage is assumed to be 48 hours or two days and the annual failure rate of each segment of the pipeline (τ_p) is assumed to be $0.2/year.\ thousand\ km$ [47, 109]

9. The 6% interest rate was assumed for valuing the time cost of money

10. The average cost of a new pipeline is assumed to be $\$100,000/cm-km$ based a study on North America midstream infrastructure through 2035 prepared for the Interstate Natural Gas Association of America (INGAA) [110]

11. The frictional factor f, the base pressure Γ_b, the base temperature T_b, the NG gravity G, the gas compressibility factor Z, and the flow temperature T_f are assumed to be 0.01, 100 kPa, 288^oK, 0.66, 0.9268, and 283^oK respectively [18]. Z is computed based on the relationship presented in [111].

12. Adequate reactive power compensation was assumed for the entire long-term planning horizon

13. The expansion planning of the transmission system and the substation is assumed to be out of the jurisdiction of the distribution utility planner

14. The rated line voltage of the systems is 23kv

15. the technical specifications of the 9 and 33 bus test distribution systems are presented in [94] and [80] respectively

16. The 10 years planning horizon is divided into four stages of 2.5 years i.e. $\Delta T = 2.5$ based on the assumed time required to implement a set of NG distribution and NGDG expansion option. In addition, ΔT is selected to improve trackability and representation of results. It is important to note that the accuracy of the result increases with the decrease in ΔT

17. The demand volatility σ and drift rate τ are taken to be 8% and 4% respectively which is the average of the volatility of residential and industrial power load [23,84]

4.4.2 9 bus distribution test system

The 9 bus radial distribution system shown in Fig. 4.5 [22, 94], connects to the transmission grid via a distribution substation located at *bus* 0. Buses 1 - 9 are load buses pending the integration of NGDGs. A similar configuration was utilized in [19].

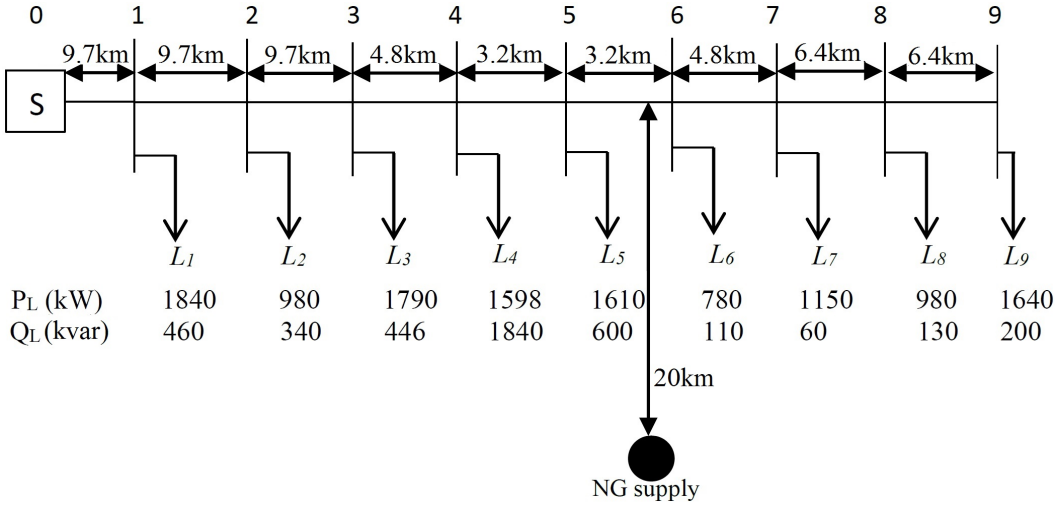


Figure 4.5: 9 bus test system

4.4.3 33 bus distribution test system

To ensure the proposed planning methodology is suitable for larger and complex distribution systems, the proposed model is also illustrated on a standard $33-bus$ distribution system [80] with two NG source nodes i.e. NGS_1 and NGS_2 as shown in Fig. 4.6.

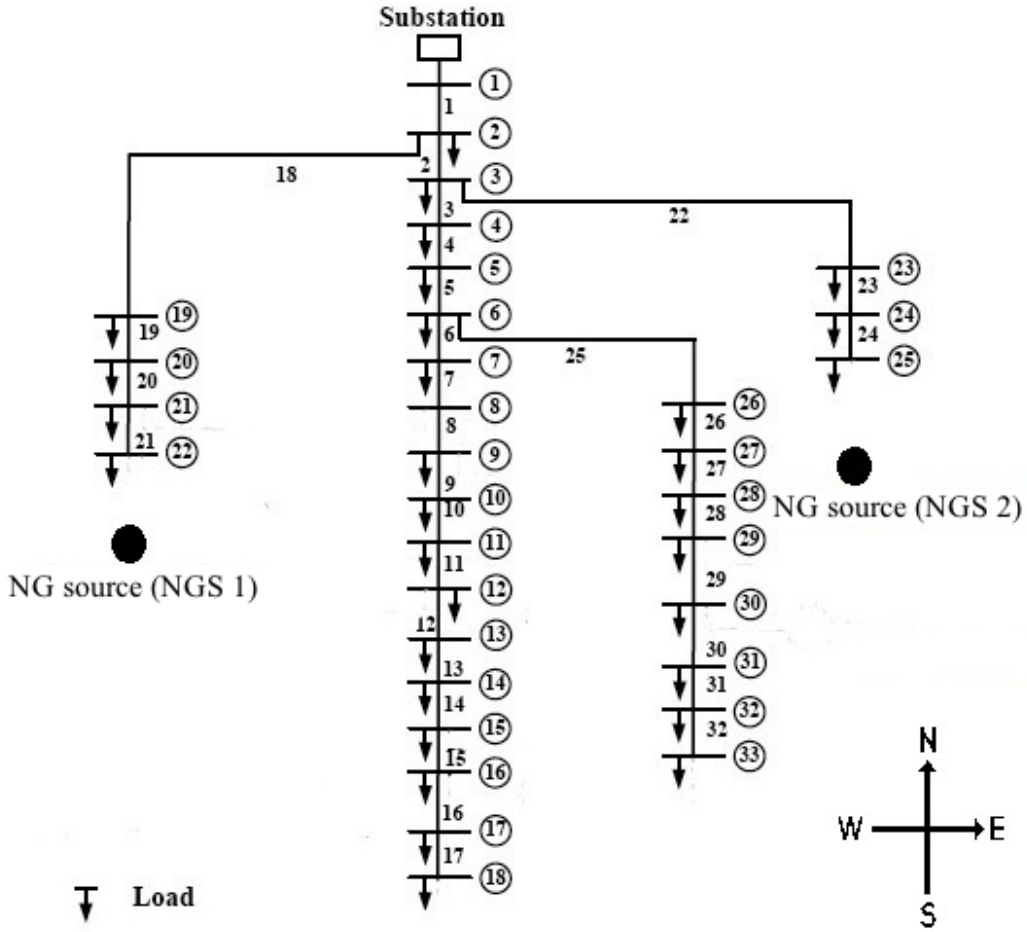


Figure 4.6: Single-line diagram of 33-bus radial distribution system

The following assumptions and modifications were made specifically for the $33-bus$ distribution system:

1. The NG sources are assumed to be 8 *km* south of *bus* 22 and *bus* 25. The length of feeders between the buses was assumed to be 4.8 *km* except for $feeders$ 18, 22, and 25 that are taken to be 16 *km*, 16.1 *km* and 9.7 *km* respectively from their feeding buses [23].

2. The candidate NG distribution pipeline is assumed to share the same right of way with the electric power distribution feeders.

The ROA assessment of the options presented in each scenario of electric power demand growth is solved using a combination of Matlab R2014a and GAMS 24.2 [112].

4.4.4 Identified real options and underlining assets

The candidate expansion plans η for the NG pipelines and NGDGs expansion of the 9 and 33-bus test distribution system and the associated incremental cost shown in Table 4.1 and 4.2 [23]. In selecting the candidate expansion plans, the candidate expansion plans for NG pipelines and NGDGs are separated to accommodate the different construction times of NG pipelines and NGDG's. A visual representation of a one-off expansion plan is presented in Fig. 4.7.

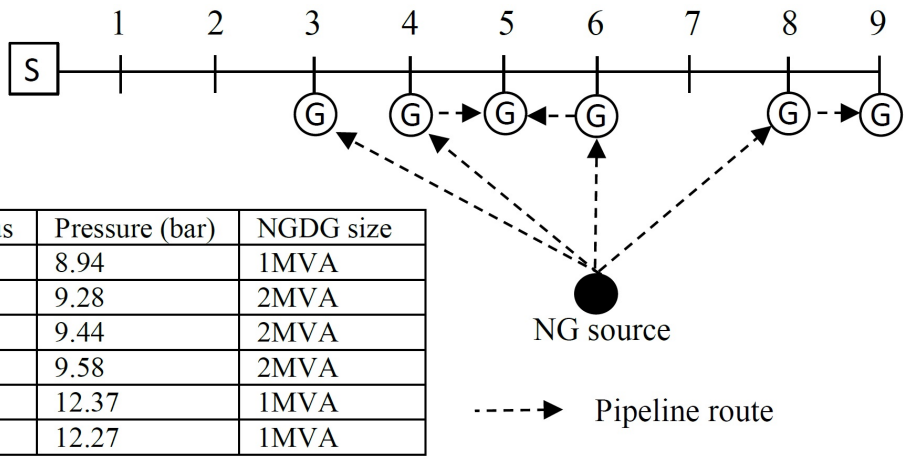
Table 4.1: Candidate expansion options and incremental cost for the 9 bus distribution system

Expansion options	NGDG location & size (MVA_{bus})	NG pipe line route $y_{(i\longrightarrow j)}$	Incremental cost $US\$'$
$\eta 1$	-	$y_{(NGS\longrightarrow 4)}, y_{(NGS\longrightarrow 6)}, y_{(NGS\longrightarrow 8)}, y_{(4\longrightarrow 5)}, y_{(6\longrightarrow 5)}, y_{(8\longrightarrow 9)}$	7,865,000
$\eta 2$	$1_4, 2_4, 2_5, 2_6, 2_8, 1_9$	-	10,400,000
$\eta 3$	$1_4, 2_4, 2_5, [1_6], 2_6, 2_8, 1_9$	-	1,200,000
$\eta 4$	$1_4, 2_4, [1_5], 2_5, 1_6, 2_6, 2_8, 1_9$	-	1,200,000
$\eta 5$	-	$y_{(NGS\longrightarrow 4)}, y_{(NGS\longrightarrow 6)}, y_{(NGS\longrightarrow 8)}, y_{(4\longrightarrow 5)}, y_{(6\longrightarrow 5)}, y_{(8\longrightarrow 9)}, [y_{(NGS\longrightarrow 3)}]$	2,128,000
$\eta 6$	$[1_3], 1_4, 2_4, 1_5, 2_5, 1_6, 2_6, 2_8, 1_9$		1,200,000
$\eta 7$	$1_3, 1_4, 2_4, 1_5, 2_5, 1_6, 2_6, [1_8], 2_8, 1_9$	-	1,200,000
Total cost			25,193,000

[ ] indicates additions to previous expansion plan

4.4.5 Binomial lattice process

The binomial lattice forecast of the evolution coefficient of the complex electric power demand growth is presented in Table 4.3.



Bus	Pressure (bar)	NGDG size
3	8.94	1MVA
4	9.28	2MVA
5	9.44	2MVA
6	9.58	2MVA
8	12.37	1MVA
9	12.27	1MVA

Figure 4.7: NG pipe layout for a one-off expansion plan

Table 4.2: Candidate expansion plan and incremental cost for the 33 bus distribution system

Expansion options	NGDG location & size (MVA_{bus})	NG pipe line route $y_{(i\longrightarrow j)}$	Incremental cost $US\$$
$\eta 1$	-	$y_{(NGS2\longrightarrow 25)}, y_{(25\longrightarrow 5)}$	2,700,000
$\eta 2$	$1_5, 1_{25}$	-	2,400,000
$\eta 3$	-	$y_{(NGS2\longrightarrow 25)}, y_{(25\longrightarrow 5)}, [y_{(5\longrightarrow 26)}]$	900,000
$\eta 4$	$1_5, 1_{25}, [1_{26}]$	-	1,200,000
$\eta 5$	-	$y_{(NGS2\longrightarrow 25)}, y_{(25\longrightarrow 5)}, y_{(5\longrightarrow 26)}, [y_{(NGS1\longrightarrow 22)}]$	500,000
$\eta 6$	$1_5, [1_{22}], 1_{25}, 1_{26}$	-	1,200,000
$\eta 7$	$1_5, [1_5], [1_{22}], 1_{25}, 1_{26}, 1_{22}$	-	1,200,000
$\eta 8$	$2\times 1_5, 1_{22}, 1_{25}, 1_{26}, [1_{26}]$	-	1,200,000
Total cost			11,300,000

[ ] indicates additions to previous expansion plan

4.4.6 Factual result: The real option analysis of investment

Ignoring the value of flexibility options, the present values of a one-off implementation of the expansion options ηs shown in Table 4.1 and Table 4.2 for the entire long-term planning horizon are $\$25,193,000$ and $\$11,300,000$ for the 9 and 33 bus test systems respectively. A One-off investment approach is typically employed in situations or locations where the legal, social and environmental cost of a flexible implementation of the expansion plan outweighs the potential benefits. In these cases investment decisions are made based on available information. The contingency expansion plan for the flexible expansion of the NG distribution and NGDG in the 9 and 33 bus test distribution system in response to uncertain electric power demand with drift rate of

Table 4.3: Coefficient of the evolution of electricity demand

	Coefficient of demand for scenario s					
Scenarios	t =1 (Year 0)	t = 2 (Year 2.5)	t = 3 (Year 5)	t = 4 (Year 7.5)	t = 5 (Year 10)	Probability $\mathbb{P}^s$
1	1.00	1.07	1.14	1.22	1.30	0.064
2	1.00	1.07	1.14	1.22	1.14	0.063
3	1.00	1.07	1.14	1.07	1.14	0.063
4	1.00	1.07	1.14	1.07	1.00	0.063
5	1.00	1.07	1.00	1.07	1.14	0.063
6	1.00	1.07	1.00	1.07	1.00	0.063
7	1.00	1.07	1.00	0.94	1.00	0.063
8	1.00	1.07	1.00	0.94	0.88	0.062
9	1.00	0.94	1.00	1.07	1.14	0.063
10	1.00	0.94	1.00	1.07	1.00	0.063
11	1.00	0.94	1.00	0.94	1.00	0.063
12	1.00	0.94	1.00	0.94	0.88	0.062
13	1.00	0.94	0.88	0.94	1.00	0.063
14	1.00	0.94	0.88	0.94	0.88	0.062
15	1.00	0.94	0.88	0.82	0.88	0.062
16	1.00	0.94	0.88	0.82	0.77	0.061

4% is presented in Fig. 4.8 and Fig. 4.9 respectively. The associated value of the real options presented by each stage of the contingency plan is shown in Table 4.4. The optimal contingencies i.e. contingencies with the largest real option value, as shown in Table 4.4, are processes 10 and 6 for the 9 and 33 bus test systems respectively. The optimal process for mitigating the risk of the uncertain demand for the 9 bus test system is to implement $\eta 1$ and $\eta 2$ in year 0, then watch the future demand realization. Similarly, the optimal risk mitigating process for the 33 bus system involves the implementation of $\eta 1$ in year 2.5 and then watch future demand realization. Each of the options captured in Table 4.4 is explained in detail in the following sections.

4.4.7 Interpretation and discussion of results

The uncertain electric power demand and the flexibilities offered by NGDGs allows the management of an electric distribution company with NG distribution facility interested in employing NGDGs for the purpose of meeting future demand the options to execute, delay or abandon identified expansions options. These options arise from the adaptability, scalability, and modularity

Table 4.4: Value of the real option presented by each stage of the contingency plan

	Values of Options ($'000$)							
	9 bus test system				33 bus test system			
Contingency process	Delay	Abandon	Implement	Total	Delay	Abandon	Implement	Total
1	421.7	0.0	120.3	542.0	382.6	0.00	112.2	494.8
2	292.7	0.0	78.9	371.7	311.3	102.7	47.4	461.5
3	320.2	364.3	157.9	842.3	217.6	650.5	94.9	963.1
4	372.3	182.2	78.9	633.4	168.4	325.3	47.4	541.1
5	306.0	284.9	40	630.3	189.3	325.3	47.4	561.2
6	306.0	565.2	78.3	949.5	189.3	1,053	0.00	1,242.3
7	424.5	182.2	78.9	685.6	415.9	325.3	47.4	788.6
8	358.1.0	284.9	39.5	682.5	0.0	0.0	0.0	0.0
9	0.0	1,176.7	0.0	1,176	0.0	0.0	0.0	0.0
10	0.0	2,334.4	0.0	2,334.4	0.0	0.0	0.0	0.0

offered by NGDGs and NG distribution pipelines. The value that arises from leveraging these options in comparison to a less flexible approach i.e. one-off investment approach to meeting uncertain electricity demand is discussed in next subsections.

4.4.7.1 Managerial option to **implement** identified expansion plan

The options to execute an expansion plan typically accompany the realization of the minimum favorable forecast on which the expansion plan is based. In this situation, the utility is least exposed to the financial risk that accompanies an overbuilt system. In consequence to this, the utility is able to fast-track the implementation of existing expansion plans and in some cases revise the plans to exploit the opportunities presented by new realities. The continuous realization of the electric power demand along the $\mathbb{P}^u$ as shown in Fig. 4.8 and Fig. 4.9 i.e. contingency process one presents the maximum real option to executive the expansion plan as planned and also maximize the value of existing assets. For instance, in the 9 bus case system, the ratio of the investment in NG pipeline to electric power generation capacity for $\eta 1$ and $\eta 2$ equals $\$1,826,500/MW$ in the year 0. $\eta 1$ however gives rise to real option to integrate more NGDGs year 2.5, 5 and 10 i.e. $\eta 3$ and $\eta 5$ and $\eta 7$. The value of this option is $\$120,288$ as highlighted in process 1 of Table 4.4. The total real option to execute a process of the contingency for both 9 and 33 bus test system

is presented in Table 4.4. It is important to note that contingency process 9 and 10 of the 9 test system and process 9 and 10 of the 33 bus test system does not include any of the expansion options consequently no values are associated. The value of the real option to implement tends to increases with the realization of an optimistic electric power demand realization as shown in Table 4.4. It is important to note that process 3, 9 and 10 is a combination of multiple processes and their relative probabilities. The value of the identified options increases the financial viability of the expansion plans. Other values of this options not quantified could arise from improved financial negotiations for future expansion plans based on an existing stream of income and validated business case.

4.4.7.2 Managerial option to **delay** the implementation of expansion plan

The option to delay investments as planned can be called to reduce the exposure of the utility to financial risks that might result from an overbuilt system and/or a reduction in revenue due to decreasing electric power demand. The value of the option to delay is mainly due to the savings on the cost of capital that would have been incurred in the one-off investment approach. For instance, in the 9 bus test case, should there be a reduction in the electric power demand in year 2.5, the management of the utility is able to delay future investment i.e. $\eta 3$ and $\eta 4$ till year 7.5 and perhaps, year 10 as shown in Fig. 4.8. The value of this option as highlighted in process 7 of the 9 bus test system shown in Table 4.4 is $\$424,497$. Similar options to delay future investment exist in the 33 bus case studies where the management of the utility company is able to delay future investments as shown in Fig. 4.9. For instance, there is an option to delay $\eta 2$ till year 10 as opposed to year 5 should there be a reduction in electric demand in year 5 and high favorable demand growth in consecutive years. The value of the option to delay η_2 in the 33 bus test case as a result of a reduction in demand post year 2.5 is $\$168,411$ as highlighted in process 4 of Table 4.4. Other options for the delay of an investment existing in both cases studies depending on the realization of the uncertain electric power demand growth.

4.4.7.3 Managerial option to **abandon** the implementation of expansion plan

The option to abandon investment plans allows the management of the utility to reduce potential financial loss by abandoning future investment based on new realities. The value of this option is associated with the reduction of non-viable sunk cost. For example in the 9 bus case study as shown in Fig. 4.8, the utility is able to abandon its expansion plans as early as year 5 should there be a continuous reduction in electricity demand. Although the utility would have incurred cost in implementing $\eta 1$ and $\eta 2$, it is still able to reduce its financial risk exposure by abandoning expansion plans $\eta 3 - \eta 7$. Assuming a continued reduction in electricity demand i.e. process 9 or 10, the values of the option to abandon are $\$1,176,616$, and $\$2,334,407$ respectively as shown in Table 4.4. Similarly, in the 33 bus case study, the management of the utility can completely abandon the entire expansion plan in year 5 should there be a continuous reduction in electricity demand as shown in Fig. 4.9.

In summary, the option to execute, delay and abandon investment in expansion plans, allows the management of the utility adapt its expansion plans to new realities. The values of these options are either associated with the downstream opportunities created in the advent of a favorable electric demand reality or the potential savings on the cost of capital as a result of investment delay or cancellation in the advent of a less desirable electric demand growth. In most cases, it was advantageous to build the NG pipeline and then exploit the short installation time of the NGDG by reassessing the investment plans in light of new realities of electricity demand. The scalability, modularity and adaptable that characterizes NGDGs offers flexibilities that can be of immense benefits to the utility and this value of this benefit can help the management of energy utilities make well-informed investment decisions. The flexible expansion approach allows the planner adapt the expansion plan to new realities of the electric power demand, thereby reducing their exposure to the risks associated with uncertain electricity demand. In addition, it reduces the challenges of financing future stages of the expansion plan as the utility is able to build a business case based on proceeding from previous investments. This is especially helpful in developing regions where the

budgetary constraint is often prevalent.

4.4.8 Sensitivity analysis

The value of the real option presented by the flexibility of the NGDG candidates is dependent on the uncertainty of the electric power demand. Consequently, the value of the real options varies with the drift rates of the electricity demand from the mean annual growth forecast. Table 4.5 shows the sensitivity of the real options to 2%, 4% and 6% drift rates for each of the contingency process in the long-term planning of the 33 bus distribution system. It can be noted that the values of the real options increase with an increase in drift rates i.e. uncertainty of electricity. Intuitively, this is right since the values of the real options analysis are in its ability to allow the management of the utility leverage flexibilities in the expansion plan for risk mitigation. Therefore as the amount of risk associated with electricity demand increases, the value the management of the utility get from being able to adapt its expansion plan to the risk associated with uncertain electricity demand increases. Also, higher drift rate means more options are for the optimistic scenarios, this consequently increases the values of the real options to delay and abandon the expansion plan in the presence of non-optimistic demand growth as shown in Table 4.5. In addition, in the 6% drift rate scenario, $\eta 1$ was proposed for year 0 for all processes resulting in options for process 8-10.

Figure 4.8: Contingency development for NGDG and NG pipeline for the 9 bus distribution test system under uncertain electric power demand with drift rate of 4%

Figure 4.9: Contingency development for NGDG and NG pipeline for the 33 bus distribution test system under uncertain electric power demand with drift rate of 4%

Table 4.5: Value of the real option presented by each stage of the contingency plan

	Values of Options ('000)											
	2% drift rate				4% drift rate				6% drift rate			
Process	Delay	Abandon	Implement	Total	Delay	abandon	Execute	Total	Delay	Abandon	Implement	Total
1	141.8	0.0	0.0	141.8	382.6	0.00	112.2	494.8	393.1	0.00	172.8	565.8
2	0.0	0.0	0.0	0.0	311.3	102.7	38.6	461.5	242.3	308.2	4.2	554.5
3	0.0	0.0	0.0	0.0	217.6	650.5	77.1	963.1	296.1	666.3	8.2	970.6
4	0.0	0.0	0.0	0.0	168.4	325.3	38.6	541.1	400.9	308.2	4.1	713.2
5	86.6	222.6	0.0	309.2	189.3	325.3	38.6	561.2	190.8	633.4	2.0	826.2
6	86.6	441.6	0.0	528.2	189.3	1053.0	0.0	1,242.3	190.8	1,256.8	4.1	1,451.6
7	0.0	0.0	0.0	0.0	415.9	325.3	38.6	788.6	526.1	308.2	2.3	836.6
8	0.0	0.0	0.0	0.0	0.0	0.00	0.0	0.0	316.0	633.4	2.1	951.4
9	0.0	0.0	0.0	0.0	0.0	0.00	0.0	0.0	225.0	1664.4	0.0	1,889.4
10	0.0	0.0	0.0	0.0	0.0	0.00	0.0	0.0	378.6	3302.1	0.0	3,680.7

4.5 Conclusion

In this paper, the flexibilities presented by the scalability, modularity, and adaptability of the NGDGs and NG distribution pipelines were evaluated. The value of the downstream options generated as a result of current investment in the development of the integrated natural gas distribution network and NGDGs plan was assessed. We show that the investment in time t offers the management of an energy utility real options to implement, delay or abandon expansion plans. The value of the real option to implement the expansion plan increases with the realization of favorable outcomes from the uncertain electric power demand. This presents the utility with an option to exploit new demand realization. In addition, the option to implement increases the value of existing investments that are expanded or leveraged on for new investments. The values of the real options to delay or abandon investment plans in the advent of less favorable electric power demand outcome is shown to arise mainly from the savings in the cost of capital. The real options approach to investment planning provides a tool that allows a utility to assess current investment in the light of future opportunities it provides. This approach is very useful in helping utilities improve profitability, reduce exposure to financial risk and make well-informed decisions on future investments, especially where access to capital is limited.

Chapter 5

Reliability Programming in the Integrated Planning of Electricity Generation and Natural Gas Networks [1]

Global electricity generation from natural gas is expected to continue in an upward trend in the coming years thereby increasing the interdependency between the electricity and the Natural gas transportation system. The reliability concerns associated with this interdependency has necessitated an integrated approach to planning both systems to achieve an overall system reliability. This paper proposes a planning approach that minimizes the capital and operational cost of the electricity and natural gas transmission system subject to probabilistic constraints such that a desired confidence level of supply is attained. A Chance constrained and reliability programming optimization model was proposed for solving the long-term integrated planning problem and their performance was compared by illustrating them on the standard IEEE 30 bus test system superimposed on the Belgian high-calorific gas network.

[1] © **2017 IEEE. Reprinted, with permission, from [113]: Odetayo, Babatunde and MacCormack, John and Rosehart, William D, Zareipour, Hamidreza, and Ali Reza Seifi "Reliability Programming in the Integrated Planning of Electricity Generation and Natural Gas Networks ," Energy, under review, 2017.**

5.1 Nomenclature

A. Abbreviation

NG	Natural Gas
NGG	Natural Gas-fired power Generator
CCP	Chance Constraint Programming
RP	Reliability Programming

B. Indices

b	Index of source electric power bus
r	Index of sink electric power bus
i	Index of source NG node associated with an NG pipeline
j	Index of sink NG node associated with an NG pipeline
t	Index of planning time horizon, t = 0,1,...T
ρ	Index of NG-fired generator sizes
p	Index of NG pipeline
c	Index of compressor stations

C. Binary Variables

$\lambda_{\rho,b,t}$	1 if a new NG fired generator type ρ is installed on b in year t. 0 otherwise
$y_{i,j,t}$	1 if a pipeline is installed between NG nodes i, j in year t. 0 otherwise
$\psi_{i,j,t}$	1 if a compressor is installed between NG nodes i, j in year t. 0 otherwise
$z_{i,j,t}$	1 when there NG flows from node i to j and 0 otherwise.
$\phi_{i,t}$	1 when the upper limit of NG source is increased by $5Mm^3$ from previous year

D. Random Variables

ξ_1	Electricity demand forecast uncertainty
ξ_2	NG demand uncertainty

E. Variables

$P_{b,t}^{(e)}$ Power generation from existing(e) generators

$P_{b,t}^{(n)}$ Power generation from new(n) NGG's

$fl_{b,r,t}$ Power flow to bus b to r in time t

$\Theta_{j,t}$ Square of the NG pressure at sink NG nodes j in time t

$\Theta_{i,t}$ Square of the NG pressure at source NG nodes i in time t

$\Gamma_{i,t}$ NG pressure at source NG nodes i in time t

$\Phi_{i,j,t}$ NG flowrate between nodes i, j in time t

F. Chance constraint variable/parameters

α Desired confidence-level for the electricity system

β Desired confidence-level for the NG system

γ Desired confidence level for the entire system

G Parameters

$C_{\rho}^{(I)}$ The overnight investment cost (I) of NG-fired generator size ρ

$C_{p}^{(I)}$ The overnight investment cost (I) of NG pipeline p

$C_{c}^{(I)}$ The overnight investment cost (I) cost of compressor station c

$C_{\rho}^{(o)}$ Operating cost (o) of NG -fired generator size ρ

$C_{c}^{(o)}$ Operating cost (o) of NG compressor c

$X_{b,r,t}$ Reactance of the transmission lines connecting buses b, r in time t

$\theta_{b,t}$ Angle of the voltage phasor at bus b in time t

$P_{b,t}^{(L)}$ Local electricity demand at bus b in time t

$\overline{P_b}$ Unforced capacity of NGG connected to bus b

$\underline{P_b}$ Minimum operating capacity of NGG connected to bus b

$\overline{fl}$ Upper limit on capacity of the power transmission line

$\underline{fl}$ lower limit on capacity of the power transmission line

Parameters continued

$L_{i,j}$	Length of existing and candidate pipelines connecting NG nodes i and j
$\Delta_{i,j}$	Diameter of existing and candidate pipeline connecting nodes i and j
a_i, b_i, c_i	Fuel rates coefficients of the NG-fired generators
$M_{1,t}$	Large number set to maximum possible NG flow in in a pipeline in time t
M_2	Large number used to limit the square of the nodal pressure
M_3	A large value greater or equal to the maximum acceptable pressure
$\underline{\Gamma_{i,t}}$	Lower limit on the square of the nodal pressure at source node i in time t
$\overline{\Gamma_{i,t}}$	Upper limit on the square of the nodal pressure at source node i in time t
κ	Maximum pressure increase multiplier at a compressor station
$s_{i,t}$	NG supply at node i in time t
$d_{i,t}^{(e)}$	NG demand for existing (e) electric power generation at node i in time t
$d_{i,t}^{(n)}$	NG demand for new (n) power generation at node i in time t
$d_{i,t}^{(h)}$	NG demand for non-electric power generation at node i in time t
$\underline{s_{i,t}}$	Lower limit on NG supply at node i in time t
$\overline{s_{i,t}}$	Upper limit on NG supply at node i in time t
ir	Interest rate on capital
δ	Annuity

H. Sets

Ω_b	Set of electricity buses (indexed by (b,r))
Ω_p	Set of NG pipeline types by size
Ω_n	Set of all NG pipeline nodes
Ω_ρ	Set of new NG- fired generator sizes
Ω_d	Set of NG demand nodes
Ω_s	Set of NG supply nodes
Ω_c	Sets of NG compressor nodes associated with active arcs

5.2 Introduction

The worldwide electricity generation capacity is expected to grow by 69% from 21.6 trillion kilowatt-hours (kWh) in 2012 to 36.5 trillion kWh in 2040 [95]. In the same time period, electricity generation from Natural Gas (NG) is expected to increase from 22% to 28% of global generation capacity [95]. To put this in perspective, NG-fired generation accounted for 40% of the 81,621GWh of net electricity generation in the Alberta Canada in comparison to 51% from coal in 2015, NG is expected to account for 70% of net electricity generation by 2030 [3].

A number of factors have stimulated this growth amongst which are the availability of relatively cheap natural gas supply, and comparatively clean nature of NG fuel [4–6, 19, 23, 29–32, 70]. This growth, however, implies an increasing dependency of the electric system on the natural gas transportation systems. The cascaded dependency between these systems, however, raises reliability concerns because of the ease of propagation of reliability concerns between them. For instance, during 2013/2014 polar vortex in the northeast of USA, increased NG demand for heating led to shortage of NG supply for electricity generation, thereby raising serious reliability concerns in the electricity system [114]. These reliability concerns have necessitate an integrated approach to planning electric power and NG systems.

The integrated planning of the electricity and NG transmission system has been approached from an operation [77, 115] and/or investment [4, 28, 33, 116, 117] perspective. In most of these proposed approaches, the integrated planning problem is a nonlinear, non-convex optimization problem which is very difficult to solve [6]. Some of the proposed solution approaches includes, sequential [5, 29], analytical [6], decomposition [19, 28, 29, 77], and heuristic [19]. In most of these models, the objective of the planning model is the minimization of the capital and operational costs of ensuring the electric power and NG demand are reliably met. In most cases, these cost increases exponentially with the size of the interconnected systems and the level of interdependencies. The reliability of the electricity system, however, tends to reduce with increasing complexities and dependencies because, in a cascaded system, the reliability of the system is a product of the reli-

ability of the constituent systems [40]. The exponential relationship between investment cost and upper-reliability percentiles tends to reduce the financial viability of NG-fired Generators (NGGs), especially in a least-cost dispatch system. This can be managed by utilizing Probabilistic planning models [118] that ensures that the uncertain electricity and NG demand are met with an average desired confidence level at a minimum cost.

A probabilistic modeling approach [118] such as Chance Constraint Programming (CCP) [42, 119], and Reliability Programing (RP) [120] are reliability-based optimization approach where the objective and/or constraint are modeled with probability measures of the extent to which they can be violated. In the CCP models, the desired reliability level(s) of the probabilistic constraints are set a priori while in the RP model the objective of the planning model is optimized without fixing the desired confidence level, rather a cost called the loss function is associated with the violation of the reliability criteria [121, 122].

In this paper, we extend ours and other previous research [4–6, 23, 28–32] on the integrated planning of electricity and natural gas systems by first comparing a sequential planning approach with an integrated one. Next, we present two novel probabilistic planning approach i.e. a CCP and RP approach to modeling and solving the planning problem in the presence of uncertain electric power and NG demand. Both probabilistic approaches ensures the power and NG demand are met with at least the desired level of confidence. This approach affords the system planner the opportunity to allow manageable level of reliability violations in exchange for a reduction in the overall investment cost of the power and NG systems. The proposed approach was illustrated on a standard IEEE 30 bus test system superimposed on the Belgian high-calorific gas network.

The rest of this paper is structured as follows. Section III describes the integrated energy planning problem. Section IV presents the solution methodology. Section V discusses the results from testing this model on a simple test system. Section VI provides concluding remarks.

5.3 The integrated planning problem

The long-term integrated planning usually entails the minimization of the sum of the capital and operating cost of NG-fired generators, NG pipelines and NG compressors subject to the physical and operating constraint of the electric and NG systems and the coupling constraint between both systems.

5.3.1 The integrated planning problem objective

The integrated planning problem is modeled in (5.1) [116, 123]

$$min \;\; z = \sum_{t}^{T} \left[IC_t^{(n)} + OC_t^{(n/e)} + IC_t + IC_t^{(c)} + OC_t^{(c)} \right] \tag{5.1}$$

Where IC_t^n is the present value (PV) of the capital cost of building new NGG. This cost is defined further in (5.2). The annuity $\delta_t = \frac{ir}{1-(1+ir)^{-t}}$

$$IC_t^{(n)} = \sum_{b \in \Omega_b} \sum_{\rho \in \Omega_\rho} \delta_t \lambda_{\rho,b,t} C_\rho^{(I)} \tag{5.2}$$

The second term of (5.1) i.e. $OC_t^{(n/e)}$ defined in (5.3), is the operating cost of new and existing electric power generations.

$$OC_t^{(n/e)} = \sum_{b \in \Omega_b} \sum_{\rho \in \Omega_\rho} \delta_t P_{b,t}^{(n/e)} C_\rho^{(o)} \tag{5.3}$$

The PV of the capital cost of building new or extending existing pipelines, IC_t i.e. the third term of (5.1) is modeled in (5.4).

$$IC_t = \sum_{(i,j) \in \Omega_n} \sum_{p \in \Omega_p} \delta_t C_p^{(I)} L_{i,j} (y_{p,i,j,t+1} - y_{p,i,j,t}) \tag{5.4}$$

A Compressor increases the pressure differential and consequently the flowrate of NG along a pipeline segment. IC_t^c modeled in (5.5) is the PV of the capital cost of compression stations.

$$IC_t^{(c)} = \sum_{(i,j) \in \Omega_n} \sum_{c \in \Omega_c} \delta_t C_c^{(I)} (\psi_{i,j,t+1} - \psi_{i,j,t}) \tag{5.5}$$

The operating cost of the compressor OC_t^c is defined in (5.6).

$$OC_t^{(c)} = \sum_{(i,j) \in \Omega_n} \sum_{c \in \Omega_c} \delta_t \psi_{i,j,t} C_c^{(o)} \tag{5.6}$$

5.3.2 Physical and operating constraints on the electric power system

The physical and operational constraints on the electric transmission system is modeled in (5.7) - (5.12) [124, 125]. The Kirchhoff's flow conservation nodal balance constraint is modeled in constraint (5.7).

$$P_{b,t} = P_{b,t}^{(L)}(\xi_1) + \sum_{r \in \Omega_b} fl_{b,r,t} \quad \forall b, r \in \Omega_b, t \in T \tag{5.7}$$

$$P_{b,t} = P_{b,t}^{(e)} + P_{b,t}^{(n)} \qquad \forall b \in \Omega_b, t \in T \tag{5.8}$$

The total power generation $P_{b,t}$ at any time t consist of power generation from new (n) and existing (e) power generators as modeled in constraint (5.8). Constraint (5.9) models the approximate power flow $fl_{b,r,t}$ in the transmission line connecting buses (b,r) in time t.

$$fl_{b,r,t} = \frac{1}{X_{b,r,t}}(\theta_{b,t} - \theta_{r,t}) \quad \forall b, r \in \Omega_b, t \in T \tag{5.9}$$

Constraint (5.10) fixes the angle of the voltage phasor at the slack bus to zero.

$$\theta_{b,t} = 0 \qquad \forall b = slackbus, t \in T \tag{5.10}$$

Constraints (5.11) and (5.12) are limits on the capacities of generators and the transmission lines respectively. PG_ρ is the name place capacity of NGG type ρ

$$0 \leq P_{b,t}^{n} \leq \lambda_{b,\rho,t} PG_\rho \quad \forall b \in \Omega_b, t \in T \tag{5.11}$$

$$\underline{fl_{b,r}} \leq fl_{b,r,t} \leq \overline{fl_{b,r}} \quad \forall b, r \in \Omega_b, t \in T \tag{5.12}$$

5.3.3 Electricity - NG coupling constraint

The NG demand for electricity generation from new (n) and existing (e) NGGs as a function of power output assuming the electric bus and NG nodes are co-located is modeled as a relaxed

coupling constraint (5.13) [6].

$$d_{i,t}^{(n/e)} \geq a_i + b_i P_{b,t}^{(n/e)} + c_i (P_{b,t}^{(n/e)})^2 \quad \forall b \in \Omega_b, \forall i \in \Omega_n \tag{5.13}$$

5.3.4 Physical and operational constraints on the NG transmission system

The steady-state flow phical and operational constraint on the NG transmisison system is modeled in (5.14)- (5.35) [5,50,51,86]. Constraint (5.14) sets the pressure at the NG source to the maximum possible pressure.

$$\Gamma_{i,t} = \overline{\Gamma_i} \qquad \forall i \in \Omega_s, t \in T \tag{5.14}$$

Constraints (5.15) and (5.16) limits the square of the NG pressure at the NG demand nodes and the NG flow rate in a pipeline connecting NG nodes (i, j) respectively.

$$\underline{\Gamma_{i,t}}^2 \leq \Theta_{i,t} \leq \overline{\Gamma_{i,t}}^2 \qquad \forall i \in \Omega_d, t \in T \tag{5.15}$$

$$\Phi_{i,j,t} \leq M_{1,t} z_{i,j,t} \qquad \forall (i,j) \in \Omega_n, t \in T \tag{5.16}$$

The different sources of NG demands are modeled in (5.17) while (5.18) sets the physical and contractual limits on NG supply.

$$d_{i,t} = d_{i,t}^{(e)} + d_{i,t}^{(n)} + d_{i,t}^{(h)} \qquad \forall i \in \Omega_d, t \in T \tag{5.17}$$

$$\underline{s_{i,t}} \leq s_{i,t} \leq (\overline{s_{i,t-1}} + 5\phi_{i,t}) \qquad \forall i \in \Omega_s, t \in T \tag{5.18}$$

Constraint (5.18) allows an increase in the NG supply by a factor $\phi_{i,t}$, provided the physical and operational constraints of the NG transmission system are not violated. The NG flow conservation at demand/supply and transshipment/compression nodes are modeled in constraints (5.19) and (5.20) respectively.

$$s_{i,t} + \sum_{j \in \Omega_n} \Phi_{j,i,t} - \sum_{j \Omega_n} \Phi_{i,j,t} = d_{i,t}(\xi_2) \qquad \forall i \in \Omega_n, t \in T \tag{5.19}$$

$$\sum_{j\in\Omega_n}\Phi_{i,j,t}-\sum_{j\in\Omega_n}\Phi_{j,i,t}=0 \qquad \forall(i,j)\in\Omega_c,t\in T \tag{5.20}$$

The general steady-state flow of NG is modeled in constraints (5.21)- (5.23 [5, 86].

$$(\Theta_{i,t}-\Theta_{j,t})-\Psi_{i,j}\Phi^2_{i,j,t}\geq M_2(z_{i,j,t}-1) \qquad \forall(i,j)\in\Omega_n,t\in T \tag{5.21}$$

$$(\Theta_{i,t}-\Theta_{j,t})-\Psi_{i,j}\Phi^2_{i,j,t}\leq M_2(1-z_{i,j,t}) \qquad \forall(i,j)\in\Omega_n,t\in T \tag{5.22}$$

$$\Psi_{i,j}=\left(\frac{1}{1.1494\times10^{-3}}\right)^2\frac{GT_fL_{i,j}Zf}{\Delta^5_{i,j}}\left(\frac{\Gamma_b}{T_b}\right)^2 \tag{5.23}$$

Constraints (5.21) and (5.22) together states that the difference between the square of the NG pressure between two connected nodes (i,j) is equal to the product of the square of NG flowrate between these nodes and the resistance of the pipeline connecting them. Constraints (5.21) and (5.22) are formulated such that there is a pressure drop between two NG nodes (i,j) only when they are connected i.e. when $z_{i,j,t}=1$, [50]. The pipeline resistance $\Psi_{i,j}$ is defined in (5.23). Constraint (5.24) ensures unidirectional flow of NG per time.

$$z_{i,j,t}+z_{j,i,t}\leq 1 \qquad \forall(i,j)\in\Omega_n,i<j,t\in T \tag{5.24}$$

Constraint (5.25) ensures that for NG to flow between two NG nodes i and j a pipelines must exist to connect them.

$$z_{i,j,t}+z_{i,j,t}\leq\sum_{p\in\Omega_p}y_{p,i,j,t} \qquad \forall(i,j)\in\Omega_n,p\in\Omega_p,i<j,t\in T \tag{5.25}$$

Constraint (5.26) ensures that once a pipeline p connecting NG nodes (i,j) is installed, it remains installed for the rest of the planning period.

$$y_{p,i,j,t}\leq y_{p,i,j,t+1} \qquad \forall(i,j)\in\Omega_n,p\in\Omega_p,i<j,t=1,...|T|-1 \tag{5.26}$$

Constraint (5.27) restricts the NG pressure to positive values only.

$$\Gamma_{i,t}\geq 0 \qquad \forall i\in\Omega_s\cup\Omega_d,t\in T \tag{5.27}$$

Constraint (5.28) ensures a unidirectional pressure increase while constraint (5.29) ensures that existing or new compressor station remains installed and available for the entire planning horizon.

$$\psi_{i,j,t} + \psi_{j,i,t} \leq 1 \quad \forall (i,j) \in \Omega_c, i < j, t \in T \tag{5.28}$$

$$\psi_{i,j,t} \leq \psi_{i,j,t+1} \qquad \forall (i,j) \in \Omega_c, t = 1,..|T|-1 \tag{5.29}$$

Constraint (5.30) and (5.31) ensures that for a segment of an active pipeline where NG flow exists between i and j i.e. $z_{i,j,t} = 1$ and a compressor station is present i.e. $\psi_{i,j,t} = 1$, the increase in pressure is a multiple of a multiplier coefficient of the compression station κ.

$$\Gamma_{j,t} - \kappa\Gamma_{i,t} \leq M_3(2 - z_{i,j,t} - \psi_{i,j,t}) \qquad \forall (i,j) \in \Omega_c, t \in T \tag{5.30}$$

$$\Gamma_{j,t} - \kappa\Gamma_{i,t} \geq M_3(z_{i,j,t} + \psi_{i,j,t} - 2) \qquad \forall (i,j) \in \Omega_c, t \in T \tag{5.31}$$

Constraints (5.32) and (5.33) ensures that the pressure at the compressor inlet and outlet stays equal when there is zero NG flow through the compressor i.e. if $\psi_{i,j,t} = 0$ and $z_{i,j,t} = 1$ [50].

$$\Gamma_{j,t} - \Gamma_{i,t} \leq M_3(1 - z_{i,j,t} + \psi_{i,j,t}) \qquad \forall (i,j) \in \Omega_c, t \in T \tag{5.32}$$

$$\Gamma_{j,t} - \Gamma_{i,t} \geq M_3(z_{i,j,t} - \psi_{i,j,t} - 1) \qquad \forall (i,j) \in \Omega_c, t \in T \tag{5.33}$$

Constraint (5.34) ensures that when a compressor is present i.e. when $\psi_{i,j,t} = 1$, the NG flowrate through a compressor should not exceed the capacity limits of the connecting the pipelines. Where ς is the capacity of the compressor station.

$$\varsigma \sum \psi_{i,j,t} - \sum_k \Phi_{i,t,k} \geq M_1(\psi_{i,j,t} - 1) \qquad \forall (i,j) \in \Omega_c, t \in T \tag{5.34}$$

Constraint (5.35) constrains $z_{i,j,t}$, $y_{p,i,j,t}$, and $\psi_{i,j,t}$ to binary values.

$$z_{i,j,t},\ y_{p,i,j,t},\ \psi_{i,j,t} \in \{1,0\} \tag{5.35}$$

5.4 Solution methodology

Four solution approaches for solving the long-term integrated planning problem are presented. The first two approaches allow for a comparison between the sequential and integrated planning approaches for solving the long-term integrated planning problem. The integrated planning approach further provides a reference for comparing the proposed probabilistic approaches i.e. the CCP and RP planning approaches.

5.4.1 Expectation models

In the expectation model, the stochastic power and NG demands in (5.7) and (5.19) are replaced with their respective approximate deterministic equivalent. This planning model is solved using a sequential [5, 22, 29] and an integrated solution approach [6, 31].

5.4.1.1 Expectation sequential models

In the sequential approach, the annual expansion plan for the electric system is first determined i.e. (5.2) and (5.3) are minimized subject to (5.7) - (5.11). The computed size and location of NGGs are imputed into the electricity-NG coupling constraint modeled in (5.13) to compute the annual NG nodal demand for electricity generation. Based on the computed NG nodal demand and the expected non-electricity NG demand, the annual NG expansion plan is developed i.e. (5.4) - (5.6) are minimized subject to (5.14) - (5.35). This process is repeated for the entire planning horizon.

5.4.1.2 Expectation integrated models

In the integrated model, both systems are planned simultaneously based on expected sets of power and NG demands i.e. (5.1) is minimized subject to (5.7) - (5.35)

The expectation models are a Mixed-Integer Nonlinear Problem (MINLP) because of the presence of nonlinear flow variables in (5.21)- (5.22) [6,50], therefore a global optimum solution cannot be guaranteed. The Branch-and-Bound method has been shown to be efficient in computing the globally optimal solution to MINLP's with non-convex function [52].

5.4.2 Probabilistic constraints model

The constraints associated with the uncertain power and NG demand in (5.7) and (5.19) are modeled in probabilistic terms as a chance constraint in (5.36) [43, 54].

$$\mathbb{P}\big[\bigcap_{b}\big(P^{(e)}_{b,t}+P^{(n)}_{b,t}-\sum_{r\in\Omega_b} fl_{b,r,t}\geq P^{(L)}_{b,t}\big)\big]\geq\alpha \quad \forall b,r\in\Omega_b,t\in T \tag{5.36a}$$

$$\mathbb{P}\big[\bigcap_{i}\big(s_{i,t}+\sum_{j\in\Omega_n}\Phi_{j,i,t}-\sum_{j\in\Omega_n}\Phi_{i,j,t}\geq d_{i,t}\big)\big]\geq\beta \qquad \forall i\in\Omega_n,t\in T \tag{5.36b}$$

$$\alpha\times\beta\geq\gamma;\quad 0\leq\alpha\leq 1;\quad 0\leq\beta\leq 1 \tag{5.36c}$$

Assuming both electric and NG demand follows a normal distribution [17, 43], (5.36a) and (5.36b) can be approximated to (5.37).

$$P^{(e)}_{b,t}+P^{(n)}_{b,t}-\sum_{r\in\Omega_b} fl_{b,r,t}=\mu^{P^{(L)}_{b,t}}+\sigma^{P^{(L)}_{b,t}}Z_\alpha \quad \forall b,r\in\Omega_b,t\in T \tag{5.37a}$$

$$s_{i,t}+\sum_{j\in\Omega_n}\Phi_{j,i,t}-\sum_{j\in\Omega_n}\Phi_{i,j,t}=\mu^{d_{i,t}}+\sigma^{d_{i,t}}Z_\beta \qquad \forall i\in\Omega_n,t\in T \tag{5.37b}$$

Where $\mu^{P^{(L)}_{b,t}}$ and $\mu^{d_{i,t}}$ are the means of the nodal electric power and NG demands respectively. $\sigma^{P^{(L)}_{b,t}}$ and $\sigma^{d_{i,t}}$ are the standard deviations of the power and NG demands respectively. Z_α and Z_β are the inverse cumulative distributions of the random real electric power and NG demand respectively [17, 43]. Two probabilistic approaches for solving the planning model are presented.

5.4.2.1 Chance constrained programming integrated planning model

The CCP solution algorithm first solves a deterministic/expected integrated expansion problem then a feasibility check is carried out by solving an NG constrained Optimal Power Flow (NGOPF) modeled in (5.38) for N_{times} sets of monte Carlos generated scenerios of annual electric and NG demand. The NGOPF problem is a convex optimization problem [86]. This allows for a guarantee of the optimality of the CCP solution. The CCP solution flow chat is presented in **Algorithm 1** [17, 23, 43, 44, 54].

Algorithm 1: CCP based integrated planning solution algorithm

1 **Initialization:** Select the desired confidence levels α and β and a tolerance level (Δ_α) on optimality ;
2 **Iteration I: Deterministic expansion problem** Solve the deterministic integrated planning model i.e. (5.1) - (5.35) to obtain the initial to obtain a starting point in the feasible domain;
Input : Expected electricity and NG demands, and other system parameters
Output: NGG locations and sizes, NG pipeline routes and NG compressor locations
3 **Iteration II: Feasibility check Interpolation** Check the feasibility of the solutions in **3**, by solving the NGOPF i.e. minimize $z^{\diamond}$ modeled in (5.38) for sets of $N_{samples}$ Monte Carlo generated scenarios of power and NG demand ;
Input : Fixed generators location and size, fixed NG route and compressor location
Output: p_{feas}. Where P_{feas} is the average NGOPF feasible solutions
4 **Z-Value update** **if** $|p_{feas} - \alpha| \leq \Delta_\alpha$ *and* $\alpha \times \beta \geq \gamma$
5 **then**
6 | Stop ;
7 **else**
8 | Update the Z_α i.e. the electric power demand using (5.39) and return to **2** ;
9 **end**
10 Repeat **2** - **8** till target α and γ is reached

5.4.2.1.1 The NG constrained Optimal Power Flow (NGOPF) model:

$$min \;\; z^{\diamond} = \sum_{t}^{T} \Big(\sum_{b \in \Omega_b} \sum_{\rho \in \Omega_\rho} P_{b,t}^{(n/e)} C_{\rho}^{(o)} + \sum_{(i,j) \in \Omega_n} \sum_{c \in \Omega_c} u_{i,j,t} C_{c}^{(o)} \Big) \tag{5.38a}$$

$$s.t. \;\; P_{b,t}^{(e)} + P_{b,t}^{(n)} - \sum_{r \in \Omega_b} fl_{b,r,t} = P_{b,t}^{(L)} \quad \forall b \in \Omega_b, t \in T \tag{5.38b}$$

$$s_{i,t} + \sum_{j \in \Omega_n} \Phi_{j,i,t} - \sum_{j \in \Omega_n} \Phi_{i,j,t} = d_{i,t} \quad \forall i, j \in \Omega_n, t \in T \tag{5.38c}$$

$$\underline{P_b} \leq P_{b,t}^{(n)} \leq min\Big[\frac{d_{i,t}}{HR}, \overline{P_b}\Big] \quad \forall b \in \Omega_b, t \in T, i \in \Omega_d \tag{5.38d}$$

$$0 \leq \Phi_{i,j,t} \leq \overline{\Phi} \qquad \forall i, j \in \Omega_n, t \in T \tag{5.38e}$$

$$\underline{s_{i,t}} \leq s_{i,t} \leq \overline{s_{i,t}} \qquad \forall i \in \Omega_s \cup \Omega_d, t \in T \tag{5.38f}$$

$$\Theta_{i,t} - \Theta_{j,t} = \Psi_{i,j} \Phi_{i,j,t}^2 \quad \forall i, j \in \Omega_n \tag{5.38g}$$

$$\Theta_{i,t} - \Theta_{j,t} \leq -\Psi_{i,j} \Phi_{i,j,t}^2 \quad \forall i, j \in \Omega_c \tag{5.38h}$$

$$\Gamma_{j,t} - \kappa \Gamma_{i,t} = 0 \qquad \forall (i,j) \in \Omega_c, t \in T \tag{5.38i}$$

$$(5.8) - (5.14), (5.17), (5.19), (5.20), (5.23), (5.27) \tag{5.38j}$$

Constraints (5.38a) minimize the operation cost of generators and compressors. $u_{i,j,t}$ is a binary

parameter that indicates the presence of a compressor along a pipeline connecting NG nodes (i, j) in time t. Constraints (5.38b) and (5.38c) ensures a nodal balance of electric power and NG flow. Constraints (5.38d), set the capacity limits on local power generation as a minimum of the ratio of NG demand to the heat-rate (HR) at bus b and the unforced capacity of the NGG $\overline{P_b}$. Constraints (5.38e) are (5.38f) sets the capacity limits on NG flow rates and supply. $\overline{P_b}$ is the capacity limits on NG flow in a pipeline arc. Constraints (5.38g) and (5.38h) are the NG flow conservation equation in passive and active pipelines, while (5.38i) limits the compression capacity of a compressor. The components of constraint (5.38i)are discussed above.

5.4.2.1.2 The Z-Update algorithm The Z-value update algorithm is model (5.39) and detailed in [17, 43, 44, 54].

$$Z_\alpha \leftarrow Z^{Lo} + \Big[\frac{Z_{\frac{\gamma}{\beta}} - Z_2}{Z_1 - Z_2}\big(Z^{Hi} - Z^{Lo}\big)\Big] \tag{5.39}$$

Z^{Hi} and Z^{Lo} are the inverse distribution of the selected lower $\mathbb{P}_1$ and upper $\mathbb{P}_2$ confidence levels for the electricity system. Z_1 and Z_2 are the updated inverse distribution i.e. Z-Value of the P_{feas} associated with $\mathbb{P}_1$ and $\mathbb{P}_2$ respectively. $Z_{\left(\frac{\gamma}{\beta}\right)}$ is the minimum Z_α required for achieving a system-wide confidence level γ.

5.4.2.2 Reliability programing model

A drawback of the CCP is that the planner is tasked with selecting the exact desired confidence levels α, β and γ by which the power and NG demands are met. This can often give rise to an overstated expansion plan. This is because the confidence levels by which the constituent systems meet its demands are treated separately rather than in an integrated fashion that captures cross compensation of reliability between them. The RP model address this challenge employing a two-dimensional Fibonacci search algorithm [122, 126] to optimize α and β based on predefined risks loss functions [127]. The RP solution algorithm is itemized below.

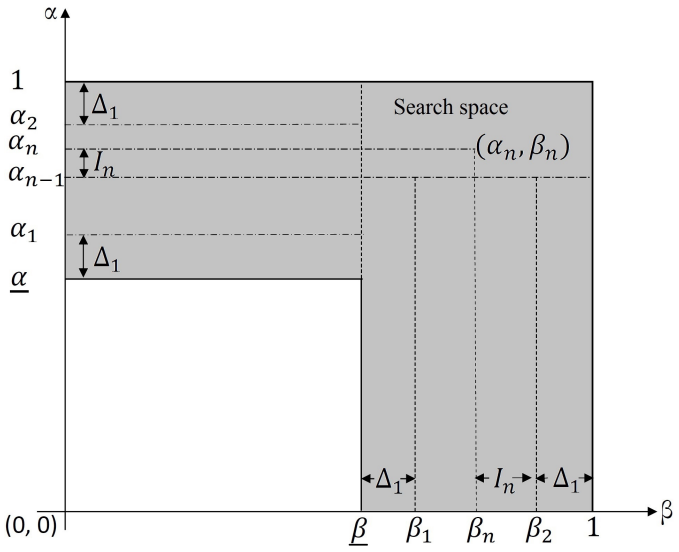


Figure 5.1: Schematics of a couple NG and electric power system

Algorithm 2: Reliability programing Algorithm

1 **Initialization:** Define the search interval $\underline{\alpha} \leq \alpha < 1$ and $\underline{\beta} \leq \beta < 1$ as illustrated in Fig. 5.1. Set a tolerance level (η) on optimality and the desired integrated system confidence level (γ) ;

2 **Interpolation 1** Set $\beta = \underline{\beta}$ i.e. the lowest acceptable confidence level of meeting NG demand as captured in Fig. 5.1.

3 Carry out a one-dimension Fibonacci search on the interval $\underline{\alpha} \leq \alpha \leq 1$ by solving for $z(\alpha_1, \underline{\beta})$ and $z(\alpha_2, \underline{\beta})$ i.e. $(Z_{\alpha_1}, Z_{\underline{\beta}})$ and $(Z_{\alpha_2}, Z_{\underline{\beta}})$ respectively in (5.1) - (5.35) and (5.37) for two interior points $\alpha_1 = \underline{\alpha} + \Delta_1$ and $\alpha_2 = 1 - \Delta_1$. $\Delta_1 = I_1 \frac{F_{n-2}}{F_n}$. Where $Fn-2$ and F_n are Fibonacci numbers. n is the search steps $1, 2, 3, ...$ and $I_1 = 1 - \underline{\beta}$

4 **One dimension feasibility check** Evaluate z^* in (5.40) for N_{times} scenarios of Monte Carlo generated set of power and NG demands. Compute $p_{feas}(\alpha_1)$ and $p_{feas}(\alpha_2)$. $p_{feas}(\alpha_1)$ is the average feasible cases when z^* is solved for α_1

5 **Search space update** If $p_{feas}(\alpha_1) \geq p_{feas}(\alpha_2)$, the new search interval is set to $(\alpha_1, 1)$. If otherwise, the interval is set to $(\alpha_2, \underline{\alpha})$;

6 **Stopping test 1:** Continue **2** and **3** until $z^*(\alpha_n, \underline{\beta})$ is in the interval with length $I_n = \frac{F_0}{F_n}$;

7 **Interpolation 2** Fix α at newly computed α_n i.e the computed optimum confidence level of meeting power demand as illustrated in Fig. 5.1.

8 Compute β_n by carrying out a one-dimension Fibonacci search on the interval $\underline{\beta} \leq \beta \leq 1$ along the line α_n i.e. repeat **2** - **5** for two interior points $\beta_1 = \underline{\beta} + \Delta_1$ and $\beta_2 = 1 - \beta_1$ as illustrated Fig. 5.1 ;

9 **Stopping test 2:** Continue **step 8** until $z^{\diamond}(\alpha_n, \beta_n)$ is in the interval with length $I_n = \frac{F_0}{F_n}$. ;

10 **Final Stopping** ;

11 Repeat entire algorithm until the difference between the minimum of $z(\alpha_n, \beta_n)$ and $z(\alpha_{n+1}, \beta_{n+1}) < \eta$ and $\alpha_n \times \beta_n < \gamma$;

$$min\ \ z^* = \sum_{t}^{T}\Big(\sum_{b\in\Omega_b} L_1\vartheta_{b,t} + \sum_{i\in\Omega_n} L_2\nu_{i,t}\Big) \tag{5.40a}$$

$$s.t.\ \ P_{b,t}^{(e)} + P_{b,t}^{(n)} - \sum_{r\in\Omega_b} fl_{b,r,t} = (1-\vartheta_{b,t})P_{b,t}^{(L)} \quad \forall b\in\Omega_b, t\in T \tag{5.40b}$$

$$s_{i,t} + \sum_{j\in\Omega_n}\Phi_{j,i,t} - \sum_{j\in\Omega_n}\Phi_{i,j,t} = (1-\nu_{i,t})d_{i,t} \quad \forall i,j\in\Omega_n, t\in T \tag{5.40c}$$

$$0 \le \vartheta_{b,t} \le 1 \tag{5.40d}$$

$$0 \le \nu_{i,t} \le 1 \tag{5.40e}$$

$$(5.38e) - (5.38j) \tag{5.40f}$$

Where $L_1(\vartheta_b)$ and $L_2(\nu_i)$ are the annual risk loss functions [127] which captures the severity of failures associated with unserved electricity ϑ and NG ν_i demand.

5.5 Test system and result

The expectation and the probabilistic models are tested on 30 bus IEEE superimposed on the Belgian NG network detailed in [32, 128]. A summary of the test system is presented in Table 5.1 and the following assumptions were made:

Table 5.1: Summary of the test system

IEEE_30-bus system		Belgian NG system	
Buses	30	Total nodes	22
Generators	6	Compressors	3
Base lines	41	Base pipelines	24
Candidate lines	41	Candidate pipes	30
Existing gas generators	2	Candidate nodes	29

1. The frictional factor f, base pressure Γ_b, base temperature T_b, NG gravity G, gas compressibility factor Z, and flow temperature T_f are assumed to be 0.0012, 1 bar, 288^oK, 0.66, 0.805, and 283^oK respectively [86]

2. The electrical and NG annual demand growth is assumed to be 3% and 2% respectively. The uncertainties in these demands are modeled as a normal distribution function that satisfies the three-standard deviation criteria i.e. $3\mu = 0.25\sigma$ [17, 44]

3. N_{times} is set to 1000 and Monte Carlo simulation is used to generate scenarios of uncertain power and NG demands

4. For simplicity sake, candidate electric power generators are assumed to be NGGs in this paper. However, the proposed methods can be easily extended to accommodate other types of generations such as renewable energy resources

5. α, β and γ are assumed to be 0.98, 0.98, 0.96 respectively in the CCP solution approach. γ remains at 0.96 in the RP solution approach. It is important to note that although these confidence level might seem low in developed systems, they can be an ambitious target in developing environments where rolling blackout is frequent. In addition, these confidence levels allows the ease of comparing result

6. The size and cost assumptions for the candidate generators, compressors and pipeline are presented in Table 5.2 [60, 129, 130].

Table 5.2: Characteristic and capital cost of candidate generators and Pipeline

	Generator		Compressor	NG pipeline			
MW	100	200	4974kW	Diameter (mm)	890	590	315
Capital Cost ($'000,000)	90	170	11.419	$'000,000/km	2.1805	1.4455	0.9555

$2,450 *per millimeter of diameter per kilometer* [60]

$1,712 *per hp for compressor stations* [129]

The proposed model was solved using a combination of BARON solver under General Algebraic Modeling System (GAMS) [131] and Matlab R2014b on a computer with a processor speed of dual 3.50 GHz and a RAM memory of 64GB.

5.5.1 Results and Explanation

Although the computation time is often not an influencing factor when developing a long-term expansion plan, the computational time for each of the proposed models are presented in Table 5.3 for the purpose of completeness. A combination of investments and updates to the contractual lim-

Table 5.3: Computation time for the proposed planning approaches

	Sequential expectation	Integrated expectation	CCP	RP
Computation time	23 sec	37 sec	93.3min	117.5min

its of NG supply is required to ensure the electricity and NG demand is met 96% of the time. The proposed combinations of NGGs, NG pipelines, compressors and increase to NG supply limits for the sequential expectation, integrated expectation, CCP and RP solution approaches are presented in Table 5.4. The option of increasing the upper limits of NG supply is considered in this test case because existing NG transmission system is able to accommodate some increase in the NG supply from *Algerian gas* via *Zeebrugge* or *Norvegian gas* via *Voren*. The choice of the NG supply limit that is increased is dependent on the cost of NG supply, the capacity of the connecting pipelines, and the locations of the various NG demand. A discrete increase in the upper limits of the NG source is employed to ease the tracking of results.

5.5.1.1 Sequential expectation planning model

The expectation long-term planning model ignores the uncertainties of electric power and NG demand. The planning approach plans the electric system first and then the NG system. In consequence to this, NGG's integration is proposed once there is a violation of the flow conservation nodal balance constraint on the electricity network without considering the cost of extending the NG pipelines required to transport NG to the NGG. On the flip side, this approach ignores the effect of NG constraints that might arise from potential competing NG demands from other sources such as transportation, manufacturing, and export on the location of the NGG. This planning approach results in an expensive solution in comparison to the expectation integrated planning approach as depicted in Table 5.4. A 100% in the size of NGG and NG pipeline extension was proposed.

Table 5.4: Computed electricity generation and NG expansion targets

	Sequential expectation		Expectation integrated		CCP		JRP	
t	$P_b^{(n)}$(MW)	$y_{i,j}$(km) / $\psi_{i,j}$	$P_b^{(n)}$(MW)	$y_{i,j}$(km) / $\psi_{i,j}$	$P_b^{(n)}$(MW)	$y_{i,j}$(km) / $\psi_{i,j}$	$P_b^{(n)}$(MW)	$y_{i,j}$(km) / $\psi_{i,j}$
1	-	-	-	-	100_{24}	$y_{(Voeren\rightarrow 24)}$	-	-
2	100_{24}	$y_{(Voeren\rightarrow 24)}$	-	-	-	-	100_{24}	$y_{(Voeren\rightarrow 24)}$
3	-	-	-	-	-	-	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$
4	-	-	100_{24}	$y_{(Voeren\rightarrow 24)}$	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$	-	-
7	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$	-	-	100_{10}	$y_{(Sinsin\rightarrow 10)}$	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$
8			-	-	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$	100_{10}	$y_{(Sinsin\rightarrow 10)}$
9	100_{10}	$y_{(Sinsin\rightarrow 10)}$	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$	-	-	-	
10	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$	-	-	-	-	-	$\psi_{(Pèronnes,Mons)}$
11	-	-	-	-	-	$\psi_{(Pèronnes,Mons)}$	-	$\bar{S}_{Voren} :\uparrow 5Mm^3$
12	-	-	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$	-	$\bar{S}_{Voren} :\uparrow 5Mm^3$	-	-
14	-	$\psi_{(Pèronnes,Mons)}$	100_{10}	$y_{(Sinsin\rightarrow 10)}$ $\psi_{(Pèronnes,Mons)}$	100_{21}	$y_{(Voeren\rightarrow 21)}$ $\bar{S}_{Voren} :\uparrow 5Mm^3$	100_{21}	$y_{(Voeren\rightarrow 21)}$ $\bar{S}_{Voren} :\uparrow 5Mm^3$
15	100_{21}	$y_{(Voeren\rightarrow 21)}$	-	-	-	-	-	-
16	-		-	-	-	-	-	$\bar{S}_{Voren} :\uparrow 5Mm^3$
17	-		-	-	-	$\bar{S}_{Voren} :\uparrow 5Mm^3$	-	-
18	-	$\bar{S}_{Voren} :\uparrow 5Mm^3$	-	$\bar{S}_{Voren} :\uparrow 5Mm^3$	100_{17}	$y_{(Wanze\rightarrow 17)}$	100_{17}	$y_{(Wanze\rightarrow 17)}$
19	-		-			-	-	$\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$
20	100_{17}	$\bar{S}_{Voren} :\uparrow 5Mm^3$	-	$\bar{S}_{Voren} :\uparrow 5Mm^3$	100_{12}	$y_{(Mons\rightarrow 12)}$ $\bar{S}_{Zeebrugge} :\uparrow 5Mm^3$	-	-
Summary	400	42km $\bar{S}_{Voren} :\uparrow 10Mm^3$ $\bar{S}_{Zeebrugge} :\uparrow 10Mm^3$ $1 \times \psi_{(Pèronnes,Mons)}$	200	21km $\bar{S}_{Voren} :\uparrow 10Mm^3$ $\bar{S}_{Zeebrugge} :\uparrow 10Mm^3$ $1 \times \psi_{(Pèronnes,Mons)}$	500	57km $\bar{S}_{Voren} :\uparrow 15Mm^3$ $\bar{S}_{Zeebrugge} :\uparrow 15Mm^3$ $1 \times \psi_{(Pèronnes,Mons)}$	400	42km $\bar{S}_{Voren} :\uparrow 15Mm^3$ $\bar{S}_{Zeebrugge} :\uparrow 15Mm^3$ $1 \times \psi_{(Pèronnes,Mons)}$

5.5.1.2 Integrated expectation planning model

The integrated expectation model solves the independent solution challenge associated with the sequential model by simultaneously optimizing both systems. It, however, ignores the uncertainty of the electric power and NG demand. In the integrated exponential approach, the physical, operational and financial constraints of the electric power and NG systems simultaneously constrain the location of NGG, the extension of NG pipelines and the location of compressors. Since the NG demand for power generation accounts for a small portion of the total NG demand forecast, its influence on the expansion plan for the NG system is minimal as shown by the similarities in the NG expansion plan in both expectation solution approaches shown in Table 5.4. This approach ensures the financial viability of newly built NGG by delaying its integration until there is a substantial electric power and consequently NG demand to justify an investment in both the NGG and supply NG pipeline. Consequently, 50% less number of NGGs and NG pipeline extension is proposed for

the planning period. This in addition to ignoring the electric power and NG demand uncertainties results in large amount of reliability violations as shown in Table 5.5.

Table 5.5: Comparison of the overnight capital cost and average violation for each integrated planning approach

	Integrated Expectation model		CCP		RP				
Year	Capital cost (US$ Million)	Average violation	Capital cost (US$ Million)	Violation	α	β	γ	Capital cost (US$ Million)	Violation violation
1	-	23	94.36	2	0.9760	0.9840	0.9604	-	4
2	94.36	3	-	8	0.9985	0.9800	0.9785	94.36	1
3	-	8	-	9	0.9907	0.9951	0.9859	-	3
4	-	24	-	9	0.9870	0.9908	0.9779	-	7
5	-	42	-	13	0.9821	0.9876	0.9699	-	10
6	-	73	-	19	0.9752	0.9846	0.9601	-	13
7	-	113	90.22	3	0.9694	0.9903	0.9600	-	7
8	-	154	-	4	0.9959	0.9807	0.9767	90.22	3
9	-	203	-	8	0.9903	0.9695	0.9601	-	17
10	-	263	-	13	0.9864	0.9921	0.9786	11.42	9
11	-	312	11.42	10	0.9802	0.9995	0.9797	-	6
12	-	366	-	9	0.9754	0.9931	0.9687	-	7
13	-	423	-	18	0.9676	0.9880	0.9600	-	19
14	101.64	40	91.36	2	0.9951	0.9860	0.9811	91.36	3
15	-	91	-	8	0.9893	0.9720	0.9616	-	19
16	-	169	-	16	0.9801	0.9892	0.9695	-	7
17	-	231	-	14	0.9739	0.9856	0.9600	-	18
18	-	312	90.01	5	0.9994	0.9947	0.9941	90.01	2
19	-	398	-	16	0.9869	0.9859	0.9730	-	7
20	-	488	90.53	2	0.9817	0.9791	0.96120	-	13
Summary	196	186.8	467.9	9.4	-	-	-	377.37	8.8

5.5.1.3 Chance constrained planning model

The CCP model addresses the reliability concerns of the expectation integrated model by ensuring the uncertain electric power and NG demands are met with confidence levels of 98% each and a cumulative system confidence level of 96%. This, however, comes with a 138% increase in the proposed investment cost in comparison to the integrated expectation planning model as shown in Table 5.4. This increase in due to a 150% and a 171% increase in the proposed NGG integration and NG pipeline extension respectively as shown in Table 5.4. The significant increase in reliability

that accompanies this increase in investment cost is depicted by the reduction in average system violations as shown in Table 5.5. Although the desired confidence level for the individual system is always achieved, the complementation of the confidence levels of the dependent systems are not captured in the proposed solution.

5.5.1.4 Reliability programming planning model

The RP model optimizes the reliability of the entire system via the co-optimization of the confidence levels by which each of the constituent dependent systems meets it uncertain demands. This results in a 19.3% reduction in the investment cost for the planning period under consideration in comparison to the solution of the CCP planning approach. This cost saving is as a result of delays in the integration of NGG and NG pipeline as captured in Table 5.4. The delay in investment is a product of the complementing confidence levels of the power and NG systems.

The complementation of confidence levels allows the planner to relax the confidence level of the constituent system in response to an increase in the confidence level of the dependent system. For example, the integration of NGG can increase the confidence level by which the electric power system meets the uncertain power demands way above the minimum requirement. This allows the planner some potential room to accommodate a lower confidence level of meeting the uncertain NG demand without violating the reliability of the entire system. Consequently, investment in the NG system can be delayed. In addition, the complementation of the reliability of both systems results in an overall increase in system reliability in comparison to the CCP model as evident with the 7% reduction in overall average violations for the planning period shown in Table 5.5.

It is also worth noting that the expansion of the NG system and the increase of the contractual limits of NG supply from textitAlgerian gas via *Zeebrugge* or *Norvegian gas* via *Voren* happens earlier in the RP model in comparison to the CCP model. This is because a higher loss function is associated with the reliability of the NG system. That being said, sometimes lower reliability levels in the NG system are compensated for by higher levels in the electric power system and vice versa as shown in 5.5. This complementation of the reliabilities of the constituent systems is illustrated

in year 3 as captured in Table 5.5. An increase in the upper limit of the NG supply from *Algerian gas* via *Zeebrugge* increases the confidence level of the meeting the NG demand and consequently the overall system. A similar trend is noticed in year 10 with the integration of compressor station $\psi_{(Pèronnes,Mons)}$. The RP planning approach allows the planner to accommodate confidence levels that are less than the minimum 98% set in the CCP model without compromising on the desired system reliability of 96% as illustrated in Table 5.5. It is important to note that the similarity in the overall compressor station expansion plan is due to the dominant influence of non-electricity NG demand growth forecast on the integrated planning problem in this case study.

5.6 Conclusion

In conclusion, the integrated planning of the electricity and NG systems affords the system operator an opportunity to develop an overall cheaper and more reliable expansion plan. In addition, modeling the planning problem in probabilistic terms allows the system operator develop a long-term that leverage the complementation of the reliabilities of the constituent systems to ensure the desired system reliability and delay future investments. Finally, we show that the proposed planning models and solution algorithm are able to leverage a combination of financial, technical and contractual solutions to ensure the desired system reliability in the presence of increasing interdependencies between electricity and the NG transportation systems.

Chapter 6

Summary and Conclusion

In this thesis, the long-term integrated planning of natural gas-fired electric power generators and Natural Gas (NG) transportation systems in the presence of uncertain electric power and NG demand are discussed. First, a model for the comprehensive planning problem at the distribution system level with predictable NG demand was proposed. Next, an integrated approach to solving the integrated planning problem in the presence of stochastic electric power and NG demand is proposed and solved. Bearing in mind that the long-term planning of these systems is as much a technical problem as a management decision problem, a real option assessment of the management flexibilities in the long term planning of NG-fired distributed generators and NG distribution system was proposed and solved. Finally, reliability based- probabilistic approaches to modeling and solving the long-term integrated planning problem at the transmission systems level was presented. The detailed conclusions for each of the Chapters 2 to 5 are summarized in Section 6.1.

6.1 Research Contributions and their Associated Significance

In Chapter 2, a sequential planning approach for determining the location and size of natural gas fired distributed generators (NGDGs) and NG distribution pipelines is proposed. The proposed modeling approach assumes a predictable NG demand for the planning horizon while the uncertainty of the electric power demand is accommodated by modeling the NGDG planning problem as a chance constrained programming optimization problem. This modeling approach in addition to accommodating uncertainties, allows the planner to achieve a desired level of reliability. In addition, a reliable NG system is ensured with the minimization of the cost associated with outages on the NG distribution system. The sequential solution framework entails the minimization of the investment and operation cost of proposed NGDG and then that of the NG distribution system. This

planning approach resulted in a cheaper and more reliable long-term expansion plan in comparison to a deterministic planning approach. The proposed sequential planning approach allows the distribution energy utility with predictable non-electricity NG demand to ensure reliable electric power supply in the presence of budgetary and transmission capacity constraints.

In Chapter 3, an integrated approach to the long-term planning of NGDGs and NG distribution systems in the presence of uncertain complex electric power demand was proposed. The integrated planning problem was modeled as a chance constrained programming problem that ensures the active and reactive electric power demand is met with predefined reliability levels. The output of the integrated planning approach is less expensive and more reliable than the output of a sequential planning approach for the same sets of nodal electricity demand and system characteristics. In addition, the integrated planning approach ensures system reliability by accommodating the dynamics of NG demand for non-electricity generation purposes and optimizing the NG flow-rate. This integrated planning approach equips an energy utility with a tool to plan its electricity and NG distribution infrastructure development in terms of future uncertain electricity and NG demand. In addition, it accommodates the effects of uncertain competing NG demand in the development of the expansion plan thereby allowing the energy utility ensure the desired level of energy supply reliability.

In Chapter 4, the management flexibilities presented by the modularity, scalability, and adaptability of the investment in NGDGs and NG distribution was valued and incorporated into the long-term integrated planning of the electric and NG distribution systems. A real option valuation of the downstream flexibilities presented by existing investment was assessed as part of the solution to the integrated planning problem. It was shown that an investment in time t offers the management of an energy utility options to implement, delay or abandon expansion plans in the future. The value of the options is dependent on the realization of uncertain electricity demand and increases with the realization of positive electricity demand growth. This is because; expected demand growth reduces the risk associated with delaying and abandoning future stages of the ex-

pansion plan. In addition, it presents the utility with an option to improve its profitability via the expansion of initial plans. The values of the options to abandon or delay investment plans should the realization of the stochastic electric power demand compare less favorably with forecast values was shown to arise mainly from the savings accrued from avoiding or delaying non-profitable investments. This approach to investment planning and assessment equips a distribution utility with a tool that can be leveraged to assess current investments in the light of future opportunities. In addition, it allows utilities improve profitability, reduce exposure to financial risk and make well-informed decisions on future investments, especially where access to capital is limited.

In Chapter 5, a reliability based probabilistic approach to the integrated planning of natural gas fired generators, NG transmission pipelines, and NG compressors is presented. The proposed models accommodated the cascaded reliability interdependency of both systems in probabilistic terms. Two probabilistic solution approaches i. e joint chance constrained and reliability programming were introduced. The chance constrained programming approach, optimizes the location and size of NGG's, NG compressor and the route of NG pipelines to meet a reliability level set a priori. The reliability programming approach improves the on the chance constrained solution algorithm by simultaneously optimizing the reliability levels of the component system thereby allowing cross compensation of reliability. Both probabilistic planning approaches were compared to a deterministic model and shown to result in a reduction in investment cost and an increase in system reliability. The reliability programming approach because of its ability to accommodate cross-compensation of system reliability results in a further reduction in investment cost without violating the over all desired system reliability. The proposed probabilistic planning models and solution algorithm allows the system operator leverage a combination of financial, technical and contractual solutions to ensure the desired system reliability in the presence of increasing interdependencies between electricity and NG transportation systems.

In summary, this thesis focuses on the development of analytical tools for planning and assessing investments in the natural gas fired generators and natural gas transportation infrastructure in

the advent of the increasing contribution of NG to the electricity generation fuel mix. Analytical tools such as those proposed in this thesis offer energy utilities and the system operator with tools that can be used to better plan long-term investment and ensure system reliability.

6.2 Supplementary discussion

This section clarifies the assumptions made in the general steady state NG flow constraints in the NG distribution route planning model and its effects on the results presented in this thesis.

6.2.1 Natural gas compressibility factor

A compressibility factor of 0.805 was assumed in Chapter 2 and Chapter 3 which was based on the value presented in [18]. In chapter 4, the compressibility factor for NG at the distribution was computed using the relationship presented in [111]. This relationship is suitable for computing the compressibility Z-factor for natural gas with specific gravities between 0.5 and 0.8 and pressure up to 34,473.79kPa. The compressibility factor is a function of the nodal NG pressure differential The compressibility factor for the pressure range (i.e.14kPa - 1380kPa) under consideration is shown in shown in Fig. A.

When developing a long time plan, it is typical to ensure the plan is capable of sustaining maximum acceptable pressure in the system. In consequence to this, taking the maximum possible pressure to be 1380kPa, the correct compressibility of factor for our illustration is 0.9268 as shown Fig. A.

It is important to point out that utilizing a compressibility factor of 0.805 instead of 0.9268 did not change the optimum NG pipeline route computed in Chapter 2 and Chapter 3. This is because the length and diameter of the pipelines are the most influential parameters in the optimization NG distribution pipeline route. The difference in the pipelines resistances and nodal pressures based on a compressibility factor of 0.805 or 0.9268 is not significant enough to influence a change in the optimum pipeline route. To illustrate this, assuming a pipeline of length 25km with a diameter

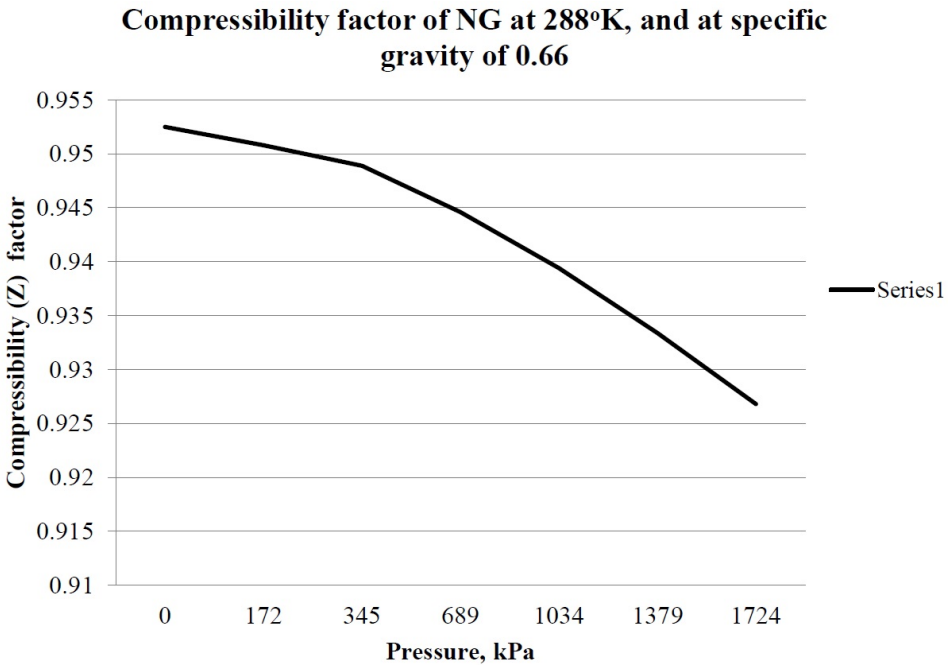


Fig. A: Change in compressibility factor with change in pressure.

of 153mm, a frictional factor of 0.01, the base temperature of 288^oK, NG gravity of 0.66, flow temperature of 288^oK, compressibility factor of 0.9268, the pipeline resistance is 4.79×10^{-9}. This is 0.63×10^{-9} greater than the pipeline resistance of 4.16×10^{-9} computed base on the initial assumption of 0.805. Fig. B shows the variation of the pipeline resistants with changes in compressibility factors.

For example assuming a pipeline feeding a 2 MW NG -fired distributed power generator, the difference between the NG pressure at the demand node for NG compressibility factor 0.9268 and 0.805 is 0.0000199 bar. This difference in pressure did not affect the computation of the optimal NG pipeline route.

6.2.2 Natural gas assumed frictional factor

A frictional factor of 0.01 was assumed throughout this thesis based on [18]. The frictional factor as modeled by Colebrook equation is a function of the pipeline relative roughness and the Reynolds number [132]. Assuming a 153mm NG distribution pipe, with a relative roughness of 0.001, transporting natural gas with a density of 0.8. The Reynolds number is computed to be approximately

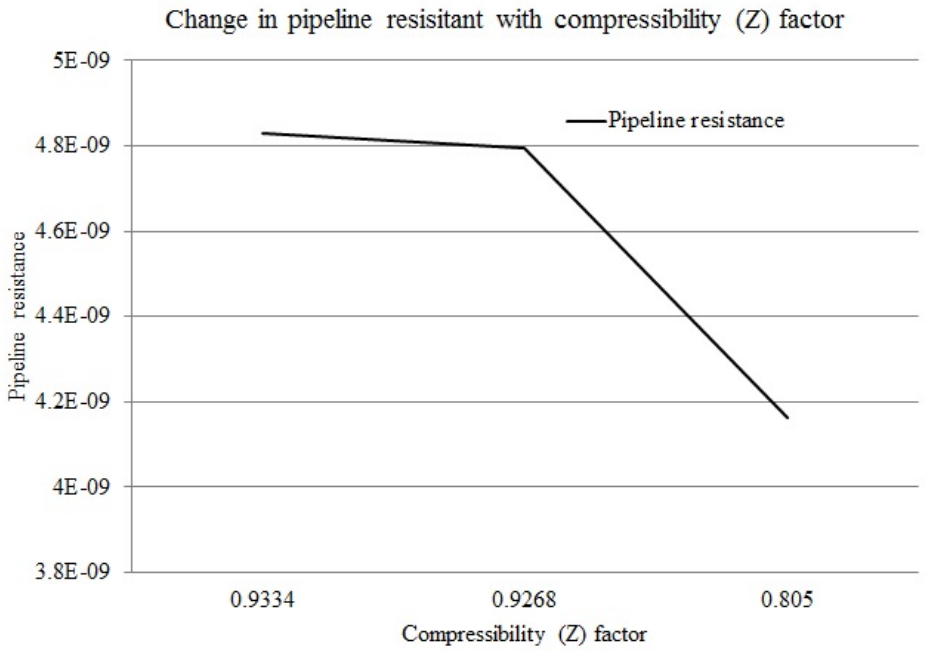


Fig. B: pipeline resistance with changes in compressibility factor

715,054. Using the Colebrook equation and the Moody diagram the fictional factor in this pipe is approximately 0.02.

Although this value differs from the value of 0.1 used in this thesis, it did not affect the optimum pipeline route presented in this thesis. This is because of the dominant nature of the length and diameter of the pipeline in determining the optimum NG distribution pipeline route. The sensitivity of the pipeline resistance to changing frictional factor assuming a compressibility factor of 0.9268 is presented in Fig. B below.

The sensitivity of the pipeline resistance to changes in frictional factor is in the order of 10^{-9}. As shown while discussing the sensitivity of the pipeline to compressibility factor, this order of change has a minimum effect on the NG pressure differential and the NG pipeline route.

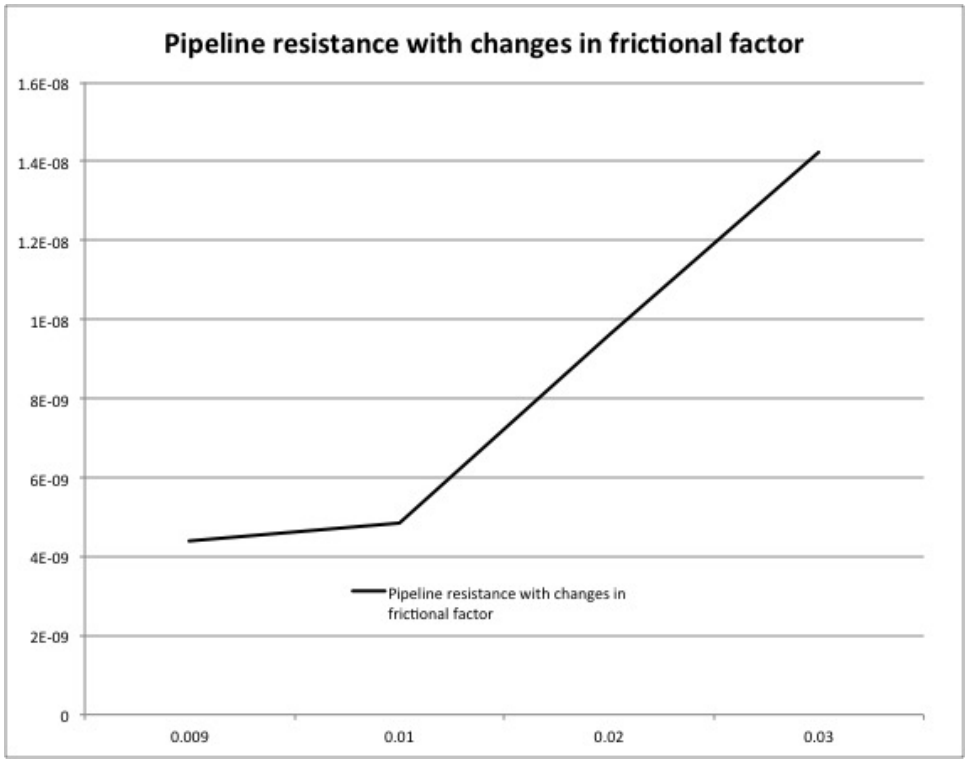


Fig. C: pipeline resistance sensitivity to changes in frictional factor

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Publication: Energy

Publisher: Elsevier

Date: 15 May 2017

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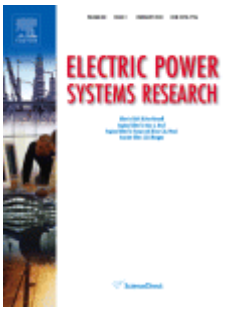

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Author: Babatunde Odetayo,John MacCormack,W.D. Rosehart,Hamidreza Zareipour

Publication: Electric Power Systems Research

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