

Methodologies and Techniques for Transmission Planning Under Corrective Control Paradigm

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Abstract

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Methodologies and Techniques for Transmission Planning Under Corrective Control Paradigm

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Environmental concerns and long term energy security are the key drivers behind most current electric energy policies whose primary aim is to achieve a sustainable, reliable and affordable energy system. In a bid to achieve these aims many changes have been taking place in most power systems such as emergence of new low carbon generation technologies, structural changes of power system and introduction of competition and choice in electricity supply. As a result of these changes, the level of uncertainties is growing especially on generation side where the locations and available capacities of the future generators are not quite clear-cut. The transmission network needs to be flexibly and economically robust against all these uncertainties. The traditional operation of the network under preventive control mode is an inflexible practice which increases the total system cost. Corrective control operation strategy, however, can be alternatively used to boost the flexibility, to expedite the integration of the new generators and to decrease the overall cost. In this thesis, the main focus is on development of new techniques and methodologies that can be used for modelling and solving a transmission planning problem under the assumption that post-contingency corrective actions are plausible. Three different corrective actions, namely substation switching, demand response and generation re-dispatch are investigated in this thesis.

An innovative multi-layer procedure deploying a genetic algorithm is proposed to calculate the required transmission capacity while substation switching is deployed correctively to eradicate the post-fault network violations. By using the proposed approach, a numerical study shows that the network investment reduces by 6.36% in the IEEE 24 bus test system. In another original study, generation re-dispatch corrective action is incorporated into the transmission planning problem. The ramp-rate constraints of generators are taken into account so that the network may be overloaded up to its short-term thermal rating while the generation re-dispatch action is undertaken. The results show that the required network investment for the modified IEEE 24 bus test system can be reduced by 23.8% if post-fault generation re-dispatch is deployed. Furthermore, a new recursive algorithm is proposed to study the effect of price responsive demands and peak-shifting on transmission planning. The results of a study case show that 7.8% of total investment can be deferred. In an additional study on demand response, a new probabilistic approach is introduced for transmission planning in a system where direct load curtailment can be used for either balancing mechanism or alleviating the network violations.

In addition, the effect of uncertainties such as wind power fluctuation and CO₂ emission price volatility are taken into account by using Monte Carlo simulation and Hypercube sampling techniques. Last but not least, a probabilistic model for dynamic thermal ratings of transmission lines is proposed, using past meteorological data. The seasonal correlations between wind power and thermal ratings are also calculated. £26.7 M is the expected annual benefit by using dynamic thermal ratings of part of National Grid's transmission network.

Declaration

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Dedication

To my beloved Mum and Dad

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A. K. Kazerooni, J. Mutale, M. Perry, S. Venkatesan, and D. Morrice, "Dynamic thermal rating application to facilitate wind energy integration," *PowerTech, 2011 IEEE Trondheim*, 19-23 June 2011.

A. K. Kazerooni and J. Mutale, "Network investment planning for high penetration of wind energy under demand response program," *Probabilistic Methods Applied to Power Systems (PMAPS), 2010 IEEE 11th International Conference on*, pp.238-243, 14-17 June 2010.

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A. K. Kazerooni and J. Mutale, "Flexible transmission network planning with post-contingency network switching," *Universities Power Engineering Conference (UPEC), 2009 Proceedings of the 44th International*, 1-4 Sept. 2009.

Chapter 1. Introduction

In this chapter, the background and the research motivation of the work reported in this thesis are given. The research objectives are also crystallised and the main contributions of the work are explained. The organisation of thesis is also outlined.

1.1 Background

The electric energy industry has been undergoing many changes. The key driver for these changes is to make the electric energy system more sustainable, reliable and affordable. All sectors in a power system including generation sector, transmission and distribution networks and consumers are experiencing these changes. The major changes can be listed as follows:

- Power system restructuring
- Rapid growth of renewable energies
- Evolutions on consumer side such as integration of smart meters, and electrification of transport and heating systems
- Decentralisation of the generation sector

In the following sections these changes and their drivers are elaborated.

1.1.1 Power system restructuring

Restructuring of the power system was the major change which was introduced in the late 20th century. Driven by the belief that the generation sector as a whole is very likely to function more efficiently in a competitive power system, many countries have gradually reformed their power system structure from a centralised and monopolistic system to an open energy market in which many independent generator companies (GenCos) compete with each other [1]. Due to the competitive nature of any market, in the energy market, generators try to increase their efficiency so as to be able to offer a lower energy price in the market.

Unlike the generation sector, transmission and distribution networks are a natural monopoly. Therefore, the transmission companies (TransCos) and distribution network operators (DNOs) remain regulated to ensure these companies provide a non-discriminatory environment for competition between other stakeholders. In addition, the system regulator oversees network investments by TransCos and DNOs in order to avert any excessive investment which eventually should be paid by network users.

1.1.2 Rapid growth of renewable energies

In many countries fossil fuels are currently the key source for generating electrical energy. The biggest drawbacks of using fossil fuels are global warming and emission of harmful gases. In addition to that, fossil fuel resources are not reliable energy resources as, firstly, they are depleting resources and, secondly, there are a few countries which exercise a monopoly on exploitation of these resources. Therefore, fossil fuels need to be replaced with other sustainable energy resources.

In order to address concerns about global warming issues, an international agreement, the Kyoto Protocol, was made by 37 industrialised countries as well as European the community in order to set a binding limit on the level of greenhouse gas emission. Renewable energies have been recognised as the most promising alternative to fossil fuels to meet Kyoto protocol commitments. European unions have set a target of supplying 20% of energy consumption from renewable sources by the year 2020 [2]. The United Kingdom (UK) government 2008 renewable energy consultation documents estimate that there will be around 35 GW of renewable energy generation, of which 28 GW is wind power, to meet the emission reduction target by 2020 [3]. The energy decarbonisation scheme will not stop in 2020 and the next horizon target is year 2050 when CO₂ emission is planned to be reduced by 80%. Therefore renewable energy generation, especially wind power, is the major part of future generation mix which is expected to be completely different from the past generation mix.

1.1.3 Evolutions on consumer side

Consumption behaviour in the future power system is likely to see a significant change. Consumers will be equipped with smart meters which update them on the real-time energy price and their consumption. Therefore, consumers are aware of the cost of energy on a short-term basis so that the consumption in high energy price periods is very likely to be partly shifted to other times when the energy price is cheaper. This

simply reforms the load profile to a rather flat consumption pattern. Governments and policy makers in many countries are convinced that deploying smart meters can highly reduce investment in primary assets just serving during peak-time period, hence, the overall cost of service delivery can be reduced. As one of the UK's CO₂ emission reduction schemes, every residential consumer across the UK will be fitted with a smart meter by 2020. On a larger scale, approved by European parliament, smart meters should be installed for 80% of all electric energy consumers in Europe.

Moreover, electrification of the transport system is also considered as one of the key options for energy decarbonisation since 20% of greenhouse gas emissions comes from the transport sector [4]. On one hand, the green electric transport system increases the level of consumption of electrical energy significantly, while on other hand, the capability of electric vehicles to store the energy and deliver it back to the network in times of need enhance the flexibility of the power system.

1.1.4 Decentralisation of the generation sector

Distributed generation technologies are recognised as one of the options employed to achieve the energy policy goals [5]. Generating power near the points where demands are increases the overall efficiency of the power system. Combined Heat and Power (CHP), photovoltaic and micro-wind turbines are some other green technologies which can be used by households as domestic generators. Consumers will be able to supply their own energy demand locally and even at sometimes export the power to other parts of the network. In other words, consumers can be conceived as a micro scale generator. By integration of more and more distributed generation into the system, the traditional power flow, which is usually from central generators to consumers will change to a more bidirectional power flow.

In general, there will be changes on both the demand side and generation side. On the demand side, consumers are very likely to actively respond to the security and price signals which they may receive from system operators and the electricity market. On the generation side, the future generation mix and the generator size will be different from conventional centralised fossil fuel based generators. The transmission network, which is located between the generation and the demand, should be able to accommodate the changes stemming from energy policy targets. In the following the role of transmission network and the grid-related issues which need to be addressed are explained.

1.2 The importance of the transmission network

The primary role of the transmission network is to transfer electric power from central power plants to load centres which are in different geographical places. In addition to that, the quality of transmission network services can greatly affect the performance of the market, reliability of supply and CO₂ emission reduction targets.

Lack of transmission capacity can affect the non-discriminatory competitive environment of a perfect electricity market. In an ideal electricity market, different stakeholders should be able to compete with each other without being constrained by the transmission network services. Insufficient capacity and the congestion problems can give out-of-merit generators the opportunity to stay in the supply-demand chain so that the energy cost, which is ultimately paid by consumers, increases.

Security of supply has always been a paramount factor in the power system. Consumers, especially in a modern, high-tech society, incur significant losses if electrical energy is interrupted. The security of the power system and continuity of energy delivery very depend on the performance of transmission network. The transmission network needs to be operated and designed to withstand all credible contingencies. It is the transmission operator's responsibility to settle the energy trading transactions which do not jeopardise the security of the system. Traditionally, "N-1" and "N-2" security criteria are applied for planning and operating the transmission network. Under these criteria, while meeting the standards for quality of energy, the delivery of energy should not be interrupted if one circuit (N-1) or two circuits (N-2) trip. A circuit in a transmission network can be conceived as a transmission line or a transformer.

Moreover, the carbon emission reduction targets are unlikely to be met if there is not sufficient transmission capacity to accommodate the renewable energies securely. Most of the sites which are suitable for harvesting renewable energies are far from existing transmission networks or load demand centres. For example in the United States the potential sites for generating wind powers are located in the middle of the country whereas the load energy centres are mostly in the coastal areas. Therefore, a significant transmission network reinforcement/expansion should be carried out in order to facilitate the integration of renewable energies. In the UK, Electricity Networks Strategy Group estimates that a £4.7bn investment in transmission network is required to integrate the future generation mix adapted to UK green energy policy [6].

It is, therefore, very important to plan and design a network which is able to securely accommodate the developments on the generation and demand side. This is not an easy task and involves many challenges, especially because the transmission network expansion should be planned well in advance. In the next section, the difficulties involved in planning of the transmission network are discussed.

1.3 Challenges and issues in transmission network planning

Planning of transmission network is challenging tasks. Any practice undertaken by any of the stakeholders in a power system affects the power flowing in the transmission network. This ultimately affects the required capacities in different designated transmission corridors. Transmission network planning becomes more complicated in modern power systems as the network planner needs to take into account a high level of uncertainty on both the generation side and the demand side. In order to accommodate these uncertainties planners need to consider different scenarios so that an economic transmission investment plan for all those scenarios can be proposed. Transmission proposal should be approved by an independent regulator. For example in the UK, Ofgem is the regulatory body which examines the transmission investment to make sure that transmission companies do not use their monopoly to over-invest in primary transmission assets. Some of the uncertainties which can affect transmission investment plans are explained below.

- 1- The uncertainties in the electricity market:* Network planning should taking into account the performance of all generators. Any participant in a market can perform independently without being controlled by any regulatory body. This imposes a high level of uncertainty on the generation side. Commissioning and decommissioning of generators are entirely decided by GenCos. This can affect the generation scenario for the year for which the transmission planning is carried out.
- 2- The intermittency of renewable energies:* A large portion of the future generation mix is renewable energies, especially wind power, which offers an intermittent generation. In the future power system, the amount and the directions of powers flowing in transmission lines are highly dependent on meteorological conditions which are very volatile and hard to predict, especially for long-term studies. This poses a significant uncertainty on the generation side

which considerably complicates the operation and planning of transmission network.

3- The uncertainties in future demand: The future of demand growth and the consumption pattern are not clear. Consumers, especially residential consumers who are equipped with smart metres, are likely to partly shift consumption to the periods when the energy price is lower. However, the plan for electrification of transport and heating will significantly increase the demand for electric energy. These programmes are still partly under implementation phase and partly in study stage. There are still many issues such as infrastructure, regulation etc to tackle in order to fully implement these programmes. For this reason, it is not clear how demand profile and consumption behaviour will change in future. As transmission projects are very time-consuming, however, transmission network should be planned well in advance. Demand is one of the main drivers of transmission network expansion. All these ambiguities on the demand side make transmission expansion planning quite a challenging task.

4- Uncertainties by policy makers: The plans for future generation mix or demand response programmes can be affected by the policy makers' decisions. For example, Germany, in the light of the Fukushima nuclear power plant incident in 2011, planned to phase out all nuclear power plants by 2022 whereas the initial plan was to decommission nuclear power by 2036. Because of this, the wind power integration rate will significantly increase in proportion to loss of generation capacity from nuclear. This dramatic change in energy policy will challenge transmission planners to adapt the network expansion schedules to new generation mix.

In addition to this transmission projects are difficult to undertake. These projects are very time-consuming and prohibitively expensive to accomplish. One of the main challenges for installing a new overhead line is obtaining the right of way. This is a time-consuming process as it includes negotiation with all landowners in the corridor of a transmission lines. Due to these difficulties, the completion of transmission projects usually lags behind the time when power plants are ready to connect. Therefore, due to lack of transmission capacity, the connection of generators may be delayed or generators may be constrained to operate below their actual capabilities. This can

jeopardise the integration of renewable energies in order to achieve green energy policy targets.

1.4 Planning and operation under preventive control mode

Traditionally, transmission network is planned and operated under a preventive control regime. Under this regime, the transmission network should be robust against any credible contingency without taking any post-fault action. The level of security criteria is defined differently by different system operators. “N-1” (single outage) and “N-2” (double outage) security criteria are the most common constraints which are considered for planning and operation of transmission network. In the preventive control operation, the network and all participants in the network are assumed to be passive and inflexible when a contingency occurs, so part of transmission network capacity should be kept reserved for the contingent conditions.

Operating under a preventive control philosophy results in need for an extra investment in transmission network just to cope with outages which do not occur very frequently. This is a conservative approach for network operation and the network assets are not efficiently utilised. Although operation in preventive control mode has served power system well for many years this operation regime is not the solution for the future power system where there are many uncertainties in both generation side and demand side.

In future power systems, in order to survive contingencies and uncertainties a very large investment is required if the network is operated and planned assuming the preventive control mode. A very large network expansion is not feasible in practice and the network regulators do not approve such a large investment which should be ultimately paid by network users.

Transmission planning under the preventive control paradigm which suggests low efficiency in utilisation of existing network and an overinvestment in primary transmission assets cannot be consistent with affordability and sustainability targets in the energy policy as:

- 1- The overinvestment in transmission assets should ultimately be paid by consumers. The load is expected to grow rapidly in the next decade, so by practicing the preventive control strategy, a significant transmission investment

is required. The higher transmission investment imposes a higher transmission charge and ultimately a higher overall energy charge on consumers.

- 2- The environmental and visual impacts of transmission lines have always been an issue that makes the installation of the new transmission lines problematic, at least in the eyes of the public. In order to obtain a corridor for a transmission line, trees have to be cut down and some farmland is occupied. In the UK, the environmental impacts of overhead lines are more noticeable as the available land is very limited.

Therefore, it seems imperative to rethink the architecture of future electric network and the network operation strategy.

1.5 Corrective actions: a solution for flexible network

A flexible transmission network is one of the key requirements for achieving an affordable, sustainable and secure electrical energy system. The conservative and inflexible preventive operation strategy needs to be replaced with a flexible and smart operation regime. The network should be able to flexibly follow the variations in the generation and demand side while security of supply is maintained at a high standard.

In many countries the idea of having a smart grid is the key focus of power system engineers and energy policy makers. The vision of a smart grid for developing future network architecture has been recognised by European countries [7] and the United States [8]. The European Commission conducts studies and task force groups to crystallise possible smart grid solutions and the requirements for achieving the smart grid [9]. The definition of smart grid according to EU Commission Task Force for Smart Grid is:

“A Smart Grid is an electricity network that can cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety”

This definition clearly emphasises the flexibility of the network in terms of accommodating the different behaviours of stakeholders and consumers. The flexibility of the network can be enhanced by either increasing the transmission capacity while

operating under preventive control regime, or by increasing the controllability and a better monitoring of the network components.

The flexibility feature of future grid is also important for coping with contingencies just in time when they occur so that the system does not need to operate under preventive control mode. Under preventive mode, the flexibility can be achieved by significant investment in transmission capacity. However, unlike preventive mode, under corrective control mode, the network can be flexibly operated to survive contingencies while the transmission assets are used in a more efficient way. The post-contingency network violations can be alleviated by deploying corrective actions. The decision-making process for post-contingency corrective actions usually needs to be swift and the relevant corrective commands also need to be sent quickly to network components, generators or consumers.

Collier [10] elaborates ten steps which need to be taken for achieving the smart grid. The most important step is the integration of real-time control and decision-making software underpinned by a broad two-way communication system. The network should be able to constantly monitor the status of the power system components and the margins of network violations whereby the intelligent systems can determine the most effective post-fault corrective action while taking into account the severity of the outage(s). In such a system, the network overload, voltage violations, and stability problems can be predicted and alleviated quickly once the contingencies occur. The “self-healing grid” is the phrase used by some researchers as the ultimate controllability and the intelligent decision-making of the network [11].

Different post-contingency corrective actions may be deployed to eliminate post-fault contingency violations:

- 1- **Network reconfiguration:** the active and reactive power flowing in the transmission network can be changed by switching in/out the transmission lines. Moreover, by switching the circuit breakers in a substation, the topology of the network can be changed. In a fully automated network, corrective switching action can be undertaken very quickly after an outage. Although network/substation switching is practiced sometimes by network operators, this corrective action has not been fully deployed in power systems as in the absence

of intelligent systems the success of switching action depends very much on the operator's experience.

- 2- Generation re-dispatch:** Generators may vary their outputs to eliminate post-contingency network violations. The post-contingency action undertaken by generator can be contractually agreed between the system operator and the generators. Generators may receive the re-dispatch signals when network face a security breach. The main problem of post-contingency generation re-dispatch corrective action is the element of time required to ramp up/down a generator. The reaction of a generator to a re-dispatch request from system operator is constrained by the ramp rate capability of the generator.

The future generation fleet is likely to embody distributed generations which can offer a fast generation variation. Distributed all over the network, the generation side can be a promising option for boosting the flexibility of the network to deal with contingencies as well as uncertainties.

- 3- Demand response:** The ability of consumers to shed consumption in times of need can be used as one of the feasible options for maintaining the security of the network. Under a contract or by offering other incentive packages, consumers can participate in a demand response program which obliges them to reduce the load within a given time when a network security breach occurs. The fundamental requirement for a successful demand response program is the existence of a two-way communication channels between the system operator (or decision-making software) and the consumers.
- 4- Deploying FACTS:** Flexible AC transmission systems, such as phase shifter transformers (PSTs) and thyristor controlled series compensators (TCSCs), can be used to control the power to flow in the transmission corridors where enough capacity is available so that network overloads can be eliminated. By a coordinate control of FACTS devices the network can be utilised in a more efficient way and the flexibility of the network increases. Using power electronic technologies and fast electronic switching, FACTS are a promising option in the creation a flexible transmission network. Reactive power as well as active power flows can be quickly changed following a contingency so that post-contingency network violations are swiftly eliminated.

- 5- Other options:** Other methods such as using energy storage technologies and interconnection with other countries may be also used to enhance the flexibility of the network. Storage technologies can be deployed as fast ramp generators which are able to serve in power balance mechanism or post-contingency corrective action. Interconnecting to other power grids also increase the overall operation flexibility by relying on the capability of other grids to vary the direction and amount of power flowing in the interconnections in times of need.

While the operation regime becomes more flexible under smart grid umbrella, the strategy for transmission expansion also needs to be adapted to this new flexible operation philosophy. Transmission network expansion/reinforcement projects need a long lead time – usually 7 to 10 years – hence transmission network investment needs to be planned well in advance. As the network is planned to be smarter and more flexible in the next decade it is now time to contemplate the methodologies and techniques which should be deployed for transmission expansion planning studies assuming the flexibilities of the grid. Network operation under corrective operation philosophy seems to be imperative for enhancing the flexibility of the network.

The flexibility of the network and the idea of smart grid is one of the essentials to deliver energy policy targets, so the system regulators are trying to stimulate innovation in the grid. For example, in the UK, Ofgem has introduced the innovation funding incentive (IFI) which allows DNOs to spend on research and development (R&D) for achieving carbon reduction targets. TransCos and DNOs are encouraged to propose and implement ideas which can contribute alternatives to just reinforcement of the grid. The major scope of these R&D activities are proposing the methodologies and technologies to facilitate the connection of low carbon emission generators and upgrading the utilisation of the network assets to their maximum capability. For example, National Grid has set pilot zone, the Humber Estuary region, to investigate and implement possible smart grid solutions which can expedite the connection of wind energies and enhance the efficiency of network utilisation [12].

In this regard, the Flexnet consortium ,which was embodied many universities and industrial partners, was funded by Engineering and Physical Science Research Council (EPSRC) for four years commencing in October 2007 to develop the techniques and methodologies for a smarter planning and operation of future power system. The Flexnet consortium was organised in 8 work-streams each of which dealt with different

aspects of the flexibility of the future network, ranging from technical aspects to public perceptions of future grid. This thesis is conducted under “Market and Investment” work-stream in Flexnet consortium in the University of Manchester.

1.6 Thesis objectives

A lot of research has been carried out on transmission planning techniques in majority of which the preventive control regime has been assumed as being essential to meet security criteria. However, motivated by the trend towards a flexible and smart grid, the preventive operation regime is very likely to be replaced with a corrective control operation regime. This flexible operation regime needs to be taken into account in the timing of transmission investment. This is a new chapter in transmission planning studies. The techniques, methodologies, algorithms, and adequate tools for transmission planning studies need to be developed in order to adapt the transmission investment planning strategies to the flexibility of the future network.

The primary objective of this thesis is development of innovative algorithms and techniques for transmission investment in a network whose key features are the controllability of network components and flexibility in operation. Unlike the traditional approach to transmission planning studies assuming preventive control mode, the post-contingency corrective actions have been assumed to be plausible so that corrective actions are incorporated into transmission planning problem. Using the proposed techniques, the required transmission investment can be determined along with the post-contingency corrective actions which should be taken once a credible outage occurs. Moreover, the proposed algorithms should be able to incorporate the uncertainty aspect of renewable energy generation in transmission investment studies. In this thesis, a social welfare maximisation approach is taken as the objective of the transmission expansion planning. In other words, a transmission operator/planner assumes a given generation costs (or generation merit order) to propose the network reinforcement proposal which minimises the investment cost along with generation cost. In particular, the research objectives of this thesis are as follows:

- ***To model the uncertainties in transmission planning studies***

The future network should be able to accommodate many uncertainties on both the generation side and the demand side. The deterministic approaches which have been used by transmission planners for many years do not suit the

planning for the future transmission network. Instead, a probabilistic approach needs to be adopted whereby the most economic transmission expansion proposal can be determined by taking into account the possible generation or demand scenarios. In this project, uncertainties in the future power system are modelled and they are incorporated in the transmission planning problem. The methods used to generate scenarios considering the probabilistic model of uncertainties are also investigated.

- ***To investigate the operational constraints and cost of post-contingency corrective actions***

In order to accurately model a post-contingency corrective action in transmission planning problem the operational constraints associated with that corrective action should be taken into account. Some corrective actions may be subject to time constraints as a mechanical action may be required to perform the action. For instance, the generation re-dispatch corrective action depends on the ramp rate of generators. Further, there can be a cost associated with the corrective action. This cost also need to be modelled in the transmission planning study as an economic proposal should be a trade-off between the cost of corrective actions and the cost of transmission network reinforcement.

- ***To develop algorithms for solving transmission planning problems under corrective control paradigm***

The formulation and modelling of the transmission planning problem considering corrective actions is more complicated than the transmission planning under the preventive control operation regime. Incorporating corrective actions into transmission planning problem enlarges the scale of this problem as additional decision variables should be considered for modelling the corrective actions in the contingent networks. Transmission planning under corrective control is an area that has been rarely studied so far. In this project, the focus is to develop techniques and methodologies for modelling corrective actions in transmission planning problem. New algorithms also need to be developed to solve this problem. Development of these algorithms and techniques is imperative in order to determine the required transmission investment when the future network is set to be flexible and smart.

- *To quantify the benefit which can be gained by deploying the flexible transmission planning*

It is important to demonstrate that the transmission planning under the corrective control paradigm can reduce transmission investment while the security of the network is not jeopardised. To do that, the proposed methodologies need to be implemented on the test systems and the results should be compared with the traditional approach in which preventive control is used to meet the security criteria.

1.7 Contributions

Driven by the trend towards flexible and smart grids, it is now necessary to consider a more sophisticated transmission planning approaches taking account of plausible post-contingency corrective actions. This area has rarely been studied and flexible transmission planning is a new chapter for the transmission network planners. In particular, this thesis investigates three corrective actions, namely substation switching, demand response, and generation re-dispatch. It is demonstrated that the utilisation of the network assets can be improved and consequently a smaller transmission investment is required if post-contingency corrective actions are assumed to be plausible. In addition, the utilisation of network can be enhanced by operating based on the real-time thermal rating of transmission lines. This option is also investigated in this thesis.

The contributions of this thesis can be listed as follows:

- *The extensive review on the methods for modelling the transmission planning problem and issues which impact on transmission expansion plans in the modern power system*

The issues related to transmission planning study have been thoroughly reviewed in this thesis. This review gives a great insight to a reader wishing to understand the process of a transmission planning study in practice. The operational constraints which are crucial to be considered in the timing of transmission planning have been also discussed. The review has been divided to two main streams elaborated in Chapter 1 and Chapter 2. The first stream explains the fundamental formulations, network modelling, assumptions and methodologies which have been traditionally used for transmission planning studies. In the second stream, the focus is more on

the uncertainties affecting transmission expansion plans in the modern power system.

- ***Extensive review on post-contingency corrective actions***

The feasible post-contingency corrective actions have been reviewed in this thesis. The operational conditions and the practicalities associated with each corrective action are examined. This extensive literature surveys has shown that most of post-contingency corrective actions are not taken into account in timing of transmission planning. This is a major research gap which is addressed in this thesis.

- ***Proposed a new linear model for network losses which can be incorporated in the transmission planning problem***

A new linear model for the losses in the transmission network has been proposed. The proposed model offers simplicity as well as accuracy. The existing models for losses usually either sacrifice accuracy to simplify the modelling or increase accuracy by proposing a complicated model. The losses modelled in this thesis, unlike the existing models, do not include any binary variables which make the formulation complicated and difficult to solve. This is a completely linear model which accurately models the nonlinear nature of the losses of the network. The accuracy of the model has been demonstrated on a test case system.

- ***Investigated the effect of CO₂ emission price volatility on transmission network capacity***

The CO₂ emission trading market has been recently introduced into the electrical energy sector. In the CO₂ emission market, installations may be given a specific allowance for CO₂ emission so that any excessive emissions should be bought in the market from those installations which managed to keep the level of emission below their allowance. This can greatly affect the operating cost of different generation types. Consequently, the optimum generation re-dispatch and the required transmission capacity can be affected. As observed in the past, the CO₂ emission price is very volatile. The effect of CO₂ emission volatility on transmission expansion plans has not been studied yet. In this thesis, the volatility of the CO₂ emission has been modelled in the transmission planning problem. Moreover, a probabilistic approach has been proposed to determine a transmission expansion proposal which economically accommodates the variations in CO₂ emission price. The probabilistic transmission planning study has been undertaken

for two different models for emission market. The superiority of the proposed method has been demonstrated through comparison between the results of a traditional transmission planning and the results of transmission planning proposed in this thesis.

- ***Proposed a methodology for transmission planning under substation switching corrective action***

The topology of the network can be altered in order to control the power flowing in the transmission lines or eradicate any network violation. This can be undertaken by switching on and off the circuit breakers. Network re-configuration is usually practised as a corrective action to eliminate network overload problems or over/under voltage violations. However, network re-configuration corrective action has been rarely considered in the transmission planning process so far. In this thesis, however, the capability of network re-configuration to meet the “N-1” security criteria is assumed to be plausible in timing of transmission planning. It is assumed that once a contingency occurs, the connectivity of the transmission lines can be changed by switching on/off the circuit breakers in the substations. Under this assumption, a methodology has been proposed for calculating the transmission expansion plan. Genetic algorithm has also been deployed in the proposed methodology for finding the best post-contingency corrective substation action. Through numerical studies, it has been demonstrated that deploying the proposed techniques can reduce the required transmission investment while the security criteria are satisfied.

- ***Proposed techniques for calculating the required transmission capacity under different demand response programmes***

The consumers will be equipped with smart meters and they supposedly will have more contribution to network security. In this thesis, the effect of two different demand response programmes, namely the priced-based demand response and the direct load control demand response, on required transmission capacity have been investigated.

An algorithm has been proposed to determine the required transmission capacity while demand is assumed to be responsive to the energy price. A methodology is also proposed for calculating the transmission charge which should be allocated to

each bus in the network. In this way, the final energy price which consists of the transmission charge and generation cost is calculated for each bus.

In addition, transmission expansion planning has been investigated in a case where a high penetration of wind power has been scheduled and the direct load control demand response program is practised. A probabilistic technique has been proposed to calculate the transmission capacity along with the required load curtailment at each bus.

- ***Proposed an algorithm for solving the transmission problem under generation re-dispatch corrective action***

Generators can provide ancillary services to enhance the security of the network. The generators may ramp-up or ramp-down after a contingency occurs so as to mitigate the network violations. Although generation re-dispatch is sometimes deployed to eliminate network violations, the effect of this corrective action on network investment has rarely been studied. In this thesis, however, the generation re-dispatch corrective action has been incorporated in transmission planning problem. Generation re-dispatch corrective action includes the mechanical process of ramping up/down generators, hence this corrective action is usually associated with a performance time. The proposed approach to transmission planning under this corrective action models the duration within which the network can be partly overloaded while the generation re-dispatch corrective action is undertaken.

- ***Modelled the dynamic thermal rating (DTR) and determined the benefit of deploying DTR***

One of the features of the smart grid is utilisation of transmission assets in an efficient way. One way to do that, the network operation need to be undertaken based on the real-time thermal ratings of network assets. In this thesis, by using past meteorological data, a probabilistic model for a thermal rating of transmission lines in part of National Grid network has also been calculated. Moreover, a seasonal probabilistic model for off-shore wind power has been estimated. The practical data has also been used to determine the correlation between wind power and the available transmission capacity. These models for wind energy and dynamic thermal rating of transmission lines have been hardly addressed by other researchers. Using the proposed models, Monte Carlo simulation has been used to

calculate the benefit of using dynamic thermal rating in the UK National Grid network.

1.8 Thesis structure

This thesis consists of 8 chapters which are summarised below:

Chapter 1 describes the background, motivation and the objectives of this research. Corrective control action is introduced as a solution to the need for flexibility in future electric power grids. Moreover, in this chapter the transmission network-related issues which are addressed in this thesis are reviewed. The contributions of this thesis are also summarised.

Chapter 2 reviews the fundamental assumptions and formulations for modelling the transmission planning problem. The traditional techniques for solving this problem are also introduced through a thorough literature survey. A new linear model for the losses in transmission network is also proposed. The application of Bender's decomposition techniques for calculating the optimum transmission capacities is also explained and demonstrated on a three bus test system.

Chapter 3 introduces the issues which make transmission planning studies more complicated in the modern power system. The uncertainties affecting a transmission expansion proposal and the methods used to deal with uncertainties in timing of transmission planning are explained. In addition, the effect of the CO₂ emission market and the volatility of CO₂ emission price on the required transmission capacity are investigated by deploying a probabilistic transmission planning technique.

Chapter 4 proposes a methodology for incorporating the substation switching corrective action into the transmission planning problem. First, a review on the applications of network/substation switching action to eliminate post/pre-fault network violation is given in this chapter. This is followed by formulation of post-contingency substation switching in the transmission planning problem which is solved by a multi-stage optimisation algorithm. A genetic algorithm is used as part of this algorithm to find the best switching action. The proposed methodology is implemented on a test case system and the resultant transmission investment is compared with the required transmission investment calculated using the traditional approach.

Chapter 5 investigates the impact of demand response programmes on transmission investment. A review of different demand response programmes is given. In particular, price-based demand response and direct load control demand response are elaborated. Under price-based demand response, where consumers respond to energy price variation, a recursive algorithm is proposed in order to solve the transmission planning problem. As higher transmission investment imposes a higher transmission charge, a transmission charge allocation method is also proposed which can calculate the overall charge imposed on consumers sitting at a particular bus in network. A probabilistic approach for calculating the transmission capacity along with the required load curtailment is proposed and tested on a system where a large amount of wind energy is connected.

Chapter 6 focuses on generation re-dispatch corrective action. The applications of generation re-dispatch action are reviewed and the relevant practicalities for a successful re-dispatch action are investigated. A methodology is also proposed for calculating transmission capacity along with the required re-dispatch for eradicating the post-fault overload problems. The proposed methodology is demonstrated on a test system containing different generation types each of which offers different level of flexibility in terms of ramp-up and ramp-down of the generation within a specific time.

Chapter 7 investigates the application of dynamic thermal rating as one of the options for improving the utilisation of the transmission network. Dynamic thermal ratings of transmission lines vary based on weather conditions. In order to quantify the benefit of deploying dynamic thermal ratings, a probabilistic model for thermal ratings of transmission lines is developed using past meteorological data. The correlation between available off-shore wind power and the thermal ratings of transmission lines are also calculated. Using the probabilistic models for thermal ratings and the wind energy, the benefit which can accrue by implementing dynamic thermal rating in part of the National Grid network is estimated.

Chapter 8 presents the conclusions of this thesis. The results and the findings of this thesis are summarised in this chapter. Suggestions for possible future work on this topic are also given.

1.9 Conclusions

In this chapter the motive and the background of this thesis were reviewed. Many changes have been taking place in the power system to achieve a sustainable, reliable and affordable electric energy supply system. In order to accommodate these changes a new philosophy emphasising flexible operation and planning of the transmission network is required. Post-contingency corrective control actions were noted in this chapter as a promising option to enhance the flexibility of the network. A problem which needs to be addressed is how the transmission planning should be undertaken while the network is assumed to be flexible by deploying post-contingency corrective actions. This problem is the main focus of this thesis. Furthermore, the research objectives of this thesis were crystallised and the contributions which are elaborated throughout the thesis were explained briefly. Finally a general view on the structure of this thesis was given.

Chapter 2. Transmission Planning: Fundamentals

In this chapter the fundamental assumptions and traditional techniques for transmission planning problem are reviewed. The modelling of the network as well as loss modelling are also discussed and a new linear model for network losses is proposed. In addition to that, the application of Bender's decomposition technique in transmission planning problem is demonstrated on a three bus test system.

2.1 Introduction

The transmission network is meant to deliver electrical energy to consumers reliably and economically. The key drivers of transmission network expansion are load growth, security of supply, generation costs, and relative location of demand and generation. Transmission planners aim to propose an economic transmission expansion scheme to satisfy consumers' demand for reliable energy at an affordable price. Traditionally, the key objective of transmission planning is to propose a network expansion plan which leads to the optimum investment cost as well as minimum operation cost. Investment cost is the total capital spent on installing new transmission lines along with reinforcement of the existing network. Operation cost is the cost of electric power generated by power plants. A successful transmission planning proposal can provide the opportunity for existing low cost power plants to make more contribution to supplying consumers. The investment cost and the operation cost are contradictory objectives. The higher investment in transmission expansion will result in reducing the operation cost (or customers' outage cost) and vice versa [13]. Figure 2-1 shows the concept that a global optimal plan reconciles these contradictory objectives.

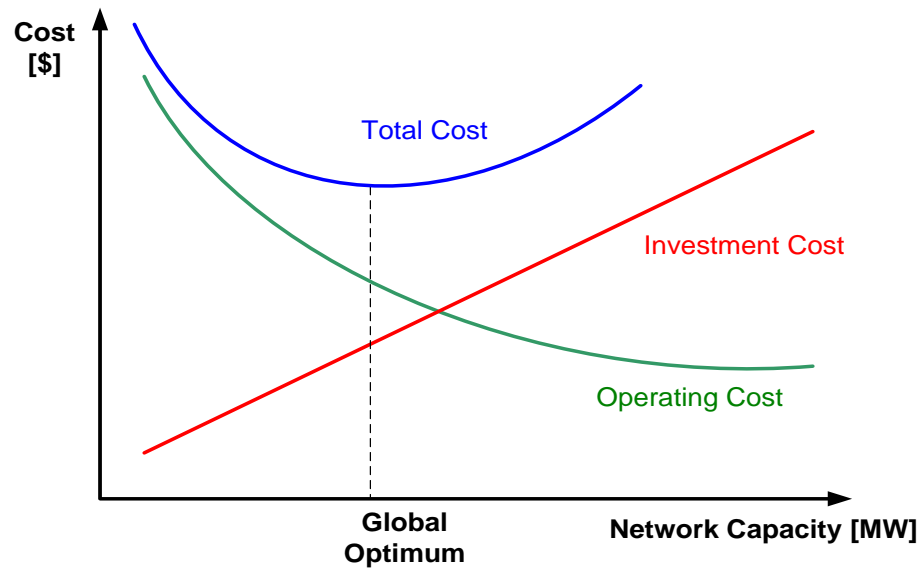


Figure 2-1: The investment cost versus operating cost

Furthermore, transmission network expansion is one of the major challenges facing modern power systems. Difficulties in obtaining rights of way to construct new transmission lines as well as high costs associated with network expansion make transmission line projects problematic and often behind schedule. These problems underline the importance of an economic transmission expansion proposal which meets the requirements for a reliable supply at minimum cost. Generally speaking, a transmission expansion plan should address the following three questions:

1. **Where** are the transmission lines required?
2. **What** are the capacities of the transmission lines?
3. **When** should the transmission lines be commissioned?

Regarding these three questions, two different approaches can be taken to the transmission planning problem:

- i) Static planning [14, 15]
- ii) Dynamic planning [16-19]

In the first approach, static planning, the optimal transmission network configuration and capacity are calculated for a specific horizon year. In the dynamic planning approach, however, the lead time of transmission network projects are also taken into account so that the optimisation is carried out for the years before the horizon year as well. In other words, static planning deals with **Where** and **What**, whereas dynamic planning answers to **Where**, **What**, and **When**. The dynamic planning problem is

usually complex and very large as it includes all time restrictions coupling transmission expansion projects over the years together. An additional comparison between static planning and dynamic planning is given in section 2.2.

Security criteria dictate that a transmission network should be robust against outages of power system components – generation units, overhead lines and cables [20] [21]. In other words, even in a contingent network, the continuity of supply to consumers must be preserved. Depending on investment budget or characteristic of a transmission network, security criteria may include different degrees of severity of outages [22]. Section 2.5 introduces security criteria which may be taken into account by transmission network planners.

Transmission networks usually consist of a mesh connection of many overhead lines and cables so that many different credible outages need to be taken into account in the transmission planning problem. Moreover, as the load demand varies, these outages should be modelled for different load levels. This turns the transmission planning problem into a large scale optimisation problem which requires a long time to solve. In some cases, desktop computers may not have adequate memory or processing speed to deal with such a large scale optimisation problems. Some decomposition techniques [23, 24] as well as heuristic methods [25, 26] have been proposed to split the transmission planning problem into sub-problems which are solvable by desktop computers. These techniques will be elaborated in section 2.6.

In the following chapters, by reviewing previous studies, the fundamental issues which need to be considered for a transmission network planning study are elaborated.

2.2 Dynamic and static transmission planning

A transmission planning study is a static study if the network expansion plan is reviewed just for a single horizon year [27]. In this approach, planners are not concerned whether a transmission line proposed for the horizon year is required to be in service in the years before the horizon year. The planning horizon year is usually five to seven years ahead of the year when the transmission planning study is carried out. In the static transmission planning, the equivalent annual cost or annuitised cost of transmission investment and all other costs are determined for the planning horizon. The equivalent annual cost (EAC) of a transmission project depends on the lifetime of assets

(n), the total investment (P) and interest rate (r), which is expressed mathematically by (2-1).

$$EAC = P \cdot \frac{r \cdot (1+r)^n}{(1+r)^n - 1} \quad (2-1)$$

Taking into account the annutized costs as well as loads in the horizon year, the most economic transmission expansion plan which meets security criteria is determined. A simple form of objective function for a static transmission planning study can be expressed by (2-2).

$$\text{Minimise } \sum_{i=1}^{\overline{Nl}} x_i \cdot EAC_i \quad (2-2)$$

Where EAC_i is the annutised cost of transmission line i , x_i is a binary variable which shows if transmission line i is required and \overline{Nl} is the number of candidate lines.

The planning horizon for dynamic planning studies, however, is an interval of several years [17, 18]. The transmission scheme is optimised over this interval so that some variations such as load growth, interest rate changes, and decommissioning assets during this period can be taken into consideration. Unlike static planning, dynamic planning specifies that in which year of planning interval a particular transmission line should be commissioned. A typical objective function considering time of installation of the transmission lines is given by (2-3).

$$\text{Minimise } \sum_{j=1}^{ND} \sum_{i=1}^{\overline{Nl}} x_i^j \cdot EAC_i^j \quad (2-3)$$

Where ND is the number of years.

Figure 2-2 shows the different intervals which are studied in dynamic planning and static planning.

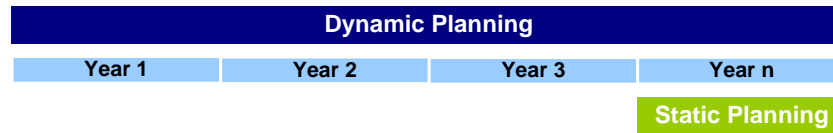


Figure 2-2: Intervals covered by dynamic planning and static planning

In a dynamic transmission planning study, the optimal network expansions for all years are calculated simultaneously. Hence, the decision variables, which are mainly transmission capacities, are coupled between years. This turns the problem into a relatively complex and large optimisation problem which cannot be solved by conventional desktop computers. Rudnick et al [17] deployed Genetic Algorithm to solve dynamic transmission planning for a relatively small network.

There are some techniques, generally referred to as pseudo-dynamic approaches, to tackle this large-scale problem. One of these methods entails division of the temporal planning problem into static sub-problems which calculate the optimal transmission topology of each year. In this method the optimal plan of each sub-problem is considered as the initial state for the following year [19]. A reverse course can also be taken, in such a way that the proposed transmission lines for the final year are the candidates for transmission planning in the previous year and so on. The latter approach is called “backward” method and the former is named “forward” method [27]. These approaches usually result in an overinvestment in transmission network as the solutions may be optimum for every year but the global optimal solution will be different if all years are simultaneously integrated into optimisation. Romero et al [28] proposed a multistage planning method to deal with the large scale nature of the dynamic planning problem.

2.3 Transmission network model

The electric power transmission network, in some respects, is similar to roads in a transportation system as the main concept in both systems is to transfer commodities from suppliers to consumers. Nonetheless, transmission networks ought to comply with some physical rules whereas there is no such restriction for transportation system. These physical laws governing the power system express the relationships among variables in a power system such as voltages, voltage angles, active and reactive powers. Depending on how accurately the power system is modelled, different levels of simplification can be made in the mathematical relationships among network variables while still respecting the physical laws that govern power flow. In general, for transmission

planning studies, the power system can be modelled with one of the three following models:

- 1- Alternating Current (AC) model [16, 29, 30]
- 2- Direct Current (DC) model [31-34]
- 3- Transportation model [20, 25, 28, 35, 36]

The transportation model is the least accurate model and usually used in cases meant to give a general insight to the transmission expansion or a rough estimation of the power flows, whereas the AC model is the most accurate which all details are considered. In the following each of these models is elaborated.

2.3.1 AC model

In the AC model, no simplification is made. Therefore a nonlinear relation between variables in a power system exists. The reactive power (P_k) and active power (Q_k) flowing in a transmission line k between bus i and j are given by (2-4) and (2-5), respectively [37].

$$P_k = V_i V_j (G_{ij} \cos(\theta_i - \theta_j) + B_{ij} \sin(\theta_i - \theta_j)) - G_{ij} V_i^2 \quad (2-4)$$

$$Q_k = V_i V_j (G_{ij} \sin(\theta_i - \theta_j) - B_{ij} \cos(\theta_i - \theta_j)) + B_{ij} V_i^2 \quad (2-5)$$

V_j and θ_j are the voltage magnitude and voltage angle at bus j . G_{ij} and B_{ij} are the real and imaginary part of i^{th}, j^{th} element of the Nodal Admittance Matrix, also known as Ybus Matrix. If r_{ij} is the resistance and x_{ij} is the reactance of the transmission line connecting bus i and j , then G_{ij} and B_{ij} is mathematically expressed as follows.

$$G_{ij} + jB_{ij} = \frac{r_{ij}}{r_{ij}^2 + x_{ij}^2} - j \frac{x_{ij}}{r_{ij}^2 + x_{ij}^2} \quad (2-6)$$

Equations (2-4) and (2-5) are nonlinear constraints to a transmission planning problem which considers the AC model for the network, turning the transmission planning into a nonlinear optimisation problem. Nonlinearity of power system variables is one of the issues that challenges the transmission planners as transmission planning is, in essence,

a large scale optimisation problem, let alone having nonlinear constraints. Some studies, however, have assumed the AC model for transmission planning [16, 29, 30] although they have applied some linearization to the final model. For instance, Siddiqi [29] has deployed the AC model for the peak time whereas for other time intervals– off peak times – a linear model has been proposed.

2.3.2 DC model

The AC model is complicated, so it leads the transmission planning problem to a time consuming and computationally expensive optimisation. The DC model could be conceived as a linearised version of AC model. The DC model expresses the fundamental relationships of parameters in the power system while it offers a relatively simple model. Simplicity of DC model is the reason that it is widely used in transmission planning studies. The three main assumptions made in the DC model are as follows:

- i. The voltage magnitude at all buses is equal to 1 p.u. — $V_i = 1$
- ii. In the transmission network, reactance is much greater than resistance ($r_{ij} \ll x_{ij}$).
- iii. The difference between voltage angles of two endings of a transmission line is quite small — $\cos(\theta_i - \theta_j) = 1$, $\sin(\theta_i - \theta_j) = (\theta_i - \theta_j)$.

Using these three assumptions gives a linear form of AC model. Therefore, Equations (2-4) and (2-5) can be changed to linear Equations (2-7) and (2-8), respectively. (2-7) is effectively KVL.

$$P_k = \frac{1}{x_{ij}}(\theta_i - \theta_j) \quad (2-7)$$

$$Q_k = 0 \quad (2-8)$$

Another essential constraint in the DC model is the power balance at each bus, this implies the Kirchhoff's Current Law (KCL). For bus d the KCL is given by equation (2-9).

$$\sum_{\forall i \in N_{gd}} G_i + \sum_{\forall k \in N_{ld}} P_k - L_d = 0 \quad (2-9)$$

Where N_{gd} and N_{ld} are a set of generations and transmission lines connected to bus d , respectively. G_i is the power generated by generator i (MW) and L_d is the load at bus d (MW).

It can be seen from equations (2-7) and (2-8) that a transmission planning study which considers DC model disregards the reactive power and voltage magnitude. Therefore, a second stage study, which uses AC model, needs to examine the voltage and reactive power requirements [38]. In other words, for long-term planning, as most researches have shown, a linear DC model is a viable solution. However the final proposed network which has been determined by using DC model should be checked with the AC model study in order to make sure violations do not exist in the future network. The final network topology should fulfil all operational criteria. Figure 2-3 shows the procedure of a typical transmission planning. As shown, for a given demand and generation scheme as well as possible candidate transmission lines in a horizon year, the transmission expansion planning is studied using DC model. Next, considering the proposed expansion, the possible network violations are examined with the AC model. If there is any violation, reactive power resources or in some cases some transmission lines may be suggested so that the final plan meet all essential security criteria.

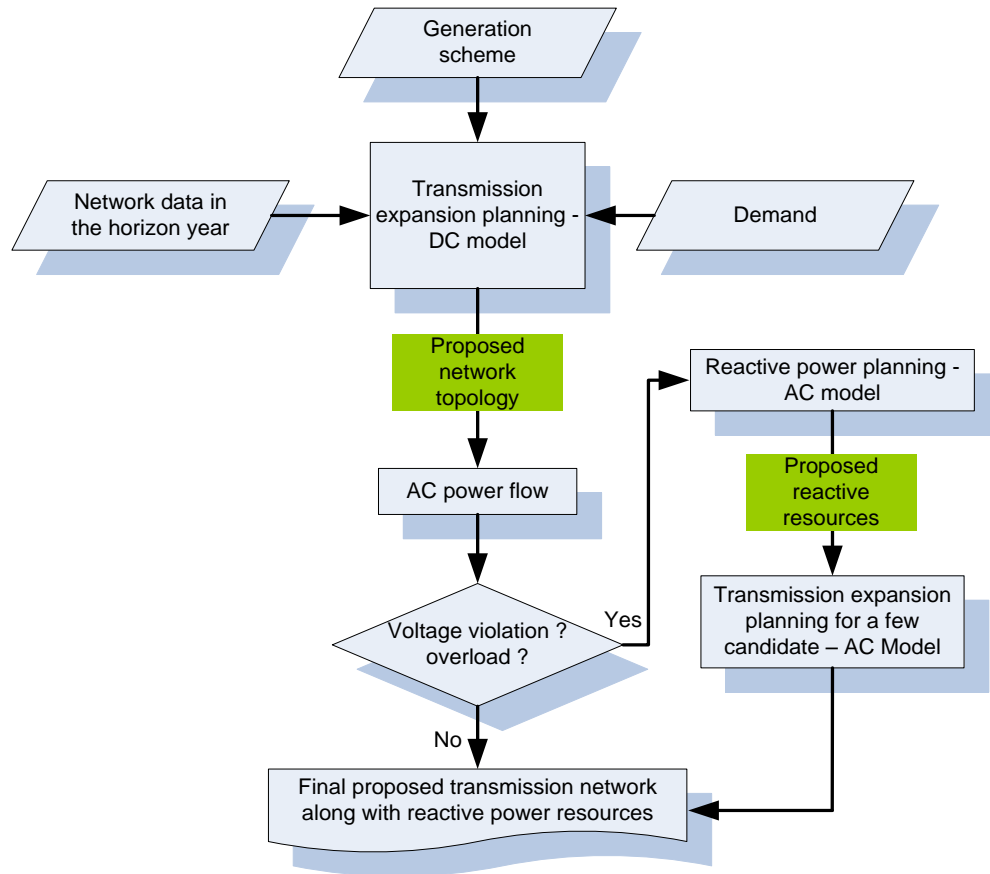


Figure 2-3: The procedure of transmission planning using both DC model and AC model

2.3.3 Transportation model

This is the least accurate model of the transmission network. In this model the main constraint is the nodal balance equation which was given by (2-9). All other constraints are relaxed. Some transmission companies may use this model to estimate the power flows between regions. Another application of transportation model is to find those transmission corridors which can be considered as transmission expansion candidates in transmission planning studies using DC or AC models [25]. Mutale et al [20] used transportation model as a model for fully flexible network where power flows can be fully controlled by flexible AC transmission system (FACTS) devices.

2.4 Losses in transmission network

Losses in a transmission network depend on the network topology and generation pattern. Hence, different transmission network proposals result in different transmission network losses. Losses increase the total operating cost in a power system. Armando et al [39] noted that 4% of energy is lost in transmission network in Brazil. From the

transmission planning point of view, losses can also have an impact on the optimum generation dispatch that consequently affects the required transmission capacities. Therefore, transmission planning which takes the losses into account benefits from a higher accuracy.

In the AC model, losses in a transmission line have a nonlinear relation with other network variables. The losses of transmission line k , which connects bus i to bus j , are calculated with equation (2-10) [37].

$$P_{loss_k} = G_{ij} \left(V_i^2 + V_j^2 - 2V_i V_j \cos(\theta_i - \theta_j) \right) \quad (2-10)$$

Also, in DC model which is a linear model of power system, losses have a nonlinear relationship with power flows. Equation (2-11) shows the losses in transmission line k , considering the DC model in p.u. system [40].

$$P_{loss_k} = r_{ij} P_k^2 \quad (2-11)$$

Losses should be compensated by generators. Therefore the power balance in the whole system should comply with (2-12).

$$\sum_{i=1}^{N_g} G_i - \sum_{d=1}^{N_b} L_d - \sum_{i=1}^{N_l} P_{loss_k} = 0 \quad (2-12)$$

One of the methods widely used to calculate the total losses is the B-coefficients method [41, 42]. In this method, the total losses are expressed by a quadratic function of generator outputs, see (2-13).

$$P_{loss} = \sum_{i=1}^{N_g} \sum_{j=1}^{N_g} G_i B_{ij} G_j + \sum_{i=1}^{N_g} B_{i0} G_i + B_{00} \quad (2-13)$$

P_{loss} are the total losses in the network. B_{ij} , B_{i0} , and B_{00} are the coefficients which are calculated based on the network configuration as well as parameters of the network [37].

Using these nonlinear models in the transmission planning problem introduces additional complexity. Moreover, a nonlinear model of losses is not compatible with a linear model of the network, the DC model, which is usually used for transmission planning. Some studies have proposed a linear model for losses so that losses can be incorporated into the DC model of transmission network. In the simplest way, a curve fitting technique can be used to model the quadratic equation (2-11) with an straight line [15].

In a more accurate approach, instead of modelling the loss function with just one line, Motto et al [43] proposes a piecewise linear model. This piecewise model, however, is a complicated model as some binary variables are involved in the calculation requiring mixed-integer programming to solve the model. Figure 2-4 illustrates the aforementioned modelling.

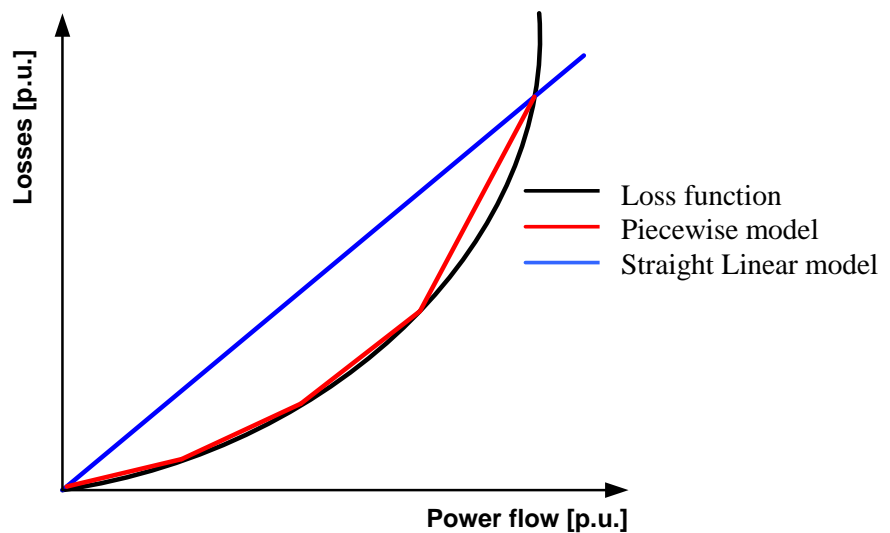


Figure 2-4: The modeling of losses proposed by [15, 43]

Another issue in modelling of losses is the allocation of losses. Based on conventional methods, the network losses are allocated to the slack bus [42]. However, in a real power system, the losses occur in transmission lines and actually all generators participate in supplying the losses. Therefore, the generation pattern will be more realistic if the losses of each transmission line are modelled in form of an active load near the corresponding transmission line.

One method is to consider the losses of each transmission line at a dummy bus in the middle of that line [44]. This method enlarges the dimension of network model as each transmission line is split into two segments and for each transmission line an additional

dummy bus should be considered in the modelling. Enlarging the network dimension is the main drawback of this method especially when this approach is used for the large scale optimisation studies such as transmission planning.

Two problems associated with modelling of losses have been introduced so far in this section: i) The nonlinearity nature of losses and ii) Loss allocation. One of the contributions of this thesis is to propose a methodology for developing a linear model for loss function which can be adopted for transmission planning studies.

In order to have an accurate model, the losses are allocated at the point where they take place. The losses in each line are evenly divided into two parts which are assigned to both ends of the corresponding transmission line in a form of an active load. Figure 2-5 shows the proposed loss allocation.

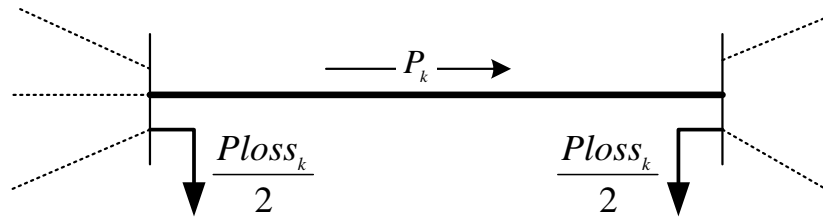


Figure 2-5: The proposed model to allocate losses

Assuming the proposed loss allocation and DC model, the power balance at bus d is written as follows.

$$\sum_{\forall i \in N_{gd}} G_i + \sum_{\forall k \in N_{ld}} P_k - L_d - \sum_{\forall k \in N_{ld}} \frac{P_{loss_k}}{2} = 0 \quad (2-14)$$

In order to linearise the relation between P_{loss_k} and P_k , a piecewise linear model is introduced. However, unlike the model proposed by [43], no binary variables are used in this model.

The loss function of transmission line k is estimated by a linear model consisting of N pieces of lines. The lines are laid between $(0,0)$ and $(P_{\max k}, r_i P_{\max k}^2)$, where $P_{\max k}$ is the maximum capacity of the transmission line k . Figure 2-6 illustrates the loss function as well as the proposed linear model of losses.

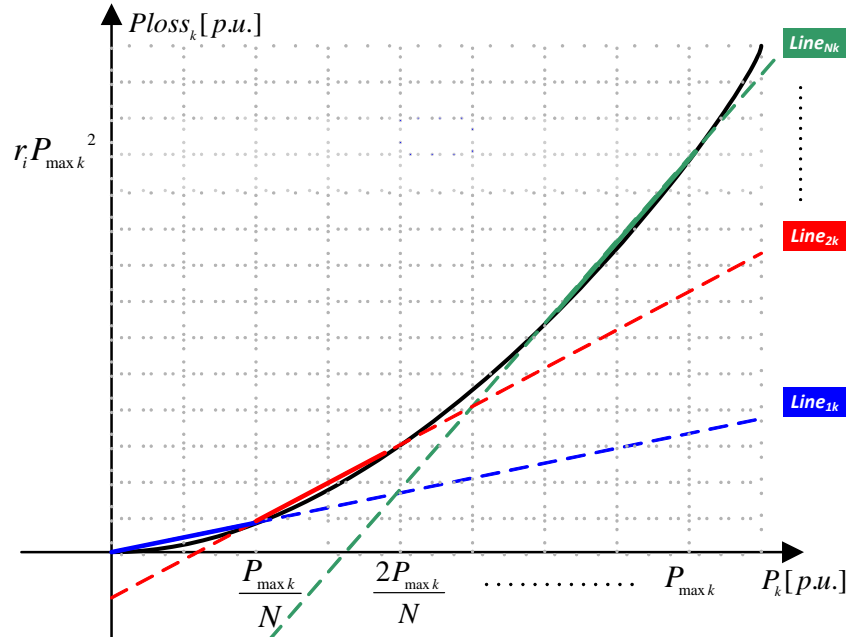


Figure 2-6: The proposed linear model for losses

The n th line ($Line_{nk}$), which is shown in Figure 2-6, is formulated by (2-15).

$$Line_{nk} : \frac{r_i \cdot P_{\max k}}{N} \left[(2n-1) \cdot P_{absk} + P_{\max k} \cdot \frac{n-n^2}{N} \right] \quad (n=1, \dots, N) \quad (2-15)$$

P_{absk} is the absolute value of power flowing in transmission line k .

As shown in Figure 2-6, only a segment of $Line_{nk}$ is used for the loss modelling. Therefore $Line_{nk}$ models the loss function when P_{absk} is within the range dictated by inequality (2-16).

$$\frac{(n-1) \cdot P_{\max k}}{N} \leq P_{absk} \leq \frac{n \cdot P_{\max k}}{N} \quad (n=1, \dots, N) \quad (2-16)$$

One way to select the relevant segment is to use binary variables as introduced by Motto [43]. This makes the problem complicated. Instead, an approach using continuous variables is proposed in this thesis. In this approach, the N inequalities defined by (2-17) are used to select the relevant segment of one of N lines formulated by (2-15).

$$P_{lossk} \geq Line_{nk} \quad (n=1, \dots, N) \quad (2-17)$$

Moreover, another set of inequalities, which are given by (2-18) to (2-20), should be added to the model in order to generate the absolute value of power flowing in transmission line k .

$$P_{absk} \geq P_k \quad (2-18)$$

$$P_{absk} \geq -P_k \quad (2-19)$$

$$P_{absk} \geq 0 \quad (2-20)$$

The proposed linear model for loss function of each transmission line consists of inequalities (2-14) to (2-20).

It should be stressed that this linear model can be adopted for optimisation problems which are meant to minimise losses. Transmission planning aims to minimise the transmission network investment along with operating costs. Operating cost includes the cost of losses and generation cost. Therefore, the model of losses proposed in this thesis can be perfectly adopted for transmission planning studies.

In the proposed model, the number of pieces (N) on the one hand boosts the accuracy of the model and, on the other hand, may enlarge the dimension of the model. By using a numerical example, it will be demonstrated in section 3.6 that a three piece model can offer a high level of accuracy.

2.5 Security constraint

Security pertains to the robustness of the network against disturbances and outages. The ability of a power system to withstand unplanned outage of power system components is set by the security criteria. Security assessment of a power system is twofold: dynamic security and static security [45].

Dynamic security assessment examines the ability of the system to remain stable following outage. A sudden outage of a transmission network branch or a generation unit can lead to loss of synchronisation by some generators. Static security assessment, however, mainly reviews the ability of a power system to continue supplying load after

a contingency occurs. Failure to meet security criteria can result in a wide area power cut, as previously occurred in Europe and United States [46].

In a privatised power system, generators and network companies are owned by different. In these power systems, generation companies are deregulated and distribution companies have geographically separate boundaries. To ensure the security in the whole power system, transmission companies can play a crucial role. To do so, transmission companies need to develop security criteria as part of their Grid Code. Grid Code states the technical requirements which should be met in the process of operation, maintenance, and planning the network in order to foster the security and efficiency of power system. National Grid, which owns and operates the 400 KV and 275 KV network in England and Wales, is responsible for developing and supervising the technical requirements of security [47]. In United States, regional transmission companies supervise their network security as well as overseeing the connection with neighbouring transmission networks. The North American Electric Utility Corporation (NERC) licensed by Federal Energy Regulatory Commission (FERC) is in charge of developing standards and monitoring the security of the power system in North America and Canada.

The level of security, which is taken into account in the process of long term transmission expansion planning, governs the level of redundancy in the network. A higher level of security is associated with a higher amount of investment in the network. The ubiquitous “N-1” security criterion is considered adequate by most transmission companies. According to the “N-1” criterion, if one branch of the network trips the transmission network should still be able to operate within the voltage limits and thermal ratings. In this way, the network operator does not need to take any action as the contingent network is able to transfer the power. Depending on the network condition, a higher level of security, “N- α ” where α is the number of branches tripping simultaneously, can also be taken into account [22]. For instance, in addition to “N-1”, National Grid respects “N-D” security criterion under which the network is secure against outage of both circuits of a double circuit transmission line [21].

Traditionally, a deterministic approach is used for security analysis so that the loss of network's components is examined without considering the probability of those contingencies. In this way, all contingencies are treated equally. Nonetheless, not all outages are very severe and not all outages are very frequent. Instead of a deterministic

approach, some studies incorporate the likelihood of contingencies into the transmission planning problem [48]. There should be a trade-off between the level of network investment in redundant components and the possible losses which are incurred as a result of contingencies [49]. The probability of the outage of each component can be determined by taking into account the duration of failure and frequency of failure [50, 51]. These values, which show the performance of a component in a system, can be computed by using the past data and prediction methods.

For a transmission network which consists of many transmission lines and transformers, the size of the transmission planning problem considering “N-1” security criteria can be significantly large as N contingent networks should be added to the optimisation problem. However, some outages do not cause overloads or voltage violations in the power system, or their effects are relatively insignificant. For the sake of simplification, these trivial outages can be eliminated from the planning problem. Therefore, prior to formulating the security constraint, a contingency ranking analysis is conducted. In order to examine the severity of each outage some performance indices are defined [52]. In several studies [37, 53, 54], the performance index for assessing the impact of an outage on network overload and voltage violation are formulated with (2-21) and (2-22), respectively.

$$PI_p = \sum_{i=1}^{Nl} w_{pi} \cdot \left(\frac{P_i}{P_{\max i}} \right)^2 \quad (2-21)$$

$$PI_v = \sum_{i=1}^{Nb} w_{vi} \cdot \left(\frac{|V_i - V_i^{rated}|}{\Delta V_i^{\lim}} \right)^2 \quad (2-22)$$

Where:

w_{pi} The weighting factor of power in line i - this factor reflects the importance of a particular line;

w_{vi} The weighting factor of voltage at bus i - this factor reflects the importance of a particular bus;

V_i The voltage magnitude at bus i ;

V_i^{rated} The rated voltage magnitude at bus i ;

ΔV_i^{lim} The voltage deviation limit.

In contingency selection analysis, the performance indices are calculated for the outage of every power system component. Those contingencies which have impact on violation of operation limits are considered in transmission planning process. As transmission planning is an off-line study, it is acceptable to carry out a contingency ranking analysis prior to formulating the transmission planning problem.

Agreira et al [55] propose a three-stage contingency ranking method so that each stage acts as a filter improving the outage ranking list. The process of this three-stage method is shown in Figure 2-7. In the first stage a simple DC model is considered for the network and performance indices are calculated for the initial contingency list. Those contingencies which cause violation are sent to the second stage where a more accurate load flow analysis is done using Fast Decouple Method [37]. In the second stage, harmless contingencies are eliminated from the list and a new contingency list is established. The new contingency list is finally analysed with Newton Raphson method in stage three. In the final stage, the contingency list is updated based on the performance indices as well as other indices which show the voltage stability [56] and severity index [57]. The severity index is the maximum acceptable voltage drop after a contingency occurs. Agreira et al [55] consider a value of 5% for this limit (k shown in Figure 2-7).

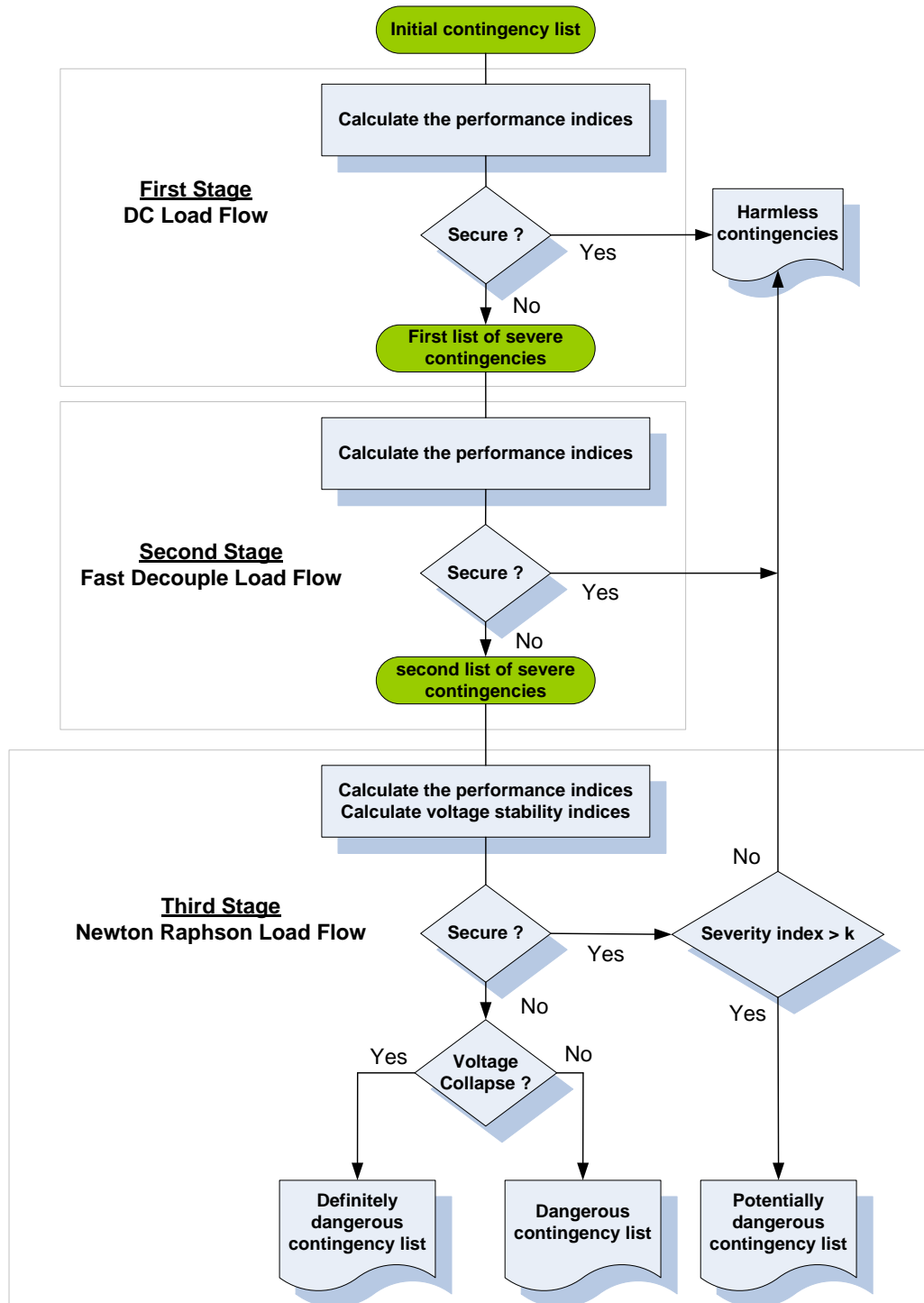


Figure 2-7: The procedure of three stage contingency ranking [55]

2.6 Decomposition techniques

Transmission network planning is in essence a large-scale optimisation problem as it is subject to many constraints modelling the security criterion along with the performance of network at different load levels. In addition to that, the size of a transmission planning problem rapidly grows when network parameters are associated with uncertainties. In an ideal approach, an integrated optimisation problem which includes

all formulations of intact network and contingent networks is constructed so that the optimal transmission capacities for contingent networks as well as intact network are calculated simultaneously.

However, desktop computers or even optimisation software are usually unable to solve such a large-scale problem as a whole. Alternatively, some decomposition techniques such as Bender's decomposition [23, 24, 58], Dantzig-Wolfe decomposition [59] and Lagrangian relaxation [59, 60] can be deployed to split the whole problem into sub-problems which relatively need less computational effort. Conejo et al [59] have reviewed these techniques and their applications in different engineering disciplines, giving a good insight into decomposition methods. Among all decomposition methods, Bender's decomposition has been received great attention by power system planners so far. In this section, this decomposition method is elaborated and an it's application in transmission planning study is demonstrated.

Bender's decomposition technique originally was proposed by Bender, J.F. [61] in 1962 and then developed by Geoffrion [62] in 1972. Since then, this technique has been widely used to tackle large-scale centralised decision-making problems. Power system planning problems which inherently embrace a large number of variables also benefit from this technique [63]. Bender's decomposition method splits a centralised problem into a master problem and several sub-problems. The master problem proposes solutions for some decision variables while other decision variables and their relevant constraints are examined in the sub-problems. The master problem and sub-problems communicate with each other via Bender's cuts. Bender's cuts appear in the form of an optimality cut or a feasibility cut. Moreover, the convergence of Bender's decomposition is checked at each iteration by comparing an upper bound and lower bound. The mathematical details and theories which underpin Bender's decomposition are comprehensively introduced by Conejo et al [59]. One of the good studies on application of Bender's decomposition in power system is by Shahidehpour [24] who introduces the application of Bender's decomposition in transmission and generation planning.

Moreover, Shahidehpour [23] notes that Bender's decomposition is expected to be increasingly deployed for planning in deregulated power systems. In a deregulated system, power system planning is undertaken in a decentralised fashion. Transmission companies are responsible for transmission expansion whereas generation companies

independently deal with commissioning and decommissioning generation units. Shahidepour proposes that in order to reach an optimal and secure plan for the whole power system, the effect of a practice by one of the participants in a power system on the other participants can be communicated through Bender's cut.

2.6.1 Example: 3 bus system

Due to popularity of Bender's decomposition, the application of this method in transmission planning is demonstrated on a 3 bus network which is shown in Figure 2-8.

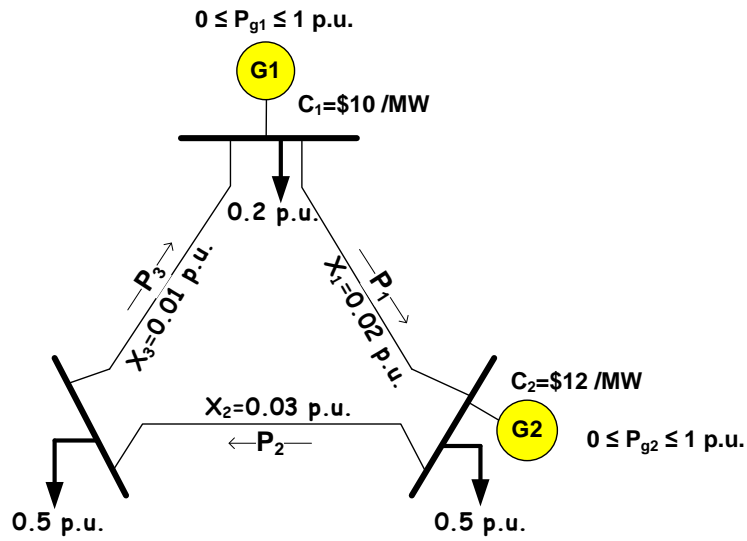


Figure 2-8: A 3 bus network case study for transmission planning using Bender's decomposition

In Figure 2-8, C1 and C2 are the generation costs of G1 and G2, respectively. The transmission cost is assumed to be 2 \$/MW, 4 \$/MW and 2 \$/MW for transmission line 1, 2 and 3, respectively. It should be stressed that this example is meant to only demonstrate the decomposition technique so for the sake of simplicity some assumptions such as different load levels, different load durations etc are neglected.

The objective function for the transmission planning is to find the optimal capacity of transmission lines along with the optimal generation dispatch. This can be mathematically expressed by (2-23).

$$\text{Minimise } 10.P_{g1} + 12.P_{g2} + 2.P_{\max 1} + 4.P_{\max 2} + 2.P_{\max 3} \quad (2-23)$$

$P_{\max 1}, P_{\max 2}$ and $P_{\max 3}$ are the capacity of the line 1, 2 and 3, respectively. P_{g1} represents the power generated by G1 and P_{g2} is the output power of G2. The objective function is subject to DC model constraints which were elaborated in section 2.3.2.

The main focus in this example is to illustrate how the optimality cuts and feasibility cuts are constructed in a transmission planning problem using Bender's decomposition technique. To do that, the transmission planning problem is solved with and without security constraints.

2.6.1.1 Transmission planning without security constraints

The master problem for the objective function (2-23) is the generation cost so that the master problem finds the optimal generation dispatch without considering the network. The sub-problem, however, calculates the optimum transmission capacity based on a generation pattern proposed by the master problem.

The optimality cut reflects the required change in decision variables determined by the master problem in order to improve the objective function towards the global optimal. The sub-problem calculates the Lagrangian multipliers which pertain to decision variables proposed by master problem. These Lagrangian multipliers are the keys to constructing the optimality cut. In each iteration a new optimality cut is added to the master problem so that the number of optimality cuts appearing as constraints in master problem is equal to the number of iterations.

In an iterative process, which is shown in Figure 2-9, the optimum generation as well as the optimum transmission capacity are calculated. In Figure 2-9, $\lambda_1^{(v)}$ and $\lambda_2^{(v)}$ are the Lagrangian multipliers and $\theta_1, \theta_2, \theta_3$ refer to voltage angles in the 3 bus network. In each iteration an upper bound and lower bound, which are shown by Z_{up} and Z_{down} in Figure 2-9 are calculated. Bender's decomposition converges to the final salutation when the difference between these two bounds is very small.

Table 1 shows the decision variables along with Lagrangian multipliers calculated by master problem and sub-problem at each iteration. Bender's decomposition reaches to the optimum solution after four iterations. The variations in upper bound and lower bound are depicted in Figure 2-10.

Table 2-1: The solutions to decision variables at each iteration

v	Master Problem		Sub-problem				
	P_{g1}	P_{g2}	$P_{\max 1}$	$P_{\max 2}$	$P_{\max 3}$	λ_1	λ_2
1	1	0.2	0.2833	0.0166	0.5166	3.333	0
2	0.2	1	0.25	0.25	0.25	3.333	4
3	0.7	0.5	0.0833	0.0833	0.41666	4	2
4	0.575	0.625	0	0.125	0.375	3.333	4

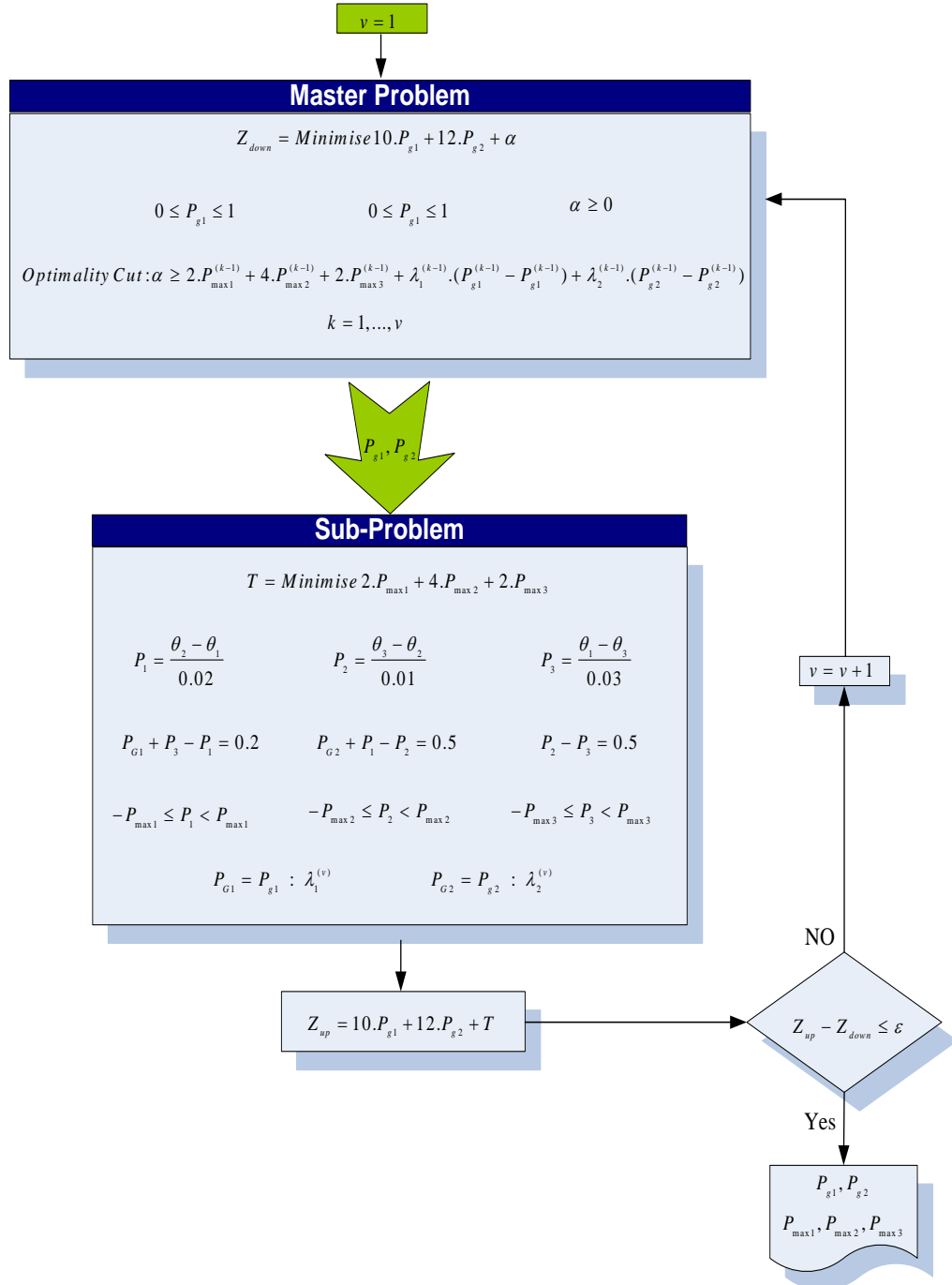


Figure 2-9: Bender's decomposition procedure to solve transmission planning problem without security constraints

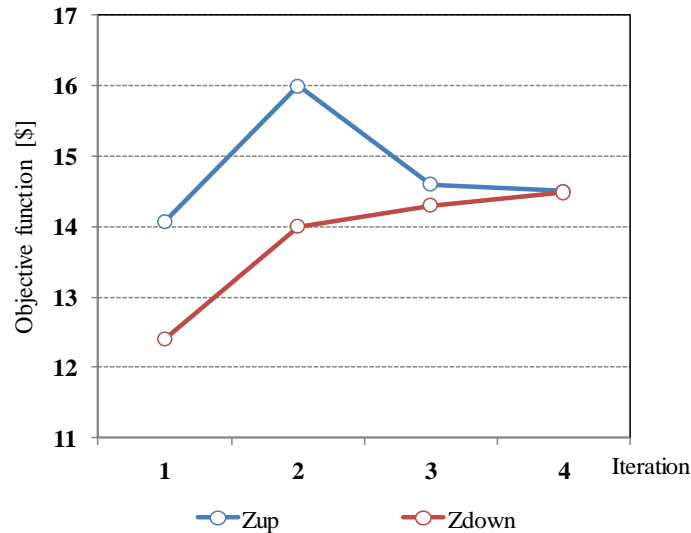


Figure 2-10: The variation of upper bound and lower bound in each iteration

2.6.1.2 Transmission planning with security constraints

In this section, Bender's decomposition is used to solve the transmission planning problem considering "N-1" criteria for the 3 bus network introduced previously. The master problem is the minimisation of operating cost and investment cost for the intact network. Three sub-problems, each of which examines the feasibility of solution of the master problem for the contingent networks, are formulated. Some solutions proposed by the master problem are not feasible for sub-problems. In such case, a feasibility cut is constructed so that the master problem is led to a solution space where the feasibility of sub-problems is respected. The whole process is illustrated in Figure 2-11.

The master problem calculates the optimum transmission capacities and generation dispatch for the intact network. Next, these values are sent to sub-problems each of which formulates the transmission network as having one transmission line tripped. The objective function of sub-problems is to minimise the summation of dummy generators (r_1, r_2, r_3) which are augmented to nodal balance equations. Dummy generators are given a value by optimisation if the proposed generation dispatch along with transmission capacity cannot satisfy contingent networks' constraints. Then feasibility Bender's cut is constructed taking into account the Lagrangian multipliers determined in each contingent network. In each iteration, one feasibility cut is added to the master problem. The process continues to the point where all dummy generators (r_1, r_2, r_3) in all sub-problems are zero. Table 2-2 shows the proposed solutions by master problem

and the summation of corresponding dummy generators in each sub-problem at each iteration.

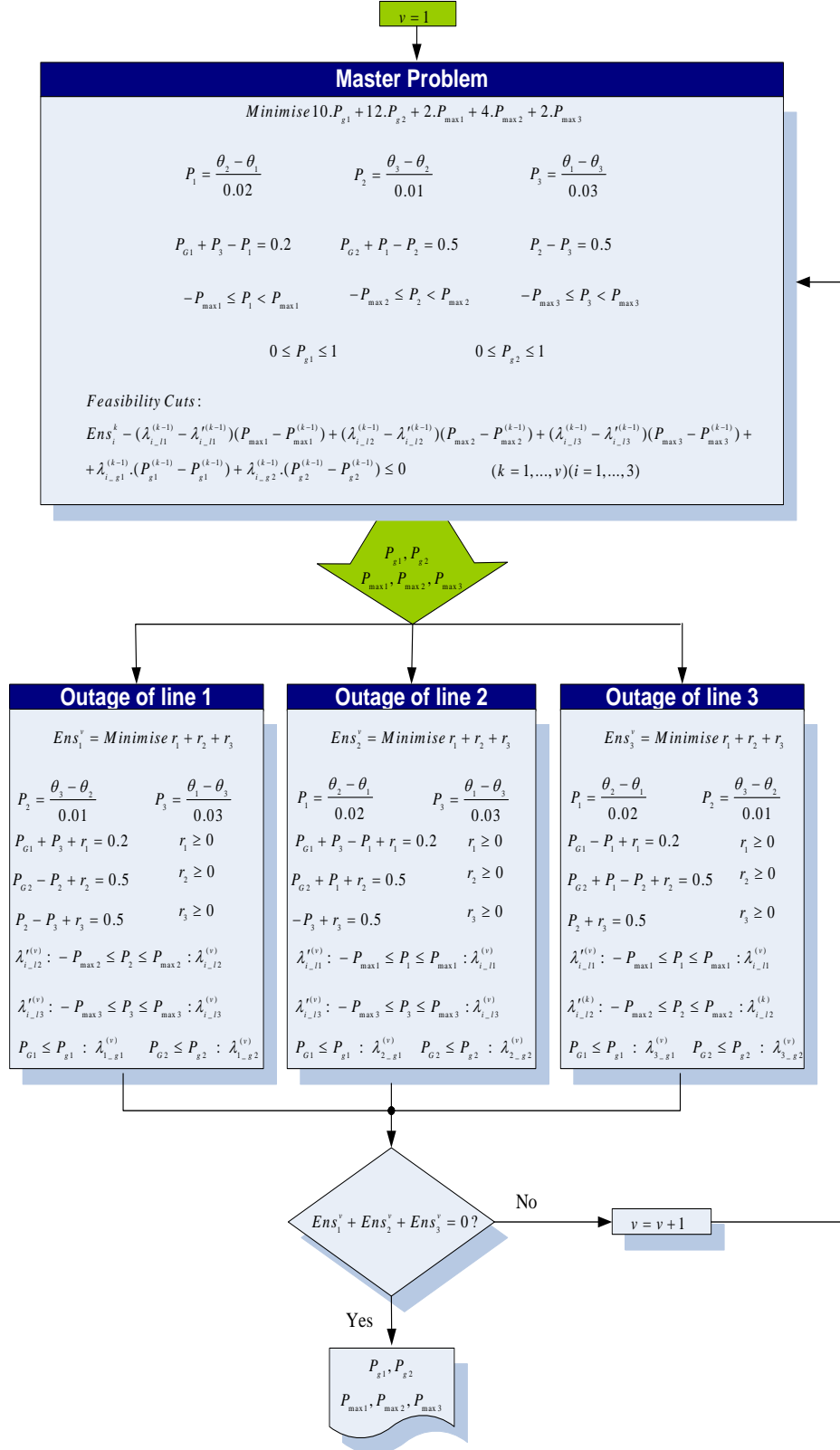


Figure 2-11: Bender's decomposition procedure to solve transmission planning problem with security constraints

Table 2-2: The solutions to decision variables at each iteration

v	Master Problem					Sub-problems		
	P_{g1}	P_{g2}	$P_{\max 1}$	$P_{\max 2}$	$P_{\max 3}$	Ens_1^v	Ens_2^v	Ens_3^v
1	0.575	0.625	0	0.125	0.375	0	0.125	0.375
2	0.95	0.25	0.25	0.5	0.5	0.25	0	0.5
3	0.7	0.5	0.5	0.5	0.5	0	0	0

2.7 Conclusions

In this chapter, the fundamental assumptions as well as traditional methodologies for transmission planning studies were reviewed. It was noted that although different level of complication can be assumed for the network modelling, most transmission planning studies are undertaken with the DC model. This model offers a level of accuracy which is adequate for long-term transmission planning. It should be noted that, in practice, transmission companies use the AC model to examine the adequacy of proposed network topology calculated using DC model.

Different algorithms for modelling losses in DC formulation of power flow problem were reviewed and a new approach for application in transmission planning studies was proposed. The proposed model is linear and it does not include any integer variables. Therefore, this model can be easily integrated into the transmission planning problem without adding any noticeable complexity to the problem.

One of the main drivers for transmission investment is the security criterion. Contingency ranking algorithms were reviewed in this chapter. It is crucial to distinguish the level of severity of different contingencies in the network so that only those having severe effect on the system security are included in the transmission study.

For a large network with several load levels and many postulated contingencies, transmission planning problem cannot be solved as a single problem as it is computationally very expensive. The problem, instead, should be split into sub-problems which can be solved by conventional computers. In this chapter, Bender's decomposition as the most used decomposition methodology in the power system was introduced. The application of Bender's decomposition in transmission planning problem was demonstrated on a 3 bus system network.

Chapter 3. Transmission planning: Contemporary issues

In this chapter the challenges facing transmission planning in a contemporary power system are investigated. A significant proportion of future demand is set to be supplied by renewable energy sources many of which are very volatile. Moreover, CO₂ emission price which has a direct effect on the generation cost may change unpredictably. Therefore, the level of uncertainties in the power system costs is becoming higher. These uncertainties are explained in this chapter and through a numerical study a probabilistic transmission planning study is undertaken, taking into account the volatility of CO₂ emission price.

3.1 Transmission network in a deregulated power system

In the past two decades, the electricity supply industry in many countries has been liberalised so that the power system structure changed from a vertically integrated system to an unbundled system where generation, transmission and distribution sectors are under the jurisdiction of different companies. In an unbundled system, under the so-called open access regime generators can enter trade competitively in an electricity market with a view to improve efficiency while keeping prices low. In a bundled power system, generation and transmission are planned and operated by a single entity. In such a system, it seems that there is no penalty for mistakes made by system planners or operators that eventually cost consumers. An unbundled structure, however, ideally provides an equal chance for generators to trade energy and provide services while competing with each other. Such a non-discriminatory and competitive environment is most likely to result in an efficient power system where participants offer their real – minimum – price of production. It should be stressed that achieving this perfectly competitive market can be affected by the network congestion or strategic gaming by some generators.

Unlike generation sector, transmission and distribution companies still have monopoly on network services regionally. Transmission networks can be owned and operated by the same company such as National Grid Company (NGC) which owns and operates the transmission network in England and Wales. An independent regulatory body, such as the office of gas and electricity markets (Ofgem) in the UK, regulates NGC network pricing to ensure that the company does not use its monopoly power to overcharge users of its network. The main statutory duties of the NGC which are set out by Ofgem are as follows [64].

- 1- To expand and maintain the transmission network in an economic and efficient way
- 2- To facilitate the competition among generators
- 3- To maintain the robustness of network against the contingencies
- 4- To preserve the environment- not affecting the landscape adversely by pylons.

In a work conducted by Sinclair Knight Mart (SKM) [65], the transmission planning approach and the security criteria which are considered by main transmission network licensees in UK, NGC and Scottish Hydro Power Electric Ltd, are elaborated.

In the United States, regional transmission operators (RTOs) and independent system operators (ISOs) are licensed by Federal Energy Regulatory Commission to operate and invest in the transmission networks. TSOs and ISOs are also responsible for maintaining the reliability of the transmission network and promoting competition in the electricity wholesale market.

Transmission companies are in charge of preparing the transmission expansion scheme which finally needs to be approved by regulatory body. This is a challenging task in a deregulated power system as, on the one hand, generation expansions which are mainly driven by the market are independently conducted by different entities and on the other hand, any transmission investments can affect market prices and consequently generation expansion. In other words, unlike a regulated system, transmission companies have almost no control – except through pricing in network access and use – over the dynamics of the generation sector. Therefore, the transmission network has to be economically and technically designed in a way that allows uncertainties stemming from generation companies practice to be accommodated. Any congestion in the transmission network enables some generators at the specific locations to potentially

exercise market power in the local electricity market, exerting unfair energy prices on consumers.

In the competitive electricity market environment, the role of transmission is more complicated and crucial than the traditional one of simply providing a reliable connection between generation units and loads. In the next section the objective functions which may be considered for transmission planning in a liberalised market are reviewed.

3.2 Transmission planning objectives in a deregulated power system

An optimum transmission network proposal is one that minimises the transmission investment while maximising the social welfare [66]. Social welfare is defined as summation of the benefits that accrue to consumers and generators [67]. In order to understand the concept of social welfare, it is useful to review the consumers' and generators' behaviour in an electricity market, see Figure 3-1.

As shown in Figure 3-1, the generation cost increases while demand increases, as more expensive generators should join to supply the demand. Consumers decrease the amount of consumption while the price of electricity increases although consumers respond to price of energy in an inelastic manner up to a certain amount of electricity demand.

The market is settled at a price called the market clearing price (MCP) where the generators' offer equals the consumers' bid. At MCP consumers pay less than their actual willingness-to-pay. The benefit which accrues to consumers is called consumers' surplus which is the A1 area in Figure 3-1. Similarly, the income of generators can be calculated by considering area A2, which is called generators surplus. The summation of generators surplus and consumers' surplus is social welfare.

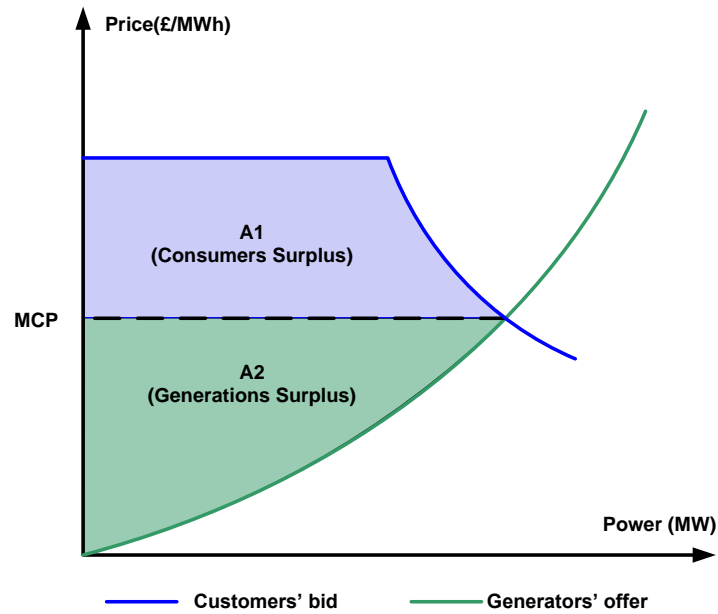


Figure 3-1: The dynamic of consumers and generators in the electricity market

In general, a transmission network planners may seek to satisfy any or a combination of the following objectives in the process of reinforcing the transmission network:

- **Enhancing competition between generation companies:** This is usually achieved by economically alleviating congestion in the transmission network [68]. It should be noted the security criteria Buygi et al [31] note that a flat locational marginal price can be an index for transmission expansion planning to boost competition among participants.
- **Minimising the constraint cost:** The objective function of transmission planning practised by transmission licensees in the UK is a trade-off between investment cost and constraint cost. As elaborated in a report produced by SKM [65], the network reinforcement can be justified for a level of investment which equals or smaller than the savings in constrained generation costs relieved by network reinforcement. The system operator takes into account the offers and bids made by generators in balancing market to calculate the constraint cost. Generators send their bids for not generating as they can save the cost of fuel. Offers are also made by generators for ramping up their generation. Based on the past bids and offers, the network planner usually have an sufficiently good estimation about the bids and offers likely made by different generation

technologies. Therefore, the behaviour of the market and the constraint cost can be estimated in the timing of transmission planning.

- **Maximising social welfare:** Torre et al [69] consider the social welfare as an indicator to measure the quality of transmission expansion proposals. Also, Shrestha et al [70] compare transmission expansion planning based on a centralised and a decentralised power system while considering the social welfare as the main objective function.
- **Maximising the reliability of supply:** One of the main concerns of the electricity supply chain in the power system is to supply the demand without any interruption. Interruption can cause a considerable loss, especially in developed countries. As the load curtailment may occur due to lack of transmission capacity, transmission planners incorporate the cost of load curtailment into the objective function of transmission planning [71, 72].
- **Minimising the environmental impact:** There is a new move among many countries to reduce the greenhouse gas (GHG) emissions. As a large portion of GHG emission is caused by the electricity sector, many generators are constrained to emit CO₂ below a specific cap [73]. This limitation also needs to be taken into account in power system planning studies. Later in this chapter, the effect of new policies relating to CO₂ emission on the power system will be elaborated.

Compared to a bundled electric supply industry, the main legacy of a restructured power system is high level of uncertainties stemming from the dynamic behaviour of participants in the electricity market. The location and size of generation in the future is not quite clear cut. Generation companies have totally jurisdiction on commissioning and decommissioning of generating units. This makes the transmission planning process more complicated. Therefore, the deterministic approaches which were traditionally used to solve transmission planning problem are no longer suitable. Instead a probabilistic approach to transmission planning problem is recommended [49]. In the following section uncertainties in the power system are reviewed and the methods used to model these uncertainties in the transmission planning problem are explained.

It should be noted that that a vertically integrated perspective is taken throughout the thesis where generation costs are deemed to be known rather a market approach where

these costs are unknown by the transmission operator/planner. In other words a social welfare maximisation approach is taken. In a liberalised electricity market transmission planning aims to find the transmission capacity that minimises the sum of congestions costs and transmission investments costs. The optimal point long run marginal costs equal short run marginal costs are equal and hence in any ideal world both formulations lead to the same result.

3.3 Uncertainties in the power system

The transmission planning problem is becoming more complicated as the recent and ongoing developments that have introduced significant uncertainties into the power system parameters. Deregulation of power system, integration of renewable energy sources, emergence of emission market etc are some of these changes which challenge transmission planners. In general, uncertainties can be categorised into random and non-random uncertainties [31].

A random uncertainty is that parameter which can be modelled with a probabilistic distribution function, taking into account its past variations. The probabilistic model of a random parameter is then used to simulate its behaviour in future. Load demand, wind speed, generations cost and outage rates of transmission lines are examples of such random uncertainties. Non-random uncertainties, however, are those which have no historical record. In order to model these uncertainties for planning studies, some possible scenarios need to be presumed. Non-random uncertainties may include future generation mix, commissioning and decommissioning power plants or transmission lines, and market rules.

In the following section, the origins of uncertainties which can affect transmission planning studies are discussed. The methods which are used to model the uncertainties and incorporate them into the transmission planning problem are also examined.

3.3.1 Uncertainties in generation and demand

In a deregulated market, consumers and generators are allowed to take different strategies for trading energy as long as the security of the power system is not jeopardised. The closure of power plants and commissioning of new generators are totally under the jurisdiction of generation companies. Transmission projects tend to have longer lead times than those for building power plants. Therefore, a transmission

expansion proposal for a given horizon year can be affected by connecting power plants that were not considered at the time of the transmission proposal was made. As a result of the uncertainties in the generation sector, transmission planners might either overestimate or underestimate the required transmission capacity. In the former, the utilisation of network assets is low and a high transmission charge may go to network users whereas, in the case of underestimation, generators should be constrained off at particular times due to lack of transmission capacity. These uncertainties in the current electricity market challenge transmission planners who have to economically design a network accommodating different scenarios of generations and load profiles.

Motamedi et al [74] note that in the early stage of transmission planning, the possible generation expansion at each bus should be examined by transmission planners, taking into account the access to fuel, environmental constraints and available land at each bus. They also consider different scenarios for generation expansion and generation strategy in the market to solve the transmission planning problem. In another piece of work, Garces et al [75] investigate the effect of the electricity market on transmission expansion by proposing a two level transmission planning approach. In that study the upper level represents the decision for transmission investment and the lower level models the market cleared for all possible generation scenarios.

The load growth rate and the behaviour of the consumers in the market usually come with uncertainty. Many factors such as government policy, rapid population growth, economic development, and demand for a higher quality of life may drive an unforeseen change in electricity demand. To model the load uncertainties, one solution is to consider an upper and lower bound for either the demand at each bus or the total demand [76, 77].

In the modern power system where consumers are equipped with smart meters and home energy management systems, it is expected that consumers will change their consumption patterns in accordance with the price variations. In other words, loads will no longer be inelastic to the price of energy. As the price-based demand response has not been implemented on a large scale, there is not enough practical information to predict consumer behaviour. Therefore, transmission planning proposals which are determined based on assumption that the demand is inelastic are likely to be suboptimal.

3.3.2 Uncertainties in renewable energy resources

Reliance on fossil fuel-based energy resources to supply the ever increasing load demand is no longer a sustainable option because these energy resources are diminishing and they produce CO₂ and other GHGs which cause climate change. These drawbacks of fossil fuels are the main drivers of the search for alternative more sustainable energy resources. Renewable energy resources such as wind and solar energy which are abundantly found in nature and are also CO₂ emission free are the most attractive option.

In many countries, especially developed countries, ambitious targets have been set to integrate renewable energy sources into the electricity supply system. For example the European Commission has set a target for countries of the European Union that 20% of total energy consumption in these countries should be supplied by renewable energy resources by 2020. In the next step the contribution of renewable energy is planned to be 80% by 2050 [78]. Among all renewable resources wind has drawn the most attention. For example, in the UK, according to the UK National Grid “Gone Green” scenario 29.1% of the total generation capacity will come from wind power in 2020. Figure 3-2 shows the generation mix under the UK National Grid’s Gone Green scenario in 2020 [6].

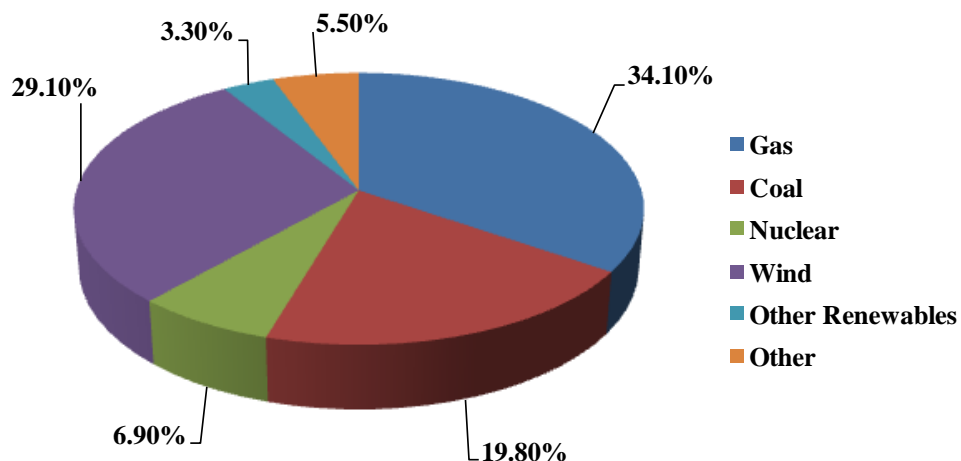


Figure 3-2: Installed generation capacity by 2020 according Gone Green scenario [6]

The potential sites for installing wind power plants are usually far away from consumers, a fact that drives a considerable amount of transmission network expansion/reinforcement. For example in the United States, the main wind power

resources are in the central part of country, whereas the higher population density inclines towards the coastal area. Figure 3-3 illustrates this geographical difference. The blue area shows the regions where wind power resources exist and the red and yellow areas represent the population density [79]. Therefore, a big investment in transmission network is expected to occur in order to connect wind energy resources to consumers. However, wind power depends heavily on wind speed which is very variable and difficult to predict. The non-dispatchable nature of wind power makes the transmission planning problem more difficult especially when considerable amount of wind power is to connect to the grid.

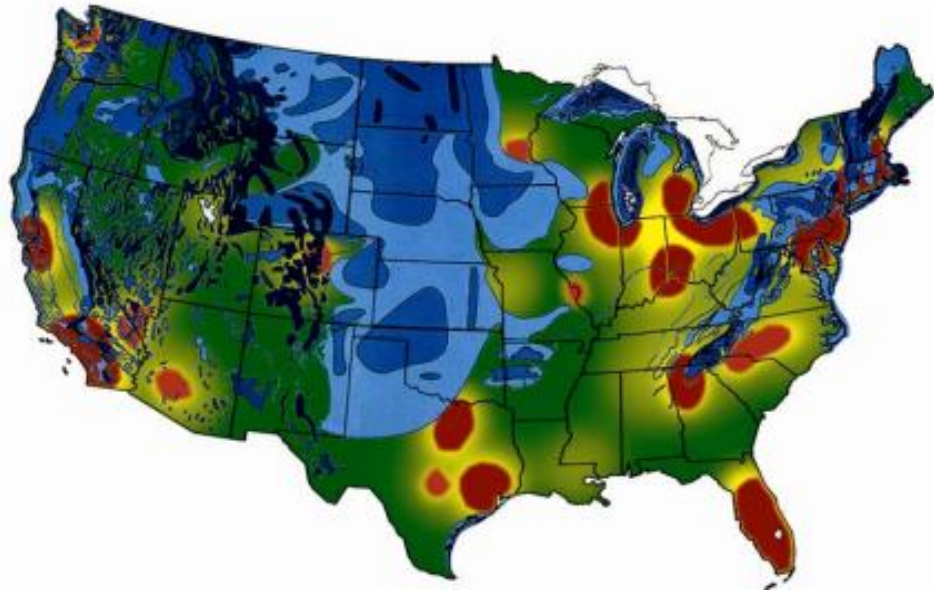


Figure 3-3: The population density (red and orange) and wind power density (blue) in the United States [79]

Transmission planning is a long-term planning problem considering a 5 to 10 year planning horizon, so the challenge is how wind power should be modelled for the selected horizon year. Taking a deterministic approach to design of the transmission network based on the maximum installed wind power capacity may result in overinvestment as the capacity credit of wind power is usually less than 30% [80]. Capacity credit is an index showing the power generated by the wind power plants at peak time. The intermittent nature of wind is one of the uncertainties which network planners should deal with. Wind speed variation in an area is random and it can be modelled with a probability distribution function representing the possible wind speeds.

The Weibull distribution formulated given in (3-1) is the most common probabilistic model of wind speed in most of the literature.

$$f(x|\lambda, k) = \frac{k}{\lambda} \left(\frac{x}{\lambda}\right)^{k-1} \cdot e^{-(x/\lambda)^k} \quad (3-1)$$

Where k and λ are the shape factor and scale factor of the Weibull distribution, respectively. The parameters of distribution function can be estimated by taking into account the past variations in wind speed [81-83] . As the wind regime can change in the course of the year some studies have proposed seasonal PDFs [81] or monthly PDFs [83]. The wind regime in the southern part of Turkey is fitted into the Weibull model by Celik [84]. Billinton et al [85] use auto-regression moving average (ARMA) for an hourly wind speed model. They used 20 years of wind speed data to develop this model.

The probabilistic model for wind should be translated to the output of a wind farm. The relation of the output of a wind turbine and the wind speed is defined by a power curve which is specified by the turbine manufacturer.

3.3.3 Uncertainties in cost of CO₂ Emission

The European Union established the first CO₂ emission trading market in the world in 2005 in order to meet the Kyoto Protocol commitments. In this carbon-trading market, installations buy or sell the emission allowances so that their emission targets can be attained at minimum cost. The European Union Emission Trading System (EU ETS) can be divided into three periods. The first period, which was from 2005 to 2007, was an experimental period – learning by doing – to understand the practicalities and difficulties in a carbon-trading market. This period was an opportunity for all participants to develop the required infrastructures to practice CO₂ trading in an actual cap-and-trade system. The second period is from January 2008 to 2012 when national emission caps are allocated to each member. The cap is designed to lower CO₂ emissions to around 6.5% below the 2005 level. Finally, in the third period from 2013 to 2020, the European Unions aims to curtail GHG emission to at least 20% of the level in 1990 [73].

In the trial period, the CO₂ allowance price appeared to be highly volatile. In April 2006, the emission allowance price rapidly fell from €32/tCO₂ to €10/tCO₂. This drop in price was due to over-allocation of emission allowances in 2005. After a year of

practice, the actual emission figures were released and installations learnt that they were in the safe margin, considering the emission cap initially assigned [86].

Although at the moment installations have enough information to calculate their actual CO₂ emissions, the CO₂ emission price is still likely to be affected by some factors resulting from possible future changes in the emission market. Some of these are:

- In the new trading system there is no designated free national emission allowance, but instead each country should participate in the market and bid for the emission allowance at an auction.
- In the third period of the emission market which starts in 2013, the total allowance cap is planned to decrease annually by a factor of 1.74% in a linear manner[73] .
- More installations will be included in the emission trading each year.
- In the current market only CO₂ has been considered. The European Union plans to include other GHGs and harmful gases in the emission trading market.

Power plants are among those installations which have a high contribution to GHG emission. For instance, in the UK, 33% of total CO₂ emissions come from power plants [87]. The generation sector will be strongly affected by any emission price volatility in the emission market. The emission price simply changes the operating cost. Hence if the emission price varies the operation cost of those power plants which have higher emission level can change markedly. This can affect the final generation dispatch as well as the required transmission capacity. Therefore, any uncertainty in emission price need to be modelled and considered in transmission planning studies as it can considerably affect the final results. In Section 3.6, a probabilistic study is carried out to find the optimum transmission capacity for a test system taking into account CO₂ emission variations.

3.4 Scenario generation

A long-term planning problem with uncertain input parameters needs to be solved for different scenarios. These scenarios are generated based on the PDFs of input parameters and each scenario is associated with a given probability. Some sampling methods such as Monte Carlo simulation (MCS) [88] [89] [90], Latin Hypercube

sampling (LHS) [91, 92], important sampling [29], and bootstrap sampling [93] can be deployed to simulate the possible conditions in the planning horizon. The planning problem is run for all possible scenarios so that the final decision is most likely to be the optimum decision in the planning horizon. Different sampling methods offer different levels of accuracy and computation effort. In the following, MCS and LHS as two sampling methods frequently used in the literature are introduced.

3.4.1 Monte Carlo simulation

MCS has been successfully used in many power system studies. With the MCS method a large number of realisations of an uncertainty are generated on a random basis and in consistency with the corresponding PDFs. In this way, a wide range of possible scenarios which may occur in future can be simulated credibly. Roh et al [88] adopts MCS to produce scenarios of generator as well as transmission line outages in a generation and transmission network planning problem. Zhao et al [89] proposes a flexible transmission planning approach in which different scenarios of load demand are modelled using MCS. Reliability assessment of the power system is the area where MCS has been used extensively. Billinton et al [90] have reviewed many studies using MCS for reliability evaluation of the power system. In the transmission planning problem, a recursive algorithm can be considered so that a scenario of random uncertainties is generated by using MCS, Next, the optimum transmission proposal is calculated for that scenario. This process repeats till the convergence criterion is met. The convergence criterion checks whether the standard deviation of optimal capacity is less than a specified small number. The expected value of all optimal network capacities can most likely be the optimum network capacity. Zhao et al [94] use MCS in transmission planning studies to generate different market scenarios each of which contains different generation capacities, load demands and generation prices. In Figure 3-4 the transmission planning procedure using MCS is illustrated.

The main drawback of the MCS is a high computational burden. Transmission planning is a large scale mixed-integer optimisation problem which needs a fairly long time to solve. Hence, MCS can be prohibitively time-consuming rendering it infeasible for large size networks. In order to circumvent the high computational burden of the MCS method, some other sampling strategy such as Latin Hypercube sampling (LHS) or Important sampling can be adopted.

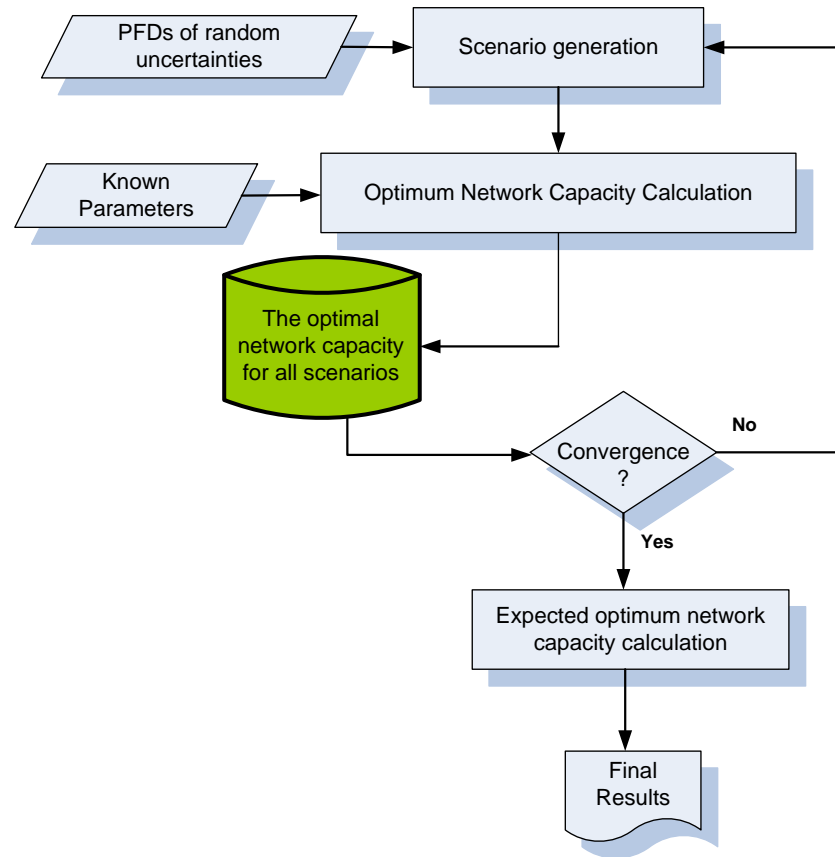


Figure 3-4: Transmission planning procedure using Monte Carlo simulation

3.4.2 Latin Hypercube Sampling

Latin Hypercube Sampling (LHS) was initially introduced by McKay et al [95]. In this method, unlike Monte Carlo, rather than repeatedly generating random numbers in consistent with the PDFs, the range of each variable is split into intervals with the same probability and a value is randomly selected from each interval. Once a sample is drawn from an interval, that interval will not be selected for the other samples. Therefore, the number of samples is equal to the number of intervals. Next, in order to generate scenarios, a sampled value from each variable is paired with samples from other variables. The LHS method with 10 sampling points for two independent variables whose uncertainties are modelled with the Weibull distribution function is shown in Figure 3-5. In this figure each black dot represents a scenario of variables.

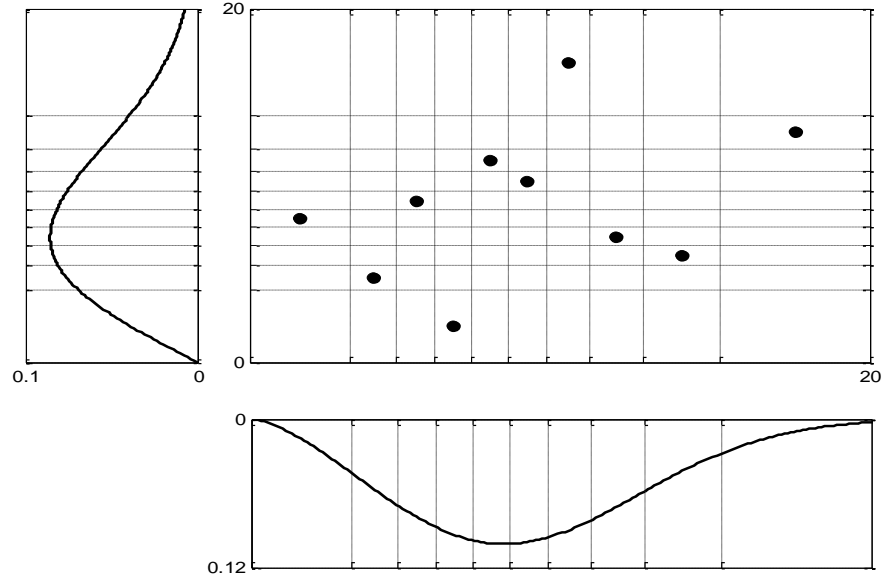


Figure 3-5: Ten sampling points using LHS

Jirutitijaroen et al [96] compare the application of Monte Carlo sampling as well as LHS in a transmission and generation expansion study assuming uncertainties in the demand. They come to the conclusion that the variance of variables in LHS is smaller than Monte Carlo sampling. The same conclusion is also drawn by Helton et al [91] who demonstrate that the convergence rate of LHS is higher than Monte Carlo sampling. Other examples of application of LHS in power system planning are in the studies conducted by Yong et al [92] and Jianhui et al [97] who estimate scenarios of wind power modelled by a normal distribution function.

3.4.3 Correlation

In practice, there may be a correlation between uncertain variables. For instance, the power generated by neighbouring wind power plants which are exposed to the same wind regime can be highly correlated. Therefore, whatever sampling method is adopted, the scenarios should comply with the correlation between variables. To do that, the sampled values should pass through a ranking filter which arranges the coincidence orders between realisations so that they are in consistency with correlation between variables. In this thesis an approach which was initially proposed by Iman and Conover [98] is taken. This ranking method is independent from the type of PDFs associated with uncertain parameters.

Assume $W_{uncorrelated}$ is a $N_s \times N_w$ matrix embodying N_s scenarios of N_w different uncertain parameters. $W_{uncorrelated}$ can be generated using any sampling method

without considering the correlation. Also, C is a $N_w \times N_w$ matrix of the correlations between parameters. The aim is to rearrange values in individual columns of $W_{uncorrelated}$ in such a way that the resulting matrix has a rank correlation very close to correlation matrix C . This is carried out by taking the following steps.

Step 1: Based on the descending rank of each column of $W_{uncorrelated}$ and its Van der Waerden scores, a new $N_s \times N_w$ matrix, S , is generated as described below.

If the descending rank of $x_{ij} \in W_{uncorrelated}$ in column j is R_{ij} then $d_{ij} \in S$ is Van der Waerden scores of $\Phi^{-1}(\frac{R_{ij}}{N_s + 1})$, where Φ^{-1} is the quantile of the standard normal distribution [99].

Step 2: A lower triangular matrix K is calculated, Using Cholesky factorization [100] :

$$C = K.K^T \quad (3-2)$$

Step 3: $W_{pattern}$ which its correlation is C is built as expressed by (3-3).

$$W_{pattern} = S.K^T \quad (3-3)$$

Step 4: If each column of $W_{uncorrelated}$ is rearranged based on the ranking order of corresponding column of $W_{pattern}$ then the correlation for $W_{uncorrelated}$ is C .

3.5 Modelling of lumpy investment

Investment in a transmission network has a lumpy nature. Mathematically speaking, the decision variable for installing a new transmission line is usually expressed with a binary variable which shows that either the candidate line is required or it is not. Moreover, the thermal limit of a transmission line is usually calculated taking into account the number of bundles, type of conductor, profile of the line etc [101]. Therefore, in practice, there are some specific capacities which can be proposed for a transmission line. In other words, the feasible capacity of a transmission line is not a continuous variable.

In order to model the lumpiness of transmission investment, a transmission planning problem is usually expressed in the form of a mixed-integer optimisation problem. Some studies, however, formulate the transmission planning problem as a continuous linear problem [14, 74, 102]. They simply consider that all candidate lines are connected to the network so that the only difference between candidate lines and existing lines is that the capacity of candidate lines are decision variables whereas the capacities of existing lines are known variables. This approach is rather useful when the reinforcement of the transmission network is the main concern as in the case where the transmission reinforcement planning overhead line path already exists so the need to replace the conductor of a transmission line is examined.

In a more realistic approach, in some other transmission planning studies, the decision variables are the connectivity of the candidate lines. As the connectivity is usually modelled with integer variables, the transmission planning problem is turned into a mixed integer problem. The problem should be formulated in such a way that if a candidate line is not selected the power flowing in that candidate line is taken to be zero. There are two different ways which are usually used to formulate the power flowing in the transmission lines: i) Parallel circuits model ii) Disjunctive model.

Parallel circuits model: In this method, the number of circuits which can be added between two buses in the network is the decision variable [76, 77, 103]. Due to difficulties in possessing right of way [104] or budget limits, there may be a cap on the number of lines which can be installed between two buses. Considering parallel circuit models in a transmission planning problem, the power flowing between bus i and bus j complies with equation (3-4) to (3-6). It should be stressed that these equations can be used both for candidate and existing circuits.

$$P_k = (n_k + n_k^0) \cdot \frac{(\theta_j - \theta_i)}{x_{ij}} \quad (3-4)$$

$$0 \leq n_k + n_k^0 \leq \overline{n_k} \quad (3-5)$$

$$-(n_k + n_k^0) \cdot P_{\max k} \leq P_k \leq (n_k + n_k^0) \cdot P_{\max k} \quad (3-6)$$

n_k is the integer decision variable which shows the number of circuits that must be added between bus i and bus j . n_k^0 , $\overline{n_k}$ are the number of existing circuits and the maximum possible circuits, respectively. $P_{\max k}$ is a known parameter which represents the capacity of each circuit between bus i and bus j .

Disjunctive model: This model is another option to model the power flowing in the candidate lines [105-107]. In this model, a binary decision variable shows the need for a candidate line. In the disjunctive model, the power flowing in each candidate line is mathematically expressed by (3-7) to (3-9).

$$P_k - \frac{(\theta_i - \theta_j)}{x_{ij}} \leq M_k \cdot (1 - X_i) \quad (3-7)$$

$$P_k - \frac{(\theta_i - \theta_j)}{x_{ij}} \geq M_k \cdot (X_i - 1) \quad (3-8)$$

$$-X_i \cdot P_{\max k} \leq P_k \leq X_i \cdot P_{\max k} \quad (3-9)$$

X_i is the binary decision variable. A candidate line is considered disconnected if X_i is zero, and it is connected if X_i is 1. M_k is a large number.

3.6 Probabilistic transmission planning: Numerical example

In the previous sections, the issues related to transmission planning were introduced and discussed. In this section, a probabilistic transmission planning study is demonstrated through an example on the IEEE 24 bus test system [108] is produced. In this example, the transmission planning problem is modelled in the form of a mixed-integer optimisation problem taking into account the network losses and uncertainty in the CO₂ emission price. Monte Carlo simulation is used to generate scenarios.

3.6.1 Objective function

The objective function is to minimise the transmission investment as well as the operating cost. Transmission investment is the annutised cost associated with the expansion of transmission network. Operating cost includes the generation cost and the emission cost. The objective function is given by (3-10).

$$\text{Minimize} : \sum_{j=1}^{N_p} D_j \cdot \sum_{i=1}^{N_g} C_i \cdot G_i^j + \sum_{i=1}^{N_g} \pi_{co2} \cdot E_i + \sum_{i=1}^{\overline{N_l}} T_{ci} \cdot l_i \cdot \overline{P}_{\max i} \quad (3-10)$$

Where:

- D_j Duration of the load level j (hour)
- C_i Incremental cost of generator i (€/MWh)
- G_i^j Power generated by generator i at load level j (MW)
- π_{co2} Emission allowance price (€/tCO₂)
- E_i Annual emission by generator i (tCO₂/year)
- T_{ci} Annuitized investment cost of line i (€/km.MW.year)
- l_i Length of transmission line i (km)
- $\overline{P}_{\max i}$ Capacity of candidate transmission line i (MW)
- $\overline{N_l}$ Number of candidate transmission lines
- N_p Number of load levels
- N_g Number of generators

In objective function (3-10), the first term is generation cost, the second term is emission cost and the last part is the transmission investment cost.

3.6.2 Credible capacity

There are some feasible transmission capacities which can be assumed for a candidate transmission line. The final solution should select the optimum capacity among a set of credible capacities envisaged for a candidate line. Therefore, if N_i feasible capacities are assumed for candidate line i then the objective function (3-10) should respect (3-11) and (3-12).

$$\overline{P}_{\max i} = \sum_{k=1}^{N_i} s_{ik} \cdot \overline{P}_{ik} \quad (i = 1, \dots, \overline{N_l}) \quad (3-11)$$

$$X_i = \sum_{k=1}^{N_i} s_{ik} \leq 1 \quad (i = 1, \dots, \overline{N_l}) \quad (3-12)$$

Where s_{ik} is the binary decision variable associated with $\overline{P_{ik}}$, the k th capacity from the set of credible capacities for transmission line i . Equation (3-12) constrains the objective function so that only one of those credible capacities is allocated to transmission line i . It should be noticed that X_i can be either 0 or 1.

3.6.3 Network physical laws

The powers flowing in existing transmission lines comply with equality constraint (3-13). A disjunctive model is considered for the candidate lines, as formulated by (3-14) and (3-15).

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{x_i} = 0 \quad (i = 1, \dots, N_l) \quad (j = 1, \dots, N_p) \quad (3-13)$$

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{x_i} \leq M_k \cdot (1 - X_i) \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (3-14)$$

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{x_i} \geq M_k \cdot (X_i - 1) \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (3-15)$$

The power balance at each bus is also formulated with (3-16), considering the losses allocation model proposed in section 2.4.

$$\sum_{\forall i \in N_{gk}} G_i^j + \sum_{\forall i \in N_{lk}} P_i^j - L_k^j - \sum_{\forall i \in N_{lk}} \frac{P_{loss}^j}{2} = 0 \quad (j = 1, \dots, N_p) \quad (k = 1, \dots, N_b) \quad (3-16)$$

3.6.4 Loss model

As elaborated in section 2.4, the losses are linearized using the inequality constraints (3-17) to (3-20).

$$P_{loss}^j \geq \frac{R_i \cdot P_{\max i}}{N} \left[(2n-1) \cdot P_{absi}^j + P_{\max i} \cdot \frac{n-n^2}{N} \right] \quad (i = 1, \dots, \overline{N_l} + N_l) \quad (j = 1, \dots, N_p) \quad (n = 1, \dots, N) \quad (3-17)$$

$$P_{absi}^j \geq P_i^j \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (3-18)$$

$$P_{absi}^j \geq -P_i^j \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (3-19)$$

$$P_{absi}^j \geq 0 \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (3-20)$$

3.6.5 Operation limits

The upper limit and lower limit of generators as well as the thermal limit of existing and proposed transmission lines should be respected. These constraints are applied using inequalities (3-21) to (3-23).

$$G_{\min i} \leq G_i^j \leq G_{\max i} \quad (i = 1, \dots, N_l) \quad (j = 1, \dots, N_g) \quad (3-21)$$

$$-P_{\max i} \leq P_i^j \leq P_{\max i} \quad (i = 1, \dots, N_l) \quad (j = 1, \dots, N_p) \quad (3-22)$$

$$-\overline{P}_{\max i} \leq P_i^j \leq \overline{P}_{\max i} \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (3-23)$$

3.6.6 Security criterion

The “N-1” security criterion is considered in this study, so the network is designed to be robust against outage of any transmission line. As for intact network, the circuit laws and the thermal limit of transmission lines should be satisfied in the contingent networks as well. These constraints are expressed by (3-24) to (3-28).

$$P_i^{j(c)} - \frac{(\theta_k^{j(c)} - \theta_l^{j(c)})}{x_i} = 0 \quad (i = 1, \dots, N_l, i \neq c) \quad (j = 1, \dots, N_p) \quad (3-24)$$

$$P_i^{j(c)} - \frac{(\theta_k^{j(c)} - \theta_l^{j(c)})}{x_i} \leq M_k \cdot (1 - X_i) \quad (3-25)$$

$$(i = 1, \dots, \overline{N_l}, i \neq c) \quad (j = 1, \dots, N_p)$$

$$P_i^{j(c)} - \frac{(\theta_k^{j(c)} - \theta_l^{j(c)})}{x_i} \geq M_k \cdot (X_i - 1) \quad (3-26)$$

$$(i = 1, \dots, \overline{N_l}, i \neq c) \quad (j = 1, \dots, N_p)$$

$$-P_{\max i} \leq P_i^{j(c)} \leq P_{\max i} \quad (i=1, \dots, N_l, i \neq c) \quad (j=1, \dots, N_p) \quad (3-27)$$

$$-\bar{P}_{\max i} \leq \bar{P}_i^{j(c)} \leq \bar{P}_{\max i} \quad (i=1, \dots, \bar{N}_l, i \neq c) \quad (j=1, \dots, N_p) \quad (3-28)$$

The notation c refers to the outage of line c . It should be noted that $\bar{P}_{\max i}$ is the coupling decision variable between intact network and contingent networks.

The generators cannot change their outputs immediately once a transmission line trips, so generation dispatch at a load level is similar to the generation dispatch for all contingent networks at the same load level. Moreover, the problem can be simplified if the contingent networks are assumed to be lossless. This assumption can be acceptable as losses have imperceptible effect on the required transmission capacity in the contingent network while the generation dispatch remains unchanged following a line outage. The losses mainly affect the operating cost in the normal condition. In order to exclude the losses from generation pattern calculated for intact network, a dummy load (r_i^j) is assumed at every generating bus in the contingent network model, see (3-29). The summation of the dummy loads should be equal to the losses of intact network as formulated by equality (3-30).

$$\sum_{\forall i \in N_{gk}} G_i^j + \sum_{\forall i \in N_{lk}, i \neq c} P_i^{j(c)} - L_k^j - \sum_{\forall i \in N_{gk}} r_i^j = 0 \quad (k=1, \dots, N_b) \quad (3-29)$$

$$\sum_{i=1}^{N_g} r_i^j - \sum_{i=1}^{N_l + \bar{N}_l} P_{loss i}^j = 0 \quad (j=1, \dots, N_p) \quad (3-30)$$

Another set of inequalities given by (3-31) and (3-32) are also added to the problem to ensure that only a small percentage (α) of each generation is curtailed in order to eliminate the contribution of generation to supplying the losses. This is to constrain the optimisation to not deduct a large portion of losses from a particular generator.

$$(G_i^j - r_i^j) \geq G_{\min i} \quad (i=1, \dots, N_g) \quad (j=1, \dots, N_p) \quad (3-31)$$

$$0 \leq r_i^j \leq \alpha \cdot G_i^j \quad (i = 1, \dots, N_g) \quad (j = 1, \dots, N_p) \quad (3-32)$$

3.6.7 CO₂ emission modelling

As the policy in the emission market may change, two different models for the emission market are assumed and the transmission planning study is conducted for both models. In the first model, Model I, the generators can fill the shortage in emission allowance through buying the emission allowance from the market or, alternatively, generators can benefit from selling their emission allowance surplus in the emission market. In order to integrate this model into transmission planning problem the annual emission of each generator complies with the equality (3-33).

$$E_i = K_{co2i} \cdot \sum_{j=1}^{N_p} D_j \cdot G_i^j - A_i \quad (i = 1, \dots, N_g) \quad (3-33)$$

Where:

K_{co2i} CO₂ emission factor of generator i (tCO₂/MWh)

A_i Emission allowance of generator i (tCO₂/year)

In the second approach, Model II, the possible benefit that a generation company can gain from keeping the emission below the allocated cap is disregarded. Instead, those power plants which are willing to exceed their emission cap are penalised. This model can be constructed by adding inequalities (3-34) and (3-35) to the transmission planning problem.

$$E_i \geq K_{co2i} \cdot \sum_{j=1}^{N_p} D_j \cdot G_{ij} - A_i \quad (i = 1, \dots, N_g) \quad (3-34)$$

$$E_i \geq 0 \quad (i = 1, \dots, N_g) \quad (3-35)$$

As previously mentioned, emission price is likely to experience unforeseen changes. Emission price can directly affect the operating cost which is one of the terms in the transmission planning objective function (3-10). The volatility of the CO₂ emission price is approximated by a Weibull PDF taking into account the past variations of emission price given by [86] . The PDF of emission price is mathematically expressed

by (3-36) and it is illustrated in Figure 3-6.

$$f(x) = \frac{2.78}{19.56} \left(\frac{x}{19.56} \right)^{1.78} e^{-\left(\frac{x}{19.56} \right)^{2.78}} \quad (3-36)$$

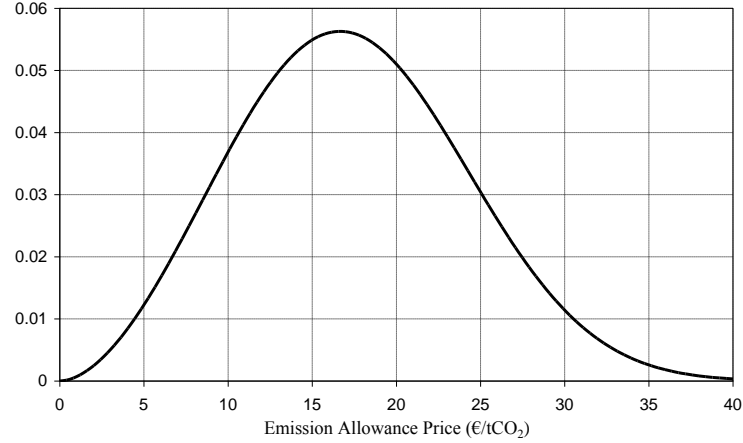


Figure 3-6: Weibull PDF modeling CO₂ emission price

3.6.8 Methodology

Using MCS method, 2000 scenarios of CO₂ emission price are randomly generated, taking into account the PDF formulated by (3-36). The objective function (3-10) which is subject to constraints (3-11) to (3-35) is solved for all those 2000 CO₂ emission price scenarios. Dash Xpress is used to solve this mixed-integer problem. The calculations are carried out for both CO₂ emission market models, Model I and Model II, which were described in (3-33) to (3-35). Twelve branches out of 38 branches of the IEEE 24 bus network are considered as candidate branches. The credible capacities for candidate transmission lines are assumed to be 100, 200, 300 or 400 MW. The relevant data about generation cost, existing and candidate lines, transmission cost are given in Appendix A.

In this study, it is assumed that the best capacity for each candidate line is the one that most is frequently proposed, taking into account all 2000 scenarios. The results of Monte Carlo simulation are also compared with two deterministic cases to demonstrate that a probabilistic approach is necessary when the CO₂ emission price is uncertain. The deterministic studies are undertaken for two different CO₂ emission prices. In the first study, the effect of the emission market is neglected and the emission price is assumed to be zero. In the other case, a price of 17.5 €/t CO₂ is considered for the emission

allowance. This price is the most probable price for CO₂ emission based on the PDF shown in Figure 3-6.

3.6.9 Results and discussion

The results of Monte Carlo simulation are shown in Table 3-1. Table 3-1 illustrates the number of times that a particular capacity is proposed for a specific candidate line. For example, according to results for Model I, a capacity of 300 MW is the best capacity for line 18 as this capacity is proposed by the optimisation 1070 times out of 2000 scenarios whereas the optimal capacity is 400 MW for only 930 scenarios. Following this strategy, the best capacity is calculated for all 18 candidates of transmission lines and the results are given in the last column of Table 3-1.

As mentioned before, two deterministic studies; one with the emission price of 0 €/tCO₂ and the other 17.5 €/tCO₂ are carried out. The optimum transmission capacities proposed by these studies are compared with the MCS's results in Figure 3-7 and Figure 3-8 For Model I and Model II, respectively. The resultant transmission capacities of deterministic studies are identical to the probabilistic study results only for the emission Model II and the emission allowance price of 17.5 €/t CO₂. For other cases, as tabulated in Table 3-2 different transmission investments have been proposed.

Table 3-1: Monte Carlo simulation transmission planning results for Model I & Model II

Emission Model	Line #	No Need	100 MW	200 MW	300 MW	400 MW	Most probable Capacity (MW)
Model I	12	0	2000	0	0	0	100
	13	0	2000	0	0	0	100
	18	0	0	0	1070	930	300
	20	0	0	0	1096	904	300
	21	0	0	35	1965	0	300
	22	1722	0	37	241	0	No Need
	31	644	165	270	921	0	300
	34	0	1195	805	0	0	100
	35	0	1195	805	0	0	100
	36	0	0	1196	804	0	200
	37	0	0	1196	804	0	200
	38	647	155	270	928	0	300
Model II	12	0	2000	0	0	0	100
	13	0	2000	0	0	0	100
	18	0	0	0	1759	241	300
	20	0	0	0	2000	0	300
	21	0	0	1153	109	738	200
	22	738	0	1218	44	0	200
	31	137	115	1748	0	0	200
	34	387	1148	464	0	0	100
	35	387	1148	464	0	0	100
	36	0	0	1854	146	0	200
	37	0	0	1854	146	0	200
	38	137	115	1748	0	0	200

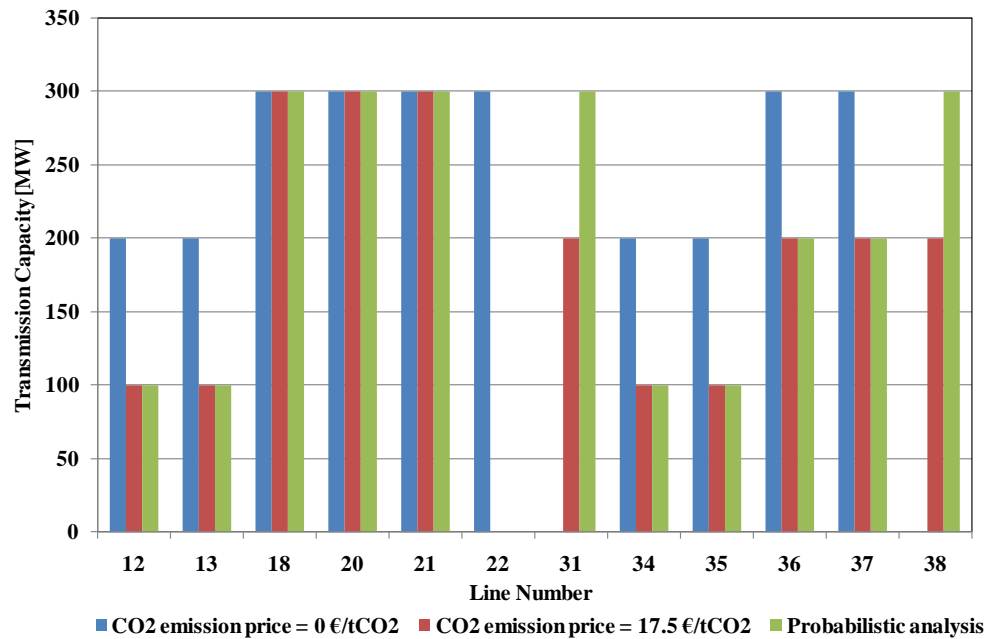


Figure 3-7: Transmission capacities; comparison between deterministic studies and probabilistic study considering Model I

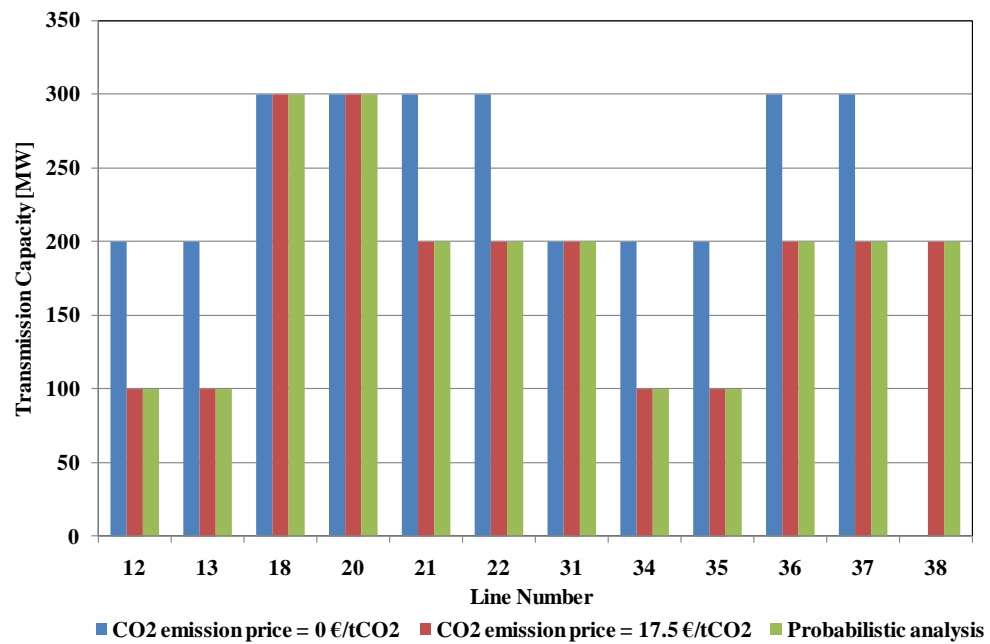


Figure 3-8: Transmission capacities; comparison between deterministic studies and probabilistic study considering Model II

Table 3-2: Transmission investment costs (€/Year) under different CO₂ emission price/market scenarios

	Probabilistic Study	CO ₂ emission price =0 €/t CO ₂	CO ₂ emission price =17.5 €/t CO ₂
Model I	1131840	1121229	990360
Model II	1052847	1121229	1052847

In order to examine whether the probabilistic approach can propose a superior transmission expansion scheme over the results of deterministic approach, the total system cost is considered as an index used to compare the probabilistic studies with deterministic studies. The total system cost embodies the operating cost as well as the transmission investment. Transmission investment can be quantified by considering the transmission expansion scheme, as calculated in Table 3-2. Operating cost, however, comprises the generation cost and emission cost. For a given transmission capacity and network configuration, the operating cost can be determined by solving a security constraint optimal power flow (SCOPF) problem. The SCOPF problem is formulated by eliminating the transmission investment term from the objective function (3-10). It should be noticed that generation (G_i^j) is the decision variable in OPF problem, see equation (3-37). The OPF objective function is still subject to the constraints formulated by equations (3-13) to (3-35).

$$\text{Operating Cost} = \text{Minimise} : \sum_{j=1}^{Np} D_j \cdot \sum_{i=1}^{Ng} C_i \cdot G_i^j + \sum_{i=1}^{Ng} \pi_{co2} \cdot E_i \quad (3-37)$$

The total system cost is calculated taking into account 2000 emission price scenarios for the set of transmission capacities given in Figure 3-7 and Figure 3-8. In this way, 2000 values for total system cost related to different transmission expansion schemes are computed. For a particular scenario the difference between the total system cost associated with the network proposed by the deterministic studies and the total system cost of network calculated by the probabilistic study shows the superiority of one study over the other. Taking into account 2000 scenarios, 2000 differentials are calculated and a normal PDF is fitted to these values, as shown in Figure 3-9 to Figure 3-11. In these figures, the negative values are for those cases where the probabilistic study proposed a network with a lower total system cost than the network calculated by deterministic study.

Considering Model I for emission market, Figure 3-9 shows that the probabilistic approach with a probability of 77.01% results in a lower total system cost compared to the deterministic study which neglects CO₂ emission price. Figure 3-10 illustrates that in 57.94% cases the probabilistic method is superior over the deterministic approach when the most probable emission price (17.5 €/t CO₂) is considered for the

deterministic study. For model II the superiority of probabilistic method is also observed. Figure 3-11 shows that the MCS proposes a transmission scheme which with a likelihood of 93.06% is more beneficial than the network determined from the deterministic study which considers an emission price of zero. The only case where the deterministic approach and probabilistic method propose the system investment cost and operating cost is the one where the emission model is Model II and the emission price is 17.5 €/t CO₂.

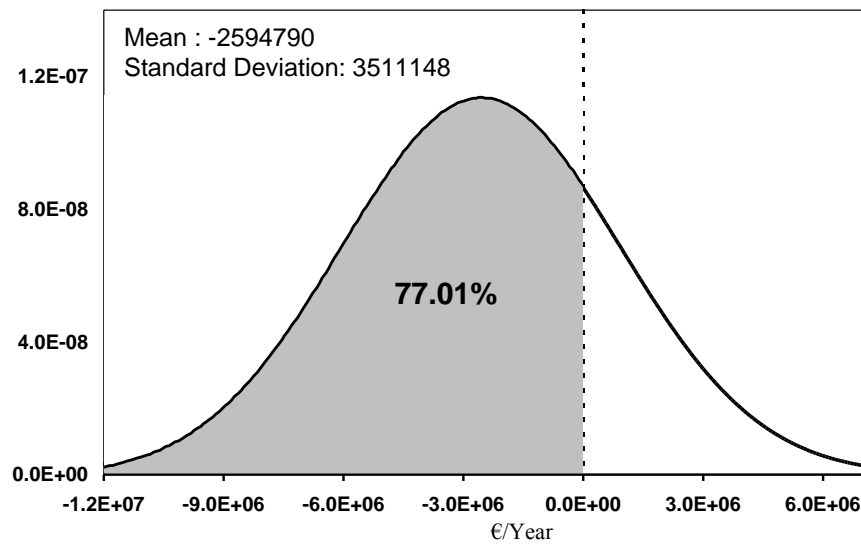


Figure 3-9: PDF of total system cost differences between the network proposed by probabilistic analysis and the network proposed by deterministic analysis when emission cost is not considered, Model I.

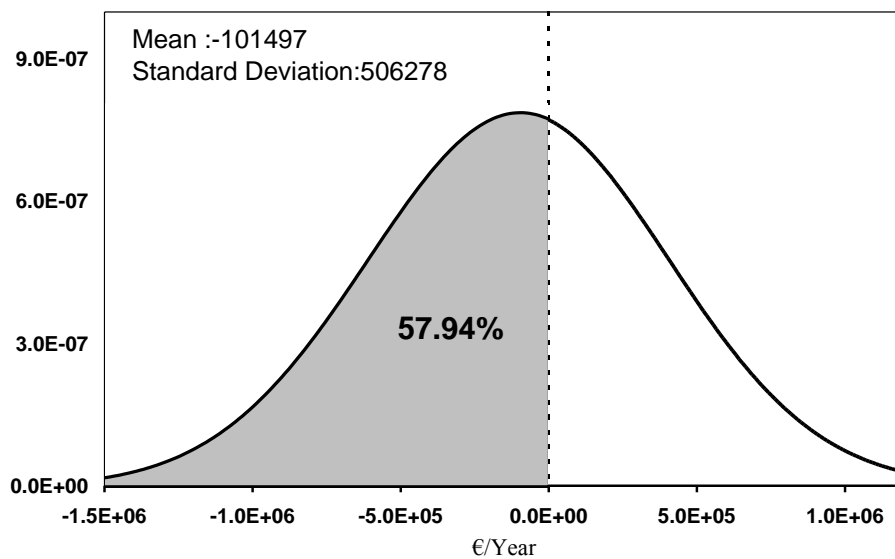


Figure 3-10: PDF of total system cost differences between the network proposed by probabilistic analysis and the network proposed by deterministic analysis when emission cost is 17.5 €/t CO₂, Model I.

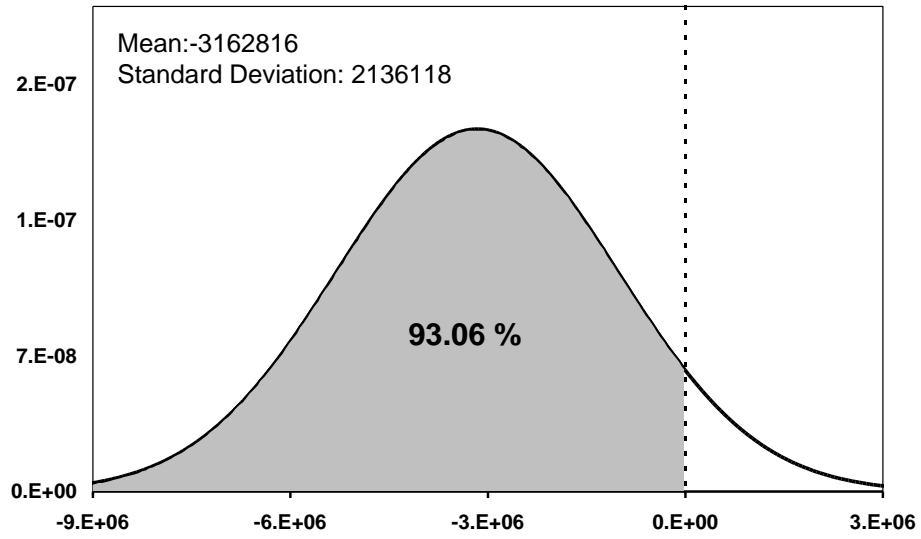


Figure 3-11: PDF of total system cost differences between the network proposed by probabilistic analysis and the network proposed by deterministic analysis when emission cost is not considered, Model II.

3.6.10 Loss model validation

A new approach for linearising the losses for transmission planning problem was elaborated in 2.4. The losses model was also used in the transmission planning study for the IEEE 24 test system. In this section the accuracy of the losses model is examined.

The model of losses which was used for transmission planning in Section 3.6 consists of three segments ($N = 3$). In this section, the main concern is to examine the accuracy of the losses model, therefore emission allowance cost is simply eliminated from the transmission planning problem and the security constraints expressed by equations (3-24) to (3-28) are ignored. The maximum capacities of transmission lines are assumed to be those which were given in Table 3-2 for Model I. Under these assumptions, OPF is run and the two following cases are assumed to evaluate the accuracy of the loss model.

Case I) The losses of line i at the load level j ($Ploss_i^j$) is calculated taking into account the proposed piecewise linear model.

Case II) After running the load flow, the quadratic equation (2-11) is used to calculate the actual losses of each line.

The total losses at each load level are the summation of the losses at all branches, as shown by (3-38).

$$Loss_{total}^j = \sum_{i=1}^{NL} Ploss_i^j \quad (3-38)$$

The results of aforementioned cases are presented in Table 2-1. The results demonstrate that the losses calculated using piecewise linear model are very close to the losses which are calculated by the quadratic equation.

Table 3-3: Calculated losses (MW) in Case I and Case II

Load Levels	Case I	Case II	Accuracy (%)
1	35.7	34.8	97
2	31.5	30.7	97

3.7 Transmission network operation

The planning and operation of transmission network is traditionally undertaken under a preventive control regime. Under this regime, after the occurrence of any contingency and without taking any post-contingency action the network should be able to continue operating within operational limits. The preventive control operation regime assumes that the corrective actions after contingencies or cascading outages are not plausible options. Therefore, the network is planned and operated considering a high safety margin under which considerable capacity of the transmission network is kept reserved just for the contingencies which do not occur frequently. Under this conservative approach, an overinvestment in transmission network is expected since the network assets are not utilised efficiently.

Some system operators may use analytical software as well as human experience to estimate the security indices of the network on a short-term basis, taking into account possible network contingencies. Once the vulnerability of the network has been realised, the system operator, under the preventive control philosophy, may take some pre-contingency action to ensure that the network performance is not interrupted by postulated contingencies. Some of these precautionary measures are listed below:

- *Generation dispatch:* The system operator may constrain off some generators to make sure that no contingency results in network overload or voltage violation

problem. A security constrained OPF simulating network's condition a couple of hours ahead is run by the system operator to find the most economic generation dispatch which satisfies security constraints [109].

- *Network reconfiguration:* Network switching as well as substation switching may be used to alleviate the overload, remove voltage violation and enhance the security margin. Rolim et al. reviews the application of switching in the transmission network [110].
- *Use of FACTS:* Flexible AC transmission systems are widely used for both post-contingency and pre-contingency actions to hold the power system variables within the designated limits. Among FACTS, phase shifting transformers (PST), Static Var Compensators (SVC) and Thyristor Controlled Series Capacitors (TCSCs) have received more attention by power systems engineers. The time response of FACTS is the key to relying upon them for preventive or corrective measures. A review of applications and modelling of FACTS is produced by Padiar et al. [111].
- *Load shedding:* Load shedding may be the last option that a system operator considers as a healing action. If the system operator predicts that the power system moves towards a blackout the load curtailment can be one of the quickest choices to save the network from a wide power cut [112].
- *Islanding:* Islanding is the action which may be taken if system is approaching to an emergency condition and none of the aforementioned actions averts the black out. The system operator may carry out a controlled islanding so that the network is split into several safe islands where most of consumers can be still supplied. The main difficulty in a controlled splitting strategy is the need to have a real-time decision-maker in order to determine the best lines which should be tripped to split the network [113]. The combination of islanding action and load shedding can potentially be a viable solution to survive a blackout if a power system experiences severe outages.
- *Under load tap changing (ULTC):* ULTC is widely used by system operators to adjust the voltage across the transmission network [114]. Tap changing is a mechanical measure which cannot be undertaken very quickly, so it is usually

used as a preventive measure. However, in some cases when the contingent network can temporarily tolerate some short-term violation, the system operator has enough time to carry out the post-fault under load transformer tapping.

All remedial actions listed above can be deployed for pos-contingency corrective actions [115]. The feasibility of each post-fault corrective action highly depends on the severity of the contingency as well as the required time to conclude the action. In Figure 3-12 the approximate required time to conclude different network remedial actions are shown [116-119]. The required temporal interval during which a corrective action is undertaken includes the computational time delay, signalling delay, and the performance delay of power system components. Some corrective actions such as generation re-dispatch, transformer tap changing and phase shifter tapping which require mechanical operations need longer times to be accomplished.

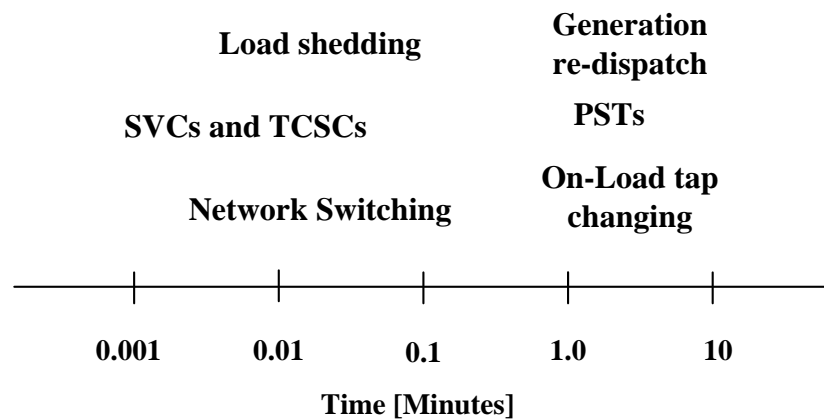


Figure 3-12: The required time scale to conclude network remedial actions

Operating the system under corrective action enhances the flexibility and efficiency of the transmission network. This can be achieved by using intelligent systems underpinned by a broad communication system so that following a contingency the best corrective action solution is determined and the essential commands are sent to power system components. Under the “smart grid” vision, an intelligent and flexible power system is one of the features of future power system [120]. In such a smart transmission grid, the transmission investment proposals studied under preventive control regime are no longer economically justifiable. Instead, post-contingency corrective actions are plausible and they need to be considered in the transmission planning studies.

3.8 Conclusions

The level of uncertainties in the power system is becoming higher. A large part of future generation mix is set to be renewable energies resources which rely highly on weather condition. This significantly increases the level of uncertainty on the generation side. The main challenge for transmission planners is to design the future transmission network which can accommodate all possible uncertainties economically. Therefore, rather than deterministic approaches which were traditionally used by transmission planners, probabilistic methods should be deployed. In this chapter, the source of uncertainties in the future power system was explained and the methodologies to estimate the future scenarios were investigated. Among all uncertainties, the effect of volatility in CO₂ emission price on transmission planning is investigated. Through a numerical study, it was demonstrated that the required investment in transmission network is more likely to be lower if a probabilistic approach is deployed in transmission planning.

Chapter 4. Transmission planning assuming post-fault substation switching corrective action

In this chapter, a methodology to solve the transmission planning problem, which assumes post-fault substation switching action is plausible, is introduced. It is assumed that network topology can be altered through transmission line switching and substation reconfiguration in order to eradicate post contingency overloads. A genetic algorithm is deployed to find the best post-contingency corrective switching action. The proposed methodology is tested on a 5 bus network and the IEEE 24 bus network and the results demonstrate that a smaller transmission investment is required by using proposed algorithm.

4.1 Introduction

The distribution of currents flowing in transmission lines, voltage profile across the network and losses can be changed by re-configuration of the network. Therefore, one preventive/corrective action to alleviate overloads or eradicate voltage violation in a power system is to alter the connectivity of transmission lines. Network operators may alter the topology of the network based either on a given instruction or experience to keep the network from any violation [121]. A simple example can be de-energizing a long transmission line during off-peak time to avoid the over-voltage problem due to Ferranti effect. Re-configuration is mainly practiced as a preventive action so that network switching action can be taken if a network operator realises that the upcoming network state may not meet security criteria. Nonetheless, Bertram et al [119] suggest network switching as a corrective action which can be used for real-time security enhancement. The application of network switching as a post-contingency corrective action is not broadly practised by the system operators as, firstly, they are not equipped with the software or the intelligent systems which are able to swiftly find the best switching action once a contingency occurs. Secondly, there is not a quick and wide communication system which sends the relevant commands to update circuit breakers status based on the required switching action.

However, intelligent systems along with a swift communication system linking power system components are main features of the future grid. Therefore, the future grid is supposed to be more flexible and smarter so that the application of network switching is a plausible option for post-contingency corrective actions. In such a network, in order to avoid overinvestment any transmission expansion plan should consider flexibility of the network in terms of post-contingency action. Therefore, unlike traditional approaches which ignore corrective actions, a transmission expansion planning taking into account the flexibility of the network should be adopted.

In this chapter, network reconfiguration is assumed to be a plausible post-contingency action which can be undertaken once a transmission line trips. Under this assumption, a methodology is proposed to solve the network planning problem. Using the proposed methodology, the possible decrement in required transmission investment is examined while contingency criteria are still fully respected. This chapter is twofold. First, a review of studies relating to applications of transmission network reconfiguration is introduced. Next, a methodology of solving the transmission planning problem is proposed, assuming post-contingency corrective substation switching action. This method is demonstrated on a 5 bus network as well as the IEEE 24 bus network.

4.2 The purposes of network switching

System operators may reconfigure the network for a number of different reasons. Rolim et al [110] have reviewed the objectives of corrective switching action in transmission networks. Some of these objectives are listed below:

Alleviation of overloads: Disconnecting a transmission line or changing the connectivity arrangements in a substation can affect the power flows in other branches. Wrubel et al [122] propose a substation switching approach as a corrective action to solve the post-contingency overload problem. Discussing the practicality of switching action, they suggest that a switching scenario selection algorithm should be run every 5-10 minutes to find the most effective switching strategy corresponding to the state of system which constantly changes. Shao and Vittal [123] recommended overload eradication by deploying both line switching and substation switching. The overload problem is also tackled by Makram et al [124] who propose a fast computing algorithm to find the best line switching corrective action. Granelli et al [125] use substation switching to change the impedance seen by different parallel power flowing between two different regions.

In this way, they attempt to circumvent the undesired circulation of inter-regional parallel flows.

Eradicating voltage violations: Voltages can be kept within the acceptable operational limits by switching corrective/preventive action. Rolim and Machado [126] use line switching to control the voltage across the network. They propose a fast algorithm based on an expert system to find the best switching action.

Loss reduction: Losses can be reduced by altering the network topology. Losses, unlike overload or voltage violation problems, do not lead the power system to an emergency condition or widespread power cut. Therefore, the re-configuration action with the purpose of loss reduction does not need to be concluded very quickly although the system operators usually try to minimise the losses as quickly as possible in order to gain the most benefit from operating cost reduction. Bacher and Glavitsch [127] have studied the effect of branch switching on network losses. As computation time in this case is not very crucial, they have deployed an accurate AC model for the network.

Operating cost reduction: The system operator may constrain off some in-merit generators to circumvent a post-fault overload problem. Alternatively, however, the network reconfiguration action can be deployed to avoid out-of-merit generation. Hedman et al [128] claim a 15% saving in generation cost of the IEEE 118 bus test system by incorporating the line/transformer switching into a security-constrained OPF. They assume that a line which is intentionally disconnected in the intact network will remain disconnected even if a contingency occurs. Hedman continues his work with another study which solves the unit commitment problem considering branch switching [129]. In another piece of work, Khodaei [130] also solves the unit commitment problem by assuming that network switching is a plausible action. Khodaei decomposes the problem into a master and sub-problems. The master problem is a typical unit commitment problem, and sub-problems are transmission network switching problems for contingencies. The main advantage of decomposition is to split a large-scale problem which is difficult to solve as a whole into small-scale sub-problems. This method specially is very useful when there are many lines considered as candidates for a switching scheme. The idea of “Just-in-time transmission“ proposed by Hedman [131] is that some transmission lines may be switched out to achieve the minimum operation cost. Nonetheless, once an unplanned outage occurs, originally disconnected

transmission lines can be switched in to circumvent the post-contingency overload problem.

Security enhancement: Network switching can be implemented to boost the security of the network. Sclynider [132] notes that network switching action is an option which can be used to make the network robust against cascading outages. In other words, following an unplanned outage, the network's topology may change in such a way that the contingent network respects "N-1" security criteria. Delgadillo et al. [133] propose the line switching corrective action to tackle the vulnerability of the power system to malicious outages or terrorist attacks.

4.3 Switching elements

Network reconfiguration is undertaken by changing the status of circuit breakers in the substations where a transmission line is connected to the rest of the network. In general two types of switching action may be considered. In the simplest type of action, some lines may be switched in/out to achieve the desirable network topology. In a more complex way, however, a bus-bar switching can be carried out. In bus-bar switching, the connections of transmission lines to bus-bars in the substations are changed so that various network topology may materialise. The flexibility of bus-bar switching action depends on the substations arrangement. In general, there are six different types of substation arrangement [101] each of which offers different level of flexibility for bus-bar switching action. Some of these arrangements are shown in Figure 4-1.

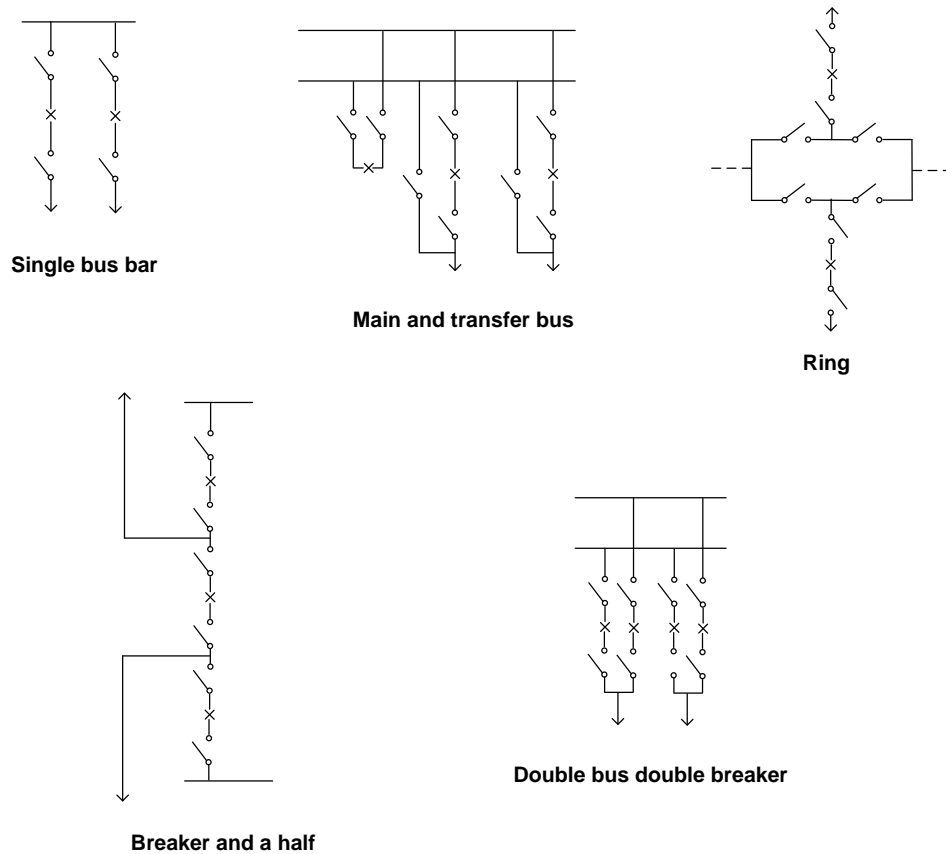


Figure 4-1: Some of typical substation arrangements

In a substation whose layout is single bus bar, main and transfer bus or ring layout, the manoeuvre entails switching on or switching off a transmission line whereas with break and a half or double bus and double breaker layout the transmission line can be also switched to another bus bar. Among all available substation layouts, the double bus double breaker has the most flexible layout in terms of switching action.

4.4 Network switching action in the modern power system

In an electricity market, network congestion may give some generators the opportunity to exert market power on the consumers. Network switching might be deployed by system operator in order to avert congestion. This has been studied by Doll et al [134]. However, based on the traditional approach for operating the network a fix topology is considered in normal and contingency condition. Using network switching action can give a flexible feature to the transmission operation regime.

Hedman et al [135] note that although the combination of network switching and economic dispatch is beneficial, the system operators may forgo this gain as the financial transfer right (FTR) is calculated based on a static network topology. In a

supplementary piece of work [136], Hedman analyses the variation in congestion rent – the difference between nodal prices at both ends of a transmission line multiplied by the power flowing in the corresponding transmission line – while the number of allowable switching elements varies.

Network switching has not been fully deployed by transmission operators yet, although this action, to some extent, is practiced by regional transmission companies. Some practicalities should be satisfied in order to integrate the switching action into the operating activity routines. Fisher et al [137] introduce these practicalities which mainly embrace quick computational systems underpinned by a fast communication system which does not exist in most power systems. Nonetheless, intelligent systems as well as wide area communication systems are key features of the notion of the “smart grid” upon which the next generation of power systems are expected to be constructed. In a smart grid, the network is supposed to be self-managing, self-healing, adaptive and intelligent. In other words, in a smart grid the state of the power system is constantly monitored by intelligent systems which organise preventive or corrective measures in order to keep the system operational.

In such an intelligent network, the network reconfiguration can be considered as a plausible corrective action. This assumption may affect the long-term and short-term transmission planning studies. For instance, transmission expansion planning is traditionally undertaken under a preventive control mode under which extra transmission capacities are proposed to ensure that network is secured against some postulated outages. In an alternative approach, the expansion scheme can be proposed with the assumption that the network topology may intelligently change once an outage or a set of outages occurs. In this way, a smaller transmission investment may be made as there is no need to reserve a considerable capacity of network just for outages which do not occur frequently.

4.5 Transmission planning under corrective switching action

In this section a flexible transmission planning approach is proposed, assuming that transmission network is intelligent and quick enough to change the configuration when a transmission line trips. Network reconfiguration planning is a challenging task as the optimum switching action has to be searched for among many possible combinations of circuit breaker switching options.

The status of each breaker is defined with a binary variable, the circuit breaker is either closed or open. Therefore, the network reconfiguration, in the simplest way, is formulated in the form of a linear mixed-integer problem. This problem becomes more complicated if the capacity of the transmission network is also a decision variable. The main contribution in this chapter is to optimally calculate the network capacity along with the switching action for credible outages. This problem has rarely been solved by previous researchers although just recently khodaei et al [138] proposed a transmission planning approach taking into account the transmission line switching. In this thesis, bus-bar switching rather than just transmission line switching is integrated into the transmission planning problem.

The arrangements of substations are assumed to be double-bus-double-breaker, so a variety of connections in the substation is possible. The problem is a large scale problem which cannot be solved as one single integrated problem. Instead, the problem is split into sub-problems, each of which uses a Genetic algorithm (GA) to calculate the required transmission capacity as well as the corrective switching action. Based on the output of each sub-problem, as part of a multi-stage approach a heuristic method is proposed to calculate the final required transmission capacities. The resultant transmission capacities and switching actions should satisfy the “N-1” security criterion. The proposed method is tested on a 5 bus system as well as the IEEE 24 bus system. In the following the formulation and the proposed approach are elaborated.

4.5.1 Problem formulation

The transmission planning problem is formulated as optimisation whose objective function is to minimise the transmission investment cost along with the generator operating cost. The operating cost is assumed to be a linear function of generators outputs. The transmission investment depends on the length of transmission lines and their proposed capacities. The objective function is expressed in (4-1).

$$\text{Minimize} : \sum_{i=1}^{N_g} C_i \cdot G_i + \sum_{j=1}^{\overline{N_l}} T_{cj} \cdot l_j \cdot \overline{P}_{\max j} \quad (4-1)$$

Where:

C_i Cost of generation i (€/MWh)

G_i Output of generation i (MW)

T_{cj} Annutised transmission investment cost j (€/MW.Km.Year)

l_j The length of transmission line j

$\bar{P}_{\max j}$ The proposed capacity of transmission line j

N_g Number of generators

\bar{N}_l Number of candidate lines

$\bar{P}_{\max j}$ and G_i are decision variables. The DC power flow model is used in this formulation. The objective function (4-1) is subject to physical laws that govern power flow in electric circuits namely Kirchhoff's current law (KCL) and Kirchhoff's voltage balance law (KVL) which are formulated by (4-2) and (4-3).

$$\sum_{\forall i \in N_{gd}} G_i + \sum_{\forall j \in N_{ld}} P_j - L_d = 0 \quad (d = 1, \dots, N_b) \quad (4-2)$$

$$P_i - \frac{(\theta_k - \theta_l)}{X_i} = 0 \quad (i = 1, \dots, N_l + \bar{N}_l) \quad (4-3)$$

L_d The load demand at bus d

P_i Power flowing in transmission line i

N_{gd} A set consisting of generators which are connected to bus d

N_{ld} A set consisting of transmission lines which are connected to bus d

X_i the impedance of transmission line i

The power flows and generation outputs should also be within the limits, as expressed by (4-4) to (4-6).

$$-P_{\max i} \leq P_i \leq P_{\max i} \quad (i = 1, \dots, N_l) \quad (4-4)$$

$$-\bar{P}_{\max j} \leq P_j \leq \bar{P}_{\max j} \quad (j = 1, \dots, \bar{N}_l) \quad (4-5)$$

$$G_{\min i} \leq G_i \leq G_{\max i} \quad (i = 1, \dots, N_g) \quad (4-6)$$

Equations (4-2) to (4-6) are the main constraints which should be respected in the intact network as well as in contingent networks. In other words, for every contingent

network a similar set of constraints should be considered. It is assumed that generators do not participate in post-contingency corrective action. Therefore, an identical generation dispatch is assumed for normal and post-contingency conditions. Moreover, the proposed capacities for candidate transmission lines are coupling decision variables between intact network and contingent networks.

4.5.2 Lumpy transmission investment

The transmission planning problem which was formulated by (4-1) to (4-6) is a linear optimisation where transmission capacities are defined as a continuous variables. In practice, however, the conceivable capacities for a transmission line are not continuous variables. In other words, the transmission capacities proposed by linear optimisation are not exactly available in real life. Instead, a step-wise model for feasible transmission capacities (FTC) is assumed so that the lumpy nature of transmission investment is taken into account. Figure 2-1 illustrates this model where the horizontal axis refers to the capacity proposed by optimisation whereas the vertical axis is the actual capacity which is available in practice. For example, if the linear optimisation proposed a capacity \bar{P}_{maxi} which falls between two feasible capacities L_1 and L_2 ($L_1 < \bar{P}_{maxi} \leq L_2$) a transmission line with a capacity L_2 should be constructed (FTC = L_2).

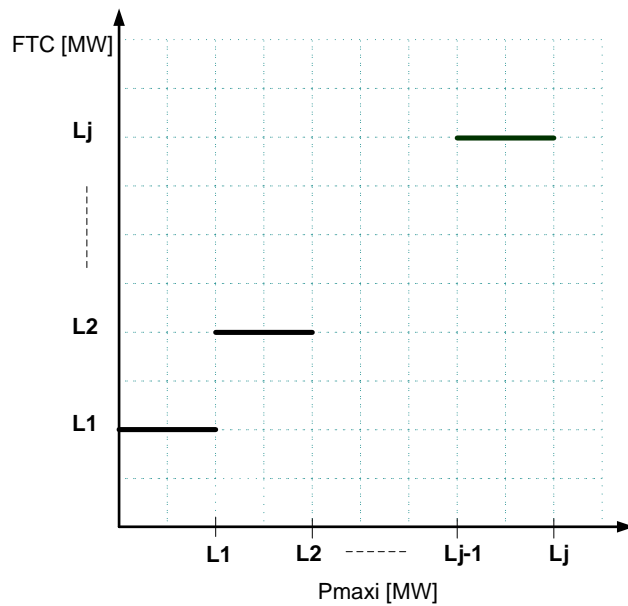


Figure 4-2: Stepwise model for transmission investment

4.5.3 Substation switching model

In this work, those substations which participate in the post-contingency corrective switching action are assumed to have a double-breaker-double-bus layout, see Figure 4-3. Depending on the circuit breaker statuses, three possible combination connections can be assumed for a transmission line coming to the substation shown in Figure 4-3. As given in Table 4-1, a transmission line i may be connected to bus-bar A or bus-bar B or it can be disconnected from the substation. It is assumed that generator and load demand are only connected to bus-bar A and it is not possible to switch them to the other bus-bar. Each possible connection for a transmission line is given a corresponding code. These codes will be used in the genetic algorithm to find the optimum switching combinations.

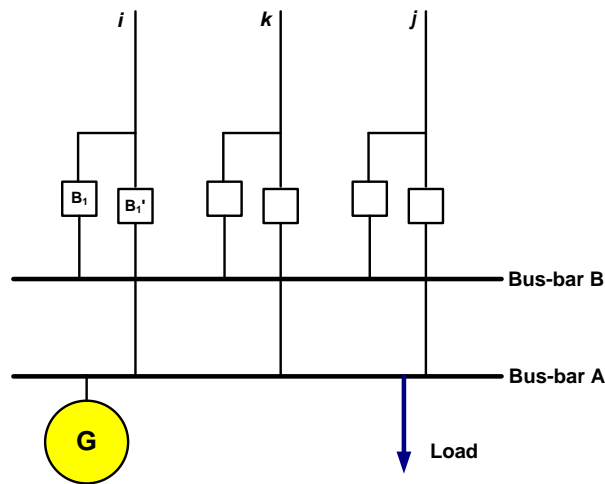


Figure 4-3: Double bus-double breaker model for the substation

Table 4-1: Different connection status for line i shown in Figure 4-3

Connectivity code	B_1	B_1'	Connected to
1	Open	Closed	Bus A
2	Closed	Open	Bus B
3	Open	Open	Disconnected

4.5.4 Genetic Algorithm

Genetic algorithm (GA) is a heuristic method that is usually used to search for the optimum solution among all feasible solutions to a problem. This method was originally inspired by natural evolution in which species do not remain unchanged and they evolve gradually to adapt with the environment. Those creatures who have better adaptation

with the environmental conditions can survive and they participate in reproducing the next generation. Therefore, the next generation is likely to be fitter than their parents. A generation in GA called population.

The candidate solutions are quantitatively evaluated using a fitness function. Each solution is kept in a chromosome which consists of genes representing the decision variables. The solutions (chromosomes) improve gradually towards the global optimum solution generation by generation. In a process called selection, those solutions with higher fitness calculated by fitness function have more chance to participate in producing the next generation. Crossover operator is applied on the selected parent chromosomes to generate offspring.

The mutation operator is also deployed to deter the algorithm from being stuck in local optimum points. This operator is used to randomly amend some genes in new generation so that some offspring do not exactly inherit the characteristic of their parents. The process of generating new population is repeated until the fitness of the best chromosome does not improve after several iterations.

GA is widely used in power system studies, especially for problems having a discrete decision variables [76, 139]. Finding the optimum bus-bar switching action is in essence a discrete problem, so GA is adopted in this thesis as well. In the following, the structure of GA used in this research is elaborated.

4.5.4.1 Chromosomes

A population in GA consists of several chromosomes made of genes. Genes embrace the possible answer for the relevant decision variables. In this study, each gene represents a transmission line's connection status coded in Table 4-1. For a network with N_l transmission line and $\overline{N_l}$ candidate lines, $2 \times (N_l + \overline{N_l})$ genes should be considered in each chromosome, assuming that all substations participate in bus-bar corrective switching action. With this arrangement, each gene can be given a value of (1,2,3) which represents the connectivity of one end of a transmission line. Figure 4-4 shows the structure of a chromosome in this study.

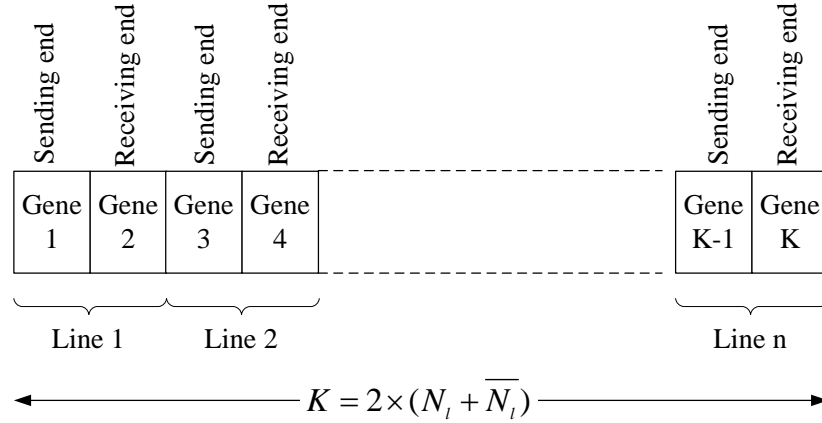


Figure 4-4: The structure of chromosome used for switching action

4.5.4.2 Crossover

Crossover is the operator that combines two chromosomes to produce offspring. The idea is that if offspring inherit characteristics of their parents the next generation is more likely to have better fitness compared to the parents' generation. There are different types of crossover, namely one-point, two-points, uniform etc. In this work, a two-point crossover is used. The two crossover points are randomly selected on parent chromosomes, and the genes between two crossover points are swapped between parent chromosomes, so two offspring which have carry some genes of their parents are produced. In this study a probability of 0.8 is assumed for crossover operation. Figure 4-5 illustrates the two-points crossover.

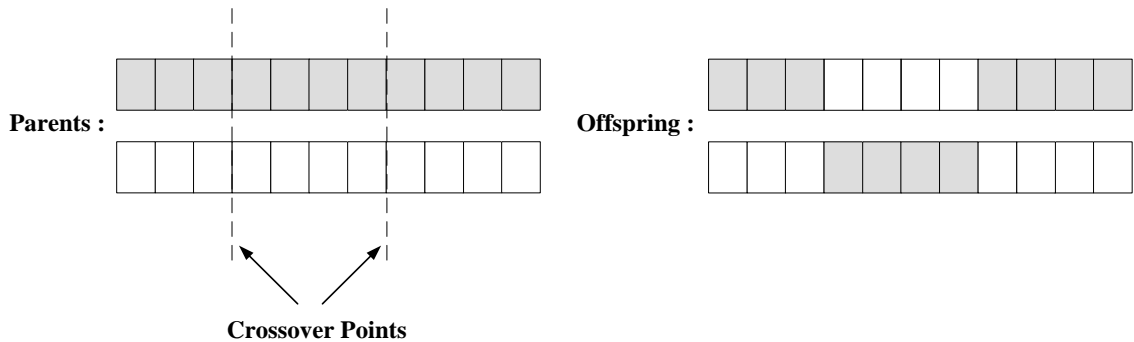


Figure 4-5: Two-point crossover

4.5.4.3 Mutation

Mutation operator makes a random change in some chromosomes. This operator is meant to make diversity in the solutions proposed in each generation so that GA is unlikely to be stuck in local optimums. In this study, an adaptive mutation method is used so that the probability of mutation increases when in the diversity of chromosomes is has a lower value.

4.5.4.4 Selection

Selection is the process whereby parents are selected to produce the next generation. Parents with higher fitness have more chance to participate in reproduction. The Roulette wheel is the selection method used in this work. In Roulette wheel method, a fictitious wheel is split into as many sectors as the population size—number of chromosomes in each generation. Each sector represents one chromosome and the portion of the wheel allocated to each chromosome is calculated by (4-7) .

$$Area_i = \frac{Fit_i}{\sum_{k=1}^n Fit_k} \quad (4-7)$$

Where n is the population (it is assumed to be 100 in this study) size and Fit_i is the fitness of chromosome i . Therefore a wheel similar to Figure 4-6 can be constructed. In order to select the parents, the wheel is randomly spun and the sector indicated by arrow when the wheel stops is the chromosome which is selected for producing the next generation.

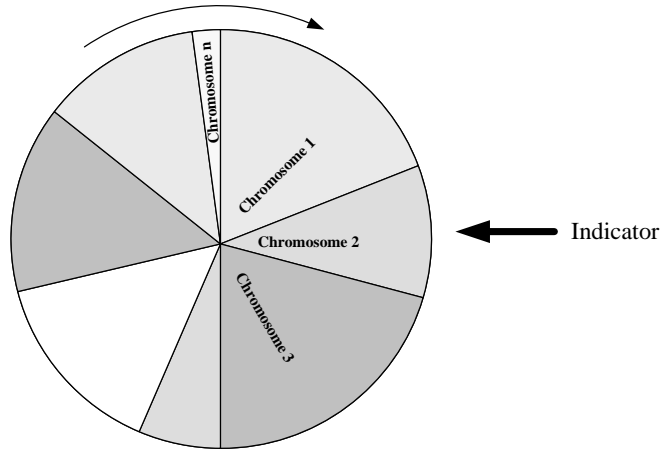


Figure 4-6: Roulette wheel for selection the parent chromosomes

4.5.5 Methodology

The transmission network planning problem under corrective bus-bar switching action is a large scale mixed-integer problem as many binary decision variables representing the status of circuit breakers are involved. Therefore, it is very difficult to treat this problem as a single optimisation problem which can be solved as a whole. Instead, in this thesis, a three stage iterative approach is proposed in order to solve the intact network and every contingent network as separate sub-problems.

In each iteration, the transmission capacities are proposed by a heuristic method. This proposal is sent to sub-problems where intact network and contingent networks are solved. Sub-problems may demand for additional transmission capacity to the initial proposal. In this case, the heuristic algorithm proposes a larger transmission capacity based on sub-problems request. This process continues till all sub-problems are satisfied with the proposed capacity. In the following, the procedure for every stage is elaborated.

Stage I: Proposal for Transmission Capacity

Stage I utilises a heuristic algorithm to make a proposal for the sub-problems. The proposal becomes updated at every iteration. In order to expedite the convergence process, the heuristic algorithm for the first iteration is different from the algorithm for the other iterations.

First iteration: The capacities of all candidate transmission lines are assumed to be zero. However, as the transmission network should be robust against all postulated single outages, those load buses which have less than or equal to two transmission line connections are singled out. Each transmission line connected to these buses is given a capacity which is equal to the load at that bus so that the load can be supplied even at the time of single outage. The given capacities should comply with the stepwise model for feasible transmission capacities shown in Figure 4-2. For example, if there is a load bus whose load is $D(L_{j-1} < D \leq L_j)$ and this bus is supplied by two transmission lines, according to the stepwise model of transmission capacity depicted in Figure 4-2, a capacity of L_j is given to each transmission line.

Other iterations: The proposal for transmission capacities is calculated by taking into account the required transmission capacities determined by sub-problems. The heuristic algorithm to calculate the proposal is as follows.

- $$\text{if } \left| P_{avgi}^{(k)} - L_{j-1} \right| \leq \left| P_{avgi}^{(k)} - L_j \right| \text{ then } P_{proi}^{(k)} = L_{j-1}$$
-
- $$\text{else } P_{proi}^{(k)} = L_j$$
- $$\text{if } \forall i P_{proi}^{(k)} = P_{proi}^{(k-1)} \text{ then}$$
- - $$\forall i P_{jumpi} = P_{avgi}^{(k)} - P_{proi}^{(k)} \text{ and for transmission line } i \text{ having the biggest } P_{jumpi}$$
 - $$\text{do } P_{avgi}^{(k)} = L_j \text{ where } L_j > P_{avgi}^{(k)} \text{ and } L_j \text{ is the closest RTC to } P_{avgi}^{(k)}$$

Where:

$P_{proi}^{(k)}$: Proposed capacity for transmission line i in k th iteration

$P_{avgi}^{(k)}$: The average of all solutions to required capacity for line i in k th iteration.

These solutions are calculated by stage II and stage III.

$P_{avgi}^{(k)}$ is calculated by (4-8).

$$P_{avgi}^{(k)} = \frac{\sum_{c=1}^{N_c} P_{\max i}^{c(k)} + P_{\max i}^{net(k)}}{N_c + 1} \quad (4-8)$$

$P_{\max i}^{c(k)}$: The capacity required for transmission line i when line c trips (This value is calculated in stage III)

$P_{\max i}^{net(k)}$: The capacity required for transmission line i when network is intact (This value is calculated in stage II)

The outcome of this stage is a proposal transmission capacity sent to Stages II and Stage III.

Stage II: Intact Network

In this stage only the intact network is taken into account. The minimum required transmission capacities as well as the optimum generation dispatch are calculated while different bus-bar switching arrangements can be applied. GA is used to find the best bus-bar switching for the normal condition. Using GA, each chromosome proposes a

switching arrangement according to which a corresponding network configuration can be considered. For the proposed network configuration the minimum transmission investment as well as operating cost is calculated, solving the optimisation problem formulated by (4-9) to (4-15). The fitness of each chromosome is equal to the inverse value of objective function (4-9). Therefore, those chromosomes — bus-bar switching arrangements — which are associated with a higher transmission investment and operation cost received a lower fitness so that they are unlikely to be selected as the optimum switching arrangement.

$$\text{Minimize : } \frac{1}{\text{Fitness}_{\text{stage II}}} = \sum_{i=1}^{N_g} C_i \cdot G_i^{(k)} + \sum_{i=1}^{\overline{N_l}} T_{mi} \cdot I_i \cdot P_{\max i}^{\text{net}(k)} \quad (4-9)$$

Subject to:

$$\sum_{\forall i \in N_{gd}} G_i^{(k)} + \sum_{\forall i \in N_{ld}} P_i^{(k)} - L_d = 0 \quad (d = 1, \dots, N_b) \quad (4-10)$$

$$P_i^{(k)} - \frac{(\theta_k^{(k)} - \theta_l^{(k)})}{X_i} = 0 \quad (i = 1, \dots, N_l + \overline{N_l}) \quad (4-11)$$

$$-P_{\max i}^{\text{net}(k)} \leq P_i^{(k)} \leq P_{\max i}^{\text{net}(k)} \quad (i = 1, \dots, \overline{N_l}) \quad (4-12)$$

$$-P_{\max i}^{(k)} \leq P_i^{(k)} \leq P_{\max i}^{(k)} \quad (i = 1, \dots, N_l) \quad (4-13)$$

$$G_{\min i} \leq G_i^{(k)} \leq G_{\max i} \quad (i = 1, \dots, N_g) \quad (4-14)$$

$$P_{\max i}^{\text{net}(k)} \geq P_{\text{proi}}^{(k)} \quad (i = 1, \dots, \overline{N_l}) \quad (4-15)$$

The notation k indicates to k th iteration. Inequality (4-15) is meant to find the closest optimum transmission capacity to the proposed transmission capacity in k th iteration by Stage I.

It should be stressed that one of the chromosomes may propose a bus-bar switching arrangement with which no feasible solution can be found, taking into account inequality and equality constraints (4-10) to (4-15). In this case, a very low value is given to the fitness of corresponding chromosome to ensure that infeasible solutions are very unlikely to participate in producing the next generation.

The outputs of this stage are the required transmission capacities, generation dispatch and the optimum bus-bar switching arrangement for the intact network. It is assumed that generation re-dispatch does not change if a transmission line trips. Therefore, the same generation dispatch calculated at this stage is considered for all contingent networks as well.

Stage III- Contingent Network

The proposal for transmission capacities calculated in stage I and the optimum generation dispatch calculated in stage II are inputs to this stage. In this stage, for every contingent network, the optimum bus-bar switching arrangement which results in the minimum transmission investment is calculated. GA, similar to stage II, is deployed to find the optimum switching arrangement. The fitness of each chromosome is the reverse value of the objective function embodying only the transmission investment, see objective function (4.16). Unlike stage II, the outputs of generators are known parameters so the objective function does not include the operating cost.

$$\text{Minimize : } \frac{1}{\text{Fitness}_{\text{Stage III}}} = \sum_{i=1, i \neq c}^{\overline{N_l}} T_{mi} \cdot l_i \cdot P_{\max i}^{c(k)} \quad (4-16)$$

Subject to:

$$\sum_{\forall i \in N_{gd}} G_i^{(k)} + \sum_{\forall i \in N_{ld}, i \neq c} P_i^{(k)} - L_d = 0 \quad (d = 1, \dots, N_b) \quad (4-17)$$

$$P_i^{(k)} - \frac{(\theta_k^{(k)} - \theta_l^{(k)})}{X_i} = 0 \quad (i = 1, \dots, N_l, i \neq c) \quad (4-18)$$

$$-P_{\max i}^{c(k)} \leq P_i^{(k)} \leq P_{\max i}^{c(k)} \quad (i = 1, \dots, N_l + \overline{N_l}, i \neq c) \quad (4-19)$$

$$G_{\min i} \leq G_i^{(k)} \leq G_{\max i} \quad (i = 1, \dots, N_g) \quad (4-20)$$

$$P_{\max i}^{c(k)} \geq P_{\text{proi}}^{(k)} \quad (i = 1, \dots, N_l) \quad (4-21)$$

Notation c denotes the outage of transmission line c .

This optimisation process is run for all possible single outages. The output of this stage is a set of required transmission capacities associated with a specific bus-bar switching arrangements determined for every single contingency.

Convergence condition

The outputs of Stage II and Stage III, transmission capacities for contingent networks as well as intact network, are sent to stage I where a new proposal for transmission capacities is calculated. The process is repeated till the identical proposal for transmission capacity is realised by stage I in two consecutive iterations. In other words, the last proposal can satisfy the security criteria in intact as well as contingent networks.

The whole procedure is shown in Figure 4-7.

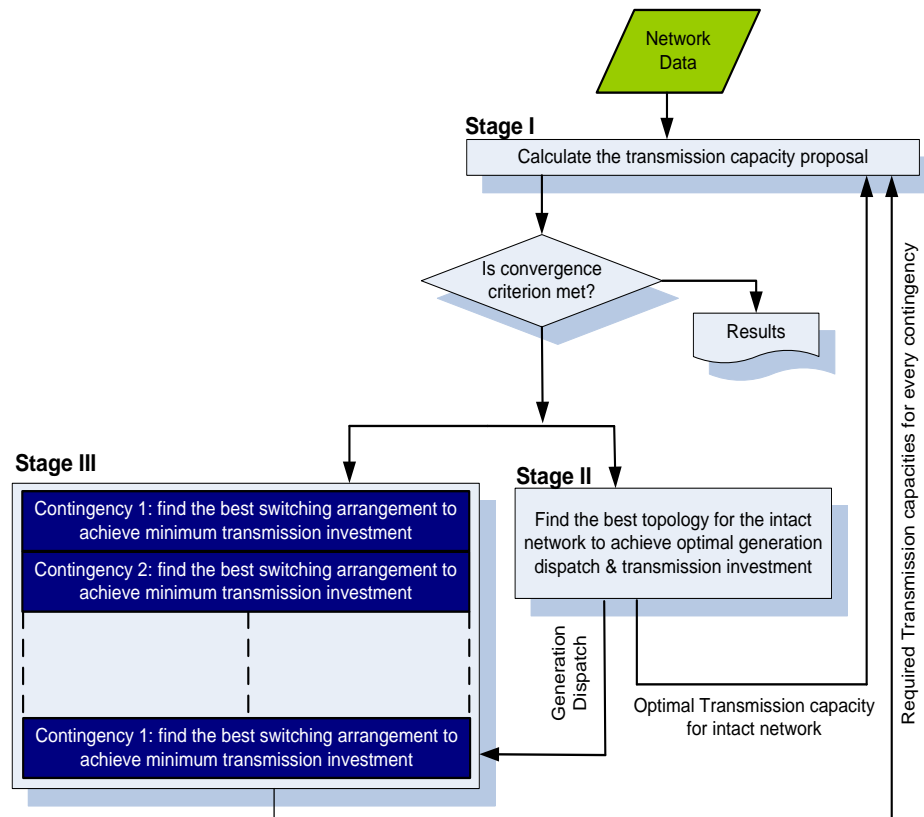


Figure 4-7: Transmission network planning procedure under post-contingency corrective bus-bar switching action

4.5.6 Numerical examples

The proposed approach is demonstrated on two test case studies. First, the methodology is tested on a simple five bus network. This small network is meant to provide a better understanding of the methodology as the power flows are easy to demonstrate in a small network. Next, the proposed algorithm is applied on the IEEE 24 bus test system which represents a larger scale network. In the following section the details of each test case and the relevant results are elaborated.

4.5.6.1 Five bus network

In this example, the required capacities of all transmission lines in the five bus network shown in Figure 4-8 are calculated, considering the post-contingency corrective switching action is plausible. It is assumed that each transmission line in this network can take one of the capacities of 50 MW, 75 MW, 100 MW, 120 MW or 150 MW. All five substations – bus 1 to bus 5 – have double bus bar-double breaker layout. The proposed network should respect “N-1” security criterion.

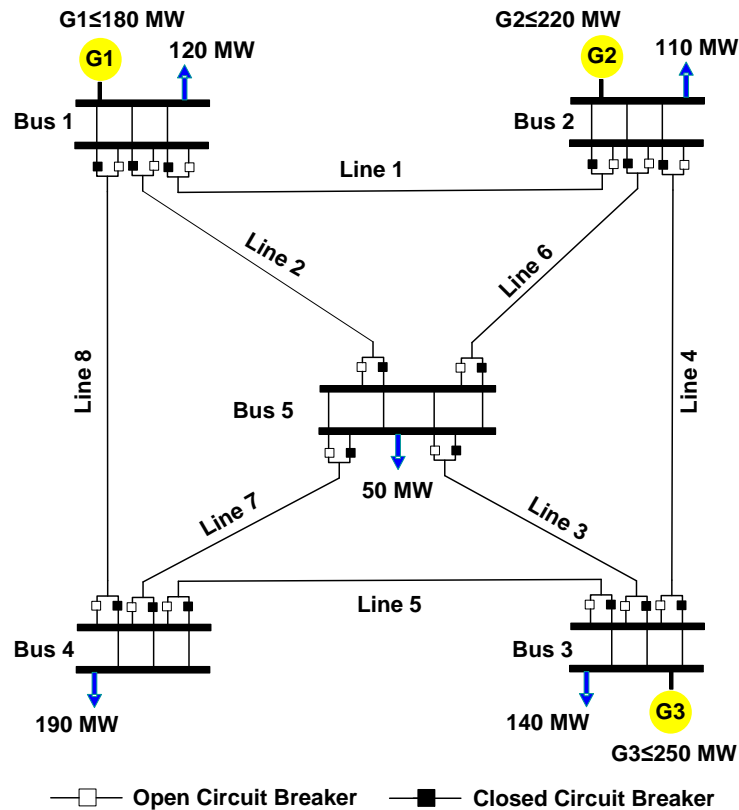


Figure 4-8: Five bus network for studying the corrective switching action

For the 5 bus network, the proposed algorithm converges to the final solution in 11 iterations. In Table 4-2 the proposed capacities at each iteration are illustrated. The

transmission capacity proposal is recalculated at each iteration, based on the feedback from sub-problems. The final solution, iteration 11, satisfies all security criteria. The optimum generation dispatch for G1, G2 and G3 are 140 MW, 220 MW and 250 MW, respectively.

Table 4-2: The required transmission capacity proposed by the algorithm in each iteration

		Transmission Capacity (MW)							
		Line 1	Line 2	Line 3	Line 4	Line 5	Line 6	Line 7	Line 8
Iteration	1	0	0	0	0	0	0	0	0
	2	0	0	100	0	50	100	120	50
	3	0	0	100	0	75	100	150	50
	4	0	50	100	0	75	100	150	50
	5	50	50	100	0	75	100	150	50
	6	50	50	100	0	75	100	150	75
	7	50	50	100	0	100	100	150	75
	8	50	50	100	75	100	100	150	75
	9	50	50	100	75	120	100	150	75
	10	50	50	100	75	120	100	150	75
	11	50	50	120	75	120	100	150	75

In order to demonstrate how post-fault corrective switching action can reduce the required transmission investment, the powers flowing in the network when Line 7 trips with and without corrective action are examined. Considering the optimum generation dispatch, if Line 7 trips the power flowing in Line 5 reaches 126.4 MW, see Figure 4-9. Therefore, under preventive control mode, a transmission line with a capacity of 150MW should be considered for line 5 as the closest available capacity to 126.4 MW power flow is 150 MW.

However, using the proposed algorithm, the required capacity for Line 7 is 120 MW and a post-fault bus-bar switching action which drops the power flowing in Line 5 to 119.1 MW is suggested. This is 30 MW less than the capacity proposed under preventive control mode. The post-contingency bus-bar switching action is disconnecting line 4 from bus 2 once Line 7 trips— all power flows are shown in Figure 4-10. This simple example demonstrated that 30 MW saving in transmission investment can be achieved by taking into account the post-contingency switching action.

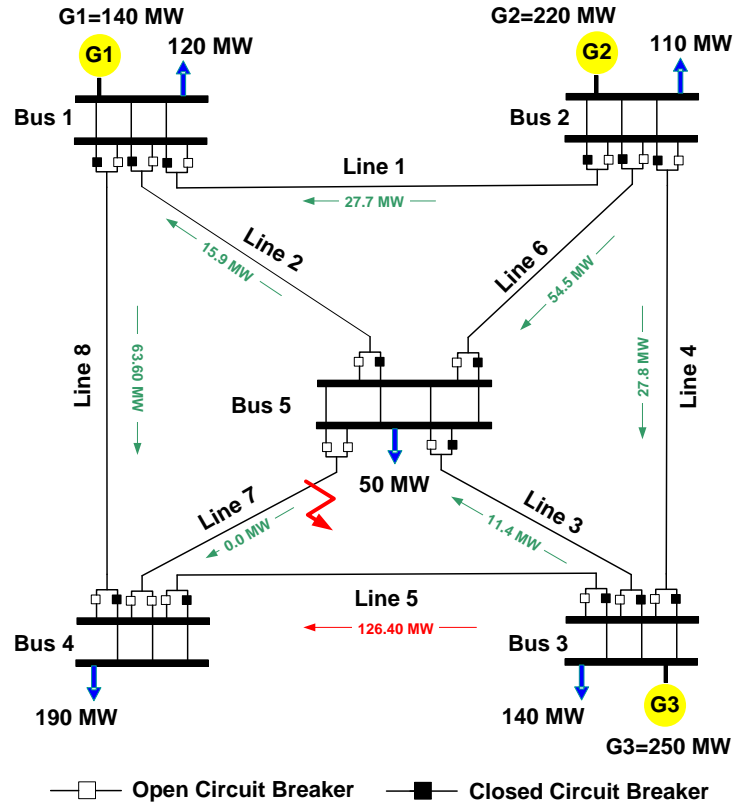


Figure 4-9: The power flows in the 5 bus network after outage of Line 7

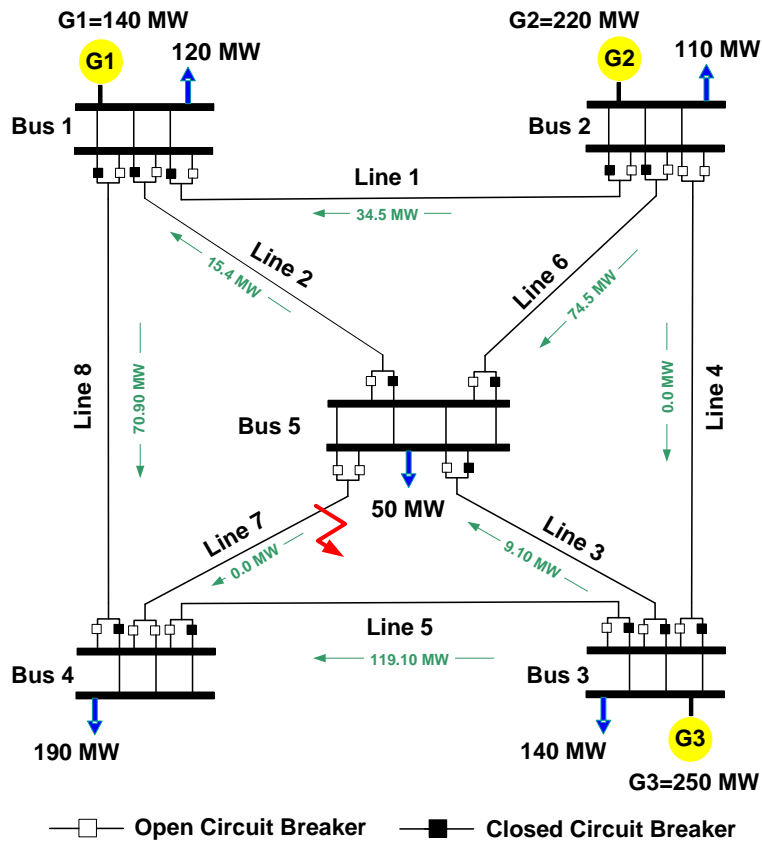


Figure 4-10: The power flows in the bus network after outage of line 7 and corrective switching action on line 4

4.5.6.2 IEEE 24 bus network

The proposed methodology is also carried out on the IEEE 24 bus test system. It is assumed that all transmission lines in this network are candidates, so the capacities of all transmission lines are decision variables. In addition to that, all substations are considered to have double bus double breaker layout so the substation switching action can be undertaken in all 24 substations.

The costs of generation at each bus, load demands are given in Appendix B. The feasible transmission capacities for this network can be 50 MW to 600 MW with 50 MW steps. The annutised network investment cost is assumed to be €11.79/MW.Km.Year. The proposed network topology and the switching action should satisfy “N-1” security criterion. The outage of all transmission lines except line 7-8, which is a radial network, is taken into account.

The transmission planning procedure shown in Figure 4-7 converges to the final solutions in 91 iterations for IEEE 24 bus system. The output of the calculation is the required transmission capacities, generation dispatch and the corrective active actions required in the case of contingencies. In order to demonstrate the superiority of the proposed approach to the traditional transmission planning techniques the same problem is also solved without considering the switching action. The formulation for the latter study is similar to the example which was previously given in section 3.6, except a lossless model is assumed in this study.

Table 4-3 shows the required transmission capacities of all 38 transmission lines calculated with and without substation switching actions. These two studies propose different topology with different capacities for the network. The transmission investments corresponding to these two studies show that the transmission planning under corrective switching action proposes a 6.36% less investment than the transmission planning assuming without corrective action. It should be noticed that the optimum generation dispatch calculated in both studies is similar, see Figure 4-11.

Table 4-3: The required transmission capacities considering transmission planning with and without post-contingency corrective switching action

Candidate line Number	Proposed methodology	Traditional approach	Candidate line Number	Proposed methodology	Traditional approach
1	600	400	20	0	100
2	0	250	21	0	0
3	600	400	22	250	300
4	350	300	23	500	600
5	500	300	24	400	500
6	200	200	25	250	300
7	300	250	26	250	300
8	300	200	27	300	250
9	550	350	28	400	450
10	300	150	29	500	550
11	50	50	30	350	400
12	200	200	31	50	100
13	250	200	32	100	150
14	200	150	33	100	150
15	0	100	34	150	200
16	150	150	35	150	200
17	0	100	36	150	200
18	350	300	37	150	200
19	300	400	38	50	100
Total network investment assuming proposed approach [€]					3045946
Total network investment assuming traditional approach [€]					3252861

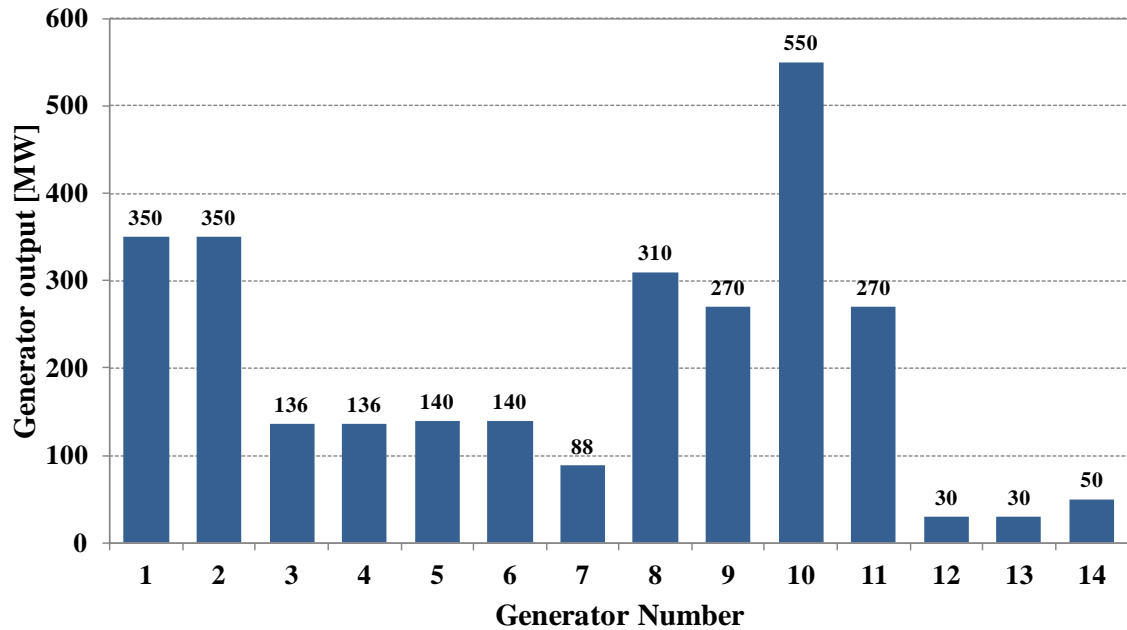


Figure 4-11: Generation dispatch calculated by flexible transmission planning studies for the IEEE 24 bus test system

Table 4-4 gives the contingencies which need post-contingency corrective switching actions. As it is shown, only 6 contingencies out of 37 contingencies cause overloads which can be alleviated by substation switching. For instance, if transmission line 4 trips, transmission line 16 experiences overload which can be immediately eradicated by switching line 12 and line 8 to the second bus bar at substation 9. The switching codes are the same codes introduced previously in Table 4-1.

Table 4-4: Post-contingency substation switching corrective action for those contingencies causing overload

	Substation	8	9	9	9	11	11	16	17	21	Overloaded Lines	
	Line numbers	13	8	12	14	16	19	24	31	38		
Contingencies	3	3									8,4	
	4	2		2								16
	23								3	3		22
	29	3	3								23,19	
	28	3										24
	30									3		31

4.6 Conclusions

Although network reconfiguration action is sometimes taken by system operator to keep the network parameters within the operational limits the feasibility of such action is usually neglected by transmission planners. Transmission investment, however, is very

likely to decrease if network reconfiguration corrective action is considered at the transmission planning stage.

A flexible transmission planning approach was proposed in this chapter. The post-fault corrective substation switching was incorporated into the transmission planning problem. The proposed methodology is a multi-layer procedure. In each layer, a genetic algorithm was used to find the best switching action for a postulated contingency. This algorithm was tested on a 5 bus network and the IEEE 24 bus network. In both study cases, compared to transmission planning under preventive control, a lower investment is required when the connections of transmission lines can be altered after a contingency. The results showed a 6.36% reduction in transmission investment for IEEE 24 bus test system. In addition to that, it was shown that only 6 outages out of 37 postulated contingencies require post-fault substation switching corrective action.

Chapter 5. Transmission planning under demand response programmes

Under demand response programs, consumers will play an active role in the management of future power systems. Consumers equipped with smart home energy management systems are very likely to partly shift their energy consumption to the periods when the energy price is low. In addition, consumers will be able to provide the reserve for balancing future power systems where a large portion of generation will be non-dispatchable such as wind power. As demand is one of the main drivers of transmission investment, the demand response programs need to be taken into account in transmission investment planning. In this chapter, price-based demand response and direct load curtailment programs are integrated into the transmission planning problem and the methodologies required to solve these problems are proposed.

5.1 Introduction

In order to meet the security criteria, the system operators, in a traditional operation regime, usually rely on the available transmission capacities as well as ancillary services provided by the generators. In such a system, consumers behave in a passive way as, firstly, there is no direct communication between the system operator and consumers, and secondly, consumers are not equipped with devices which can change consumption promptly.

In order to meet the prescribed security criteria, system operators in a traditional operation regime usually rely on the available transmission capacities as well as ancillary services provided by the generators. In such a system, consumers behave in a passive way as, firstly, there is no direct communication between the system operator and consumers, and secondly, consumers are not equipped with devices which can change consumption promptly.

In the future power system, however, consumers will play a crucial role in improving the security and reliability of the system. The idea of equipping consumers with smart home energy management systems, and on a broader scale, creating a smart grid suggests that consumers will become more alert to the energy price and system status [140]. In such a system, consumers are very likely to change their consumption pattern based on the signals which they receive from the system operator. Changes in end-user demand from the normal consumption in response to the electricity market signals or network operator signals are defined as demand response programs.

Albadi et al [118] categorise demand response programs into two main groups (see Figure 5-1): i) incentive-based programs and ii) price-based programs.

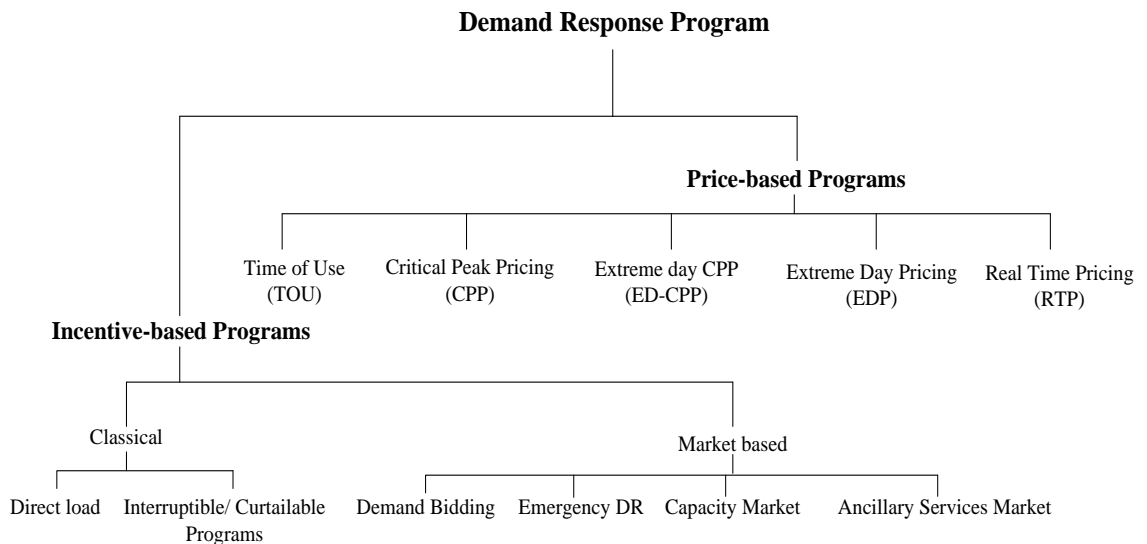


Figure 5-1: Demand response programs in different categories[118]

Under an incentive-based demand response program, a consumer may provide an ancillary service – usually in the form of load curtailment – at a time when the network experiences a security violation. The details of such a service such as the time of response, the level of load curtailment, service payments and penalties for not responding are usually set under a contract between the system operator and consumers. In another form, rather than a long-term contract, consumers may bid on particular load curtailment in the electricity market so that the system operator has more flexibility for balancing the system or dealing with possible outages.

In a price-based demand response program, consumers receive a dynamic energy price rather than a flat tariff. Being updated on the energy price for any market balancing period, consumers are very likely to shift some loads to the times when the energy price is less expensive. One of the main objectives of price-based demand response program is to have a rather flat load profile. In this way, some of the investments which are mainly made to maintain the reliability of supply just during peak time can be deferred or cancelled. Therefore, as an alternative to transmission expansion, consumers can be encouraged to either change their consumption patterns or participate in other types of demand response.

In this chapter, the transmission network investment for a system, where demand response programs are undertaken, is studied. The effect of two different demand response programs on transmission investment is investigated. In the first study, the consumption is price-responsive so that consumers vary the demand pattern, taking into account the elasticity and the energy price. In the second study, under a direct load curtailment program, the transmission investment problem is solved.

5.2 Price-based demand response

In any market, the participants competitively make bids/offers to buy/sell a commodity. As the so-called demand-supply curve implies, the price of a commodity in the wholesale market may affect the dynamic of consumers' consumption [141]. Similarly, in a perfectly competitive electricity market, consumers may vary their energy consumption according to the energy price in order to minimise the total energy cost.

In most electricity markets, however, a large proportion of consumers, especially the residential and commercial sector, do not receive real-time energy price variations. The monthly energy bills are usually the only signal which consumers receive from the market, whereas the energy trading takes place on an hourly basis in the actual wholesale energy market. Therefore, consumers show an inelastic consumption behaviour to the hourly energy price which may give the opportunity to generators to exert their market power [142].

This problem is the main driver of investment in the infrastructure and facilities which update consumers on the real-time energy price. In this regard and under the commitment to moving towards smart grids, there has been a significant investment in

many countries to replace the conventional meters with so-called smart meters which are able to provide an hourly update of energy cost. In European countries alone, the number of installed smart meters with a compound annual growth of 17.9% will reach 111.4 million by 2015 [143]. Practical experience and studies demonstrate that consumers armed with smart meters actively respond to price signal by shifting or curtailing some part of their energy usage [144, 145].

It should be stressed that in order to achieve the greatest benefit from smart meters, consumers also need to be equipped with automatic consumption management systems using the hourly energy price to optimise appliance operating times [146].

The application of smart meters is in its early stage and it is yet to be widely implemented in practice. As there are not enough historical data it is difficult to estimate the sensitivity of loads to the energy price. The elasticity of demand to price is very case sensitive as it strongly depends on the culture of consumption which can be affected by the climate, location and the social level of consumers etc [147-149]. In addition to this, the elasticity also depends on whether the consumer is a household or industrial consumer [150].

5.2.1 Transmission investment assuming price elastic loads

Load demand is one of the main drivers for investment in power system infrastructures. The need for new transmission lines is very likely to be deferred or even cancelled if consumers react to the price of energy as demand growth may slow down [151, 152]. Therefore, for the future network, rather than an inelastic model for load demand, a price-based responsive behaviour should be considered for consumers so that overinvestment in transmission network can be averted.

Transmission planning is a long-term study so the nodal prices need to be estimated for the horizon study whereby the demand corresponding with the estimated nodal price can be calculated. The energy price seen by a consumer at a particular location in the network consists of two main elements: Energy Price (EP) and Transmission Charge (TC).

EP reflects the generation cost, which is usually calculated based on generators' marginal costs. TC shows transmission charge, which depends on the investment in

infrastructures transferring the power from generators to the consumer. On the one hand, different transmission expansion proposals may impose different TCs on consumers, while on the other hand the consumption behaviour of each consumer may impact on the transmission expansion plans. In this chapter, a transmission charge allocation method is proposed so that the consumers' impact on the transmission investment plan is calculated, taking into account the load profile.

A methodology is also introduced to calculate the required transmission investment, assuming that consumers respond to the energy price. The proposed methodology is an iterative procedure so that in the first step the optimum transmission capacities as well as optimum generation dispatch are calculated, assuming the original load demands. Using the resultant transmission capacities and generation dispatch, the nodal prices which consist of TC and EP are determined. EP is calculated by a security-constrained optimal power flow (SCOPF) whereas TC is determined by the transmission charge allocation methodology proposed in this work. Having nodal prices, the demand at each bus is recalculated, taking into account the price elasticity of the demand.

A multi-load level model is assumed and a different elasticity is assigned to each load level. Moreover, it is assumed that although demands are price responsive the overall energy consumption by a consumer does not change dramatically as the load may be shifted partly to the period when the energy price is cheaper. This constraint is respected by deploying a minimisation which manipulates the resultant demands to keep the total energy variations within a pre-set amount. This procedure is repeated till an identical transmission capacity is proposed in two consecutive iterations. In the following section more details about the proposed algorithm are given.

5.2.2 Problem formulation

At each iteration, for a given demand, the optimum transmission capacities are calculated by solving a transmission planning problem which is formulated in the framework of a mixed-integer optimisation. In this problem, physical laws in the transmission network as well as power system components should be respected. In addition to that, the “N-1” criterion is a mandatory security constraint. The objective function of the transmission planning problem is formulated by (5-1).

$$\text{Minimize : } \sum_{j=1}^{N_p} D_j \cdot \sum_{i=1}^{N_g} C_i \cdot G_i^j + \sum_{i=1}^{\overline{N_l}} T_{ci} \cdot l_i \cdot \overline{P}_{\max i} \quad (5-1)$$

D_j Duration of the load level j (hour)

C_i Incremental cost of generator i (€/MWh)

G_i^j Power generated by generator i at load level j (MW)

T_{ci} Annuitised investment cost of line i (€/km.MW.year)

l_i Length of transmission line i (km)

$\overline{P}_{\max i}$ Capacity of candidate transmission line i (MW)

$\overline{N_l}$ Number of candidate transmission lines

N_p Number of load levels

N_g Number of generators

As in practice only specific capacities can be considered for a candidate transmission line a set containing feasible capacities for transmission line i is assumed. The optimum answer is one of these feasible capacities. Therefore, equality constraints (5-2) and (5-3) should also be added to the problem.

$$\overline{P}_{\max i} = \sum_{n=1}^{N_{si}} x_{in} \cdot \overline{P}_i^n \quad (i = 1, \dots, \overline{N_l}) \quad (5-2)$$

$$H_i = \sum_{n=1}^{N_{si}} x_{in} \leq 1 \quad (i = 1, \dots, \overline{N_l}) \quad (5-3)$$

Where \overline{P}_i^n is n^{th} credible capacity from S_i list, $S_i = \{\overline{P}_i^1, \overline{P}_i^2, \dots, \overline{P}_i^3, \dots\}$. N_{si} is the number of credible capacities for candidate lines i . x_{in} is a binary variable which corresponds to n^{th} credible capacity for transmission line i . The resultant H_i is either 0 or 1. Moreover, the power balance at bus k should be respected, shown by equation (5-4).

$$\sum_{\forall i \in N_{gk}} G_i^j + \sum_{\forall i \in N_{lk}} P_i^j - L_k^j = 0 \quad (k = 1, \dots, N_b) \quad (j = 1, \dots, N_p) \quad (5-4)$$

P_i^j Power flowing in transmission line i at load level j (MW)

L_k^j Load demand at bus k at load level j (MW)

N_{gk} Set of generators connected to bus k

N_{lk} Set of lines connected to bus k

N_b Number of buses

Another constraint is the physical law which governs the relation between angles and the power flowing in the transmission lines. For the existing lines this constraint is an equality formulated by (5-5) whereas for candidate lines inequalities (5-6) and (5-7) are used.

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{X_i} = 0 \quad (i = 1, \dots, N_l) \quad (j = 1, \dots, N_p) \quad (5-5)$$

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{X_i} \leq M_k \cdot (1 - H_i) \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (5-6)$$

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{X_i} \geq M_k \cdot (H_i - 1) \quad (i = 1, \dots, \overline{N_l}) \quad (j = 1, \dots, N_p) \quad (5-7)$$

M_k is a very large number. N_l is the number of existing transmission lines, θ_k^j represents the voltage angle of bus k at load level j , and X_i is the reactance of transmission line i (p.u.).

The power flowing in the transmission lines should not exceed the thermal ratings. There is an upper limit and lower limit for the power generated by a power plant. These limits are also applied to the transmission planning problem, using (5-8) to (5-10).

$$G_{\min i} \leq G_i^j \leq G_{\max i} \quad (i = 1, \dots, N_g) \quad (j = 1, \dots, N_p) \quad (5-8)$$

$$-P_{\max i} \leq P_i^j \leq P_{\max i} \quad (i = 1, \dots, N_l) \quad (j = 1, \dots, N_p) \quad (5-9)$$

$$-\bar{P}_{\max i} \leq P_i^j \leq \bar{P}_{\max i} \quad (i = 1, \dots, \bar{N}_l) \quad (j = 1, \dots, N_p) \quad (5-10)$$

In this study, the aim is to design a network secure against single contingencies. Therefore, another set of constraints, similar to (5.4) to (5.7) which model the intact network, are considered to model the contingent network, which are expressed as follows:

$$\sum_{\forall i \in N_{gk}} G_i^j + \sum_{\forall i \in N_{lk}, i \neq c} P_i^{j(c)} - L_k^j = 0 \quad (k = 1, \dots, N_b) \quad (j = 1, \dots, N_p) \quad (5-11)$$

$$P_i^{j(c)} - \frac{(\theta_k^{j(c)} - \theta_l^{j(c)})}{X_i} = 0 \quad (i = 1, \dots, N_l, i \neq c) \quad (j = 1, \dots, N_p) \quad (5-12)$$

$$P_i^{j(c)} - \frac{(\theta_k^{j(c)} - \theta_l^{j(c)})}{X_i} \leq M_k \cdot (1 - H_i) \quad (5-13)$$

$$(i = 1, \dots, \bar{N}_l, i \neq c) \quad (j = 1, \dots, N_p)$$

$$P_i^{j(c)} - \frac{(\theta_k^{j(c)} - \theta_l^{j(c)})}{X_i} \geq M_k \cdot (H_i - 1) \quad (5-14)$$

$$(i = 1, \dots, \bar{N}_l, i \neq c) \quad (j = 1, \dots, N_p)$$

$$-P_{\max i} \leq P_i^{j(c)} \leq P_{\max i} \quad (i = 1, \dots, N_l) \quad (j = 1, \dots, N_p) \quad (5-15)$$

$$-\bar{P}_{\max i} \leq P_i^{j(c)} \leq \bar{P}_{\max i} \quad (i = 1, \dots, \bar{N}_l) \quad (j = 1, \dots, N_p) \quad (5-16)$$

Notation c in the equations indicates the outage of transmission line c .

The output of generators and the thermal rating of transmission lines are the coupling variables between the intact network and the contingent networks. It is assumed that the

network is designed under preventive control mode and the outputs of generators do not change following an outage.

After solving this problem, the resultant transmission capacities are sent to the next stage where the nodal prices are calculated.

5.2.3 Nodal price calculation

As mentioned before, the nodal price seen by a consumer is made up of two components: the Energy Price (EP) and the Transmission Charge (TC). EP is the cost of serving the next MW at a particular bus. This cost is the Lagrangian multiplier of the power balance equality constraint in OPF analysis [153]. EP depends on the generation dispatch and it varies at different load levels. As a multi-load level model is assumed in this study, at each load level a different EP is calculated for every bus.

The second component of nodal price is the transmission charge. Transmission cost allocation is a challenging task which has been the object of many studies so far [154]. A successful transmission charge allocation method should fairly reflect the impact of each generator/load on transmission investment. In this thesis, inspired by [155, 156], a transmission charge allocation is proposed which can apportion the transmission cost among network users in a economically efficient way. It is assumed that the transmission investment is driven by two factors: i) the required capacity for normal condition and ii) the required capacity to meet security criteria so there is no interruption to supply the loads if any line trips. Correspondingly, each network user faces two different transmission charges: i) Usage Charge (UC) and ii) Reliability Charge (RC). In the following the methodology for calculating these charges is introduced.

The first step is to calculate Usage Expense (UE) which is the investment for a transmission line i to serve just in normal condition. UE for a transmission line i at load level j is calculated by (5-17).

$$UE_i^j = \frac{UF_i^j}{\sum_{k=1}^{Np} UF_i^k} \cdot K_i \cdot T_{ci} \cdot I_i \cdot \bar{P}_{\max i} \quad (5-17)$$

$\overline{P_{\max i}}$ is the capacity of the transmission line i .

UF_i^j is the usage factor of transmission line i in normal condition at load level j , as shown by (5-18).

K_i is the highest usage factor of transmission line i in normal condition, mathematically shown by (5-19).

$$UF_i^j = \frac{|P_i^j|}{\overline{P_{\max i}}} \quad (5-18)$$

$$K_i = \text{Max}(UF_i^1, UF_i^2, \dots, UF_i^{Np}) \quad (5-19)$$

Every network user has a different effect on the Usage Expense. A sensitivity matrix proposed by Conejo et al [155] is used to calculate the effect of power injection to a particular bus on a particular transmission line. In other words, the relationship between power flowing in line i and the injected/consumed power in the buses is defined by this sensitivity matrix, as formulated by (5-20).

$$P_i^j = \sum_{k=1}^{Nb} A_{k,i} \cdot (G_k^j - L_k^j) \quad (5-20)$$

$A_{k,i}$ represents the sensitivity of power flowing in transmission line i to the power which is consumed or injected at bus k .

The sensitivity matrix is used to calculate the Usage Charge at bus k at load level j . This is shown by equation (5-21).

$$UC_k^j = \sum_{i=1}^{Nl+Nl} \frac{|A_{k,i}|}{\sum_{l=1}^{Nb} A_{l,i}} \cdot UE_i^j \quad (5-21)$$

In addition to UE, network users should pay for RE so that the total transmission investment can be recovered. The RE for transmission line i at load level j is determined by (5-22).

$$RE_i^j = T_{ci} \cdot I_i \cdot \overline{P_{\max i}} - UE_i^j \quad (5-22)$$

RE needs to be split among network users in such a way that a larger charge should be allocated to those users who require more transmission capacity to be kept supplied when a line trips.

The Outage Factor (OF) showing the effect of tripping line c on line i at load level j is formulated by (5-23). This factor shows the increase of power in line i after outage of line c in comparison to normal condition.

$$OF_{i,c}^j = \begin{cases} P_i^{j(c)} - P_i^j & \text{if } P_i^{j(c)} \geq P_i^j \\ 0 & \text{else} \end{cases} \quad (5-23)$$

Bus Reliability Factor (BRF) formulated by (5-24) represents the effect of power consumed/injected at bus k on the reliability of transmission line i .

$$BRF_{k,i}^j = \sum_{c=1}^{Nc} OF_{i,c}^j \cdot A_{k,c} \quad (5-24)$$

Having BRF and RE, the Reliability charge for bus k at load level j is calculated by equation (5-25).

$$RC_k^j = \sum_{i=1}^{Nl+\overline{Nl}} \frac{BRF_{k,i}^j}{\sum_{j=1}^{Np} \sum_{k=1}^{Nb} BRF_{k,i}^j} \cdot RE_i^j \quad (5-25)$$

Therefore, the summation of UC and RC is the total transmission charge allocated to the users at bus k for load level j , see equation (5-26).

$$TC_k^j = RC_k^j + UC_k^j \quad (5-26)$$

It is assumed that the transmission cost is charged for a network user for every MWh injected to or consumed from the network. Equations (5-27) and (5-28) are designed to express the transmission charge in terms of energy consumption or generation at a particular bus, respectively.

$$LTC_k^j = \frac{TC_k^j \cdot \frac{L_k^j}{L_k^j + G_k^j}}{L_k^j \cdot D_j} \quad (5-27)$$

$$GTC_k^j = \frac{TC_k^j \cdot \frac{G_k^j}{L_k^j + G_k^j}}{G_k^j \cdot D_j} \quad (5-28)$$

Therefore, the nodal price which consists of Transmission Charge and Energy Price is calculated by (5-29).

$$LNP_k^j = LTC_k^j + NP_k^j \quad (5-29)$$

5.2.4 Modelling price responsive demand

Consumers respond to price based on their price elasticity factor. The elasticity factor is defined as the variation of demand in response to variation of price. The price vs. demand curve shown in Figure 5-2 is a nonlinear function, so at different point of the curve different elasticity is calculated [157].

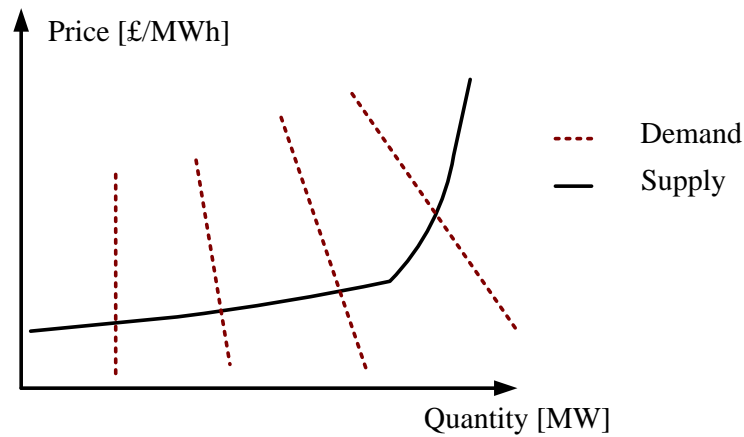


Figure 5-2: The typical price responsive demand variations

In this thesis, it is also assumed that each load level is associated with a different elasticity factor. Therefore, if a new nodal price applies to the demand at load level k at bus j , the demand can be changed in a linear manner as shown in equation (5-30).

$$L_{k(new)}^j = L_{k(original)}^j + E_k^j \cdot (NP_{k(new)}^j - NP_{k(original)}^j) \cdot \frac{L_{k(original)}^j}{NP_{k(original)}^j} \quad (5-30)$$

$L_{k(original)}^j$ Original demand at bus k at load level j

$NP_{k(original)}^j$ Original nodal price at bus k at load level j

E_k^j Elasticity for bus k at load level j

$NP_{k(new)}^j$ New nodal price at bus k at load level j

$L_{k(new)}^j$ New demand at bus k at load level j

Price-based demand response program can be one of the most successful methods for encouraging consumers to shift the demand during peak time. In this case, a rather flat consumption pattern may be expected from consumers. The total energy consumption may vary as consumers, firstly, may have the opportunity to consume more energy during off-peak period, or secondly, there is a possibility that consumers are not able to make up the consumption reduction in the peak time. In this thesis, it is assumed that the total energy consumption may vary but that this variation remains within a set limit. To model this, a quadratic minimisation is applied to the resultant demands calculated by equation (5-30) so that the demands are slightly changed to ensure that variation in total energy consumption is within a pre-set limit. This minimisation which is mathematically expressed by (5-31) to (5-33) is applied to every load following the computation by (5-30).

$$\text{Minimize: } \sum_{j=1}^{Np} (L_k^j - L_{k(new)}^j)^2. \quad (5-31)$$

Subject to:

$$\sum_{j=1}^{Np} L_k^j \cdot D_j \leq (1 + \alpha) \cdot \sum_{j=1}^{Np} L_{k(original)}^j \cdot D_j \quad (5-32)$$

$$\sum_{j=1}^{Np} L_k^j \cdot D_j \geq (1 - \alpha) \cdot \sum_{j=1}^{Np} L_{k(original)}^j \cdot D_j \quad (5-33)$$

L_k^j is the load demand with which the variation in total energy consumption is not more than $\alpha\%$ of the original energy consumption as dictated by inequality constraints (5-32) and (5-33).

The procedure for transmission network planning assuming price responsive demands is illustrated in Figure 5-3.

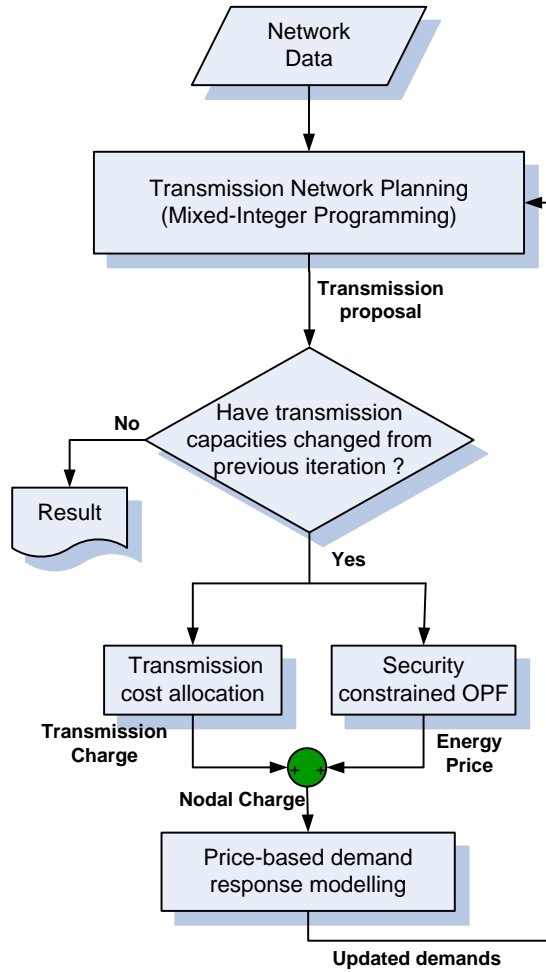


Figure 5-3: The procedure for transmission planning considering price-based demand response

5.2.5 Numerical example

The proposed approach for transmission planning is tested on the IEEE 24 bus test system. The optimum capacities of 17 transmission lines as well as 5 transformers are decision variables in this case study. The load profile consists of 4 different load levels which are associated with different elasticity factors. Detail information, including schematic diagram, generation costs, and demands is given in Appendix C.

Transmission capacities for the test system are calculated for two different cases. In one case, similar to a traditional approach, the demands are assumed to be inelastic to the energy price, so there is no change in the original demands. In the other case, however, demands are price responsive and the proposed methodology shown in Figure 5-3 is implemented.

The resultant transmission capacities of the two cases are compared in Figure 5-4. In the case where the elasticity of demand is taken into account the required transmission capacity is 500 MW smaller than the case where demand is assumed to be inelastic. In total, the transmission investment is reduced by 7.8%. Line 20 is not even required if a responsive demand model is considered.

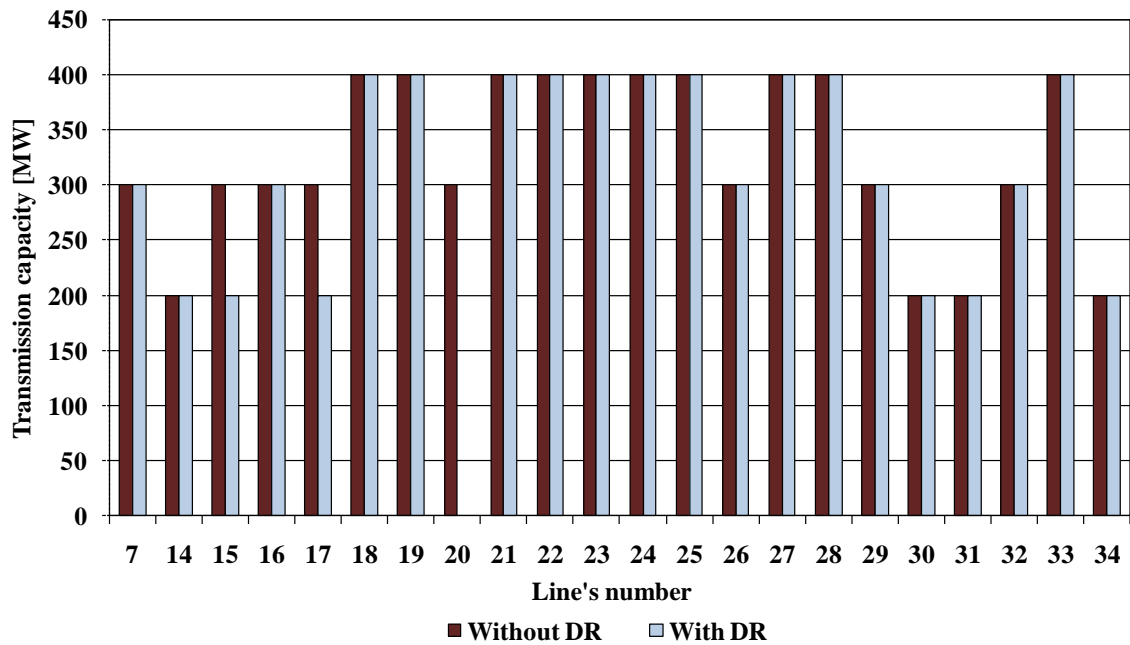


Figure 5-4: Optimum transmission capacities for the two case studies: with and without price-based demand response

In Figure 5-5 the original load profile, which shows the inelastic consumption, and the load profile under a responsive demand program, which is calculated by the proposed algorithm, are depicted. As shown, the consumptions at load levels 1& 2 have been partly shifted to lower load levels. The original total energy consumption is 12.71 GWh which reaches to 12.69 GWh after demand responds. The nodal prices calculated after applying demand response are shown in Table 5-1 . There is just 0.15% reduction in total energy consumption. In other words, the consumers by just shifting the load that

results in a very small change in total energy consumption can reduce the required transmission investment by 7.8%.

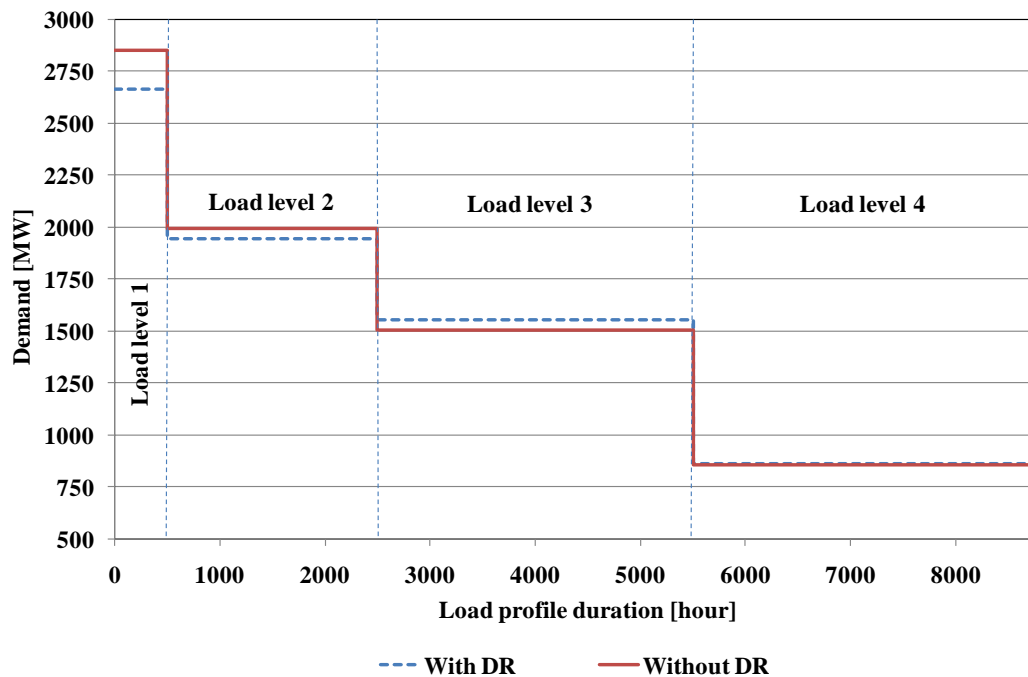


Figure 5-5: The load profile with and without demand response

In this example a real-time transmission charge signal is assumed to be sent to the network users. Although this is the right signal reflecting real-time usage of the grid, the possible distortion that can be caused to economic dispatch by deploying the time varying transmission nodal prices is still need to be addressed in further studies.

Table 5-1: Nodal prices for loads when demand response considered

Bus #	Load level 1	Load level 2	Load level 3	Load level 4
1	56.38556	50.36372	50.05765	45.3444
2	56.77577	50.37625	50.05826	45.42181
3	55.5914	50.40321	49.93486	45.14405
4	57.6272	50.55885	50.18086	46.45484
5	57.56506	50.82486	50.69495	45.70045
6	55.84188	50.3394	49.86189	45.27993
7	55.17084	50.16162	49.87188	45.03384
8	55.25033	50.23667	49.89711	45.04948
9	55.33105	50.11805	49.87776	45.14805
10	55.22242	50.18159	49.89454	45.11779
11	55	50	49.81733	45
12	55	50	49.81733	45
13	55.06682	50.01987	49.82036	45.00952
14	55.17344	50.1006	49.84206	45.06825
15	55.12378	50.06403	49.83625	45.0418
16	55.33042	50.171	49.86087	45.10364
17	55	50	49.81733	45
18	55.1557	50.07314	49.84807	45.06135
19	55.39136	50.18172	49.86125	45.12364
20	55.59626	50.23273	49.86106	45.14155
21	55	50	49.81733	45
22	55	50	49.81733	45
23	55	50	49.81733	45
24	55	50	49.81733	45

5.3 Direct load control

The other option for demand response is to encourage consumers to curtail demand if any security violation occurs in the network. There can be a contractual agreement between the network operator and the consumers so that demand is curtailed either immediately or within a time interval, depending on the system operator's decision, so as to keep the network from any possible violation. The load curtailment can be directly undertaken by the system operator [158].

A trial load control program was conducted by the California independent operating system (ISO) in summer 2000 to cope with significant load growth [159]. Under this trial consumers could compete with generators to provide reserve for the balancing mechanism. In another program, New York ISO implemented a demand response program which encourages consumers to reduce the consumption when the operating reserve deficiency exists [160]. Giannuzzi et al [161] have brought some experiences about fast load curtailment to confront with emergency and alert conditions in Italian network.

Under direct load curtailment program, the consumers contribute to enhancing the flexibility of the network against loss of generation as well as possible network contingencies. In a system with a high penetration of wind power, demand response, as a reserve capacity option, can play a crucial role in balancing the system [162]. System operators carry out direct load curtailment to cover the shortage in generation caused by sudden wind power fluctuation so other generators have enough time to ramp up and match the generation with the demand. Kirby et al [163] demonstrate that demand response as a very fast spinning reserve improves the reliability of the system.

In addition, in order to accommodate this significant growth in wind power resources, considerable transmission network expansion is required. Nonetheless, it is not feasible to undertake large scale expansion or reinforcement of the network in with in a short period of time due to financial and practical barriers. Consequently, the connection of some wind farms may be delayed or generation curtailment may be undertaken to meet the security criteria. As an alternative to transmission network expansion, the direct load curtailment can be proposed. Some consumers may be willing to cut the demand once a contingency occurs or the network security state goes into alert condition, taking into account the fact that these contingencies occur only infrequently.

Fan et al [103] consider the cost of load curtailment in a transmission planning problem assuming that the load shedding can be undertaken to secure the network against “N-1” contingency. Xiong et al [164] have demonstrated that network stability improves by deploying fast load control. National Grid Company, which owns and operates the transmission network in England and Wales, has also proposed a direct load curtailment program called “intertrip scheme” under which demand is directly disconnected if the a particular outage occurs in the network. This is an arrangement between consumers and

National Grid Company to protect the network from overload and voltage violation [165].

As demand is one of the main drivers for transmission investment, in a power system where consumers agree to be automatically disconnected from the network in case of contingencies or sudden wind power fluctuation, a different level of transmission investment would be realised. In the following section, the effect of direct load control on transmission expansion planning is investigated.

5.3.1 Transmission planning under direct load curtailment programme

Transmission planners need to consider the participation of consumers in a direct load curtailment program in the process of transmission expansion studies so as to avoid overinvestment in the network. In this section, transmission reinforcement planning for a network with high penetration of wind power is investigated. The proposed approach aims to answer two main questions:

- 1) What is the optimum transmission reinforcement assuming a high penetration of intermittent wind power?
- 2) Which consumers should be targeted for load curtailment contracts and how much load curtailment is likely to be required?

Modelling the volatility of wind power as well as the correlation between wind farms are the two key considerations in finding accurate answers to the above questions. Moreover, the maximum required capacity for a transmission line or the maximum load curtailment to eradicate overload problems do not necessarily appear at extreme load levels – Peak level or off-peak load level. Therefore a multi-level load profile needs to be considered in the transmission planning study.

5.3.2 Wind power modelling

The intermittency of wind power is usually expressed by probabilistic distribution functions. In some studies the Weibull distribution function is suggested for wind speed which is then plugged into power generation function of wind farm to calculate the wind power [166]. In this study, for the sake of simplicity, wind power is modelled by a normal distribution function. Jianhui et al [12] also consider the normal distribution

function for the probability of wind power variations. A normal distribution function is expressed by (5-34).

$$f(x) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{(x-\nu)^2}{2\sigma^2}} \quad (5-34)$$

σ and ν are the parameters of normal distribution, namely mean value and variance, respectively.

In practice, the parameters of a wind power model depend on the interval for which the model is estimated. For example, the model can be seasonal, daily etc. In this study, it is assumed that for each load level a different wind power model can be considered. This is a valid assumption as the past wind power data corresponding to the hours in a specific load level can be used to estimate the probability distribution function for wind power at that load level.

There is also a correlation between the outputs of wind farms which are geographically in different locations. Therefore, the wind power scenarios should comply with both probabilistic distribution functions of wind power plants and the correlation between wind farms, as it is assumed in this study.

5.3.3 Transmission planning formulation

In this study, the objective function is to minimise the generation cost plus transmission expansion cost as well as the cost of load curtailment. The final design of the network is a trade off between all three elements of objective function. The objective function is given by (5-35).

$$\text{Minimize : } \sum_{j=1}^{Np} D_j \cdot \sum_{i=1}^{Ng} C_i \cdot G_i^j + \sum_{i=1}^{Nl} T_{ci} \cdot l_i \cdot P_{\max i} + \sum_{j=1}^{Np} D_j \cdot \sum_{i=1}^{Nb} B_i^j \cdot DR_i^j \quad (5-35)$$

Where

DR_i^j is the load curtailment at bus i at load level j (MW)

B_i^j the bid for load curtailment at bus i at load level j (€/MWh)

The demand response program has not been practiced in many places, so historically there is not enough information about the bidding strategies or the contracts that may attract consumers to join a demand response program. In fact, as a consumer incurs an interruption cost if the load is curtailed, the offer for direct load curtailment program should be at least higher than the interruption cost in order to attract the consumers. Interruption cost very much depends on the nature of consumption, which can be residential, commercial, industrial etc. Berkeley National Laboratory at University of California conducted some projects to calculate the interruption cost and the willingness to pay for load curtailment for different demand categories [167, 168]. In addition, a consumer is very likely to bid differently at different time of the year or different level of consumption. In this study, for each load level a different bid is taken into account.

In order to model the load curtailment in transmission planning problem, the nodal power balance equation which was introduced in (5-4) is modified as shown by (5-36). As the amount of load curtailment should not exceed the actual consumption the constraints (5-37) is also added to the problem.

$$\sum_{\forall i \in N_{gk}} G_i^j + \sum_{\forall i \in N_{lk}} P_i^j - L_k^j + DR_k^j = 0 \quad (k=1, \dots, N_b) \quad (j=1, \dots, N_p) \quad (5-36)$$

$$0 \leq DR_k^j \leq L_k^j \quad (k=1, \dots, N_b) \quad (j=1, \dots, N_p) \quad (5-37)$$

5.3.4 Methodology

Monte Carlo simulation is used to produce the possible generation scenarios randomly. The generation scenarios should be consistent with PDFs of wind power plants as well as the correlation between them. For all generation scenarios, the transmission planning problem embedded with the direct load curtailment is solved. Considering the resultant transmission capacities and load curtailments for all possible generation scenarios, a statistical analysis is carried out to propose the most probable transmission capacities along with the expected amount of load curtailment at each bus.

The capacity of each transmission line is modelled with a normal distribution function whose mean value represents the proposed capacity for that transmission line. However,

an exponential distribution function is estimated for the load curtailment at each bus. Exponential distribution is the best PDF can match with resultant load curtailments calculated in the study case. It should be stressed that any other distribution functions can be also considered while using the proposed methodology. In order to calculate the required load curtailments, an optimization is proposed, as explained in the following:

Step I: An exponential cumulative distribution function is fitted to the total load curtailment at each load level, taking into account the results from Monte Carlo Simulation, see (5-38).

$$f_{total}^j(LC_{total}^j) = 1 - e^{-LC_{total}^j / \mu_j} \quad (5-38)$$

LC_{total}^j is the total demand at load level j

For a degree of certainty (α) the most probable total load curtailment at each load level can be calculated. The degree of certainty can be selected based on the decision of transmission planners. For a given degree of certainty the total load curtailment in the network is calculated using (5-39).

$$LC_{total}^j = \mu_j \cdot \ln(1 - \alpha) \quad (5-39)$$

Step II: An exponential CDF is fitted to the results of Monte Carlo simulation for load curtailment at each bus. The relevant CDF for bus i at load level j is given by (5-40).

$$\alpha_i^j = f_i^j(LC_i^j) = 1 - e^{-LC_i^j / \mu_i^j} \quad (5-40)$$

α_i^j is the probability of having load curtailment equal to or less than LC_i^j .

Step III: the best LC_i^j is calculated in a way that the summation of all LC_i^j is equal to the total load curtailment (LC_{total}^j) in Step I and the summation of load curtailment probabilities (α_i^j) is maximised. This maximisation is formulated by (5-41) to (5-43).

$$\text{Maximise } \sum_{i=1}^{Nb} \alpha_i^j \quad (5-41)$$

$$\sum_{i=1}^{Nb} LC_i^j = LC_{total}^j \quad (5-42)$$

$$\alpha_i^j = f_i^j(LC_i^j) \quad (5-43)$$

The resultant load curtailments firstly guarantee that the overall degree of certainty is achieved and secondly that the most probable load curtailment is calculated at each load level.

The proposed transmission planning procedure considering load curtailment is illustrated in Figure 5-6.

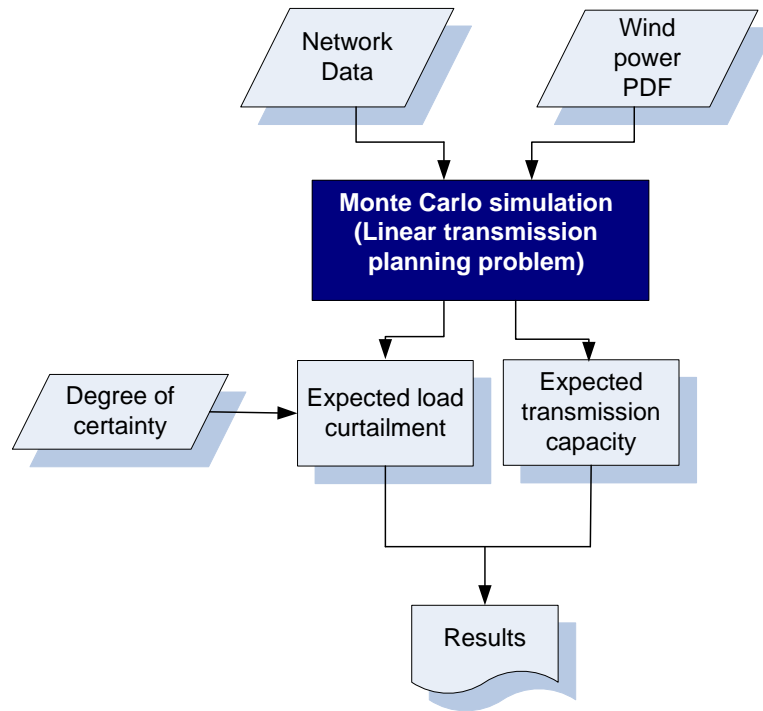


Figure 5-6: The proposed methodology for the transmission planning problem under the load curtailment program

5.3.5 Numerical study

The proposed methodology is implemented on the modified IEEE 24 bus test system which is illustrated in Figure 5-7. For this network, the proposed transmission capacities and the load curtailments are calculated by taking into account the “N-1” security

criterion. The outage of all transmission lines is postulated except line 11 which is a radial connection. The load profile at each bus consists of 10 load levels which are given in detail in Appendix C.

At each load level a different probability distribution function for wind power is considered. In this case study, there are some similar load levels associated with different wind probability density function. For example, the demands at load level 4 and 6 are similar but they come with different wind PDFs. This is due the fact that a similar demand is consumed in different times of the year when the wind speed regimes are different.

It is also assumed that consumers make different bids for different levels of consumptions. The bid at each load level is given in Appendix C.

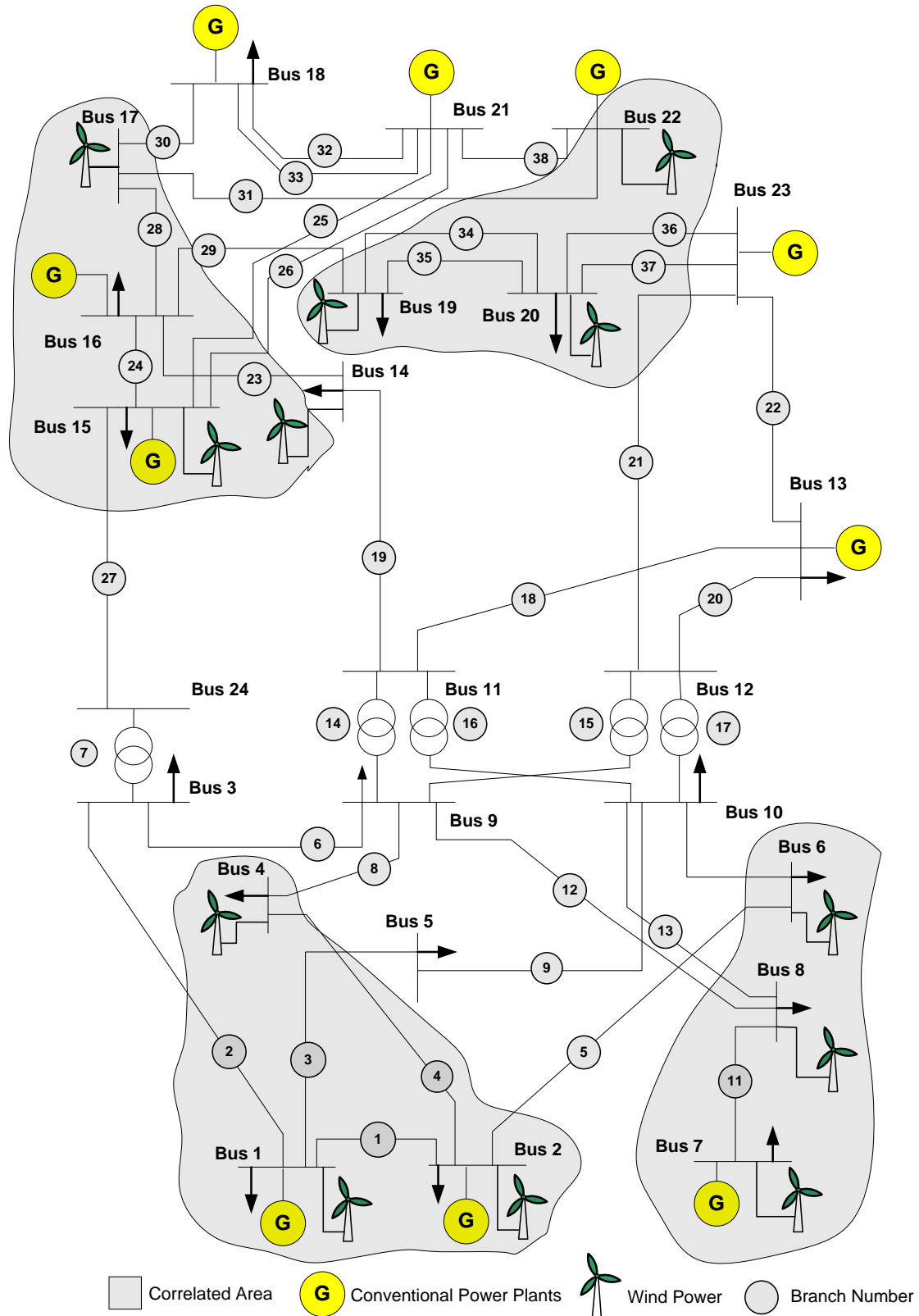


Figure 5-7: The modified IEEE 24 bus test system used for transmission planning study assuming direct load curtailment

The cost of generating wind power is neglected so that wind energy is given the first priority to supply the load. The ranking order of other generators and the maximum

generation capacities are produced in Appendix C. In this study case, taking into account the mean value of the wind power at each load level, around 20% of total energy is supplied by wind power and the remaining 80% is economically distributed among conventional generators.

For the given network, the transmission capacities and the required load curtailment at each load level are calculated considering two different assumptions. First, the wind power plants are highly correlated – 0.9 correlation – and second there is no correlation between wind power plants. In Figure 5-7 the regions exposed to a correlated wind regime are shaded. These two different case studies assuming regional wind power correlation and uncorrelated wind powers will be referred to as Case I and Case II.

Monte Carlo simulation is used to generate 2000 scenarios for wind powers, considering the probabilistic distribution function of wind power plants and the correlation between them. The transmission planning problem under demand response program is solved for all these scenarios. Therefore, 2000 values for transmission capacities as well as load curtailment at each bus are calculated.

The best matched distribution function for the values of transmission capacities is the normal distribution. The mean values of normal distribution functions fitted to transmission capacities calculated from Monte Carlo simulation are considered as the final transmission expansion proposal. The transmission expansion proposals for both Case I and Case II are shown in Figure 5-8. As can be seen in this figure, in both cases similar transmission capacities are required. This suggests that in this particular case study, the correlation between wind power plants does not affect the required transmission capacity. Nonetheless, it will be shown later that the correlation between wind power plants does affect the required load curtailment.

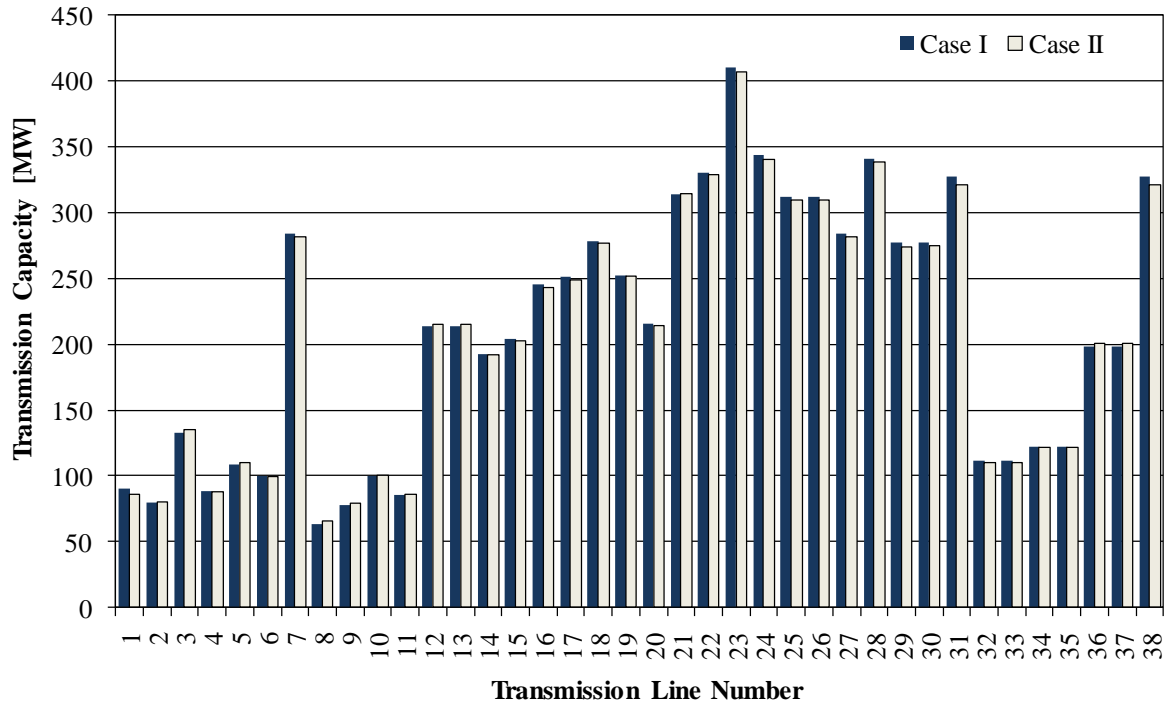


Figure 5-8: Optimum transmission capacities for Case I and Case II

The resultant load curtailments for all scenarios show that load curtailment action needs to be deployed only during peak time. An exponential probabilistic distribution function is fitted to the total load curtailments calculated by the Monte Carlo simulation. The Cumulative Distribution function of total load curtailments for Case I and Case II are shown in Figure 5-9. In order to reach an certainty level of 95% for load curtailment, according to cumulative distribution function, 148 MW load curtailment at peak load level is required for Case I whereas for Case II where there is no correlation between wind power plants a 127 MW load curtailment needs to be programmed.

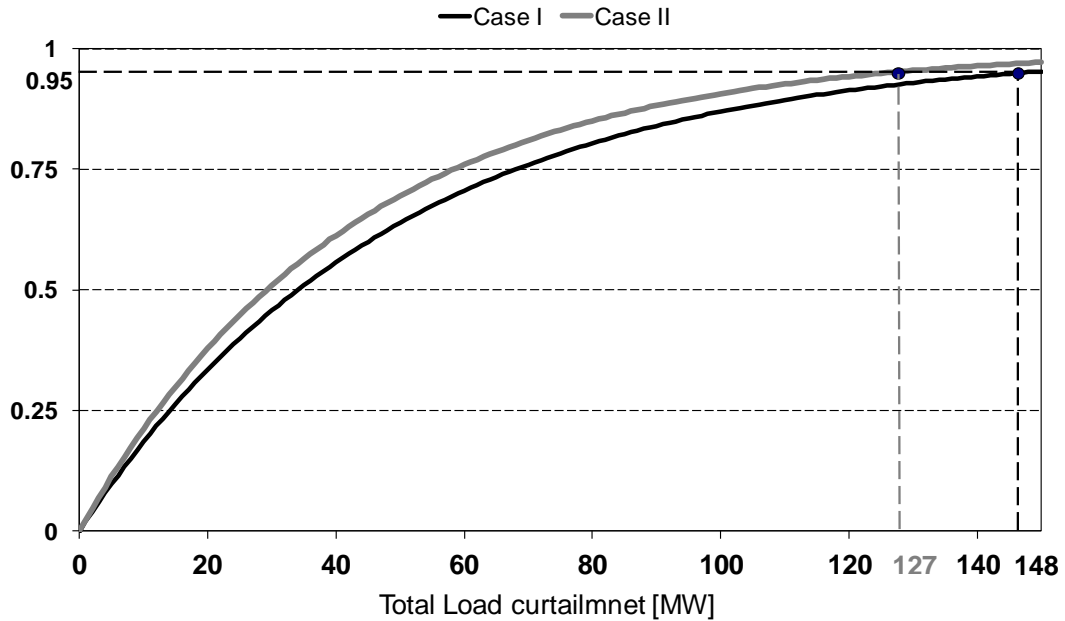


Figure 5-9: The total load curtailment in the network with and without correlation, Case I and Case II.

The Monte Carlo simulation suggests that among all 24 buses in the network, there are only 5 buses which need to be approached for direct load curtailment contracts. The parameters of cumulative distribution function fitted to the load curtailments at these 5 buses are given in Table 5-2. The total load curtailment which is calculated assuming 95% degree of certainty needs to be portioned among 5 buses. In order to do this the optimisation formulated by (5-41) to (5-43) is used. Table 5-2 shows the results of optimally distributing the total load curtailments among 5 buses to have a 95% degree of certainty degree for the whole network. Table 5-2 also shows the probability associated with required load curtailment at each bus. As demonstrated in Table 5-2, the required load curtailments are different at each bus when different correlation among wind farms is assumed. The wind power correlations do not change the required maximum load curtailment at the Bus 6 and Bus 7 whereas the load curtailment at Bus 10 shows the most sensitivity to the correlation between wind power farms.

Table 5-2: Probabilistic parameters of load curtailments at different buses

	Case I			Case II		
	CDF	Curtailed load (MW)	Probability	CDF	Curtailed load (MW)	Probability
Bus 3	0.05	18	0.98	0.06	23	0.98
Bus 6	0.08	27	0.96	0.07	26	0.97
Bus 7	0.18	44	0.91	0.17	48	0.93
Bus 8	0.05	19	0.97	0.05	20	0.98
Bus 10	0.05	19	0.97	0.09	31	0.96
Total Load curtailment (MW)		127			148	

5.4 Conclusions

Demand response programs Demand response are expected to be widely adopted in future power system. Consumers are expected to play a crucial role in providing ancillary services to enhance network security and to provide reserve in system balancing. Moreover, it is likely that consumers equipped with smart meters will change their consumption pattern in response to the real-time energy price. As demand is one of the main drivers for transmission investments, the effect of demand response programs on required transmission network investment needs to be addressed.

In this chapter, demand response programs were reviewed. In particular, priced-based demand response and direct load curtailment were elaborated. Methodologies for solving the transmission planning problem under these demand response programs were proposed.

An iterative algorithm was proposed to determine the required transmission capacities in a network where consumers are price responsive. This algorithm was tested on the IEEE 24 bus test system and the results were compared to the case which assumes demands are inelastic to the energy price. For the test system, it was demonstrated that transmission investment could be reduced by 7.8% if the elasticity of demand is taken into account.

A methodology for solving the transmission planning problem under direct load curtailment program in a system with high penetration of wind power was also proposed. Monte Carlo simulation was used to generate wind power scenarios in

consistent with probabilistic distribution functions and the correlation between wind farms. The proposed methodology determined the required transmission capacities along with the amount of load curtailments at each bus. This methodology was tested on the modified IEEE 24 bus test system. The effect of correlation between wind farms was also investigated. In the test system, it was demonstrated that the required load curtailments at some buses are sensitive to the wind power correlations.

Chapter 6. Transmission network investment under generation re-dispatch corrective action

Post-fault violation of transmission line capacities in the network can be eliminated by rearranging the generation dispatch. The network can withstand a temporary overload while generation is re-dispatched to eliminate the overload. In this chapter, a methodology is proposed for solving the transmission planning problem assuming the post-contingency generation re-dispatch corrective action is plausible. The proposed approach is demonstrated on the modified IEEE 24 bus system with a high penetration of wind power. The results show the required transmission capacity and the generation re-dispatch for each generator for different outages. The results are compared with the traditional transmission planning approach without corrective actions.

6.1 Introduction

Generation re-dispatch as a corrective action can be taken to accomplish any or a combination of the following objectives: i) to reduce generation cost [97], ii) enhance power system security [169], iii) to improve transmission network congestion while balancing supply and demand [170], iv) to relieve post-contingency overloads and alleviate voltage violations [171, 172]. Lachs [173] proposed the combination of strategic load shedding and generation rearrangement as post-contingency corrective action to alleviate post-fault overloads. In another study, Mostafa et al [174] review the methodologies and algorithms for generation re-dispatch.

The feasibility of generation re-dispatch to resolve a particular network violation mainly depends on ramp-rates of generators and criticality of the violation. In other words, generation re-dispatch should be carried out within a time window in which the network is able to stand violations. Generation re-dispatch seems to be a more reliable and credible corrective action than it used to be for the following main reasons:

- The future generation mix will include fast-ramp generation resources such as combined heat and power, hydro power and micro turbines. Gas turbine generators equipped with new technologies increasing the ramp-rate have also been recently introduced [175]. The ramp rate of generators depends on the type of generation. In Figure 6-2 a general view of ramp rate of different generation types are given [176].
- Central power plants generating a large amount of power is likely to gradually be replaced with small distributed energy resources. Each of these dispersed generation units can be conceived as a controlling point giving a wide range of options for the generation re-dispatch corrective action.
- Under the concept of “smart grid”, the power system is armed with intelligent systems underpinned by a broad communication system. Therefore generation units can receive generation rearrangement commands very quickly following a network contingency.

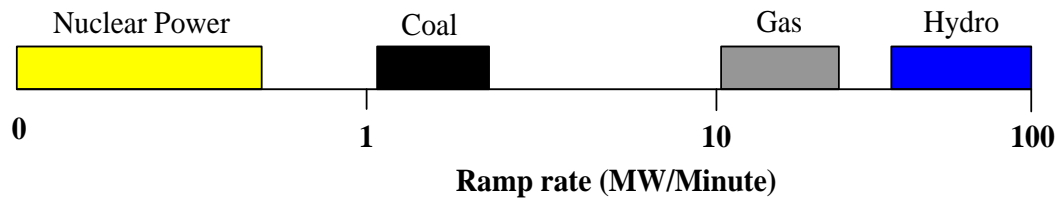


Figure 6-1: Ramp rate of different generation types

In addition to this, the feasibility of post-fault generation re-dispatch corrective action depends on the capability of the network to withstand a temporary violation while post-fault corrective action is carried out. The steady state power flowing in a transmission line ought to be limited to the static thermal rating. Any continuous power beyond static thermal rating may cause annealing of the conductor which eventually results in conductor clearance violation. Static thermal rating is calculated, taking into account the conductor parameters along with prevailing weather conditions including wind speed and direction, solar heat, ambient temperature etc. Moreover, a sudden increase in the current of a transmission line does not cause an immediate temperature change in the conductor. Depending on the weather conditions and magnitude of the current step

change, the conductor temperature increases in an inverse exponential pattern [177], see Figure 6-2.

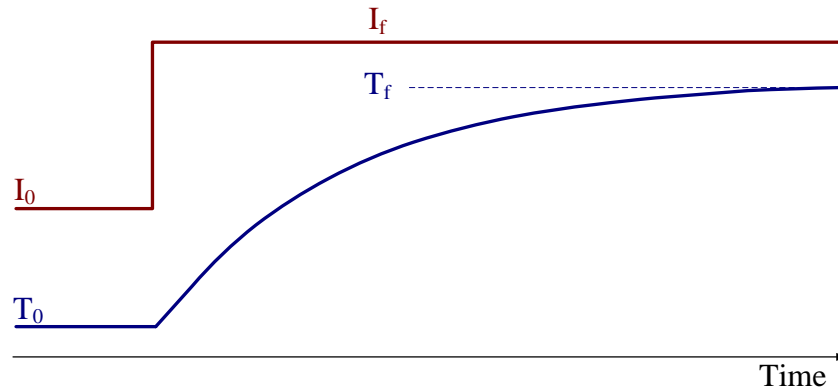


Figure 6-2: The variation of a conductor temperature following a sudden change in the current

Due to this gradual temperature change, in addition to static thermal rating, two other transient thermal ratings can be defined for a transmission line, Emergency thermal rating and Dump load thermal rating. PJM, one of the regional transmission operators in the USA, elaborates these thermal ratings as follows [178]:

- Emergency thermal rating is usually the maximum current that a transmission line can carry for a short period (not more than 15 minutes) before reaching annealing point, so all effective actions to alleviate overload should be taken in this time window.
- Dump load thermal rating is the current beyond which the overload should be eliminated immediately. In this case, the overload elimination is usually undertaken by load shedding.

The emergency thermal rating depends on the thermal capacity of the conductor and ambient conditions but it can be between 10% to 50% over the static thermal rating [179, 180].

Krogh et al [181] investigated a methodology to allocate generation ramping in a situation when there are several transmission lines experiencing post-fault overload. They concluded that the post-fault generation rearrangement should be carried out while taking into account the priority of transmission lines with severe overload.

Farghal and Shebel [182] address the optimal allocation of generation margin so that the generation cost is minimized and the generation ramping is maximized. In other words, one of the objectives of their work is to maximise the flexibility of the generation side.

The flexibility of the power system can be enhanced if generators are able to vary their outputs once a contingency occurs. Generation rearrangement is an ancillary service which can be contractually agreed between transmission operators and generators. The “intertrip scheme” is an example of generation rearrangement that National Grid has launched in 2009. Under this scheme if a particular double contingency occurs, some generating units are automatically tripped. This scheme is meant to relax the “N-2” security constraint so that the connections of new wind power plants do not need to be delayed due to lack of transmission capacity. Although the intertrip scheme with its current form is not very flexible it is still one step towards a practical generation re-dispatch corrective action.

6.2 Transmission investment under generation re-dispatch scheme

In all aforementioned studies, the corrective generation re-dispatch action has been investigated for a given transmission capacity and a known transmission topology. Nonetheless, the literature review in the course of this research shows that the effect of generation re-dispatch on the transmission investment has not been studied. In this chapter, a transmission planning approach which considers generation re-dispatch as a plausible post-contingency corrective action is proposed. Generation re-dispatch is seen as an ancillary service provided by generators to eliminate network overloads so that some network investment schemes can be cancelled or deferred. Unlike the majority of studies which consider generation re-dispatch action for a given network capacity and configuration, the proposed approach introduces a methodology to optimally determine transmission network capacities as well as post-contingency generation output rearrangements.

The ramp-up rate and ramp-down rate of generators are also taken into account. In addition to that, due to the fact that the network can be overloaded for a short period of time, the contingent network is assumed to stand some temporary overloads up to emergency thermal ratings while generation re-dispatch is carried out to bring the flows back within the static thermal ratings.

The future generation mix is expected to include a high penetration of wind energy which is a volatile energy resource. Although wind speed is accurately predictable in the short-term, this is by no means the case for long-term studies taking into account the behaviour of wind speed in the distant future. Therefore, in the transmission planning problem, which in essence is a long-term planning problem, different wind power scenarios associated with relevant likelihoods are usually considered so that the proposed network is economically designed for all possible scenarios.

6.3 Problem formulation

Generation re-dispatch as a credible ancillary service deployed after network security is added to the transmission planning problem. This service is associated with the cost of re-dispatch which should be minimized, as should transmission investment and operating costs. Therefore the objective function for the transmission planning problem consists of three terms mathematically expressed by (6-1).

$$\begin{aligned}
 \text{Minimise : } & \sum_{j=1}^{Np} D_j \cdot \sum_{i=1}^{Ng} C_i \cdot G_i^j + \sum_{i=1}^{\overline{N_l}} T_{ci} \cdot l_i \cdot \overline{P}_{\max i} \\
 & + \sum_{j=1}^{Np} \sum_{c=1}^{Nc} FR_c^j \cdot \sum_{i=1}^{Ng} (C_i \cdot \Delta G_{i,c}^{j,up} + B_i \cdot \Delta G_{i,c}^{j,down})
 \end{aligned} \tag{ 6-1 }$$

In objective function (6-1) the first term represents generation cost, the second term is the transmission investment cost and the last term represents the generation re-dispatch cost where:

- D_j Duration of the load level j (hour)
- C_i Incremental cost of generator i (€/MWh)
- B_i Bid made by generator i to curtail the output power (€/MWh)
- G_i^j Power generated by generator i at load level j (MW)
- T_{ci} Annuitized investment cost of line i (€/km.MW.year)
- l_i Length of transmission line i (km)
- $\overline{P}_{\max i}$ Static thermal rating of candidate transmission line i (MW)
- FR_c^j Average outage time of line c at load level j (hour)

$\Delta G_{i,c,up}^j$ The increase in output of generator i at load level j after outage of line c (MW), a positive value

$\Delta G_{i,c,down}^j$ The decrease in output of generator i at load level j after outage of line c (MW), a negative value

\bar{N}_l is number of candidate transmission lines, N_p is number of load levels, N_g shows number of generators, and N_c is number of possible contingencies. $\bar{P}_{max i}$, G_i^j , $\Delta G_{i,c,up}^j$ and $\Delta G_{i,c,down}^j$ are decision variables in the minimisation problem (6-1).

In practice, an opportunity cost may also be considered in the objective function as some generators may run under their maximum capabilities in order to be able to ramp-up in the contingency conditions. In this study, for sake of simplicity, however, the opportunity cost is neglected.

The objective function (6-1) is subject to physical laws which govern the power system, see equalities (6-2) and (6-3).

$$\sum_{\forall i \in N_{gb}} G_i^j + \sum_{\forall i \in N_{lb}} P_i^j - L_k^j = 0 \quad (k=1, \dots, N_b)(j=1, \dots, N_p) \quad (6-2)$$

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{Xm_i} = 0 \quad (i=1, \dots, N_l)(j=1, \dots, N_p) \quad (6-3)$$

Where:

P_i^j The power flowing through transmission line i at load level j (MW)

L_k^j Load demand at bus k at load level j (MW)

N_{gb} Set of generators connected to bus b

N_{lb} Set of lines connected to bus b

N_b Number of buses

In addition, N_l is the number of existing transmission lines, X_{m_i} represents the reactance of transmission line i (p.u.) connected to bus k and l , and θ_k^j is voltage angle of bus k at load level j (radian).

For candidate lines, however, the disjunctive form with two inequality constraints given by (6-4) and (6-5) is constructed.

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{X_{m_i}} \leq M.(1 - X_i) \quad (i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p) \quad (6-4)$$

$$P_i^j - \frac{(\theta_k^j - \theta_l^j)}{X_{m_i}} \geq M.(X_i - 1) \quad (i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p) \quad (6-5)$$

\bar{N}_l is the number of candidate transmission lines. X_i is the binary decision variable which shows whether the construction of candidate line i can be justified. If X_i is equal to 1 line i is justifiable otherwise there is no need for line i . M is a large number assumed to be 1000 in this study.

Limits on power system components including upper and lower generation boundary as well as the static thermal limit of transmission lines are expressed by (6-6) to (6-9).

$$G_{\min i} \leq G_i^j \leq G_{\max i} \quad (i = 1, \dots, N_g)(j = 1, \dots, N_p) \quad (6-6)$$

$$-P_{\max i} \leq P_i^j \leq P_{\max i} \quad (i = 1, \dots, N_l)(j = 1, \dots, N_p) \quad (6-7)$$

$$-\bar{P}_{\max i} \leq P_i^j \leq \bar{P}_{\max i} \quad (i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p) \quad (6-8)$$

$$0 \leq \bar{P}_{\max i} \leq X_i.P_{i,cap} \quad (i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p) \quad (6-9)$$

Where:

$G_{\max i}$, $G_{\min i}$ Maximum and Minimum output of generator i

$P_{\max i}$ Static thermal rating of existing transmission line i

N_g Number of generators

$P_{i,cap}$ The maximum possible capacity which can be considered for transmission line i , it is a given value.

Constraints (6-2) to (6-9) model only the intact network. The contingent networks should be modelled as well in order to examine the robustness of the network against any contingency. The contingent networks are modelled for two instants: post-contingency emergency moment and post-contingency steady state moment.

Post-contingency emergency moment is when a transmission line trips. In that instant, generation dispatch is still similar to generation dispatch for the intact network, and a line's flow may jump up to the emergency thermal rating. The post-contingency steady state moment, however, is when generation re-dispatch action is accomplished and flows are within static thermal limits, below $\bar{P}_{\max i}$ and $P_{\max i}$. As previously mentioned, the temporal difference between these two moments is the emergency period which is around 15 minutes.

Equalities and inequalities (6-10) to (6-15) are the mathematical models of the contingent network at emergency moment after outage of line c .

$$\sum_{\forall i \in N_{gb}} G_i^j + \sum_{\forall i \in N_{lb}} P_{i,c,e}^j - L_k^j = 0 \quad (k=1, \dots, N_b)(j=1, \dots, N_p) \quad (6-10)$$

$$P_{i,c,e}^j - \frac{(\theta_{k,c,e}^j - \theta_{l,c,e}^j)}{X_{mi}} = 0 \quad (i=1, \dots, N_l)(j=1, \dots, N_p)(c=1, \dots, N_c) \quad (6-11)$$

$$P_{i,c,e}^j - \frac{(\theta_{k,c,e}^j - \theta_{l,c,e}^j)}{X_{mi}} \leq M.(1 - X_i) \quad (i=1, \dots, \bar{N}_l)(j=1, \dots, N_p)(c=1, \dots, N_c) \quad (6-12)$$

$$P_{i,c,e}^j - \frac{(\theta_{k,c,e}^j - \theta_{l,c,e}^j)}{X_{mi}} \geq M.(X_i - 1) \quad (6-13)$$

$$(i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p)(c = 1, \dots, N_c)$$

$$-E_{i,e}.P_{\max i} \leq P_{i,c,e}^j \leq E_{i,e}.P_{\max i} \quad (i = 1, \dots, N_l)(j = 1, \dots, N_p) \quad (6-14)$$

$$-E_{i,e}.\bar{P}_{\max i} \leq P_{i,c,e}^j \leq E_{i,e}.\bar{P}_{\max i} \quad (i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p) \quad (6-15)$$

Subscript e refers to emergency moment. Also, N_c is the number of postulated single contingencies. $E_{i,e}$ is a factor which shows the permissible temporary overload in line i .

Comparison between (6-10) and (6-2) shows that the contingent network at the moment of outage faces the same generation pattern as for the intact network. Constraints (6-14) and (6-15) limit the lines' flows to less than emergency thermal ratings.

The network is also modelled for the post-contingency steady state moment when the generation re-dispatch corrective action is carried out. This moment is formulated by constraints (6-16) to (6-24).

$$\begin{aligned} \sum_{\forall i \in N_{gb}} G_i^j + \sum_{\forall i \in N_{lb}} P_{i,c,s}^j - L_k^j \\ + \sum_{\forall i \in N_{gb}} \Delta G_{i,c,up}^j + \sum_{\forall i \in N_{gb}} \Delta G_{i,c,down}^j = 0 \end{aligned} \quad (6-16)$$

$$(k = 1, \dots, N_b)(j = 1, \dots, N_p)$$

$$P_{i,c,s}^j - \frac{(\theta_{k,c,s}^j - \theta_{l,c,s}^j)}{X_{mi}} = 0 \quad (i = 1, \dots, N_l)(j = 1, \dots, N_p)(c = 1, \dots, N_c) \quad (6-17)$$

$$P_{i,c,s}^j - \frac{(\theta_{k,c,s}^j - \theta_{l,c,s}^j)}{X_{mi}} \leq M.(1 - X_i) \quad (6-18)$$

$$(i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p)(c = 1, \dots, N_c)$$

$$P_{i,c,s}^j - \frac{(\theta_{k,c,s}^j - \theta_{l,c,s}^j)}{X_{mi}} \geq M.(X_i - 1) \quad (6-19)$$

$$(i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p)(c = 1, \dots, N_c)$$

$$-P_{\max i} \leq P_{i,c,s}^j \leq P_{\max i} \quad (i = 1, \dots, N_l)(j = 1, \dots, N_p) \quad (6-20)$$

$$-\bar{P}_{\max i} \leq P_{i,c,s}^j \leq \bar{P}_{\max i} \quad (i = 1, \dots, \bar{N}_l)(j = 1, \dots, N_p) \quad (6-21)$$

$$G_{\min i} \leq G_i^j + \Delta G_{i,c,up}^j + \Delta G_{i,c,down}^j \leq G_{\max i} \quad (i = 1, \dots, N_g)(j = 1, \dots, N_p) \quad (6-22)$$

$$0 \leq \Delta G_{i,c,up}^j \leq G_{i,ramp-up} \quad (i = 1, \dots, N_g)(j = 1, \dots, N_p) \quad (6-23)$$

$$-G_{i,ramp-down} \leq \Delta G_{i,c,down}^j \leq 0 \quad (i = 1, \dots, N_g)(j = 1, \dots, N_p) \quad (6-24)$$

Where:

$G_{i,ramp-down}$ The maximum possible reduction in output of generation i during the emergency period (MW/15 minutes)

$G_{i,ramp-up}$ The maximum possible increase in output of generation i during the emergency period (MW/15 minutes)

Moreover, Subscript s points to the steady state moment.

Objective function (6-1) along with constraints (6-2) to (6-24) represent a mixed-integer programming problem which determines the optimum transmission capacities, optimum generation dispatch for intact network and the optimum generation rearrangements for contingent networks.

One of the key challenges which transmission planners face is designing a transmission network able to accommodate fluctuating energy resources such as wind energy. To do so, the transmission planning problem is usually solved for several scenarios. In the following, the wind power scenario generation method which is deployed in this study is introduced.

6.4 Wind power generation scenarios

6.4.1 Wind regime and load levels

As discussed in 0, many studies have modelled the wind speed with the Weibull distribution function expressed by (6-25).

$$f(x|\lambda, k) = \frac{k}{\lambda} \left(\frac{x}{\lambda}\right)^{k-1} \cdot e^{-(x/\lambda)^k} \quad (6-25)$$

Where k and λ are the shape factor and scale factor of the Weibull distribution, respectively.

Moreover, load variation is usually estimated in the form of a multi-load level model which reasonably represents the load duration curve in a horizon year. A load level may be associated with different wind regimes as load duration curve is not in chronological order.

In this study, two PDFs representing the high speed wind regime and low speed wind regime are considered. They are called PDF^{HW} and PDF^{LW} respectively. Therefore for N_p load levels 2^{N_p} load demand-wind regime combinations can be considered. Also, based on the load variation and wind historic data, a probability can be associated with allocating a wind speed regime (PDF^{HW} or PDF^{LW}) to a particular load level. In this way, each of those 2^{N_p} combinations can be given a different probability. The

probability of k th combination (P_c^k) is the multiplication of the probabilities associated with allocating wind regimes to load levels, as shown in Table 6-1.

Table 6-1: Load demand-wind regime combinations and their possibilities

	Load Level			Probability of the combination
	1	2	N	
1	PDF^{HW}	PDF^{HW}	PDF^{HW}	$P_c^1 = P_1^{HW} \times P_2^{HW} \times \dots \times P_N^{HW}$
2	PDF^{HW}	PDF^{HW}	PDF^{LW}	$P_c^2 = P_1^{HW} \times P_2^{HW} \times \dots \times P_N^{LW}$
k	PDF^{LW}	PDF^{HW}	PDF^{LW}	$P_c^k = P_1^{LW} \times P_2^{HW} \times \dots \times P_N^{LW}$

P_i^{HW} and P_i^{LW} are the likelihoods of allocating PDF^{HW} and PDF^{LW} to load level i , respectively. It should be stressed that summation of P_i^{HW} and P_i^{LW} is equal to one.

As shown in Table 6-1, different wind speed PDFs are assigned to different load levels in every load demand-wind regime combination. In order to generate the final scenarios including the value of wind speeds at each load level a sampling method should be deployed.

6.4.2 Wind power scenarios

For a given combination of wind regimes and load levels, the LHS method, which was elaborated in section 3.4.2, is applied to generate wind speed scenarios for wind farms. As in the LHS method samples are taken from intervals with equal probability the probability of a combination should be evenly divided between scenarios generated from the corresponding combination. For instance, if N_s scenarios are generated from the combination k , the probability of each of those scenarios is calculated by (6-26).

$$P_s^t = \frac{P_c^k}{N_s} \quad (6-26)$$

In total $2^{N_p} \times N_s$ wind speed scenarios for every wind farm are generated. These wind speed scenarios are converted to wind power by using a linear model of wind power curve which is expressed by (6-27).

$$P_{out}(w) = \begin{cases} 0 & w < w_{cut-in} \text{ or } w > w_{cut-out} \\ \frac{P_{rating} \cdot (w - w_{cut-in})}{w_{rating} - w_{cut-in}} & w_{cut-in} \leq w \leq w_{rating} \\ P_{rating} & w_{rating} \leq w \leq w_{cut-out} \end{cases} \quad (6-27)$$

In equation (6-27), P_{rating} is the power rating of the wind farms, w is the wind speed, w_{cut-in} , $w_{cut-out}$ and w_{rating} show the cut-in wind speed, the cut-out wind speed and the rating wind speed, respectively. In this study , w_{cut-in} , w_{rating} and $w_{cut-out}$ are assumed to be 3 m/s and 15 m/s, and 25 m/s, respectively [183].

6.5 Numerical example

The proposed method is demonstrated on the modified IEEE 24 bus reliability test system, illustrated in Figure 6-3. In Figure 6-3 dashed lines show the candidate transmission lines whereas solid lines represent the existing circuits. The cost of generation, bid for generation re-dispatch and ramp rates of generators are given in Appendix D. It should be noted that the ramp-up rate for wind power plants in post-contingency re-dispatch action is assumed to be zero so their outputs can only be reduced if a contingency occurs. Also in order to follow the CO2 emission reduction program it is assumed that the priority is to supply the demand by wind power, hence the marginal cost of wind generation is taken to be zero.

Three load levels are considered. The probability associated with occurrence of a particular load demand concurrently with either a high-speed wind regime or a low-speed wind regime is shown in Appendix D. Two Weibull PDFs representing the high speed and low speed wind regimes are considered. The scale factor and shape factor for high speed wind regime are 10.5 and 3.1, for low speed wind regime are 5.3 and 1.9, respectively. These values are borrowed from the study conducted by Jangamshetti et al [83]. An annuitized transmission investment cost of 10.7 €/km.MW.year is used. This transmission expansion cost was calculated based on the National Grid Report [184] and a currency rate of £1.00= €1.23.

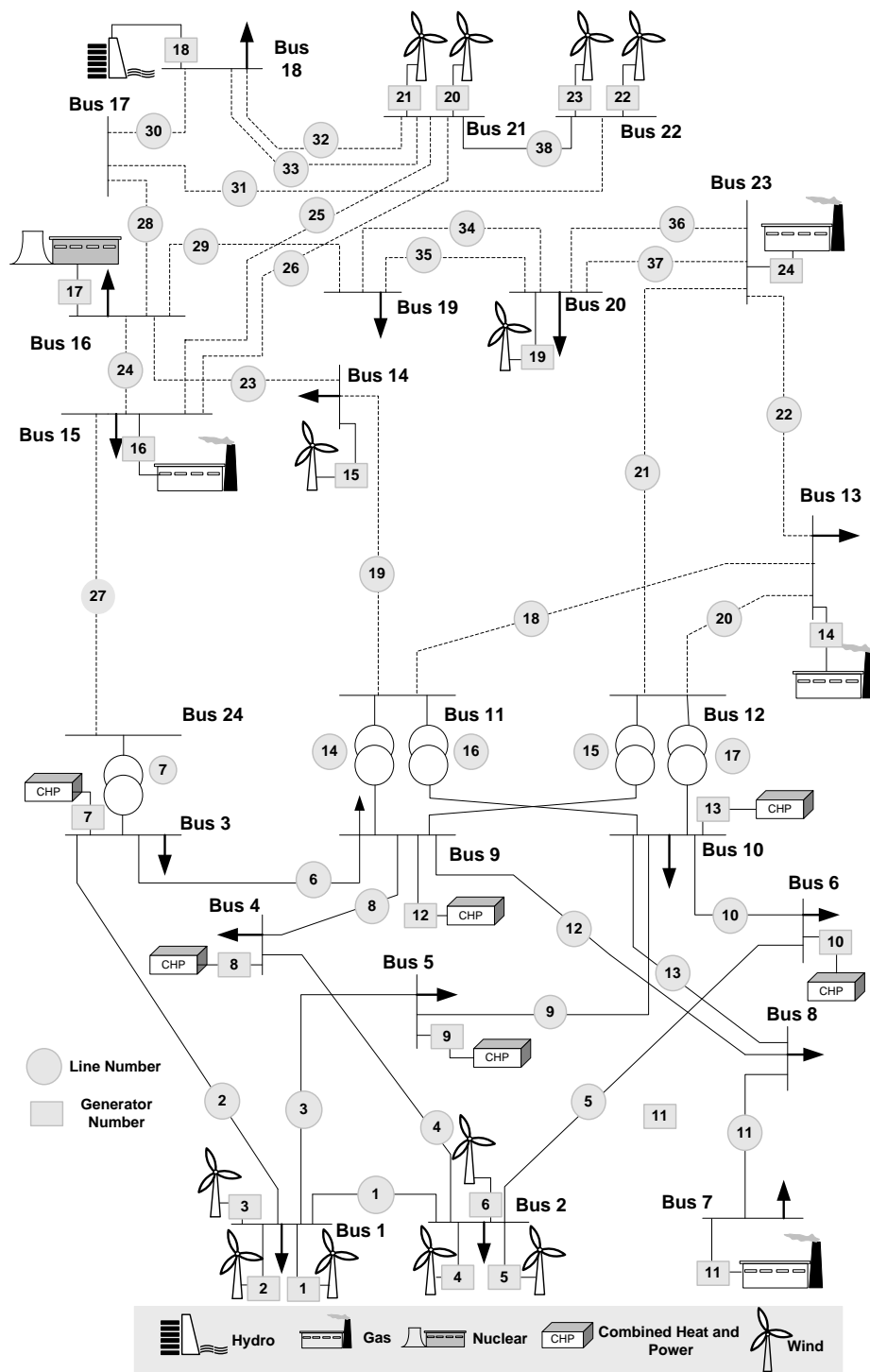


Figure 6-3: The modified IEEE 24 bus reliability test system used for transmission planning under generation re-dispatch corrective action

6.5.1 Wind power scenarios

LHS is used to generate wind power scenarios. Considering three load levels ($N_p=3$) and 30 sample points in LHS ($N_s=30$), 240 wind speed scenarios are generated. These wind speed scenarios are then plugged in (6-27) to produce wind power scenarios.

Five groups, each of which includes wind power plants with 0.8 correlations, are considered. There is no correlation between groups. Correlated wind power plants are given in Table 6-2.

Table 6-2: Correlated wind power plants

Wind power plant numbers				
1,2,3	4,5,6	20,21	22,23	15,19

The methodology introduced in section 3.4.3 is used to rearrange the ranking order of scenarios generated by LHS in order to comply with correlations between wind power plants. The outcomes of this rearrangement for some correlated and uncorrelated wind power plants are illustrated in Figure 6-4 and Figure 6-5, respectively. In Figure 6-4 each dark spot shows the wind speed in wind power plants 1, 2 and 3 in a particular scenario at load level 1. The distribution of dark spots clearly shows that there is a high correlation between the wind speeds hitting these three power plants. The same graph can be produced for other load levels as well. In Figure 6-5, however, the distribution of dark spots is totally random, which shows no correlation between power plants 1, 4 and 22, as given in Table 6-2.

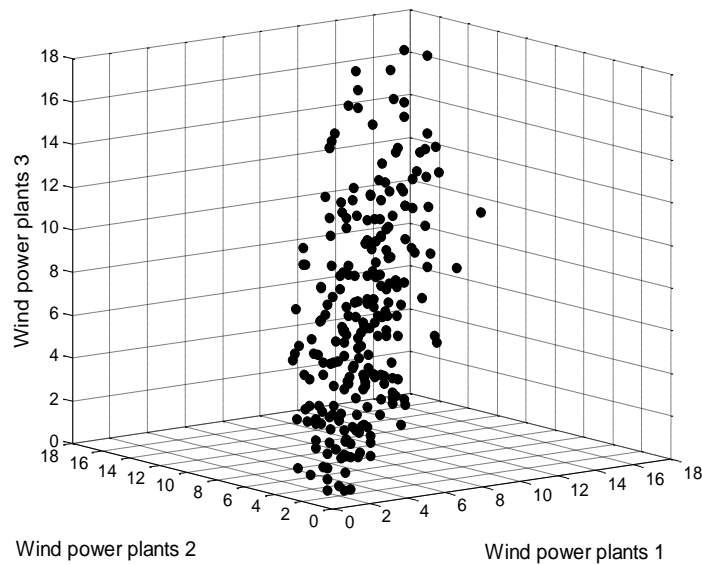


Figure 6-4: Wind speed scenarios for power plants 1, 2 and 3 which are correlated by a factor of 0.8. All values are in meters/second.

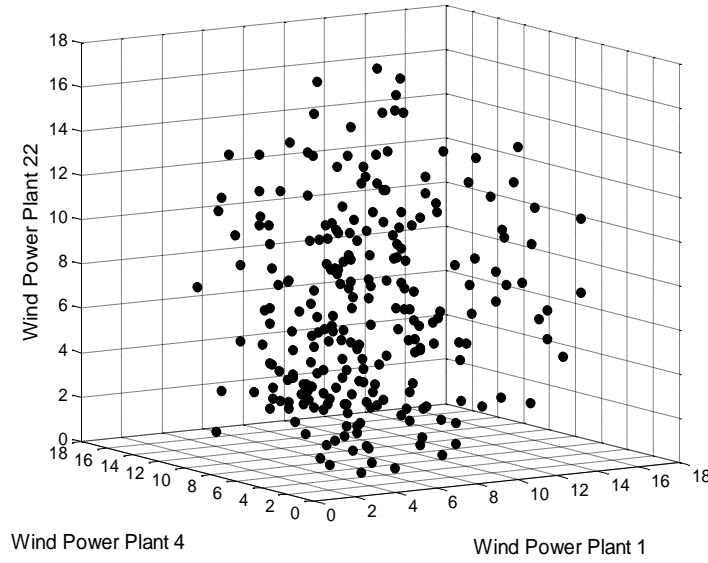


Figure 6-5: Wind speed scenarios for power plants 1, 4 and 22 which are completely uncorrelated. All values are in meters/second.

6.5.2 Resultant transmission capacities and generation re-dispatch

The proposed transmission planning method with post contingency re-dispatch action formulated by (6-1) to (6-24) was run for all wind power scenarios. Each scenario is associated with a probability. Therefore, for each candidate line 240 transmission capacities associated with relevant probabilities are calculated. The expected value for capacity of transmission line i , $\bar{P}_{\max i}^e$, can be calculated by (6-28).

$$\bar{P}_{\max i}^e = \sum_{t=1}^{240} \bar{P}_{\max i}^t \cdot P_s^t \quad (6-28)$$

$\bar{P}_{\max i}^t$ is the optimum capacity of transmission line i for scenario t , also P_s^t is the probability associated with this scenario.

In order to show the impact of generation re-dispatch corrective action on transmission investment two studies are conducted. In the first study, as proposed in this work, if a line trips generators can rearrange their output within the ramp-rate limits to alleviate the overloads whereas in the second study generation re-dispatch is not allowed and the network is designed under the preventive control paradigm. The outage of all transmission lines, except line 11 (because of the islanding problem) is taken into

account, with the average outage duration of 2 hours at each load level. The emergency thermal ratings are assumed to be 50% above the static thermal ratings.

The expected transmission capacities calculated by each of these studies, with and without generation re-dispatch, are given in Table 6-3. As results show, a 24.8% reduction in transmission investment can be achieved if post-contingency generation re-dispatch corrective action is deployed. Due to the lumpy nature of transmission lines, however, the expected values for transmission capacities given in Table 6-3 cannot be found in practice. These values should be rounded up to the closest feasible capacities. If practical transmission capacities are assumed to be available in steps of 50 MW, the practical capacity for each candidate line is proposed as shown in Table 6-3. Considering practical capacities, there will be 23.8% reduction in transmission investment.

Another interesting result relates to generation re-dispatch in the contingent networks. The range of variation of each power plant's output is depicted in Figure 6-6 which gives a general view of the contribution of each power plant to the post-contingency corrective action scheme. As shown in Figure 6-6, the largest variation belongs to generator number 18 which is a large hydro power plant. Gas power plants also make a considerable contribution to the generation rearrangement program. Among all wind power plants, however, only a small post-contingency generation curtailment should be carried out with power plants number 22 and 23.

Figure 6-7 illustrates the total generation variations after tripping a particular line at a particular load level. Figure 6-7 shows that the outage of line 28 is the most problematic contingency which needs the most generation re-dispatch if it trips. An amount of 158.2 MW generation re-dispatch is required after outage of line 28 at load level 1. The amount of re-dispatch at load level 2 and load level 3 is 370.1 MW and 102.9 MW, respectively. Also, for most cases, line outage at load level 2 requires more generation variation compared to other load levels. These results simply show the importance of analyzing the network at several load levels, as extreme cases do not necessarily occur at peak or off-peak load levels. As seen in Figure 6-7, there is no need for corrective action if some lines (such as line 1 or line 2) trip.

Table 6-3: Transmission capacities with/without generation re-dispatch

Line #	Expected Value (MW)		Practical Value (MW)	
	Without generation re-dispatch	With generation re-dispatch	Without generation re-dispatch	With generation re-dispatch
18	194.9	126.5	200	150
19	345.1	230.5	350	250
20	66.1	87.0	100	100
21	134.3	118.4	150	150
22	169.1	126.8	200	150
23	439.5	321.7	450	350
24	158.7	171.4	200	200
25	209.9	142.7	250	150
26	209.9	142.7	250	150
27	193.2	176.3	200	200
28	221.2	172.3	250	200
29	435.1	322.6	450	350
30	184.2	144.1	200	150
31	119.4	80.6	150	100
32	136.4	92.6	150	100
33	140.4	92.6	150	100
34	157.7	105.5	200	150
35	157.7	105.5	200	150
36	153.0	139.0	200	150
37	153.0	139.0	200	150
38	119.1	81.1	150	100
Investment	24.8%		23.8%	

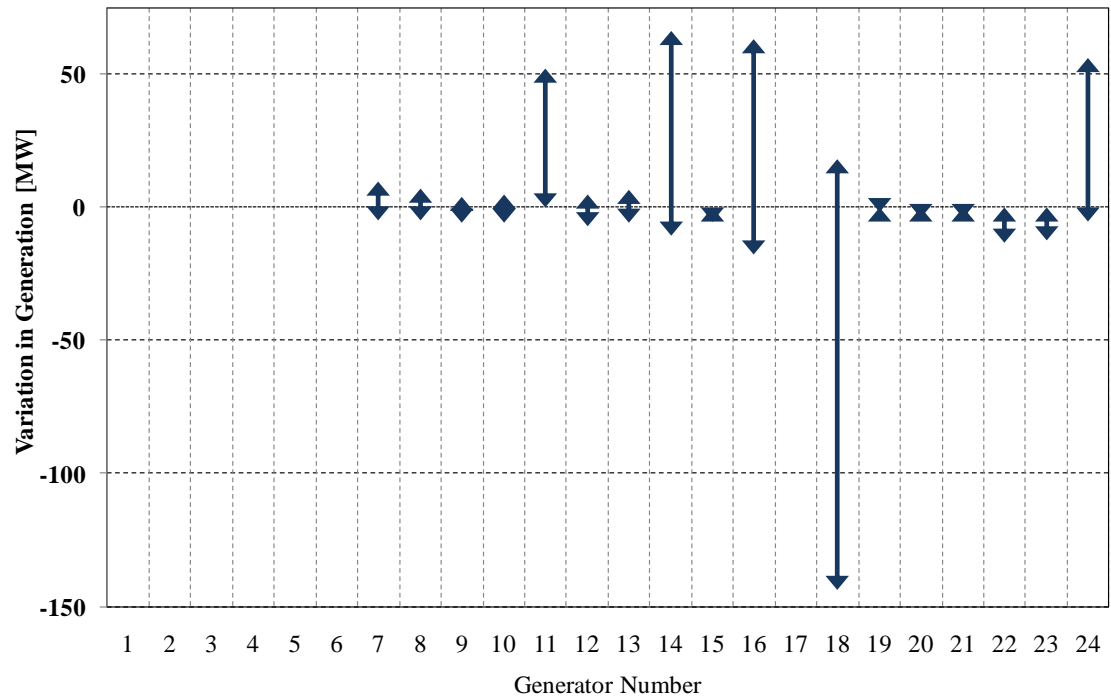


Figure 6-6: The range of variations in outputs of generators for generation re-dispatch scheme

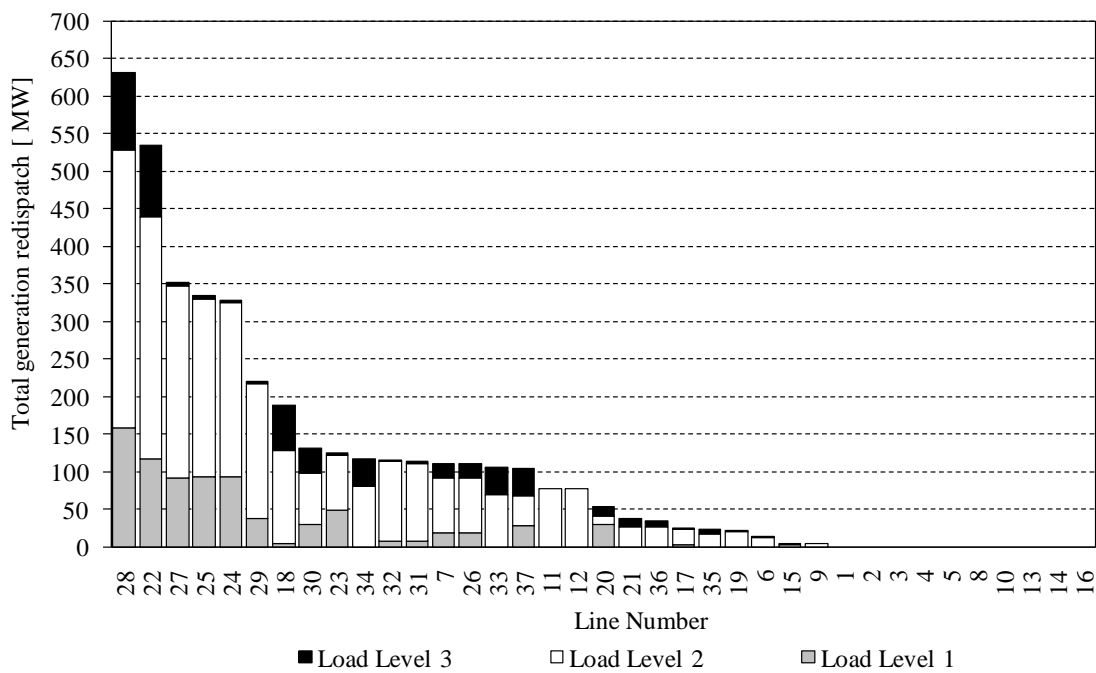


Figure 6-7: The total required generation re-dispatch after outage of a particular line at a particular load level

6.5.3 Performance in emergency conditions

As mentioned before, the expected capacity of each candidate line was rounded up to the closest practical transmission capacity. As the whole procedure for calculating the transmission capacities was probabilistic, considering the proposed practical capacities, the question which should be asked is: “What is the likelihood of having power flow exceeding the emergency thermal rating immediately after an outage?” To answer this question the probability distribution of power flowing through each of the candidate lines at the moment of outages is determined. For instance, Figure 6-8 shows the probability distribution of power flowing in line 19 following all possible outages at all load levels. The practical capacity proposed for line 19 is 250 MW and the power flowing through this line can temporarily go up to 375 MW (1.5×250 MW) which is the emergency thermal limit of line 19. The grey area covering from point 0 to 375 in Figure 6-8 represents the probability of having the power flows within the emergency thermal rating when an outage occurs. This probability for line 19 is 0.996.

The same calculation is carried out for all candidate lines and the results are depicted in Figure 6-9 where the numbers in the outer circle represent the line numbers. It can be seen from Figure 6-9 that, considering proposed capacities, the possibility of not exceeding the emergency thermal limits for most of the candidate lines is more than 0.99 which represents a reliable transmission network.

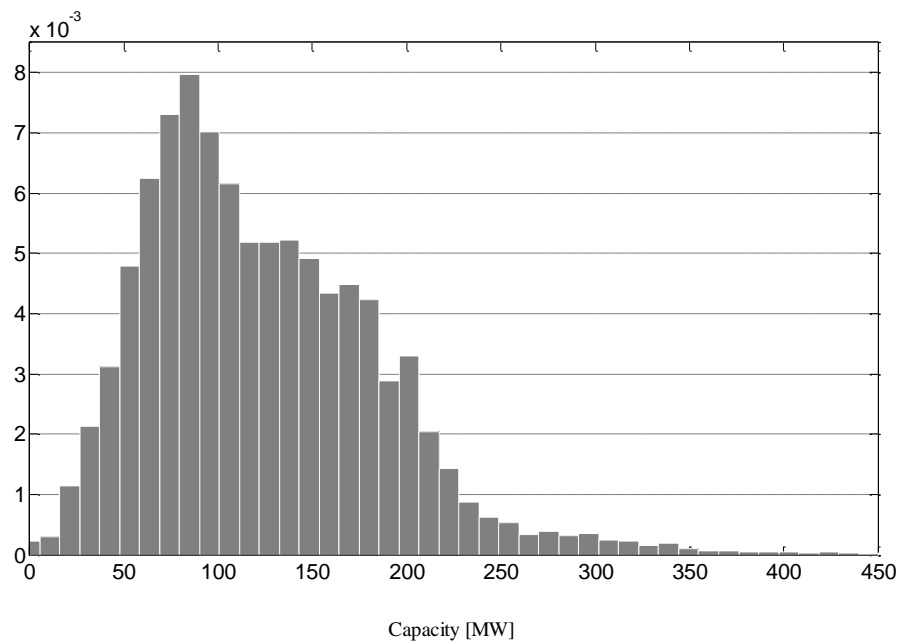


Figure 6-8: Probability distribution of power flowing through line 19, considering all outages at all load levels

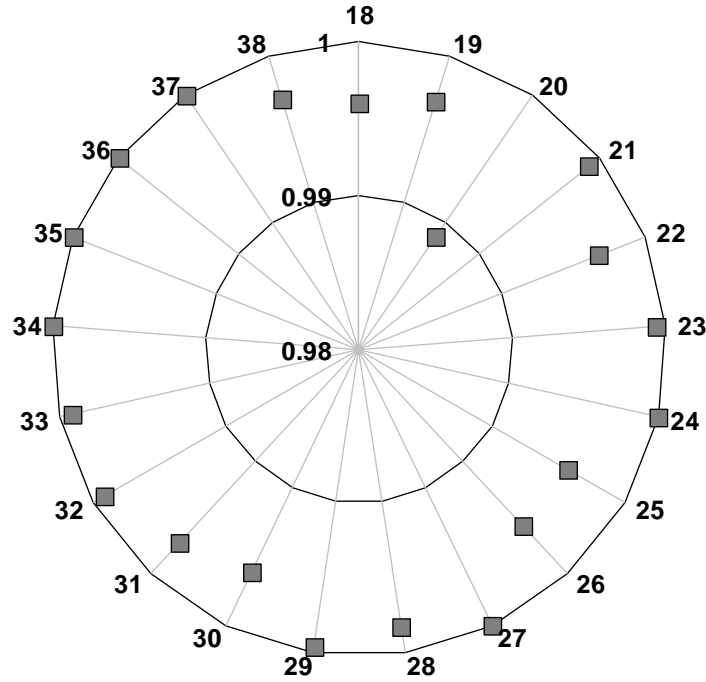


Figure 6-9: Probabilities for each candidate line to have flows within emergency thermal ratings at the moments of outages.

6.6 Conclusions

Transmission network planning under generation re-dispatch corrective control paradigm has been introduced in this chapter. Unlike traditional planning approaches assuming a dumb network, the proposed approach assumed that generators can rearrange their outputs to alleviate overloads following a line outage. The lines in the network are able to withstand overloads up to emergency thermal ratings for a short period. The generation rearrangement can be seen as an ancillary service provided by the power plants. The whole problem is formulated in the form of a mixed-integer optimization problem taking into account three states of the network, i) Intact network, ii) Contingent network in the instant of outage and iii) Steady state contingent network.

As wind power is set to be a key part of the future generation mix, a practical approach was proposed for generating wind power scenarios which should be accommodated by the transmission network. The Latin Hypercube Sampling method was deployed for generating the wind power samples. Moreover, a supplementary procedure was used to re-rank the generated samples in order to comply with correlation between wind power plants.

The proposed method was tested on the modified IEEE 24 bus reliability test system with high penetration of wind power. In general, the results answered two main questions: i) What are the required transmission topology and capacities for the horizon year? ii) What is the generators' contribution to post-contingency corrective action? The results showed that generators can effectively participate in post-contingency corrective action and a 23.8% reduction in transmission investment could be achieved. It was demonstrated that even with the reduction in transmission investment, transmission lines are still very unlikely to experience a current which is over the emergency thermal ratings. It should be stressed that these results are system specific so that the investment reduction is different in different systems.

Chapter 7. The application of dynamic thermal rating to facilitate wind power integration in Humber Estuary region

In this chapter the effect of dynamic thermal rating as one of the solutions for more effective utilisation of existing assets is investigated. Seasonal probabilistic models for dynamic thermal rating and the off-shore wind power are proposed. The correlation between off-shore wind power and the thermal ratings of transmission lines in Humber Estuary region, part of National Grid network, is also determined. In addition, the benefit of applying dynamic thermal rating is calculated.

7.1 Introduction

In the current operating regime, a constant conservative thermal rating is usually considered for a transmission line. The system operator usually calculates a constant thermal rating for a transmission line, taking into account the worst possible weather conditions. In practice, however, the thermal rating of transmission lines varies when the weather conditions change [185]. The conservative thermal rating is usually lower than the real-time thermal rating of a transmission line. Therefore, the transmission operator operates the system with a high security margin in a compromise which involves not utilising the transmission assets in an efficient way.

In order to accommodate the rapid growth of wind power generators a significant transmission investment is required, especially if a conservative thermal rating is considered for the network. However, network expansion is not an easy task and usually transmission network projects lag behind the completion of wind power plants. Therefore, wind power plants or other in-merit generators may be constrained off by the transmission operator in order to respect the transmission thermal ratings. One of the effective ways to alleviate this problem is to monitor the dynamic thermal rating of transmission lines whereby the network is operated taking into account the actual capacity of the transmission network and it is less likely that in-merit generators need to be curtailed.

Hur et al [186] note that in a deregulated environment transmission companies need to use their assets to the fullest level possible in order to maximise the benefit. In that paper the experience in The Electric Reliability Council of Texas (ERCOT) with the application of dynamic thermal rating and the benefit accruing to ERCOT is calculated. In another study, Huang et al [187] demonstrate a dynamic cable rating system (DCRS) which has been deployed to alleviate the congestion in a cable connected to a power plant in the south of Texas. In the proposed DCRS system, the weather forecast and the real-time market price are analysed in order to estimate the available ampacity and the best bidding strategy in the market.

Callahan et al [188] used the measured temperature of conductors of a 115 KV transmission line to demonstrate that 80% of the time in December the dynamic thermal rating is 15% higher than the fixed thermal rating. For June representing summer time, 90% of the time the dynamic thermal rating is 30% above the fixed thermal rating.

National Grid Company, which owns and operates the transmission network in England and Wales, faces a challenging task to accommodate the imminent wind powers. In order to facilitate the connection of wind powers, National Grid investigates different methodologies one of which is the application of dynamic thermal rating. Part of the transmission network, Humber Estuary region, is selected as a pilot zone to implement the dynamic thermal rating.

In this chapter, the benefit of using dynamic thermal rating in the Humber Estuary is calculated using a new probabilistic approach. The main contribution of this chapter is proposing probabilistic models for wind power and the dynamic thermal ratings based on the actual meteorological data of the past six years. The seasonal correlations between wind power and thermal ratings of transmission lines are also calculated. Using these probabilistic models and correlations, a sensitivity analysis is deployed to find the most effective transmission lines on which to install the dynamic thermal rating facilities as well as the expected benefit of using dynamic thermal ratings.

It should be stressed that this chapter, unlike previous chapters which mainly focused on transmission planning studies, uses dynamic thermal rating as a solution to reduce the operation cost for a given network. In other words, the network capacity is known in all studies in this chapter.

7.2 Thermal rating of transmission overhead lines

Many transmission companies, including National Grid, usually use a fixed thermal rating for short-term and long-term planning studies. This fixed thermal rating is calculated assuming extreme weather conditions and the maximum temperature which a conductor can tolerate before annealing which results in a greater conductor sag and smaller ground clearance. The fixed thermal rating is usually calculated for each season. For instance, Price et al [189] consider three different ratings for summer, spring/fall and winter. The ambient temperatures for these seasons are assumed to be 20°C, 9°C, and 2°C, respectively, and a 0.5 m/s wind speed is considered for all seasons.

The thermal rating of a transmission line is determined taking into account the thermodynamic balance between the heat generated by the conductor and the heat which the conductor loses through radiation and convection [177, 190]. The heat balance equation is expressed by (7-1).

$$P_J + P_s = P_R + P_C \quad (7-1)$$

P_J , P_s , P_R , and P_C are Joule heating, solar heating, radiative cooling and convective cooling, respectively. In Figure 7-1 the heat flows in a conductor are illustrated [191].

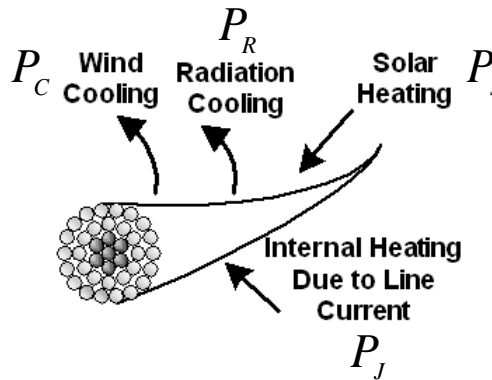


Figure 7-1: The steady state heat flows in a conductor [191]

The Joule heating is mainly generated due to current flowing in the conductor. The resistance of the conductor changes as the conductor's temperature varies. The Joule heating complies with following [189].

$$P_J = k.R_{dc}.I^2.(1 + \alpha.(T - 20)) \quad (7-2)$$

Where:

k Skin effect factor

R_{dc} DC resistance at 20°C (Ω/m)

I Current flowing in the conductor (A)

T The average temperature of the conductor (°C)

Solar heating is another driver which can increase the conductor's temperature. Solar heating is expressed by (7-3).

$$P_s = a.S.D \quad (7-3)$$

Where:

a is the Solar absorption coefficient

S is the Solar radiation (W/m²)

D is the External diameter of conductor (m)

The temperature of the conductor reduces through convection which depends on the wind velocity, the angle of wind direction and the ambient temperature. IEEE standard 738 [177] suggests two different equations for calculating the convective cooling in high and low wind speed, as formulated by (7-4) and (7-5), respectively.

$$P_c = \left(0.0119 \left(\frac{D \rho_f V_w}{\mu_f} \right)^{0.6} \right) K_f . K_{angle} . (T_c - T_a) \quad (7-4)$$

$$P_c = \left(1.01 + 0.0372 \left(\frac{D \rho_f V_w}{\mu_f} \right)^{0.52} \right) K_f . K_{angle} . (T_c - T_a) \quad (7-5)$$

Where

k_f Thermal conductivity of air W/(m·°C)

K_{angle} Wind direction factor

V_m Wind speed (m/s)

ρ_f Density of air (Kg/m³)

μ_f Dynamic viscosity of air (Pa-s)

T_c The conductor temperature (°C)

T_a The ambient temperature (°C)

Radiation also helps the cooling process of the conductor. The conductor loses heat through the radiation as formulated with (6)

$$P_r = 0.0178.D.\varepsilon \left[\left(\frac{T_c + 273}{100} \right)^4 - \left(\frac{T_a + 273}{100} \right)^4 \right] \quad (7-6)$$

Where ε is the emissivity of conductor.

The most important parameters influencing the maximum thermal rating of a transmission line are wind speed, wind direction, conductor characteristics, ambient temperature, and the profile of the overhead line. An overhead line consists of many sections (a segment of transmission line which is laid between two pylons in a transmission lines) each of which has different ground clearance. The segment which has the lowest ground clearance usually dictates the thermal rating in the whole transmission lines.

National Grid considers a seasonal constant thermal rating for the transmission lines. For example, for a two bundles 400 KV overhead line with Redwood conductor, the thermal ratings are 2660 MW, 2880 MW and 3070 MW for summer, spring/fall and winter respectively. Nonetheless, the actual thermal rating, which dynamically varies with variations in weather conditions, is usually higher than the conservative seasonal thermal ratings. The hourly thermal rating of aforementioned conductor is calculated using the hourly meteorological data and the equations (7-1) to (7-6). In Figure 7-2 the dynamic thermal rating and the seasonal thermal ratings are illustrated. According to the calculations, only in 5.9% of the time during the year the dynamic thermal rating is below constant thermal ratings. In other words, a power higher than seasonal ratings can be transported through this transmission line on around 94% of occasions.

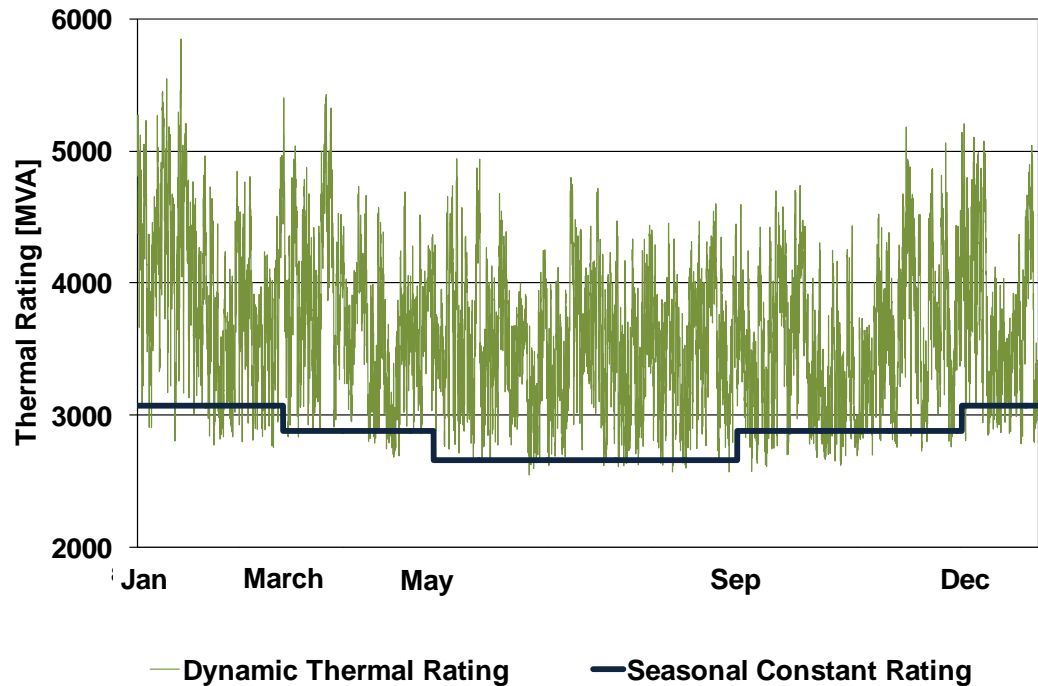


Figure 7-2: Dynamic thermal rating and seasonal constant thermal rating for a double bundle overhead line with a Redwood conductor (AAAC)

7.3 Case study of Humber Estuary region

Humber Estuary region shown in Figure 7-3 was selected as a pilot project to demonstrate the impact of dynamic thermal rating. A 3.2 GW capacity of wind power is scheduled to connect to this region by 2020. There is however insufficient transmission capacity to accommodate this amount of wind power securely as not all required network expansion/reinforcement projects will be concluded by 2020. Consequently, generators in Humber Estuary as well as other parts of the network should be constrained off. This problem will get worse when more wind power plants are commissioned. Ultimately two large wind farms, namely Dogger Bank and Hornsea with the total capacity of 11 GW are planned to connect to Humber Estuary region. Facing a high penetration of wind power along with the shortage in transmission capacity has made Humber region a suitable case study for investigating of the effect of dynamic thermal rating.

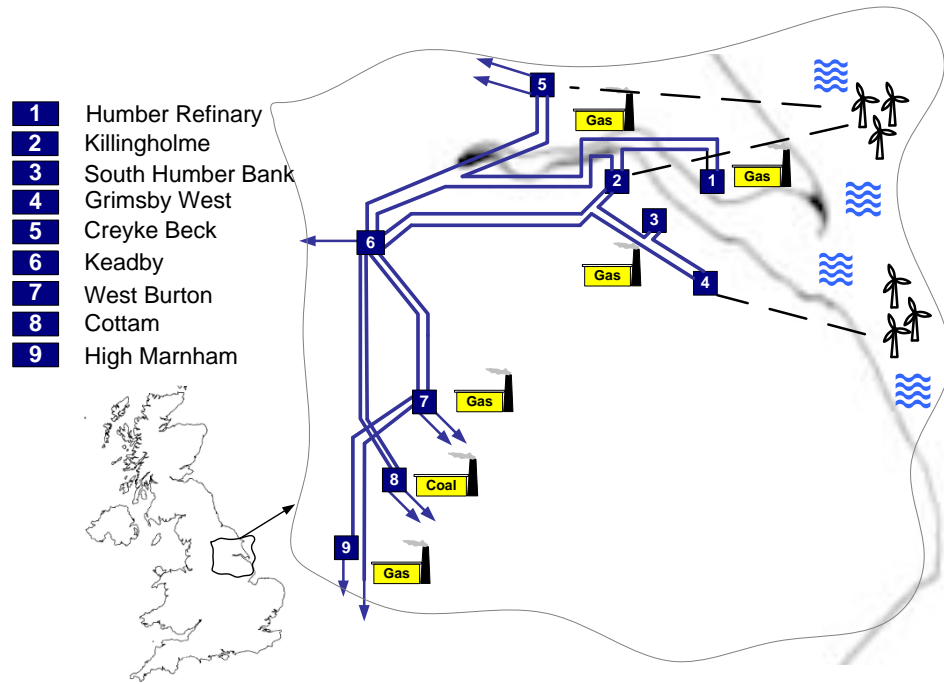


Figure 7-3: Humber Estuary region which is selected for dynamic thermal rating study

7.4 Methodology

As explained in the Introduction, section 7.1, the main focus of this study is on the application of dynamic thermal rating in the Humber Estuary region. Two main questions are answered in this study. First, which transmission lines in Humber region should be prioritised for real-time thermal rating monitoring? Secondly, what is the benefit of deploying dynamic thermal rating? The study is undertaken for the network conditions in winter 2020. Therefore, the topology of the network, demands, and generation mix are all modelled for winter 2020.

As shown in Figure 7-2, the thermal rating of a transmission line is very likely to dynamically vary in course of the year. Moreover, the available wind power is highly dependent on the wind speed which is in essence volatile. In order to model these volatilities, thermal ratings and wind powers and the availability of other generators in year 2020 are modelled with relevant probabilistic distribution functions.

Monte Carlo simulation is used to generate many generation- line thermal rating scenarios for which the impact of dynamic thermal ratings is investigated. In the process of generating the scenarios, the correlation between wind farms, correlation between thermal ratings of transmission lines, and the correlation between the thermal ratings and wind farms are also taken into account.

According to the National Electricity Transmission Security and Quality of Supply Standard (Net SQSS) [21] practiced by National Grid the network should be robust against any single outage, “N-1”, and any double circuit outages, “N-2”. These security criteria are taken into account in this study.

In order to determine the importance of each transmission line in terms of need for monitoring the real-time thermal rating a sensitivity analysis is run on the network. This sensitivity analysis is in fact a comparison between the possibility of overloads in the network with and without dynamic thermal rating model of transmission lines. For all generation- line thermal rating scenarios generated by Monte Carlo Simulation, a security constrained optimal power flow (SCOPF) in which the security criteria of only Humber region is relaxed is run. This calculation shows what the optimum generation dispatch should be in the Humber region regardless of the available transmission capacity. The next step is to assess the possibility of reaching the optimum dispatch in Humber region by using different thermal ratings, namely seasonal thermal ratings and dynamic thermal ratings. Therefore, assuming the generation dispatch proposed by SCOPF, single outages and double outages are applied to the transmission network in Humber region. The number of occasions when overloads manifest in a transmission line in the intact and contingent networks is noted for two cases where in the first case the transmission line dynamic thermal model is considered and in the other case seasonal thermal rating is considered. This analysis shows the level of overload alleviation by using dynamic thermal rating for each individual transmission line.

In addition, the economic benefit from monitoring the temperature of transmission lines is calculated. By operating the system based on real-time thermal rating, it is less likely that in-merit generators are constrained off in preference for optimally located out-of-merit generators. In other words, by the extra transmission capacity offered by dynamic thermal rating the network operator can alleviate the network congestion and enhance the competition in the energy market. The benefit of using dynamic thermal rating in the Humber region is calculated by comparing the total generation cost with and without dynamic thermal rating. The SCOPF is run for all the scenarios in winter 2020, and the total generation cost is calculated in two cases. In the first case, the capacities of transmission lines comply with seasonal thermal ratings and the other case dynamic thermal rating models of transmission lines are applied. The difference of total generation cost in these two cases is determined for all generation-line thermal rating

scenarios. The average of all these differences is the expected reduction in generation cost by using dynamic thermal rating.

7.5 Modelling

This study is carried out for winter 2020. The generation, demand and topology of the network are all modelled for winter 2020. The volatility of wind power and thermal ratings are modelled with probabilistic distribution functions. In the following subsections these models are elaborated.

7.5.1 Network topology

As the main focus of this study is on the Humber Estuary, the transmission network in this region is modelled in detail. The rest of the UK network, however, is split into five major regions, namely Scotland, North, Central East, Central West, and South. These major regions are connected to each other as well as Humber Estuary through tie lines whose thermal ratings are similar to corresponding transmission lines in the full model of the network. The boundaries and the schematic diagram of the reduced model are shown in Appendix E. The network topology has been verified by comparing the resultant power flows of tie lines between the reduced model and the 2011 full network model in PowerFactory.

7.5.2 Generation and demands

The data for generation and demand are based on the Winter Peak Model obtained from Economic Future Strategy team in National Grid Company. Due to a confidentiality agreement, the details of generation and demand information are not released in this thesis; nonetheless, general information is given in this section.

An eight load level demand model for winter period in 2020 is assumed. In Figure 7-4 the total demand and duration of each load level are depicted.

The total generation capacity for 2020 is assumed to be 93.6 GW made up of different types of generation, see Figure 7-5. The total capacity of wind power is 27.08 GW of which 3.2 GW is connected to the Humber Estuary region.

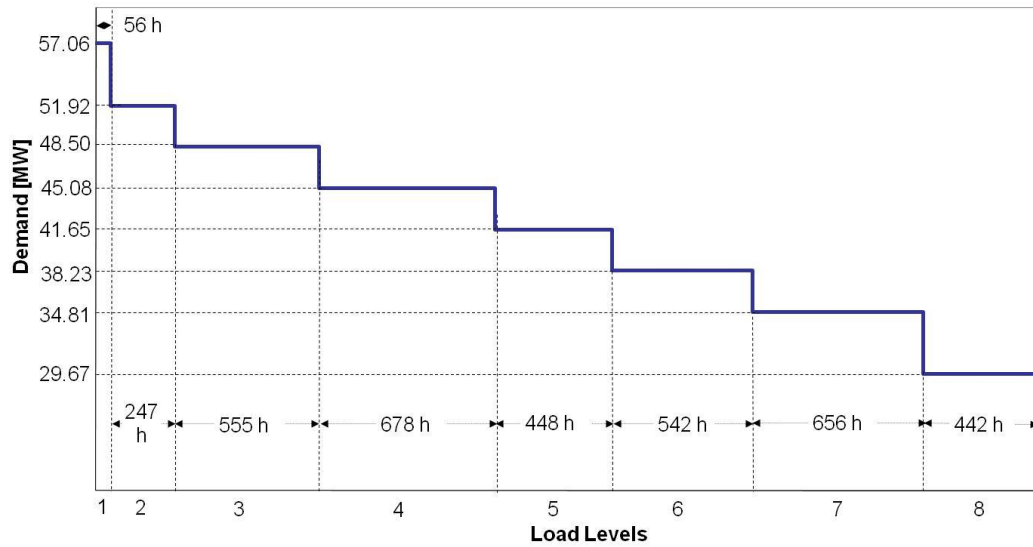


Figure 7-4: The profile of total demand in National Grid's Network in winter 2020

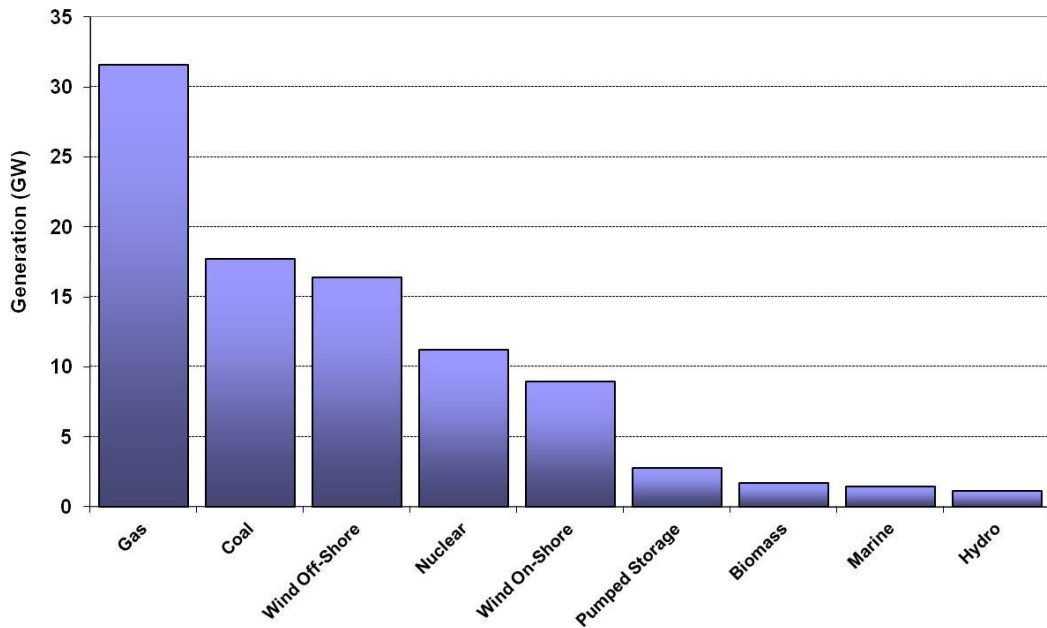


Figure 7-5: The generation mix in winter 2020

7.5.3 Wind power modelling

All wind power plants scheduled to be commissioned by 2020 are taken into account in this study. Poyry company under contract with National Grid calculated the hourly capacity factor of wind power from 2002 to 2008 in different sites in the UK [192]. The data for those sites which are close to the wind farms operating in winter 2020 are taken into account to estimate the probability distribution function of wind power. The selected spots are illustrated in Figure 7-6.

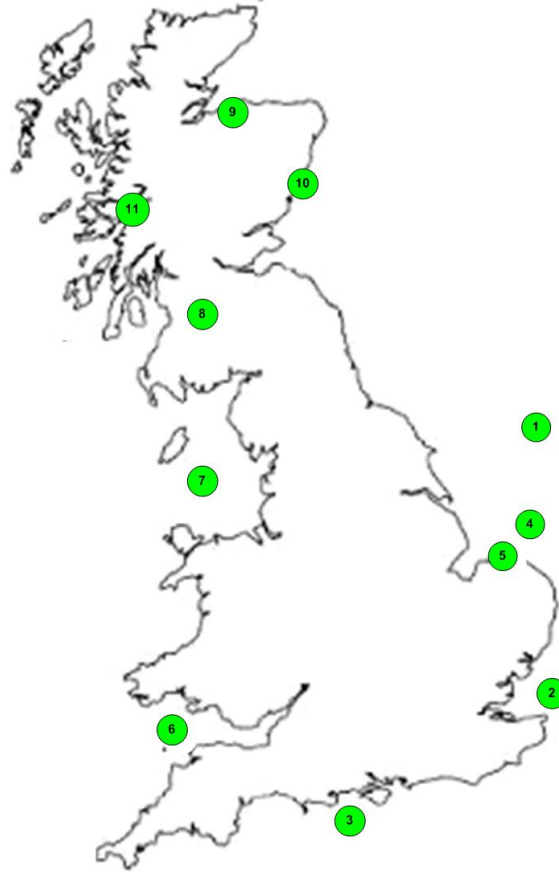


Figure 7-6: The location of sites whose hourly wind power capacity factors 2002 to 2006 are available.

The best standard probabilistic distribution function which can be fitted to the hourly capacity factor data is the Beta distribution which is mathematically expressed by (7-7).

$$f(x) = \frac{1}{B(a,b)} \cdot x^{a-1} \cdot (1-x)^{b-1} \quad (7-7)$$

Beta distribution is defined in the interval $x \in (0,1)$. a and b are shape parameters and $B(a,b)$ is the Beta function.

Different probabilistic models can be estimated for different seasons, using six years hourly capacity factors. For example, the seasonal Beta distributions of wind power capacity factor for site number 1, where Dogger Bank and Hornsea are located, are estimated from (7-7). The shape parameters of these seasonal distributions are given in Table 7-1.

Table 7-1: Parameters of Beta functions modeling the wind power

Season	a	b
Winter	0.56	0.47
Spring/Fall	0.56	0.65
Summer	0.61	1.53

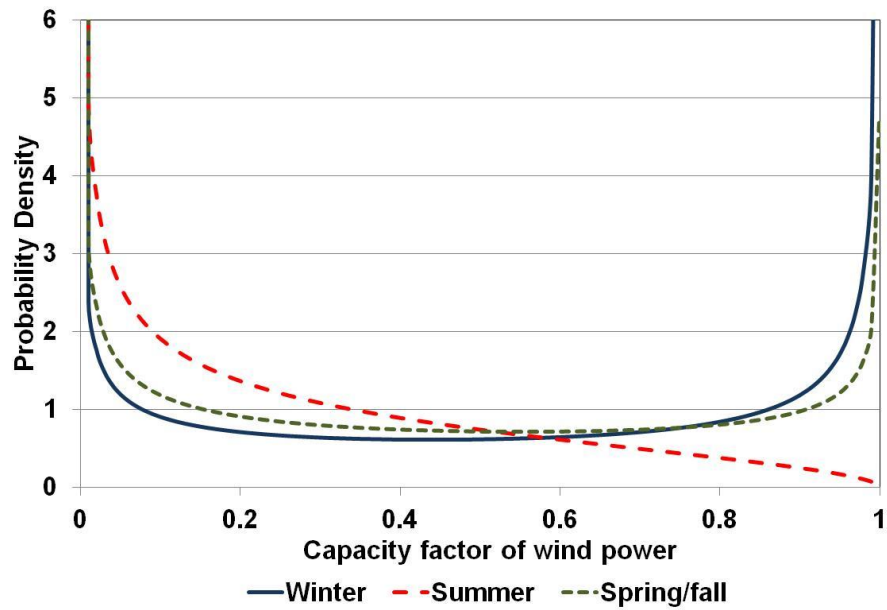


Figure 7-7: The probabilistic distribution functions of capacity factor of Dogger Bank and Hornsea

The same calculation is carried out to estimate the parameters of Beta distributions at other sites shown in Figure 7-6 . Table 7-2 shows the results this calculation for the winter period.

Table 7-2: Parameters of Beta distribution function modeling capacity factor of wind power at different sites in the UK

Site #	a	b	Site #	a	b
1	0.56	0.47	7	0.56	0.50
2	0.62	0.67	8	0.35	0.84
3	0.58	0.554	9	0.40	0.50
4	0.55	0.54	10	0.45	0.63
5	0.58	0.69	11	0.44	0.51
6	0.54	0.60			

7.5.4 Dynamic thermal rating modelling

Four years, from 2006 to 2010, historical meteorological data from a weather station near the Humber region are used to estimate the probability distribution function of thermal ratings of transmission lines in Humber region. In this calculation, it is assumed that all sections of transmission lines in Humber region are exposed to the same wind speeds and ambient temperatures.

To do so, first, for every transmission line, the hourly weather information as well as the parameters of conductor are plugged into the equation (7-1) to (7-6) to calculate the four years hourly thermal rating. The variations of thermal ratings are modelled with a probabilistic distribution function. Among all standard distributions, the best distribution function matching with calculated hourly thermal rating is the Generalized Extreme Value which is formulated by (7-8).

$$f(x) = \left(\frac{1}{\sigma} \right) \cdot \left(1 + k \cdot \frac{(x - \mu)^{-\frac{1}{k}}}{\sigma} \right) \cdot e^{\left(- \left(1 + k \cdot \frac{(x - \mu)^{-\frac{1}{k}}}{\sigma} \right) \right)} \quad (7-8)$$

Where μ is location parameter, σ is called scale parameter, and k is shape parameter.

The probability distribution functions of seasonal thermal ratings for Grimsby west-Keady are shown in Figure 7-8. It is noted from Figure 7-8 that the thermal rating is more likely to be higher in winter. Nonetheless, it is possible for summer thermal rating to be higher than winter thermal rating. In other words, as the actual variation of meteorological data is considered, this modelling is more accurate than the fixed seasonal thermal rating model, which always considers the highest thermal rating for winter time. The parameters of Generalized Extreme Value distributions for other transmission lines shown in Figure 7-3 are given in Table 7-3.

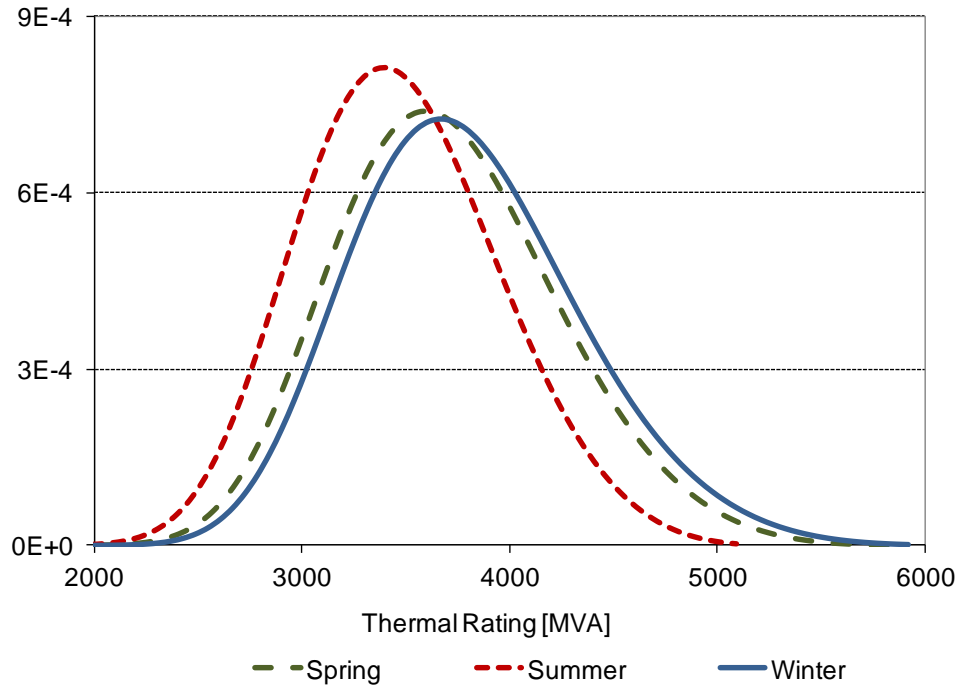


Figure 7-8: Probability distribution functions of thermal ratings of Grimsby West-South Humber Bank for different seasons

Table 7-3: Parameters of PDFs representing seasonal thermal ratings of overhead lines in Humber region

OH Lines		Spring			Summer			Winter		
From	To	k	σ	μ	k	σ	μ	k	σ	μ
3	2	-0.19	499.91	3395.10	-0.22	458.20	3185.15	-0.18	507.31	3481.10
2	6	-0.19	499.91	3395.10	-0.22	458.20	3185.15	-0.18	507.31	3481.10
4	6	-0.19	506.91	3492.09	-0.22	464.42	3285.01	-0.17	514.22	3572.25
4	3	-0.20	483.32	3187.84	-0.23	443.13	2971.20	-0.19	490.48	3287.14
2	1	-0.19	506.72	3491.41	-0.22	464.58	3285.71	-0.17	514.45	3572.45
1	5	-0.19	506.72	3491.41	-0.22	464.58	3285.71	-0.17	514.45	3572.45
2	6	-0.19	506.72	3491.41	-0.22	464.58	3285.71	-0.17	514.45	3572.45
6	7	-0.19	533.47	3134.00	-0.24	487.35	2831.70	-0.21	547.42	3308.77
6	7	-0.19	533.47	3134.00	-0.24	487.35	2831.70	-0.21	547.42	3308.77
8	6	-0.19	372.86	2468.92	-0.21	334.57	2319.49	-0.23	410.67	2525.25
8	6	-0.19	372.86	2468.92	-0.21	334.57	2319.49	-0.23	410.67	2525.25
7	9	-0.19	372.86	2468.92	-0.21	334.57	2319.49	-0.23	410.67	2525.25

As a linear DC model is used for the network, possible voltage violations or stability problems do not manifest in the power flow studies in the cases where high thermal ratings are suggested by relevant PDFs. In order to have a more practical approach, it is assumed that, firstly, 90% of the thermal ratings are available since the reactive power is neglected in the DC model, and secondly, thermal ratings scenarios are not allowed to

be larger than 25% of seasonal constant thermal ratings. In other words, the thermal ratings scenarios are generated first and if they are larger than 25% of winter thermal rating they are capped at 25% above winter thermal rating. This cap is suggested through discussion with network planner engineers working with National Grid.

7.5.5 Correlation

There is a correlation between the wind power and dynamic thermal ratings. As wind blows there is more wind power available and at the same time the conductors of transmission lines may lose more heat through convection so it is likely that there is a larger transmission capacity available. In Figure 7-9 the variations of the thermal rating of Grimsby West-Keadby and the capacity factor of Dogger Bank wind farm during winter period are shown. As it can be seen, there is a correlation between these variations. The correlation between wind power and thermal rating for each season is calculated using four years historical data of hourly thermal rating of Grimsby West-Keadby and Dogger Bank capacity factor. These seasonal correlations are given in Table 7-4.

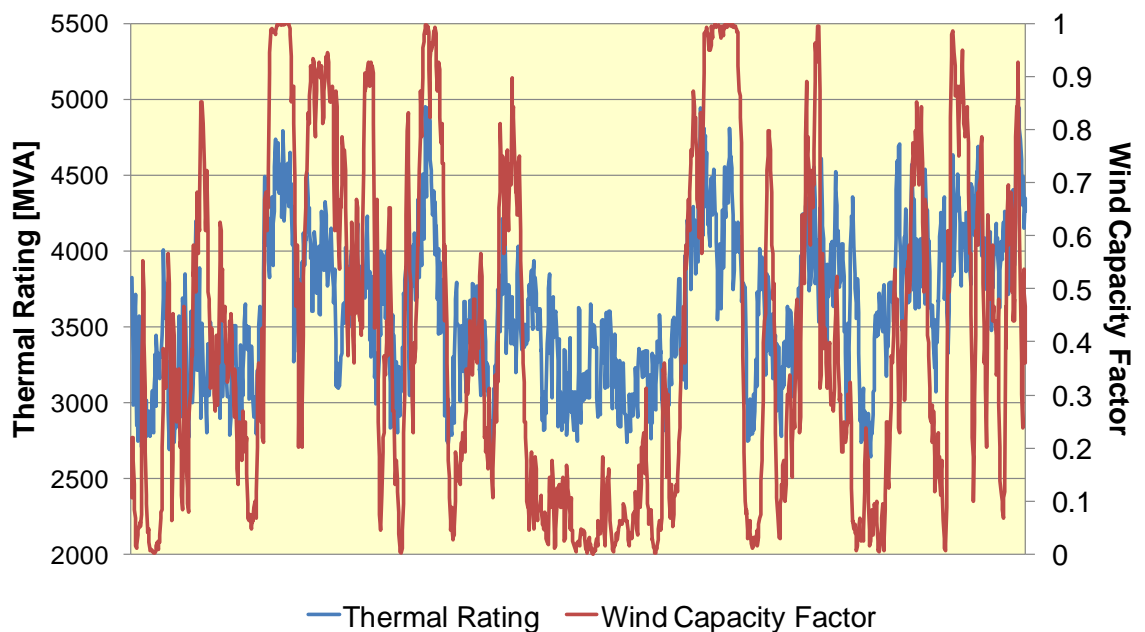


Figure 7-9: The chronological variation of capacity factor of wind and thermal rating

Table 7-4: The correlations between thermal rating of overhead lines and off-shore wind power in Humber region

	Thermal Rating		
	Spring/Fall	Summer	Winter
Capacity Factor of Wind farms	0.549	0.47	0.659

There are also correlations between outputs of wind power plants which correspond to the sites shown in Figure 7-6. Six years hourly capacity factor of all these sites are used to calculate the correlations between them. In Table 7-5, these correlations for winter period are given.

Table 7-5: The correlations between wind powers generated in winter by the sites shown in Figure 7-6

	1	2	3	4	5	6	7	8	9	10	11
1	1	0.51	0.38	0.68	0.64	0.4	0.54	0.38	0.32	0.41	0.31
2	0.51	1	0.77	0.77	0.82	0.58	0.52	0.25	0.19	0.33	0.19
3	0.38	0.77	1	0.58	0.62	0.74	0.52	0.23	0.09	0.28	0.15
4	0.68	0.77	0.58	1	0.95	0.52	0.64	0.41	0.33	0.46	0.31
5	0.64	0.82	0.62	0.95	1	0.53	0.63	0.35	0.32	0.43	0.28
6	0.4	0.58	0.74	0.52	0.53	1	0.68	0.37	0.13	0.33	0.28
7	0.54	0.52	0.52	0.64	0.63	0.68	1	0.55	0.36	0.51	0.47
8	0.38	0.25	0.23	0.41	0.35	0.37	0.55	1	0.42	0.58	0.48
9	0.32	0.19	0.09	0.33	0.32	0.13	0.36	0.42	1	0.56	0.48
10	0.41	0.33	0.28	0.46	0.43	0.33	0.51	0.58	0.56	1	0.44
11	0.31	0.19	0.15	0.31	0.28	0.28	0.47	0.48	0.48	0.44	1

Moreover, the correlation between thermal ratings of transmission lines in Humber region is assumed to be 0.8 as all transmission lines experience almost the same weather condition.

7.6 Results

Monte Carlo simulation is used to generate many generation-line thermal ratings scenarios. Each scenario consists of the availabilities of generators, the available wind powers, and the thermal ratings of transmission lines in Humber region. All scenarios firstly are in consistent with the relevant probabilistic distribution functions. Secondly, they comply with the correlations which were calculated in the previous section. It should be noted that the OPF does not converge for some generation-line thermal rating scenarios where for the given generation availabilities and thermal ratings the generation-demand balance cannot be satisfied. Those scenarios are eliminated from this study.

7.6.1 Sensitivity analysis

As explained in Section 7.4, The SCOPF with relaxed security constrained only for Humber region is run for all generation-line thermal rating scenarios. Next, the resultant generation dispatches are used to examine the effect of dynamic thermal ratings when “N-1” and “N-D” contingencies occur. 17 single outages and 9 double outages are considered.

Table 7-6 shows the probability of overload occurring in the intact network and in the contingent networks. It should be noted that Table 7-6 only shows those transmission lines which experience overload. According to Table 7-6, West Burton- High Marnham is the transmission line which has a high priority for monitoring the real-time thermal rating. Killingholme-Keadby is the next transmission line which can improve the post-contingency overloads by monitoring its real-time thermal rating.

Table 7-6: The probability of overload in transmission lines in Humber region

	OHL		Normal Condition	"N-1" Condition	"N-D" Condition
	From	To			
Constant thermal rating	7	9	0.013	0.156	0.168
	8	6	0.000	0.050	0.049
	2	6	0.000	0.011	0.071
Dynamic seasonal rating	7	9	0.007	0.016	0.029
	8	6	0.000	0.006	0.004
	2	6	0.000	0.001	0.044

7.6.2 Operation cost

There are three different types of generation in the Humber region namely gas, coal and wind. Under the current operation regime which assigns a fixed thermal rating for transmission lines, power plants are likely to be constrained off, in order to respect Net SQSS practiced by National Grid. The expected total generation cost during winter time 2020 when a fixed thermal rating is considered for transmission lines is £4632.8 M. The SCOPF is run for all generation- line thermal rating scenarios to calculate the expected reduction in generation cost if dynamic thermal rating is considered.

As mentioned before, High Marnham- West Burton is an important transmission line in terms of causing congestion in the Humber area the importance of this transmission line is examined as well. To do that, the generation cost is calculated in two cases where in

the first case the dynamic thermal ratings of all transmission lines in the Humber area except West Burton-High Marnham are modelled, and in the second case the dynamic thermal rating of West Burton-High Marnham is also taken into account.

Running the SCOPF for all generations-thermal rating scenarios, the results show that there is no saving in generation cost for the first case, whereas the saving in the second case is £26.7 M. This result stresses that West Burton–High Marnham is an important transmission line in terms of causing congestion in the Humber area.

The saving in generation cost at each load level is shown in Figure 7-10. The results suggest that a higher benefit can be achieved during high load levels.

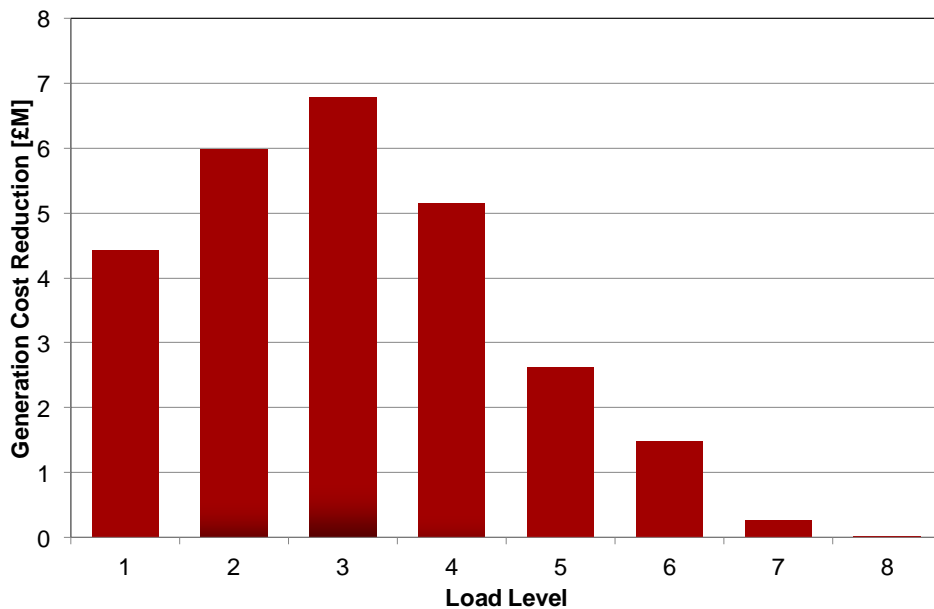


Figure 7-10: The total generation cost reduction by using dynamic thermal ratings in Humber region

Figure 7-11 shows the expected variation in energy generated by each power station in Humber region if dynamic thermal ratings are used. The base coal generation in Cottom followed by gas generation in West Burton and Killingholme are very likely to increase the total energy generation during winter period. In total, it is expected that the Humber region increases the generation by 825.3 GWh.

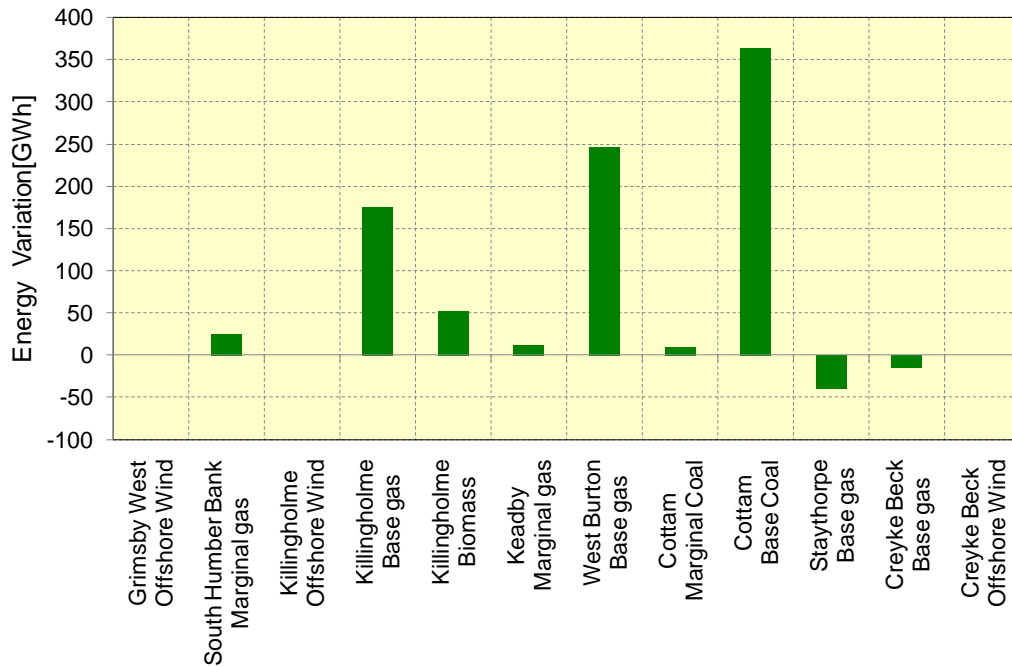


Figure 7-11: Variation in energy generated by power stations in Humber region

7.7 Conclusions

Under the current operation regime, the network is operated and planned on the basis of conservative thermal ratings for transmission assets. In this way, the transmission network is not fully utilised and the system is run in an inefficient way. In a smart operation scheme, the real thermal ratings of transmission assets are considered for the short-term operation and long-term planning. In this chapter, the application of dynamic thermal rating in a part of National Grid transmission network was examined.

The study focused on the Humber region where a high penetration of wind power is scheduled. In this region gas and coal generation types are also in operation so that Humber region always exports power to other parts of the network. Due to lack of transmission capacity, however, the generation in this region should be curtailed especially after connection of wind powers.

To alleviate the network congestion problem, the operation under the real-time thermal ratings of transmission lines was proposed in this chapter. The volatilities of wind powers in the Humber region as well as other parts of the UK network in winter 2020 were modelled with Beta distribution functions. Four years meteorological data were also used to estimate the probabilistic distribution function of thermal ratings of transmission lines in Humber region. The correlations between wind farms around the

UK were calculated. There is also a correlation between the thermal ratings of transmission lines and wind powers. This correlation was determined as well.

Monte Carlo was used to generate many scenarios representing the generation as well as thermal ratings. These scenarios comply with relevant distribution functions and the corresponding correlations. Taking into account all scenarios, a sensitivity analysis was proposed in order to find those transmission lines which are in priority for real-time thermal rating monitoring. Results showed that High Marnham-West Burton and Killingholme – Keadby were the most important transmission lines in terms of dynamic thermal rating.

In addition, the benefit from using dynamic thermal rating was calculated. The calculations demonstrated that a £26.7 M reduction in generation cost is likely to be gained if dynamic thermal rating is practiced. The Humber region is also expected to increase energy generation by 825.3 GWh whereas this amount is likely to be curtailed if dynamic thermal rating is not deployed.

Chapter 8. Conclusions

In this chapter a summary of the thesis, the main concluding remarks, achievements as well as contributions of this work are given. Suggested areas for further research are also outlined.

8.1 Overview

The architecture and the regulation of electric power systems have been evolving in many countries to achieve the energy policy targets which have been set to deliver sustainable, reliable, and affordable energy. The transmission network has a crucial role to accommodate these evolutions and facilitate the success of energy policy targets. However, there are challenges which need to be addressed and tackled by transmission network operators and planners. Transmission operation and planning philosophies need to be revised so as to fulfil the requirements of the future grid. The challenges from transmission planners' and operators' point of view arising from changes in the power system can be summarised as follows:

- ***Restructuring of the power system and operation of generators in an electricity market***

The role of the transmission network is very important in competitive electricity markets by providing non-discriminatory access to the network to all participants (generators and demand) thereby creating a level playing field. The closure and commissioning of generators are planned by different independent GenCOs. This structure introduces a high degree of uncertainty on the generation side into the transmission expansion planning problem. The challenge is to propose a transmission expansion proposal which can economically accommodate these uncertainties while the network security criteria are respected.

▪ ***Emergence of CO₂ emission trading market***

The CO₂ emission cost has a direct effect on the operating cost of generators and has exhibited a very volatile behaviour in the past. For instance, in April 2006, the emission allowance price rapidly fell from €32/tCO₂ to €10/tCO₂. The volatility in CO₂ emission price results in the uncertainty in generation costs and ultimately the merit order of generators. In particular, this affects those generator technologies which have a higher CO₂ emission. The operation cost of generators is the key term in transmission expansion planning objective function. Therefore, the challenge is to propose a transmission plan which is resilient to CO₂ emission price variations.

▪ ***Rapid growth of renewable energies***

The power availability of renewable resources depends highly on natural phenomena leading to non-dispatchable intermittent and fluctuating power output. The existing network, however, has been designed and is operated for completely different generation mix which is dispatchable and has predictable power output. The challenge is to upgrade the current network operation codes and planning approaches in order to facilitate the integration of fast growing renewable energy resources while maintaining the security of supply at a high standard level.

▪ ***Developments on demand side***

It is very likely that consumers in the next decade will be price responsive. In other words, consumers are likely to shift part of their consumption to the times when the energy price is low. This behaviour may change the consumption pattern and the load profile.. The challenge is how to consider the price responsive demands and the effect of consumption pattern changes e.g. peak shifting in transmission expansion planning study so that any excessive transmission investment can be avoided. Furthermore, the effect of other possible demand response programmes need to be taken into account in timing of transmission planning in order to avert any unnecessary investment in primary transmission assets.

In addition, the electrification of transport and heating systems are in the the energy policy agenda. Emergence of electric vehicles as the key feature of electrification of transport, on the one hand, results in a higher growth rate of energy demand than the normal rate so that a larger investment in transmission networks is required. On the other hand, however, the electric vehicles to some extent can offer a flexible supply/demand opportunity by using their storage capability. From a transmission planners' and regulatory bodies' point of view, the challenge is to provide enough transmission capacity for electric demand in transport while the energy storage capability of electric vehicles is taken into account. It should be also noted that the growth rate of electric vehicles and the success in electrification of transportation systems still depends on the developments in electric energy storage technologies and investment in charging infrastructure. This poses a high uncertainty on the future energy demand.

As pointed out earlier, the main challenge for transmission operators and planners is to revise operation philosophies and investment planning approaches so as to securely and economically accommodate a high level of uncertainties in the future power system. In order to do that, the transmission network needs to be economically and technically flexible to cope with uncertainties and credible contingencies.

Traditionally, flexibility of transmission networks can be achieved by enhancing the transmission capacity by investing in primary transmission network assets. This approach is basis for the preventive control operation strategy. Preventive control is an inflexible and conservative operational approach under which the possible post-contingency corrective actions are not taken into account and the network services must not be interrupted by any unplanned contingency. Under preventive control, a significant part of the network capacity is kept in reserve to cater for contingency conditions which occur very infrequently. This mode of operation leads to inefficient utilisation of network assets.

Although, to date, preventive control operation has served the power system well, this operation philosophy is not a smart solution for future networks. Flexibility which is the main requirement of future transmission network cannot be delivered by deploying preventive control strategies since under these strategies a significant network reinforcement is required to accommodate uncertainties on both generation and demand side while maintaining system security. It is however very difficult and expensive to

expand transmission networks. Further, investing exclusively in primary network assets is a prohibitively expensive and inefficient option for enhancing the flexibility of the network.

It was elaborated in this thesis that deploying corrective control is one of the feasible options for enhancing the flexibility and the efficiency of the transmission network. Under a corrective control regime, the post-fault corrective actions can be utilised flexibly to mitigate the post-contingency network violations. This would diminish the need to reserve part of the transmission capacity to deal primarily with contingencies.

Under the “smart grid” vision, monitoring and controlling the power system components by intelligent decision making software is essential. By utilising intelligent systems underpinned by a broad communication system which can monitor and predict accurately the status of the power system, it is expected that post-fault corrective actions will become a reliable option for a smarter operation regime in the future.

Transmission network investments, however, need to be planned well in advance as transmission planning projects tend to be very time-consuming. As the future network will be operated under a flexible operation philosophy, it is time to contemplate the size and the shape of transmission network which will be operated under a flexible operation regime. Unlike traditional approaches which fulfil the security criteria only by proposing a large transmission network, the topology and the capacity of future transmission network need to be calculated assuming the possible flexibility and corrective actions which can be deployed to tackle contingencies as well as uncertainties. Transmission network companies are encouraged by regulatory bodies , for example Ofgem in the UK, to deploy the innovative technologies and strategies by which the network can be utilised in a more efficient way while the security of supply remains at a high level of standard

Through extensive literature review on transmission planning studies, this thesis demonstrated that although post-fault corrective actions are sometimes deployed by transmission operators to eradicate transmission network violations, most studies consider the preventive control philosophy as the default practice to fulfil the security criteria. However, the transmission network planning approaches need to be reviewed in order to consider the feasible flexibilities of the future network in the timing of

investment planning. This issue was the main focus in this thesis. In general, the following issues have been investigated in this thesis:

- ***A thorough review of transmission planning issues, ranging from the network modelling to the issues in the modern power system***

The methods and techniques which are traditionally used for transmission planning were broadly reviewed. The ongoing changes in power system were also reviewed and the effects of these changes on the transmission investment decisions were elaborated.

- ***Reviewing the application of post-contingency corrective actions in the current power system***

The possible corrective actions and the objectives of deploying them by the past studies were thoroughly reviewed. The operational constraints and the associated costs with different corrective actions were investigated.

- ***Modelling uncertainties in transmission planning and investigating their effect***

In a flexible transmission planning process, the effect of uncertainties need to be taken into account in order to determine the most economic transmission expansion proposal which can securely accommodate the uncertainties. The deterministic approaches which are traditionally used for transmission planning are no longer credible for determining the size and shape of the future network. Instead, probabilistic techniques should be employed in order to model the effect of growing volatilities on both demand side and generation side. In this thesis, some uncertainties on the generation side namely wind power volatilities and CO₂ emission price variations were modelled in the transmission planning problem.

- ***Proposing techniques and methodologies for flexible transmission planning by incorporating post-contingency corrective actions into transmission planning problem***

In this thesis, the post-contingency corrective actions were incorporated in the transmission planning problem. In this way, unlike traditional approaches

which just rely on transmission capacity, robustness of network against outages was fulfilled by deploying post-contingency corrective actions. In particular, three post-contingency corrective actions namely substation switching, direct load control and generation re-dispatch were investigated.

▪ ***Investigating of the application of dynamic thermal rating for improving the efficiency of the power system***

The flexibility of the network can be enhanced by operating the network based on the real-time thermal ratings of transmission lines. Traditionally, transmission lines are operated and planned taking into account a conservative constant thermal rating for the transmission lines. Nonetheless, in reality the actual thermal ratings vary based on the weather conditions which dynamically changes. In this thesis, the variation of thermal ratings of transmission lines in part of the UK National Grid network were modelled, using the past meteorological data as well as the characteristics of conductors. Further the benefit which can be gained by deploying dynamic thermal rating was calculated.

The following general concluding remarks and recommendations can be made by taking into consideration the literature surveys and studies undertaken in this thesis:

- i) Taking into consideration growing uncertainties on both the generation side and demand side, it is imperative to revisit and upgrade the procedures which are used for transmission investment planning. The deterministic approaches which are traditionally used for determining the required transmission capacities are no longer credible. In deterministic studies, the network is usually designed based on the foreseeable extreme conditions such as peak demand or off peak demand. Nonetheless, many combinations of generation and demand scenarios can be conceived in the future. Therefore, a probabilistic approach should be used in order to take into account all these possible generation/demand scenarios as well as their likelihoods of occurrences. In this thesis, the methods to model uncertainties were reviewed and through numerical examples the superiority of probabilistic transmission planning over deterministic approach was demonstrated.

- ii)* Maintaining the network security by practicing preventive control philosophy is not a smart solution for the future network facing a high level of uncertainty. In order to fulfil the security criteria by deploying the preventive control strategy, a very large investment in the transmission network is required to accommodate the uncertainties. Transmission expansion projects are very time-consuming and difficult to run, so they usually lag behind the completion date of generators. As a result of lack of transmission capacity, either the connection of generators – especially renewable energies – may be delayed or some in-merit generators may be constrained off by system operator. These practices can slow down the integration of renewable energies and consequently the CO₂ emission reduction targets can not be met. Therefore, preventive control should be replaced with other smarter operation strategies which are adaptable to evolutions in future power systems.
- iii)* Instead of investing only in primary transmission network assets, the transmission companies should be encouraged to invest in innovative technologies and upgrade the network operation practice in order to enhance the flexibility and improve the overall efficiency of the grid. It is imperative that transmission network operators contemplate the ancillary service options which can be provided by both generators and consumers in order to tackle security breaches. The grid codes also need to be reviewed and the incentive packages should be designed to attract generators and consumers who can contribute to improving the flexibility and security of the network.
- iv)* Deploying post-contingency corrective actions is a feasible solution to increase the flexibility of the network. Corrective control is a promising replacement for the traditional preventive operation regime. By using corrective actions a lower transmission investment will be required while maintaining network security at a high standard. In this thesis, three post-contingency corrective actions, namely sub-station switching, generation re-dispatch and direct load control, were considered as plausible corrective strategies to mitigate the post-fault network violations. Assuming post-fault corrective actions, the numerical studies demonstrated that the required transmission investment is reduced compared to traditional approaches which satisfy the security criteria by applying preventive control strategy.

- v) The post-contingency corrective actions do not need to be taken for all contingencies and neither at all load levels. There are usually only limited contingencies which may cause network violations so that only for severe contingencies the corrective actions need to be programmed. Further, depending on the topology of the network as well as the location of generators and demands, the impact of each corrective action can be different. It is incumbent upon the transmission planners and network operators to determine the action and in what part of network is the most effective measure to alleviate the violations caused by a particular outage. In this thesis, the post-fault corrective actions were calculated for different test system studies. The results showed that the corrective actions only required to be taken for some of outages. Moreover, there are specific generators/consumers or substations, depending on the corrective action, which can be effective in corrective action programme.
- vi) It is expected that consumers equipped with smart meters and home energy management systems will change their consumption patterns in the next decade. Consequently the peak demand is likely to be partly shifted to other times as the results of price responsive behaviour of consumers. Therefore, a more flat demand profile is expected in future. Currently, the investment in primary network assets is mainly driven by the peak time demand which lasts for a very short period of the year. Transmission planners need to model the response of consumers to energy price in order to avert any overinvestment in the network. The impact of price responsive demand on the required transmission capacity was studied in this thesis. A numerical study on a test system showed that a lower transmission investment is required if the consumers are assumed to be price responsive.
- vii) Operating based on the real-time conditions of the network components is a crucial step towards a smart operation regime. The available transfer capacity of the network varies dynamically with the weather condition changes. Moreover, the available power generated by renewable energy generators depends on weather conditions. For example, the higher wind speed results in higher wind generators outputs and at the same time the transmission lines which are exposed to the same wind regime are very likely to have higher thermal ratings. Therefore, exploiting the dynamic thermal ratings of transmission lines is likely,

to benefit the integration of wind power. Further, the in-merit generators have more chance to participate in the supply-demand chain. In this thesis, the dynamic thermal ratings of transmission lines of part of National Grid network were modelled and through probabilistic studies it demonstrated that a fewer in-merit generators may be constrained off if dynamic thermal ratings are taken into account.

8.2 Achievements and contributions

As mentioned before the focus of this thesis was to propose methodologies and techniques for transmission planning under a corrective control paradigm. In addition, the effects of uncertainties on the required transmission capacity were investigated. In general the main contributions and achievements of this thesis can be elaborated as follows:

- **Investigated the effect of CO₂ emission market on transmission expansion plans**

One of the objectives of this thesis was to investigate the effect of uncertainties on transmission investment. In this regard, the impact of CO₂ emission price on required transmission network expansion was studied. This subject has been rarely investigated by the past studies. In order to examine the effect of CO₂ emission two different models for CO₂ emission market were taken into account. The CO₂ emission price variations were also modelled by a probabilistic distribution function. Using Monte Carlo simulation, many scenarios for CO₂ emission price were generated. For all these scenarios the required transmission network capacity for modified IEEE 24 bus test system was calculated. The resultant transmission investment and operating cost from probabilistic study was compared to deterministic cases where the CO₂ emission was assumed to be neglected in one case and in the other case it was assumed to be 17.5 €/t CO₂, the average CO₂ emission price. The results demonstrated that the overall system cost including operating cost and transmission investment are very likely to increase if a deterministic approach is undertaken.

- **Proposed a new linear model for transmission planning studies**

From an extensive review of transmission planning studies, it was found that modelling of losses in the transmission planning problem is still an issue which needs to be addressed. In this thesis, an accurate and linear model for losses which is suitable for transmission planning studies was proposed. The proposed model does not include any binary variable whereas other studies have proposed a complicated mixed-integer model in order to imitate the nonlinearity of losses. The accuracy of the proposed model was tested on the IEEE 24 bus test system in Chapter 3. It was shown with an accuracy of 97% the proposed model is close to the nonlinear model of losses which is expressed with a quadratic function.

- **Proposed a methodology for incorporating the corrective substation switching action into transmission planning problem**

The configuration of network can be correctively altered in order to eradicate the network violations. In this thesis, a methodology was proposed to calculate the required transmission capacity while the network violations in both the intact network and the contingent networks can be mitigated by changing the status of circuit breakers in the substations. This assumption in timing of transmission investment planning is a new assumption in transmission planning studies although the corrective switching action has been addressed by many past studies for operation planning. The degrees of freedom to reconfigure substations depend on the layout of substations. In this study, the layouts of all substations were assumed to be double-bus-double-breaker.

Transmission planning assuming substation corrective action is a large scale problem including many continuous and binary variables. Therefore, a multi layer procedure was proposed in which the whole problem was decomposed into several sub-problems. By using a Genetic algorithm, each sub-problem which models either intact network or a contingent network calculated the optimum switching pattern for its respective network. The proposed methodology was successfully run on the modified IEEE 24 bus test system. The results showed that the total transmission investment can reduce by 6.36% if the corrective switching action is taken into account in transmission planning

studies. It was also shown that the switching action does not need to be taken for all contingencies as in the test case only 6 out of 37 credible outages needed post-fault corrective switching action.

- **Investigated the transmission planning expansion strategy in the presence of demand response programmes**

The effects of two demand response programmes, namely price-based demand response and direct load control demand response, on transmission expansion plans were investigated in this thesis.

Under the price-based demand response programme, demands were assumed to be responsive to the energy price variation. Different price elasticity at different load levels was taken into account for each consumer. It was also assumed that although consumers may shift part of their consumptions to off-peak time, the change in total energy consumption remains within $\pm 5\%$ of original amount. Under these assumptions, an iterative algorithm was proposed to calculate the required transmission capacity. At each iteration, the transmission charge and the energy price were calculated first. Next, in accordance to the calculated charges, the new consumption level was calculated and this procedure repeated to the point when the same transmission expansion plan was proposed in two consecutive iterations. The proposed method was tested on the IEEE 24 bus system. The results showed that with only 0.15% reduction in total energy consumption, which was the result of peak shifting, the total transmission investment decreased by 7.8%.

In another study, the direct load control demand response programme was incorporated in the transmission planning study for a system with high penetration of wind power. The challenge in this study was to calculate the required transmission capacities as well as location and amount of demand while the supply-demand balance constraint and the security criteria are respected. A probabilistic approach was proposed to solve this problem. Moreover, in this study the effect of correlation between wind farms on the amount of load curtailment on each bus was investigated. The numerical studies demonstrated that the load curtailment at particular buses is sensitive to wind correlations.

▪ **Proposed the methodology for solving transmission planning problem under post-contingency generation re-dispatch corrective action**

The ability of generators to change their outputs to alleviate post-fault network overloads was taken into consideration in the transmission planning study. The generation re-dispatch action is constrained to ramp-up and ramp-down rates of generators. The transmission network may experience a temporarily overload while the generation re-dispatch corrective action is carried out. Three statuses of network were considered in formulation of transmission planning problem. These statuses are intact network, contingent network in the instant of outage and steady state contingent network. The proposed approach for transmission planning was tested on the modified IEEE 24 bus system. The volatility of wind power in the test system was estimated by different scenarios using hypercube sampling. The proposed transmission planning approach answered two main questions: i) What are the required transmission topology and capacities for the horizon year? ii) What are the generators' contributions to post-contingency corrective action? The results demonstrated that for the modified IEEE 24 bus test network a 23.8% of reduction in total transmission investment can be expected by using generation re-dispatch corrective action while the network security maintain at high standard. It should be noted however that result is system specific.

▪ **Investigated the impact of deploying dynamic thermal ratings on integration of wind energy**

The dynamic thermal ratings of transmission lines in a part of national grid - Humber Estuary region - where a large amount of wind is scheduled to connect were modelled using four years meteorological data. Moreover, the probabilistic seasonal off-shore wind power which is set to connect to Humber Estuary region was estimated with Beta distribution function. The correlation between off-shore wind power and the thermal ratings of the transmission lines were also calculated. Using practical data, the probabilistic models for wind power, thermal ratings and the correlation between them were some of contributions of this study. The results show a 0.64 correlation between off-shore wind power and thermal ratings in winter period. These modelling were used to generate possible wind power-thermal rating scenarios in the Humber

Estuary region. Using these scenarios, a sensitivity analysis was carried out to single out the transmission lines which are in priority for real-time thermal ratings monitoring. In addition, the calculation showed that a £26.7 M reduction in generation cost is expected to be achieved if dynamic thermal rating is deployed.

8.3 Future works

There are some recommendations for further research as the continuation of this thesis.

- *To investigate the methodologies for solving the transmission planning problem when several corrective actions are taken into account collectively*

In a flexible network, the decision making software receive the latest information from the network whereby the best set of corrective actions can be determined. In other words, a post-fault violation in the network can be alleviated by several different corrective actions. As a future study, this can be modelled in transmission planning problem. However, the transmission planning problem becomes a very large scale problem if several different corrective actions are taken into account collectively. This problem can be very challenging to solve if the effects of uncertainties are also incorporated into calculations. The developments of methodologies or techniques which can solve such a big problem are recommended as continuation of this thesis.

- *To incorporate the contingencies of information infrastructure into transmission planning studies*

Traditionally, a transmission network ought to be robust against credible network outages. However, the future network should be also robust against possible contingencies in information infrastructure and decision making software. The operation of future network will rely on two-way communication system between intelligent systems and the network components as well as generators and consumers. In this condition, any failure in communication systems and intelligent software can have an impact on the reliability of the network. Therefore, the network planners need to consider the contingencies in the information infrastructure as well as network components. These issues can be addressed in a further study.

- *To investigate the required change in grid code for fully implementation of corrective control paradigm*

In the current grid code, the requirements which need to be fulfilled by generators or consumers have been designed based on the preventive control regime. Studies need to be carried out to determine the minimum flexibility requirements which should be met by all network users in order to facilitate the operation under corrective control paradigm.

- *To incorporate the effect of FACTS and interconnections into transmission planning studies*

In addition to the corrective actions studied in this thesis, there are other options which can be deployed for enhancing the flexibility and mitigating the post-fault network violations. The further research may consider FACTS devices such as phase shifter transformers (PSTs), thyristor controlled series compensators (TCSCs) and static var compensators (SVCs) for controlling the power flows and voltage across the network so as to eradicate post-fault contingencies. In addition to that, the interconnections between power systems can also be used as an option to receive ancillary services from neighbouring network in times of need. By having several connections to other countries, under a controlled inter-regional power exchange, the flexibility of system to uncertainties and contingencies can be boosted. As these flexibility options can be conceived as a replacement for the network reinforcement, a transmission planning approach needs to be proposed to compare the cost of network expansion with cost of deploying these flexibility options.

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Appendix A

In this Appendix the information of the IEEE 24 bus test system which was studied in Section 3.6 are given. The load profile at each bus is given in Table A-1. Four different types of generators, namely Hydro, Coal, CCGT and Nuclear are considered in this study. The emission factors of different types of generators [193] and generation prices [194] are given in different annual emission allowances are assumed for different type of generators as shown in Table A-3. The network branch data as well as candidate transmission corridors which are shadowed are brought in Table A-4.

Table A-1: Load profile at each bus for IEEE 24 test system studied in Chapter 3

Bus #	Load Level 1 (MW)	Load Level 2 (MW)	Bus #	Load Level 1 (MW)	Load Level 2 (MW)
1	108	59.4	13	265	145.7
2	97	53.3	14	194	106.7
3	180	99	15	317	174.3
4	74	40.7	16	100	51
5	71	39.0	17	0	0
6	136	74.8	18	333	183.1
7	125	68.7	19	181	99.5
8	171	94	20	128	70.4
9	175	96.2	21	0	0
10	195	107.2	22	0	0
11	0	0	23	0	0
12	0	0	24	0	0
Load Level 1 Duration : 2920 hours					
Load Level 2 Duration : 5840 hours					

Table A-2: Generation prices and CO₂ emission factors

Gen. Type	Generation price (€/MWh)	Emission factor (tCO ₂ /MWh)
Coal	45.2	0.88
CCGT	51.2	0.37
Nuclear	35	0
Hydro	50	0

Table A-3: Generation limits and the annual emission allowance

Gen. #	Bus #	Gen. Type	Pmax (MW)	Pmin (MW)	Allowance cap (tCO₂/year)
1	1	Hydro	40	0	--
2	1	Coal	152	0	4800
3	2	Hydro	40	0	--
4	2	Coal	152	0	4800
5	7	CCGT	150	0	4000
6	13	CCGT	591	0	7900
7	15	Hydro	60	0	--
8	15	Coal	155	0	4900
9	16	Coal	155	0	4900
10	18	Nuclear	400	0	--
11	21	Nuclear	400	0	--
12	22	CCGT	300	0	4000
13	23	Coal	310	0	9800
14	23	Coal	350	0	11000

Table A-4: Existing transmission lines and candidate transmission corridors

Line #	Sending Bus	Receiving Bus	R(p.u.)*	X(p.u.)*	Capacity (MW)	Length (Km)
1	1	2	0.0026	0.0139	100	3
2	1	3	0.0546	0.2112	100	55
3	1	5	0.0218	0.0845	100	22
4	2	4	0.0328	0.1267	100	33
5	2	6	0.0497	0.192	150	50
6	3	9	0.0308	0.119	150	31
7	3	24	0.0023	0.0839	300	50
8	4	9	0.0268	0.1037	100	27
9	5	10	0.0228	0.0883	100	23
10	6	10	0.0139	0.0605	150	16
11	7	8	0.0159	0.0614	150	16
12	8	9	0.0427	0.1651	---	43
13	8	10	0.0427	0.1651	---	43
14	9	11	0.0023	0.0839	200	50
15	9	12	0.0023	0.0839	300	50
16	10	11	0.0023	0.0839	300	50
17	10	12	0.0023	0.0839	300	50
18	11	13	0.0061	0.0476	---	33
19	11	14	0.0054	0.0418	400	29
20	12	13	0.0061	0.0476	---	33
21	12	23	0.0124	0.0966	---	67
22	13	23	0.0111	0.0865	---	60
23	14	16	0.005	0.0389	400	27
24	15	16	0.0022	0.0173	400	12
25	15	21	0.0063	0.049	400	34
26	15	21	0.0063	0.049	400	34
27	15	24	0.0067	0.0519	300	36
28	16	17	0.0033	0.0259	400	18
29	16	19	0.003	0.0231	300	16
30	17	18	0.0018	0.0144	400	10
31	17	22	0.0135	0.1053	---	73
32	18	21	0.0033	0.0259	150	18
33	18	21	0.0033	0.0259	150	18
34	19	20	0.0051	0.0396	---	27.5
35	19	20	0.0051	0.0396	---	27.5
36	20	23	0.0028	0.0216	---	15
37	20	23	0.0028	0.0216	---	15
38	21	22	0.0087	0.0678	---	47

* The base power is 100 MW



Figure A-1: Schematic diagram of IEEE 24 bus test system

Appendix B

In this appendix the information of the modified IEEE 24 bus test system studied in Section 4.5.6.2 are given. Table B-1 shows the generation information of this test case. The demand at each bus is as information given in Table A-1 for load level 1. The length of transmission lines and the transmission corridors are similar to the information given in Table A-4 and shown by Figure A-1, except all 38 transmission lines are assumed to be candidate in this study.

Table B-1: Generation information used for the IEEE 24 bus test system for flexible transmission planning studies

Gen #	Bus #	Minimum Power (MW)	Maximum Power (MW)	Generation Cost (€/MWh)
1	1	0	350	52.9
2	1	0	350	45.2
3	2	0	136	52.9
4	2	0	136	45.2
5	7	0	140	51.2
6	13	0	140	51.2
7	15	0	250	52.9
8	15	0	310	45.2
9	16	0	270	45.2
10	18	0	550	35
11	21	0	270	35
12	22	0	30	51.2
13	23	0	30	45.2
14	23	0	50	45.2

Appendix C

In this appendix the information of the systems studied in Chapter 5 are presented. The load profile and the elasticity at each load level of the numerical example of Section 5.2.5 are given in Table C-1. The generation price and the generation limits at each bus are also tabulated in Table C-2. The transmission network schematic diagram is similar to Figure A-1. The information of wind power models, load profile and generation used for study in Section 5.2.5 are given by Table C-3, Table C-4 and Table C-5, respectively.

Table C-1: The load profile and elasticity used for numerical study in Section 5.2.5

Bus #	Load Level 1 (MW)	Load Level 2 (MW)	Load Level 3 (MW)	Load Level 4 (MW)
1	108	75.6	57.024	32.4
2	97	67.9	51.216	29.1
3	180	126	95.04	54
4	74	51.8	39.072	22.2
5	71	49.7	37.488	21.3
6	136	95.2	71.808	40.8
7	125	87.5	66	37.5
8	171	119.7	90.288	51.3
9	175	122.5	92.4	52.5
10	195	136.5	102.96	58.5
11	0	0	0	0
12	0	0	0	0
13	265	185.5	139.92	79.5
14	194	135.8	102.432	58.2
15	317	221.9	167.376	95.1
16	100	70	52.8	30
17	0	0	0	0
18	333	233.1	175.824	99.9
19	181	126.7	95.568	54.3
20	128	89.6	67.584	38.4
21	0	0	0	0
22	0	0	0	0
23	0	0	0	0
24	0	0	0	0
Duration (Hour)	500	2000	3000	3260
Elasticity	-1.4	-1	-0.8	-0.5
Original Price (€/MWh)	53	49	47	46

Table C-2: Generation price and generation limits used in the numerical example in Section 5.2.5

Gen #	Bus #	Minimum Power (MW)	Maximum Power (MW)	Generation Price (€/MWh)
1	1	0	40	50
2	1	0	152	45
3	2	0	40	50
4	2	0	152	45
5	7	0	300	55
6	13	0	591	55
7	15	0	60	50
8	16	0	155	40
9	15	0	155	40
10	18	0	400	35
11	21	0	400	35
12	22	0	200	20
13	23	0	310	50
14	23	0	350	45

Table C-3: The parameters of normal distribution function for wind power considered in Section 5.3.5

	Load Level									
	1	2	3	4	5	6	7	8	9	10
Expected Value	30	30	35	35	35	20	20	20	20	20
Variance	10	10	10	10	10	5	5	5	5	5

Table C-4: The load profile and load shedding bids assumed in the numerical study in Section 5.3.5

	Load Level									
	1	2	3	4	5	6	7	8	9	10
Percentage of peak load (%)	100	90	80	70	60	70	60	50	40	30
Duration (Hours)	400	500	600	800	800	1000	1000	1200	1200	1250
Load curtailment bid (€/MWh)	65	65	65	55	55	55	50	50	45	45

Table C-5: The generation price and the generation limits assumed in the numerical study Section 5.3.5

Gen #	Bus #	Minimum Power (MW)	Maximum Power (MW)	Generation Price (€/MWh)	Gen #	Bus #	Minimum Power (MW)	Maximum Power (MW)	Generation Price (€/MWh)
1	1	0	--	0	12	15	0	150	50
2	1	0	200	45.2	13	16	0	150	40
3	2	0	--	0	14	17	0	--	0
4	2	0	150	45.2	15	18	0	300	35
5	4	0	--	0	16	19	0	--	0
6	6	0	--	0	17	20	0	--	0
7	7	0	--	0	18	21	0	300	35
8	8	0	--	0	19	22	0	300	51.2
9	13	0	300	51.2	20	22	0	--	0
10	14	0	--	0	21	23	0	300	40
11	15	0	--	0	22	23	0	300	45.2

Appendix D

In this appendix the information for the study undertaken in Section 6.5 is presented. Table D-1 shows the load profile and the possibility that each load level coincides with high speed or low speed wind regime. The generation information is also given in Table D-2.

Table D-1: Load demand information for the modified 24 bus test system studied in Section 6.5

	Load Level 1	Load Level 2	Load Level 3
Percentage of the peak load (%)	100	70	30
Duration (hours)	1000	5500	2760
Probability of coincidence with PDF^{HW}	0.4	0.5	0.6
Probability of coincidence with PDF^{LW}	0.6	0.5	0.4

Table D-2: Generations' parameters in the modified 24 bus test system studied in Section 6.5

Generator Numbers	Generation Type	Maximum output (MW)	Minimum output (MW)	Ramp-down rate (percentage/15 minutes)	Ramp-up rate (percentage/15 minutes)	Generation Cost (€/MWh)
1, 2, 3, 4, 5, and 6	Wind	80	0	30	0	0
15, 19, 20, 21, 22, and 23	Wind	100	0	30	0	0
7, 8, 9, 10, 12, and 13	CHP	100	0	20	20	51
11, 14, and 16	Gas	350	0	20	20	51.2
24	Gas	300	0	20	20	51.2
17	Nuclear	500	0	0	0	35
18	Hydro	500	0	30	30	50

Appendix E

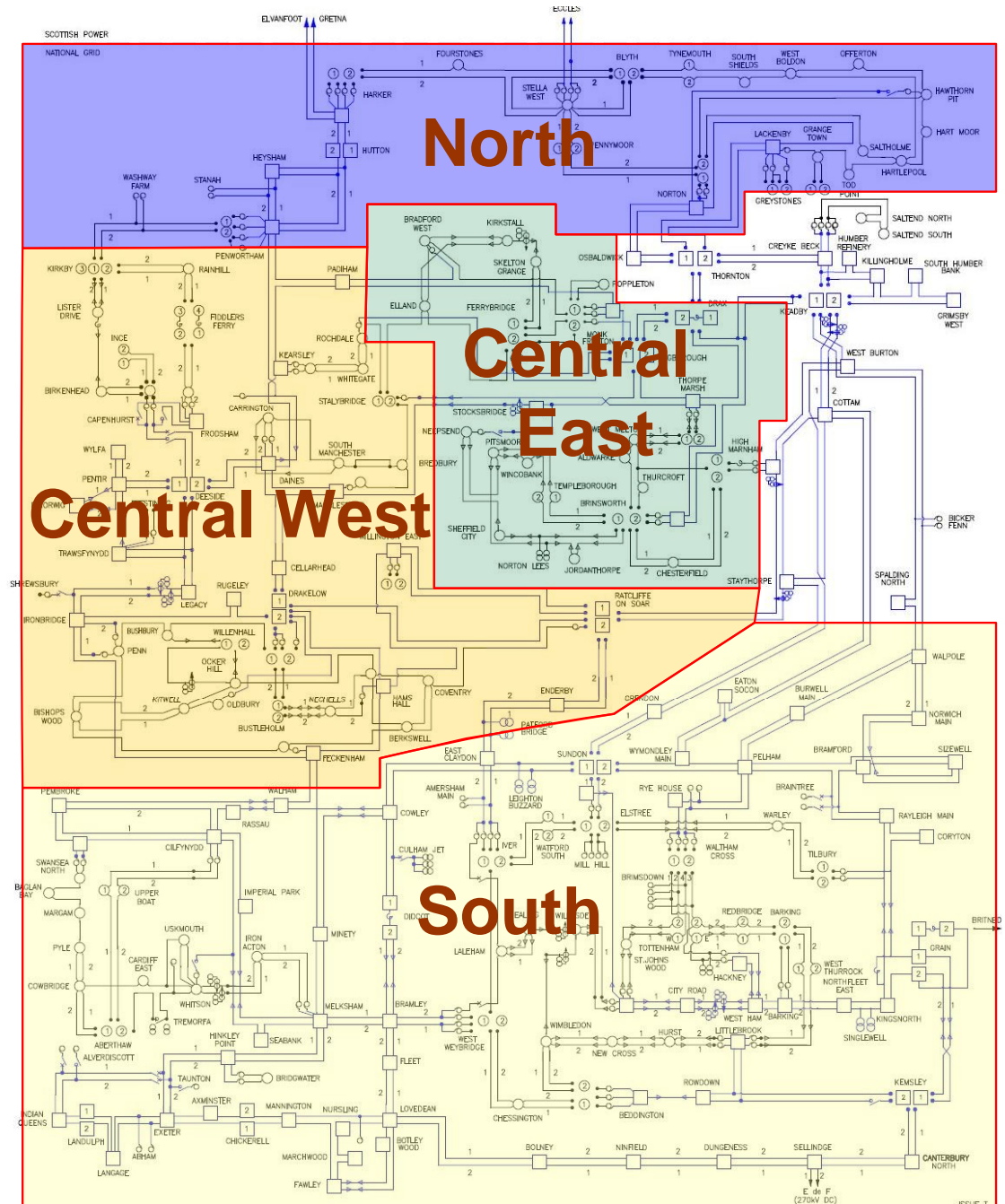


Figure E-1: The boundaries used in the reduced National Grid's network model mentioned in Section 7.5.1

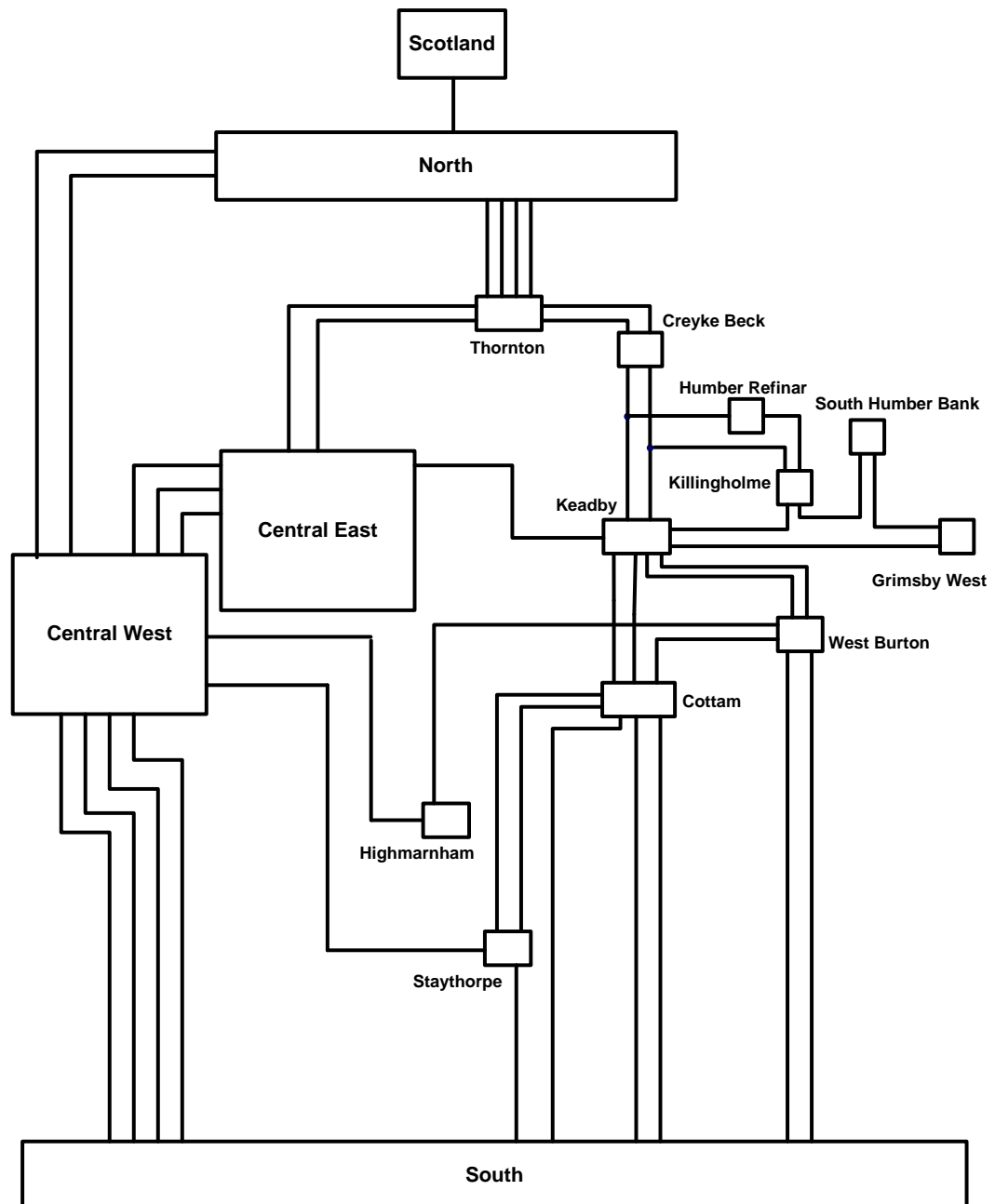


Figure E-2: The schematic diagram of National Grid reduced model mentioned in Section 7.5.1