1-1-2019

Impact of Combined Heat and Power Generation on an Industrial Site Distribution Network

Thomas Neally
Cork Institute of Technology

Impact of Combined Heat and Power Generation on an Industrial Site Distribution Network

Thomas Neally

Department of Electrical & Electronic Engineering,

Cork Institute of Technology

Supervised by Dr. Sreto Boljevic

A thesis submitted for the degree of

Master of Engineering

to Cork Institute of Technology, 2019

Declaration

I hereby declare that this submission is my own work and that, to the best of my knowledge and belief, it contains no material previously published or written by another person nor material to a substantial extent has been accepted for the award of any other degree or diploma by the university of higher learning, except where due acknowledgement has been made in the text.

Signature of Author: ______________________________

Certified by: ______________________________

Date: ______________________________

Acknowledgements

I would like to thank my supervisor Mr. Sreto Boljevic for his tremendous guidance and support throughout this work.

I would like to thank my examiners, Professor Dan D. MICU, (external) and Mr. Michael O' Donovan (internal), for assessing this work.

I would like to thank the staff of the Electrical and Electronic Engineering Department for the help and support they have given me during my years of study at Cork Institute of Technology.

I would like to thank the staff at PM Group for their time, help and information provided to me for this thesis.

I would like to thank my parents, my family and all my friends for their support and encouragement throughout my studies.

This thesis is dedicated to my family, my wife, Clodagh, son, Daniel and daughter Éabha.

List of Publications

1. Neally, Thomas, Boljevic, Sreto and Conlon, Michael F., *Impact of Combined Heat and Power Generation on an Industrial Site Distribution Network*, 47th International Universities' Power Engineering Conference (UPEC 2012), London, United Kingdom, 2012.

ABSTRACT

Presence of Distributed Generation (DG) in Industrial Site Distribution Network (ISDN) can represent a significant impact on the operational characteristics of the network. Present planning and operation criteria use for ISDN are in general not suitable to cope with the presence of a significant DG capacity. The presence of DG provides considerable benefits from both engineering and economic viewpoints. However, it changes radial configurations of the distribution feeders. Consequently it may cause coordination failure to existing protection system which is originally set based on radial configuration. In addition, high penetration of DG into ISDN may increase feeder loss, and cause system voltage profile out of a required range.

Distributed Generation may have a significant impact on the system and equipment operation in terms of steady state operation, dynamic operation, reliability, power quality, stability and safety for both ISDN user and electricity suppliers. The idea behind the connection of DG is to increase the reliability of power supplied to the customers, make use of a locally available resource and, if possible, reduce losses in transmission and distribution systems. The specific benefits depends on the local conditions and installation owner's interest. The reasons for installing DG at ISDN include:

i) Combined Heat and Power Plant (CHP) – High Efficiency

ii) Standby/emergency generation-enhanced reliability

The effect of the DG units on these quantities strongly depends on the type of DG units and the type of ISDN. DG units can be either directly connected to the ISDN, such as synchronous or asynchronous generators, or via a power electronics converter. In all these cases, the power flow in the ISDN as well as the network losses and the voltage control are affected. The introduction of DG alters the characteristics of the network. The number of technical constraints and factors are impacted by the amount of DG that is connected.

Abbreviations & Acronyms

A	Amps
CER	Commission for Energy Regulation
CHP	Combined Heat and Power
CHPC	Combined Heat and Power and Cooling
COP	Coefficient of Performance
CSA	Cross Sectional Area
DG	Distribution Generation
DN	Distribution Network
DNO	Distribution Network Operator
ESB	Electricity Supply Board
GHC	Greenhouse Gas
GRP	Glass Fibre Reinforced Plastic
IDSN	Industrial Site Distribution Network
kV	kilovolts
LCTA	Least Cost Technically Acceptable
MV	Medium Voltage
MVA	MegaVolt Amps
MVAR	MegaVolt Amps reactive
MW	MegaWatt
NO	Normally Open
NOx	Nitrogen Oxides
OLTC	On Load Tap Changer
PC	Personal Computer
PSCC	Prospective Short Circuit Current

PV	Photo Voltaic
Q	Reactive Power
R	Resistance
SOx	Sulphur Oxides
TSO	Transmission System Operator
V	Volts
VT	Voltage Transformer
X	Reactance
XLPE	Cross Linked Polyethylene
Z	Impedance

Contents

Table of Figures

CHAPTER 1

1 Introduction

This chapter presents an overview of the background and motivation behind this thesis. The research challenges and an outline of the structure of the thesis are also presented.

The emphasis of climate change across Europe has been to cut greenhouse gas emission through reductions and efficiency in energy generation sector. There is a clear focus in the European Union on promotion of low-carbon power generation technologies and renewable, with new and binding targets of 20% power generation from renewable sources by 2020 recently agreed for implementation across Europe. Over the last decade, this policy commitment has been matched with national incentives schemes and support mechanisms for renewable and low-carbon distributed energy sources.

The amount of DG located within ISDN is showing rapid growth worldwide. Certain aspects of this type of generation promote the more wide-scale usage of this technology, for instance, novel energy resources and the possibility of increasing the efficiency of a network. It has become apparent that the energy needs of today are not necessarily best met by the traditional centralised power system and supply grid paradigm.

It is estimated that industrial energy consumption has grown three times faster than general consumption over the past forty years and currently accounts for over 40% of the energy consumed worldwide. Industries play a key role in power supply, power transmission and energy management system.

Energy accounts for up to 10% of total production costs, and this figure is as much as 40% of manufacturing costs in energy intensive industries such as the steel, chemical and pharmaceutical sectors.

Climate protection, quality of supply and energy costs represent enormous challenges for industries. Yet, without industrial companies, the necessary emission reduction is unlikely to happen, since the generation of electrical and heat energy for processes and building causes high CO_2 emission. However, industrial plants can also be supplied with energy generated by distributed generation. This reduces CO_2 emission as well as the need to buy electricity and the sale of surplus energy, further offsets operating costs.

Mastering the cost of energy as part of operations and production costs is a decisive factor for a company's competitiveness. As energy becomes increasingly important for industries, industrial site distribution network solutions become more and more relevant. They combine energy supply, storage and data collection, as well as energy-optimised production planning and control. The element of an ISDN – distributed power generation, storage, electrical equipment, control technology and energy automation with corresponding application can also be individually monitored and adjusted to optimise the overall energy supply.

Distributed generation and Combined Heat & Power technologies offer the greatest potential economic and energy productivity benefits. CHP technology is the concurrent production of electricity and useful thermal energy (heating, cooling) from a single energy input.

CHP technologies provide manufacturing facilities with ways to reduce energy costs and emissions while also providing more resilient and reliable electric power and thermal energy supply. CHP systems use less fuel than when heat and power are produced separately. CHP systems are normally custom-designed and installed. When it is designed to operate independently from the grid, it can provide critical power reliability for a variety of industrial sites while providing electrical and thermal energy to the sites on a continuous basis, resulting in daily operating cost savings. A CHP system that runs every day continuously is often more reliable in an emergency than a backup generator system that only runs during an emergency.

By installing properly-sized and configured CHP systems, critical manufacturing infrastructure facilities can effectively insulate themselves from a grid failure, providing continuity of critical services and freeing power restoration efforts.

The connection of all forms of DG, including CHP generation technologies, have network impacts given the alternation of network power flow [68]. Energy generation within the ISDN lowers the load seen by the grid and particularly where the operation of CHP system is determined by heating demand. Its presence can impact significantly on operational pattern of ISDN and these impacts include:

- Bi-directional power flow and the potential to exceed equipment thermal ratings,
- Reduced voltage regulation and violation of statutory limits on supply quality,
- Increased short circuit contribution and fault levels,
- Degraded protection operation and coordination.

The impact arising from individual CHP scheme must be assessed in detail following a connection application. These impacts must be limited to protect the security and quality of energy supply. Mitigation techniques currently employed may add significantly to the cost of development and discourage investment in CHP generation.

The inappropriate sitting of new generation, or poorly-phased, development can limit an entire ISDN and lower the opportunity for development of other DGs without network upgrades.

Where the presence of such CHP plant will adversely disturb ISDN operation, its impact must be mitigated according to the Least Cost Technically Acceptable principles.

Analysis presented in this thesis will enhance the understanding of DGs within industrial site distribution system, which is only in its infancy at present in Ireland. Analysis developed in this thesis will fully analyse the technical, economic and environmental impact of DG plant on energy management within ISDN.

Analysis developed in this thesis and demonstration of its implementation will provide a selection criteria platform for the DG plant installed in ISDN. It will also demonstrate practical usefulness of DG regarding ISDN energy management, particularly in relation to economic and environmental concerns and power supply quality.

1.1 Motivation

The emphasis of climate change policy across Europe has been to cut greenhouse gas emissions through reductions and efficiency savings in the power sector. There is a clear focus in the European Union (EU) on promoting low-carbon power generation technologies and renewable, with new and binding targets of 20% power generation from renewable sources by 2020, agreed for implementation across Europe. Over the last decade, this policy commitment has been matched with national incentives schemes and support mechanisms for renewable and low-carbon distributed energy sources. This thesis shall enhance the understanding of distributed generation within industrial site distribution networks, which is only in its infancy at present in Ireland. Analysis of the model developed in this thesis will fully analyse evaluate the technical, economic and environmental impact of DG plant on energy management within ISDNs.

Analysis of the model developed in this thesis and the demonstration of its implementation will provide a selection criteria platform for the DG plant installed in ISDN. It will also demonstrate practical usefulness of distributed generation regarding ISDN energy management, particularly in relation to economic and environmental concerns and power supply quality.

The amount of DG located within ISDN is showing rapid growth worldwide. Certain aspects of this type of generation promote the more wide-scale usage of this technology, for instance, novel energy resources and the possibility of increasing the efficiency of a network. It has become apparent that the energy needs of today are not necessarily best met by the traditional centralised power system and supply grid paradigm. Increased desire for efficiency, security, stability and local control of power quality and reliability all suggest modification of central station power generation. DG has a positive impact on the usage of the electrical network, but it may also result in significant problems. These problems especially include voltage levels and more complicated protection of the network. The ISDN has traditionally been designed for a unidirectional flow of power and currents. In other words, the power is assumed to be fed from higher voltage levels and distributed further to lower voltages to the final customers. The same applies to the protection of the network; the fault current is assumed to flow downwards, which enables relatively simple schemes for achieving a fast and selective operation of protection. Protection settings can be found by calculating typical worst-case fault situations. DG located on the ISDN level changes this basis radically. DG units contribute to all faults and may thereby disturb the network protection. The directions and amplitudes of fault currents can change significantly. The thermal limits of network components may also be exceeded due to the presence of DG.

Recent development in DG technologies, together with PC-based control systems linked by fibre optics to remote monitoring, have encouraged even greater numbers of ISDN to adopt DG schemes as a sound method of providing a significant proportion of their energy needs in a way which is:

- Economically advantageous
- Efficient in the use of energy
- Environmentally beneficial
- Reliability of energy supply.

Motivation for this interest also include:

- Increase in security and reliability of ISDN energy supply: Depending on the capacity of the distributed generation within an ISDN, the ISDN may be self-sufficient from a power perspective. In the event of a power outage, an ISDN may be able to provide adequate power capacity to take the place of the utility supply. In the normal course of events, the ISDN is connected to the utility power supply and the distributed generation within the ISDN operates in synchronism with the utility network. Assuming the ISDN operator has permission, the ISDN can export any surplus distributed generation produced to the utility grid. This facility expands the energy source portfolio of the utility grid network.
- Advantages in power network planning and operation: High penetration of appropriately-integrated distributed generators reduces congestion on the upstream utility network, leading to postponement of transmission system development. Also, distributed generators can be brought online in relatively short periods of time, in the event of increased load demands, in comparison

with a central power plant. Times vary depending on the type of DG, however, a microturbine could be brought online in less than 1 minute. [69]

- More efficient use of primary energy resources (i.e. natural gas and oil) and reductions in greenhouse gas emissions: Small-scale, efficient and environmentally-friendly CHP plants can be exactly sized to match the needs of the ISDN user, allowing the use of the waste heat produced as a by-product of electricity generation. This provides high economic benefits and harmful pollutant emission reduction. In addition, the generation of energy locally reduces its transmission, leading to a reduction in power losses on transmission lines.

Connecting distributed generators to the ISDN produces a wide range of technical issues which must be limited, to protect the security and quality of the electrical supply. Major technical issues related to the presence of DG in an ISDN include, but are not limited to:

- Power Network planning. With increased distributed generation exported from ISDNs to the utility network, utility companies must redesign their network accordingly. In order to facilitate the high penetration of distributed generation from ISDNs, the network protection system must be redesigned, in order to facilitate the increase in voltage and fault current.
- Infrastructure and provisions of gas supply in remote commercial facilities can cause a serious problem for gas-fuelled CHP technologies experiencing record growth trend in implementation within ISDNs. Therefore, security of supply concerns may arise due to gas shortages or constraints in the gas network system.
- Power reserve and balancing. As the distributed generators are controlled by the ISDN owner, it is at their discretion whether or not they are producing and exporting power to the utility network. This means, it is very difficult for the utility company to predict what power is available and when. This may lead to instability in the utility companies network local to the ISDN.

1.2 Objectives

The capacity of distributed generation connected to ISDNs will increase significantly as a result of EU government targets and initiatives. Distributed generation can have a significant technical, economic and environmental impact for both consumers and utility companies.

The objectives of the thesis are quite clearly defined. From the start of the thesis through to the final conclusions, the thesis is consistently analysing and building on the knowledge detailed throughout the thesis. The objectives of this thesis are to answer the following questions:

- How is DG currently employed and integrated into ISDNs?
- What effect does installing DG have on the network?
- How are the impacts quantified?

The objective of this thesis is to determine the advantages and disadvantages of connecting DG to an ISDN and discussion and a case study is investigated in this thesis.

1.3 Contribution of the Thesis

The purpose of this thesis is to investigate the impact that DG, primarily CHPC, may have on an industrial site distribution network and in addition develop a method of analysing the performance of the DG within the industrial site distribution network and proposing methods to reduce any negative impacts the introduction of DG has on an industrial site distribution network. The thesis is driven by the fact that more and more organisations are looking at ways to reduce their overall energy costs; are more conscious of their carbon footprint and sustainablity; and are looking at ways to reduce operating costs of their facilities. The introduction of DG within their industrial site distribution networks is seen as one potential method of achieving all three goals.

The contribution of this thesis can be condensed as follows:

- Outline the background to the traditional methods of power generation, transmission and distribution in Ireland,

- Highlight the different power generation options available to consumers with particular focus on CHP,
- Discuss the potential technical issues associated with the introduction of DG into an industrial site distribution network,
- Develop a mathematical model/algorithm/roadmap that allows the performance of a CHPC system to be rated,
- Outline and explain the mathematical equations required to analyse CHPC performance from an environmental, economic and efficiency perspective.

1.4 Thesis Outline

The thesis commences by outlining the evolution of power generation, transmission and distribution in Ireland. The thesis then provides an overview of the different energy consumers within the generation, transmission and distribution system. As one may be aware, industrial site distribution networks are embedded within both transmission and distribution networks across Ireland. Characteristics of industrial site distribution networks are outlined and discussed, followed by a look at how distributed generation has been incorporated within industrial site distribution networks, since its evolution.

Distributed generation can take many forms, ranging from combustion turbines to wind turbines to fuel cells, and so on. This thesis provides a high level discussion on the different technologies used to create distributed generation throughout the world, utilising both renewable and non-renewable energy. The case study within this thesis is centred around the installation of two combined heat, power and cooling units, into an existing industrial site distribution network. For this reason, the thesis explains and discusses more about CHPC technology than any of the other available technologies. The thesis develops algorithms for a variety of reasons, but primarily to assess the performance of the CHPC. CHPC performance is examined from various different perspectives, such as, electrical efficiency, thermal efficiency, etc.

With all commercial clients, company finance is key. The thesis evaluates the capital investment (capex) costs associated with installing as distributed generation installation, as well as other key financial characteristics, such as payback period, operation costs (opex), etc.

Chapter three of the thesis, discusses the technical issues, such as fault currents, voltage rise, power flow, losses, etc. associated with the installation of distributed generation into an industrial site distribution network. The impact the installation of distributed generation has on the environment is also discussed at length in the latter half of chapter three.

Chapter four consists solely of a case study of an industrial facility which has installed distributed generation into their industrial site distribution network. The author of the thesis firstly provides a background to the facility and the importance of power to the facility and process. This is followed by an indepth explanation of the high voltage site distribution network at the facility.

A desktop study was then carried out on the impact the introduction of distributed generation would have on the facilities distribution network. An integral part of the desktop study consisted of the creation of a software model, used to calculate and simulate the revised distribution network. Eracs software was the analysis tool utilised to analyse the installation. Eracs is a power analysis software, commonly used within the electrical industry.

Live data was collected from the Vistakon facility in Limerick and utilised, to calculate the performance of the facilities site distribution network system. Following completion of the calculations, the results of both the software analysis and hand calculations were discussed.

Chapter five concludes the thesis and provides a synopsis of the findings within the thesis.

CHAPTER 2

2 Literature Review

In the first half of this chapter, literature related to Ireland’s power generation, electrical consumption and distribution system is reviewed. The second half of this chapter reviews the different types of distributed generation technologies available, with a particular focus on CHP technology.

2.1 Generation, Transmission and Distribution in Ireland

Since the late 1800s the production, distribution and utilisation of electrical energy in Ireland has evolved. In the early years of electricity in Ireland, private energy firms provided energy to urban and rural areas, each area utilizing their own technology. These technologies varied from the burning of fossil fuels to falling water in hydro plants. The Electricity Supply Board Act was passed in 1927 to facilitate the establishment of the Electrical Supply Board (ESB), a corporate body to control and develop Ireland’s electricity network. The ESB amalgamated the different technologies within cities and counties into one network [1]. The ESB then set about the design and installation of centralized power generation throughout Ireland. In 1925, Ardnacrusha power station was approved by the Irish government and work started on the station in 1925. In 1968, work started on Toulough Hill power station, this was a pumped storage hydro-electric station and was completed in 1974. In the 1980’s Aghada power station began producing electricity; the capacity of this station was increased in 2010 by the installation of a new state of the art 435MW combined cycle gas turbine, bringing the power stations capacity to 963MW. In 1987, Moneypoint power station was commissioned and in 2010 a major environmental retrofit was completed to ensure the station complied with stringent European Union (EU) coal regulations for burning coal stations. In 2000, Poolbeg power station, which first started generating electricity in 1903, was converted to a combined cycle operation along with two waste heat recovery boilers and a 170MW steam turbine. This brought the station’s thermal efficiency to over 52% and overall output to 980MW. In March of 2010, Poolbeg units 1, 2 and 3 were retired, leaving the station’s maximum output at 470MW. 2004 saw the addition of a new 100MW milled peat burning station at Lough Ree Power station, as well as the addition of West Offaly Power station, to the ESB's portfolio. In 2010, the ESB made a major investment into Moneypoint power station; this investment in emissions abatement equipment brought about a reduction in the order of up to 85% NOx and 90% SOx emissions [70].

In Ireland and throughout the world, it was thought large power plants would be the most cost effective way of producing electricity. It was thought that:

a) It is more economical to move power at high voltage. The higher the voltage, the lower the cost per kilowatt to move power any distance.

b) The higher the voltage, the greater the capacity and the greater the cost of otherwise similar equipment. Thus, high voltage lines, while potentially economical, cost a great deal more than low voltage lines, but have a much greater capacity. They are only economical in practice if they can be used to move a lot of power in one block – they are giant economy size, but they are only economical if one truly needs the giant size.

c) Utilisation voltage is useless for the transmission of power. The 250 volt/ 416 volt three-phase system used in "European systems" is not equal to the task of economically moving power more than a few hundred yards. The application of these lower voltages for anything more than very local distribution at the neighbourhood [2].

The power generated from Ireland's power stations is transmitted and distributed throughout Ireland via an intricate overhead and underground cable system - this system is known as "The National Grid". The National Grid is a meshed network of approximately 6,500km of high voltage, 110,000 volts (110kV), 220,000 volts (220kV) and 400,000 volts (400kV), and over 100 transmission stations. At transmission stations, power is transmitted from the national grid and transformed into medium and low voltages, 38,000 volts (network length approximately 6,194km), 20,000 volts (network length approximately 18,455km) and 10,000 volts (network length approximately 69,098km) and diverted into the lower voltage distribution system or directly connected to large industrial operations [4]. EirGrid is the independent state-owned body licenced by the Commission for Energy Regulation (CER) to act as Transmission System Operator (TSO) and is responsible for the operation, development and maintenance of the system. The ESB is licensed by the CER as the owner of the transmission system and is responsible for carrying out the maintenance and construction of the system. The distribution network is the medium and low voltage electricity network used to deliver electricity to connection points such as shops, offices and homes. The development, maintenance and operation of the distribution network is carried out by two licensable activities, that of "Distribution Asset Owner (DAO), which in Ireland's case is the ESB, and the "Distribution System Operator", which in Ireland's case is ESB Networks. The distribution system operator is responsible for building, maintaining and operating the entire distribution level network infrastructure including overhead lines, poles and underground cables used to bring power to Ireland's customers [19].

It was previously thought that centralized power generation was the best solution for all consumers of electricity, both domestic and commercial.

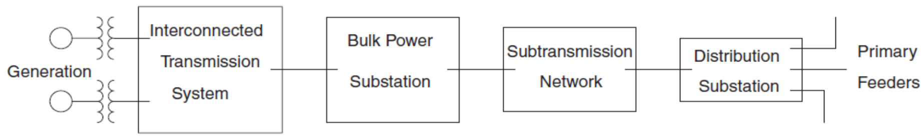


Figure 1: Traditional Transmission Network

As shown in figure 1, the electricity generated in the centralised generation power plant is stepped with the use of a transmission transformer. This higher voltage is then transmitted using the interconnected transmission system. The electricity transmitted is brought to numerous bulk power substations where it is divided out into different smaller networks at a lower voltage. These networks are called distribution networks. In some cases, the distribution substation is fed directly from a high voltage line, in which case there would be no sub transmission system. Each distribution substation would feed one or more primary feeders. Occasionally the feeders are radial, which means there is only one path for the power to flow from the distribution substation to the consumer. Traditionally Ireland's transmission and distribution networks have been passive networks. This means the real and reactive power flows from the generating stations to the various loads in one direction.

In more recent years, however, commercial entities have started moving away from their reliance on centralised power generation plants and have started investing in micro generation systems, to satisfy their base electrical and thermal loads. With the evolution of large scale industry in Ireland, electrical demand and the location of electrical load centres has changed, and more and more is expected of an aging generation and transmission system. Throughout the years, centralized power generation located far from load centres presented two significant challenges, each of which is a result of nature's thermodynamic principles. First, the most efficient generators are able to effectively convert about 40% of the thermal energy from combustion of fuel such as natural gas, coal or oil to useful electric energy. The remaining 60% of the heat energy is typically vented to the atmosphere. The second challenge is the act of transporting and managing the energy on the grid and minimising the electric losses, which is predominantly resistive losses through the wires and transformation losses associated with regulating voltage [9]. Resistive losses are the reason why high voltage levels are chosen for power transmission and distribution lines. The higher the transmission voltage, the lower the current needed to flow in the line to transmit the same amount of power of that of a lower voltage; therefore, the lower the losses in the line. Since resistive heating is related to the square of the current, it is highly beneficial from a losses perspective to reduce the current in the line by increasing the line voltage [12].

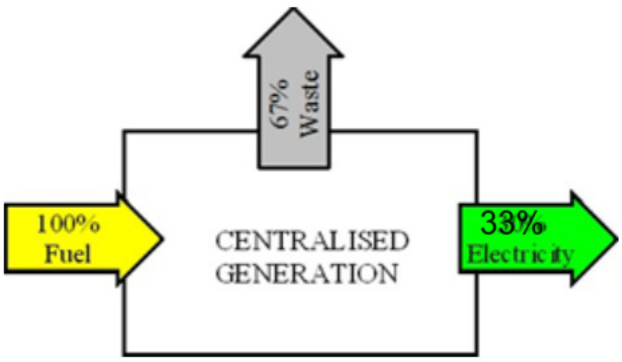


Figure 2: Traditional Centralised Electricity Generation

With traditional centralized power generation, power is transferred using the national grid to industrial site distribution networks. Approximately 33% of the generated power is utilized; the remaining 67% is waste, in the form of heat and other losses. However, with companies becoming more conscious of their carbon footprint and the cost of buying energy from utility companies, more and more companies are developing ways to limit the waste of energy from their facility. Some industrial companies have actually started exporting and selling excess energy to the national grid. This means the traditionally power flow arrangement from the centralized power station to the load centre has now been reversed and power now flows bidirectional. This introduces a new challenge to power system operators [20].

With distributed power generation, power is transferred from load centres across the industrial site using the industrial site distribution network and if the site exports energy, this energy is transported via the national grid. When DG is being exported utilising the "distribution network", the characteristics of the network change. The distribution network changes from being a passive network to an active network. This is caused by the generation as well as the loads.

Within ISDNs, CHP installation appears to be the most predominantly utilised technology to meet a facility's thermal and energy requirements. In combined heat and power generation, approximately 70-90% of the generated energy is utilised; the remaining 10-30% is waste, in the form of heat and other losses. Due to the fact there is less waste energy, the company has now reduced their energy losses and made a saving of between 10-30%, when compared with the separate supply of electrical, heat and cooling energy from conventional power stations, boilers and cooling systems. This can be illustrated with the aid of a basic diagram, as shown below.

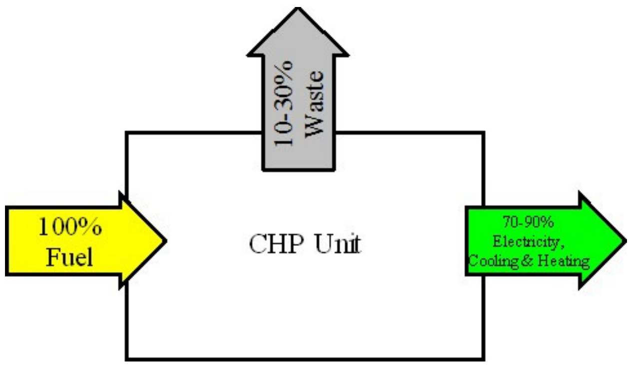


Figure 3: Distributed Generation Electricity Generation

A CHP unit can produce a specified amount of thermal and electrical energy. When the thermal needs of a facility are not achieved, the use of supplementary heating equipment, such as boilers, are required. When the electrical needs of a facility are not met, the facility would have to import electricity from the national grid; conversely, when the facility produces more electricity than it requires, the facility can export the unused electricity to the national grid, assuming it has a license to do so.

There are a number of different technologies which may be used to generate electricity utilizing distributed generation. These technologies vary from wind generation, gas fired generators, the burning of fossil fuels, etc. In 2007, it was reported that the breakdown of electricity generation in Ireland was as follows:

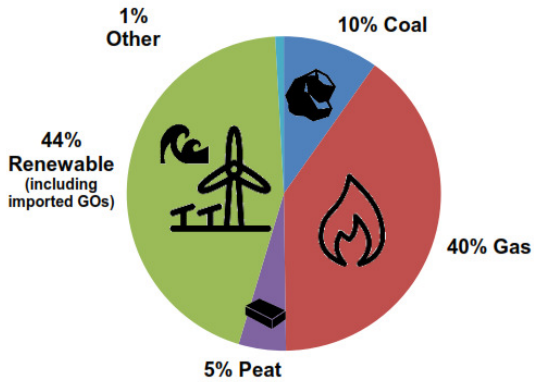


Figure 4: Breakdown of fuel types used in Electricity Generation [4]

If these values are compared to those of, say, 20 years ago, it would be clear that there is an appreciable growth in the "renewable" and "CHP" sector of power generation. The primary reasons for a rise in the "renewable" and "CHP" sector of power generation in recent years must be attributed to a) numerous countries signing up to the Kyoto Protocol, and b) the advances made in technologies within the sector.

The "Kyoto Protocol" is an historical agreement in that it was the first international agreement in which many of the world's industrial nations concluded a verifiable agreement to reduce their emissions of six greenhouse gases in order to prevent global warming. The major feature of the Kyoto Protocol is that it sets binding targets for 37 industrialized countries and the European community for reducing emissions. These amount to an average of five percent against 1990 levels, over a five year period, 2008-2012 [7].

2.2 General Energy Consumption Overview

Generally, electricity consumption has followed the growth of the domestic economy in Ireland. Energy consumption in Ireland has been increasing since 1927, with the exception of two periods. The first was in 1973, when there was a famous world energy crisis; the second is the present day, primarily due to a downturn in domestic and international economies [10,11]. Prior to the worldwide energy crisis of 1974, electricity consumption in Western Europe nearly doubled every ten years at an average rate of 7% per year [17]. As can be seen from the "Energy Growth Graph", the demand in electricity has contracted by 0.74% in a 12 month period, in Ireland.

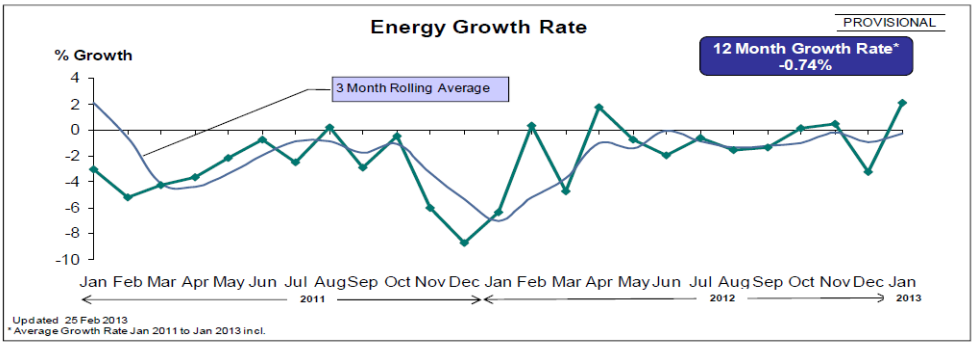


Figure 5: Energy Growth Rate [13]

Figure 6 illustrates Ireland's primary energy consumption to each sector of the economy, in relation to its energy demand. The allocation is straightforward where fuels are used directly by a particular sector. The electricity consumption used by each sector is also included in the breakdown shown. This type of primary energy supply graph provides us with a more complete picture than final energy demand (taking into account the use of oil, gas, electricity and coal bills) of the impact of the individual sectors on national energy use and on related CO_2 emissions.

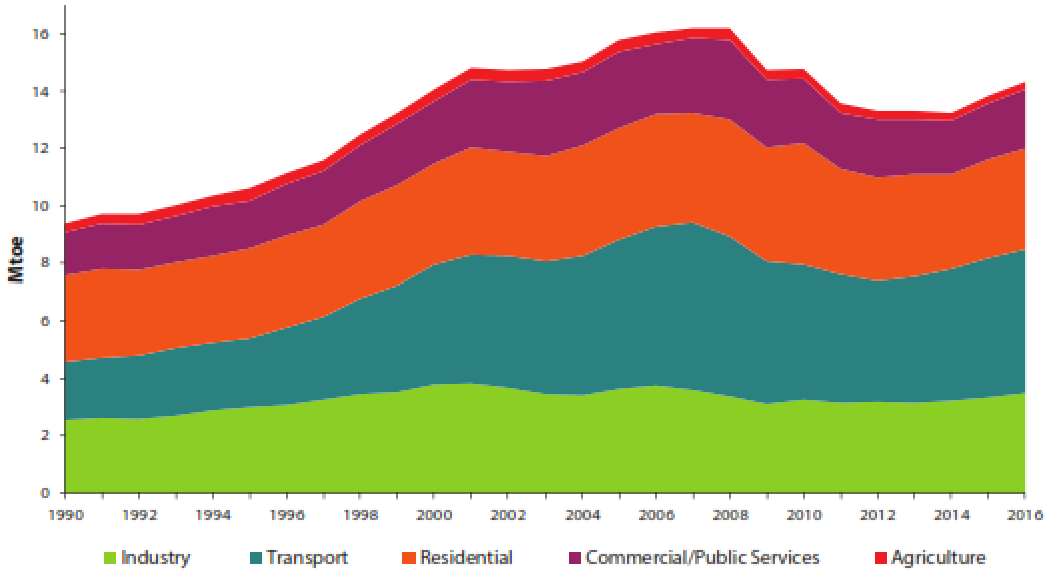


Figure 6: Total Breakdown of Energy Consumption by Sector [5]

The vertical axis shows the millions of tonnes of oil equivalent (Mtoe) used to produce an amount of energy; the horizontal axis shows the year the value was recorded. The different colour areas within the graph depict the different sectors where the energy was consumed. As can be seen from the graph, the transport and residential sectors are the largest users of energy in Ireland in recent years, followed by the industrial sector, commercial/public services sector and, finally, the agricultural sector. The transport sector takes account of energy used for international air travel. It is no coincidence that the reduction in Ireland's energy consumption comes at a time when industries are reducing their overheads, such as energy consumption and employee numbers all over the world. In some cases, industrial consumers are ceasing production due to unsustainable economic conditions. As can be seen from Figure 6, the industrial sector had an energy consumption of circa 3Mtoe in 2007; it now only has an energy consumption of circa 2.2Mtoe in 2010 and will potentially fall further in 2013.

Energy use can be categorised by its mode of application; that is, whether it's used for mobility (transport), power applications (electricity) or thermal applications (space or process heating).

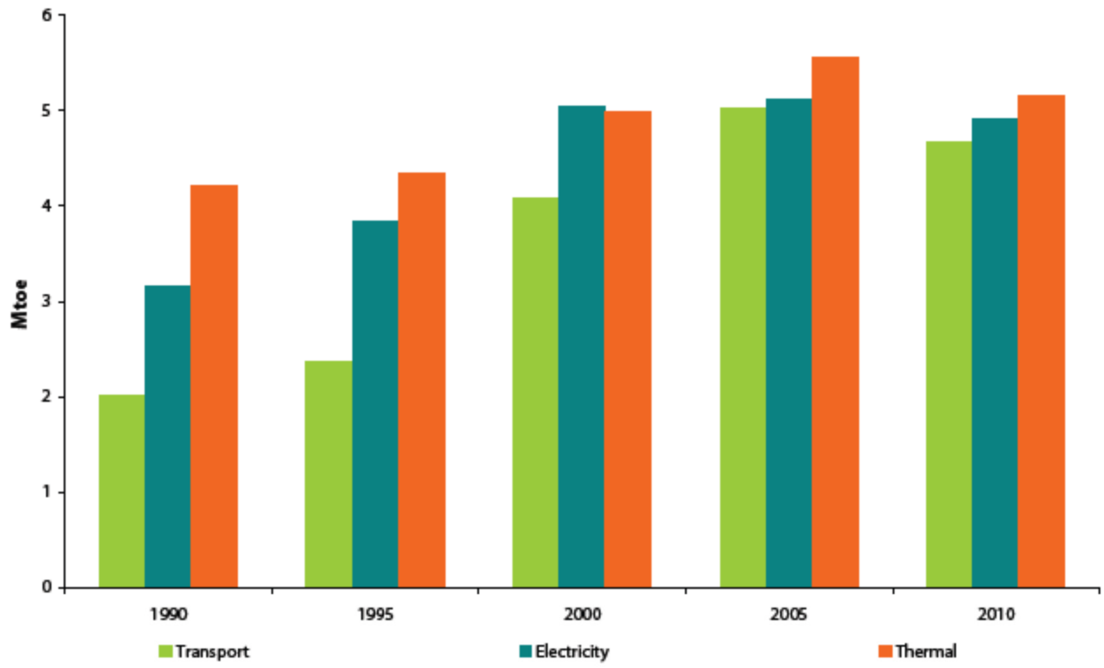


Figure 7: Energy Consumption by mode of application [5]

2.3 Industrial Site Distribution Network

Due to the numerous different distribution voltages within the national grid in Ireland, there are numerous different voltages an industrial consumer can be connected to the Distribution level of the national grid, such as 38kV, 20kV or 10kV. It would be reasonable to assume that the larger the consumer of electricity, the higher the voltage they shall be connected to the national grid. As industries across Ireland differ greatly, there is no one definitive site electrical distribution network utilised, as no two sites have the exact same requirements. The continuity of an industrial plant is only as reliable as its electric site distribution system. In general, network costs increase with system reliability, if component quality is equal. There are many factors impacting on the selection of an IDSN such as:

- the area of the site within the ISDN has to operate, the larger the area the more advantageous it is to distribute electricity at a higher voltage,
- the type of process the ISDN is supplying, for example, industries where continuity of supply is not an issue, a radial electrical network may be utilised. This network is less expensive to build, easy to maintain and simple to operate. If maintenance is required within this network, the loads would have to be shut down until maintenance was complete. Also, this network has only

one utility supply connected to it; if this utility supply is interrupted or if a transformer or switchgear fails within the network, the network will remain de-energised until the utility supply is regained or the transformer or switchgear is repaired. Usually, non-critical processes such as workshops utilise this type of cost effective, unreliable network arrangement [6]. There are some industries which rely on a continuous power supply and if there was to be an interruption to this power supply, it would cause long-term damage to the facility. One way to achieve a greater level of security of power is to have circuit redundancy. Circuit redundancy may be required in continuous process industries to allow equipment maintenance without affecting the manufacturing process of the plant. It is important when choosing an industrial site distribution network for a facility to take the following factors into consideration: a) the manufacturing process to determine the reliability, and b) potential losses and cost in the event of a mains failure [8]. A typical industrial site distribution network is shown below. This network configuration is applicable to an industry such as the pharmaceutical manufacturing industry. In such industries, batches of drugs may take days to be manufactured, cost millions of euro, and the process cannot be interrupted once started. In such scenarios, the capital expenditure of installing such an industrial site distribution system can be justified.

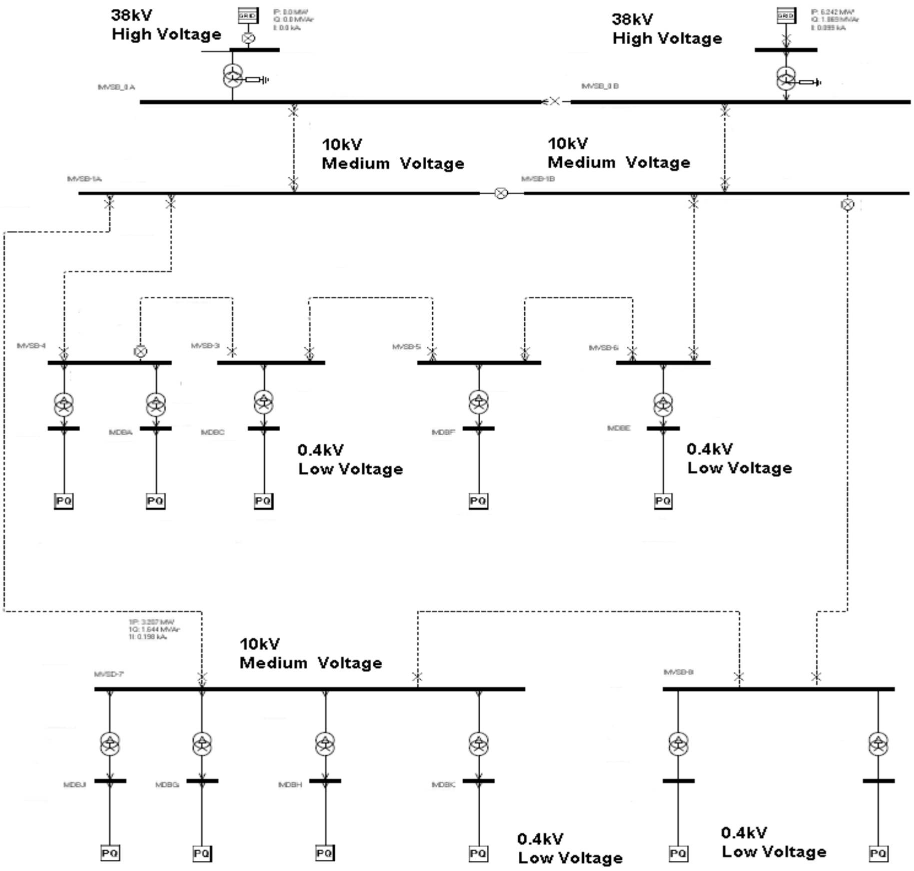


Figure 8: Typical Industrial Site Distribution Network

Note: voltage levels are defined internationally, as follows:

- Low voltage: up to 1000V,
- Medium voltage: above 1000V up to 36kV,
- High voltage: above 36kV [67].

As can be seen from the diagram above, there are two high voltage lines entering the industrial site; in this case, the point of common coupling or P.C.C. is at the HV side of the transformer. There are two reasons the voltage is stepped down by the HV/MV transformers upon entry to the site. The first reason is capital cost of equipment; MV switchgear is less expensive to procure than HV switching equipment. Secondly, it is safer to distribute electricity across the industrial site at MV as opposed to HV. It is also worth noting at this stage that the HV lines usually enter the industrial sites HV compound at high level via transmission lines. After leaving the HV/MV transformer, these cables are usually buried in underground ducts and connected to the MV substation through a system of underground trenches. Each HV/MV transformer usually has a tap changer, either on-load (OLTC) or off-load. A tap changer is a device fitted to a transformer to regulate the output voltage of the transformer. This is normally achieved by changing the ratio of the transformer on the system by altering the number of turns in one winding of the transformer. An on-load tap changer is designed to change the tapping connection of the transformer winding while the transformer is energised, whilst an off-load tap changer requires the transformer to be de-energised before a tap change can take place. About 96% of all power transformers above 10MVA incorporate on load tap changers as a means of voltage regulation [21]. Due to the arrangement of the MV board, the system should be designed in such a way that one HV/MV transformer has the capacity to power the entire facility if required. Instances where this redundancy arrangement may be required are in the event of transformer failure, in the event of a breakdown in the cabling insulation or if routine maintenance of equipment was required. Due to the fact that many industrial sites span across a large geographical area, electricity is distributed at MV rather than LV. Distributing electricity at MV reduces the issue of voltage drop within the cabling installation, therefore the primary basis of sizing the network conductors shall be based on current carrying capacity and short circuit rating of the cable. The MV cabling shall feed numerous MV/LV transformers dispersed across the industrial site. These transformers and associated LV substations are located in adjacent to the load centres across the site. The primary reason for citing the LV substations in the vicinity of the loads is to minimise the cost and size of LV cabling within the installation. It is also usual for either a central large back-up diesel generator or numerous small back-up diesel generators to be connected to the industrial site distribution network. In many sites where small generators are installed, these are connected directly to the LV substations across the site. Alternatively, these small generators can be synchronised, operated in parallel, and their voltage stepped up and distributed at MV across the site, in the event of a mains failure. The configuration of the back-up generator network is designed on a case by case basis. In some installations, all the critical loads would be located on one busbar. In this case, it is only necessary to have one generator to back up this busbar; in other installations, there may be numerous critical loads which require back-up power, and in this case it may be more advantageous to back-up the entire system and use shunt tripping or an automated switching system to disconnect non-critical loads from the network.

2.4 Distributed Generation - Definition

With the evolving demands on electrical power systems, power networks are constantly changing. In [17], the author proposes that future power systems should enable utilities to:

a) Be more competitive with their overall strategies

b) Provide better service

c) Better manage their assets

d) Extend equipment life

e) Improve diagnostics

f) Develop reliability-centred maintenance.

Distributed generation fulfils all these proposals. The term “distributed generation” is often used to depict small scale electricity generation. As discussed in [3], there is no concise definition for distributed generation and it is not easy to create a definition for distributed generation, as:

Some countries define distributed generation on the basis of voltage level, whereas others start from the principle that distributed generation is connected to circuits from which consumer loads are supplied directly. Other countries define distributed generation as having some basic characteristic such as using renewables, cogeneration, etc.

The author believes an accurate definition for distributed generation is given in an Arthur D. Little white paper. It states, that distributed generation is defined as the integrated or stand-alone use of small, modular electric generation close to the point of consumption. It differs fundamentally from the traditional model of central generation and delivery insofar as it can be located near the end users within an industrial area, inside a building, or in a community.

There are numerous different types of DG technologies that are utilised in industrial networks throughout the world. DG technologies include photovoltaic panels, wind turbines, fuel cells and combined heat and power plants, to name just a few. Due to the installation of DG technologies across the national grid, various concerns have to be addressed, such as;

- how will the new DG affect power flow direction and magnitude?,
- will DG introduce issues with existing protection schemes?,
- will power quality and reliability be improved or will the installation of DG be to the detriment of these two factors?

It is hoped these scenarios are addressed within this document and satisfactory solutions provided where issues occur.

2.5 ERACS Power System Analysis Software

ERACS electrical power system analysis software was utilised as an analysis tool within the case study of this document. ERACS software enables the operator to perform analysis of numerous network configurations and simulations on an ISDN and of a larger distribution network. Loadflow

Within Eracs radial and mesh models, interconnected AC three phase LV to HV systems with multiple generation sources may be produced. The software calculates loadflow, system losses, power / VAr / current flows, transformer tap settings, equipment loading and voltage profiles, among other calculations.

Eracs can calculate all classical fault types, such as, three phase, phase to earth etc. A fault scenario can be applied to system elements and fault levels automatically calculated at various points of the network.

2.6 Distributed Generation Embedded in Industrial Plant

2.6.1 Distributed Generation - General

As previously discussed, there are various DG technologies that are being utilised in industrial networks throughout the world. The evolving demands on the electrical power system mean the electrical distribution networks are consistently changing. DG technologies such as reciprocating engines, micro turbines, combustion gas turbines, fuel cells photovoltaic and wind turbines are currently being integrated into electrical power systems all over the world. The main drivers for utilising DG can be divided into the following sections - environmental, commercial, and technical benefit. The primary environmental benefits that are obtained from the integration of DG into ISDN are the reduction in greenhouse gas emissions and a reduction in the requirement to build large centralised electricity generation stations. The primary commercial benefits that are obtained from the integration of DG into ISDN are increased reliability of the power supply and improved power quality within the IDSN. In the event of failure of the utility company's electricity supply, the DG may be configured to run in "island mode"; this means the DG can supply the IDSN's energy requirements assuming the capacity of the DG is sufficient to take the IDSN's load. Even in the event the IDSN's load exceeds the DG's capacity, loads may be prioritised within the IDSN and non-critical loads may be temporarily disconnected from the network. Also, if DG was utilised throughout a network, the loss of one generator would have minimal effect on the network. However, if the network were supplied from a small number of large centralised power stations, then loss of power from one generating station may cause the system to overload and trigger a reaction similar to that which occurred in New York in 2003.

2.7 Different Distributed Generation Technologies

The following table is an overview of the most commonly-used distributed generation technologies and their typical module size [22].

Technology	*Typical available size per module*
Combined Cycle Gas Turbine	35 MW – 400 MW
Internal Combustion Engines	5 kW – 10 MW
Combustion Turbine	1 MW – 250 MW
Micro-Turbines	35 kW – 1 MW
Small Hydro	1 MW – 100 MW
Wind Turbine	200 W – 3 MW
Photovoltaic Arrays	20 W – 100 kW
Fuel Cells, Solid Oxide	250 kW – 5 MW

Table 1: Different DG Technologies

The diverse technologies and fuels used in making DG power is a valuable characteristic associated with the use of DG. DG is not specifically dependant on fossil fuels, sunlight, etc.; therefore, if there was a problem sourcing fuel of one particular type, then the impact would be reduced when compared to the impact of a fuel shortage for a large centralised generation station.

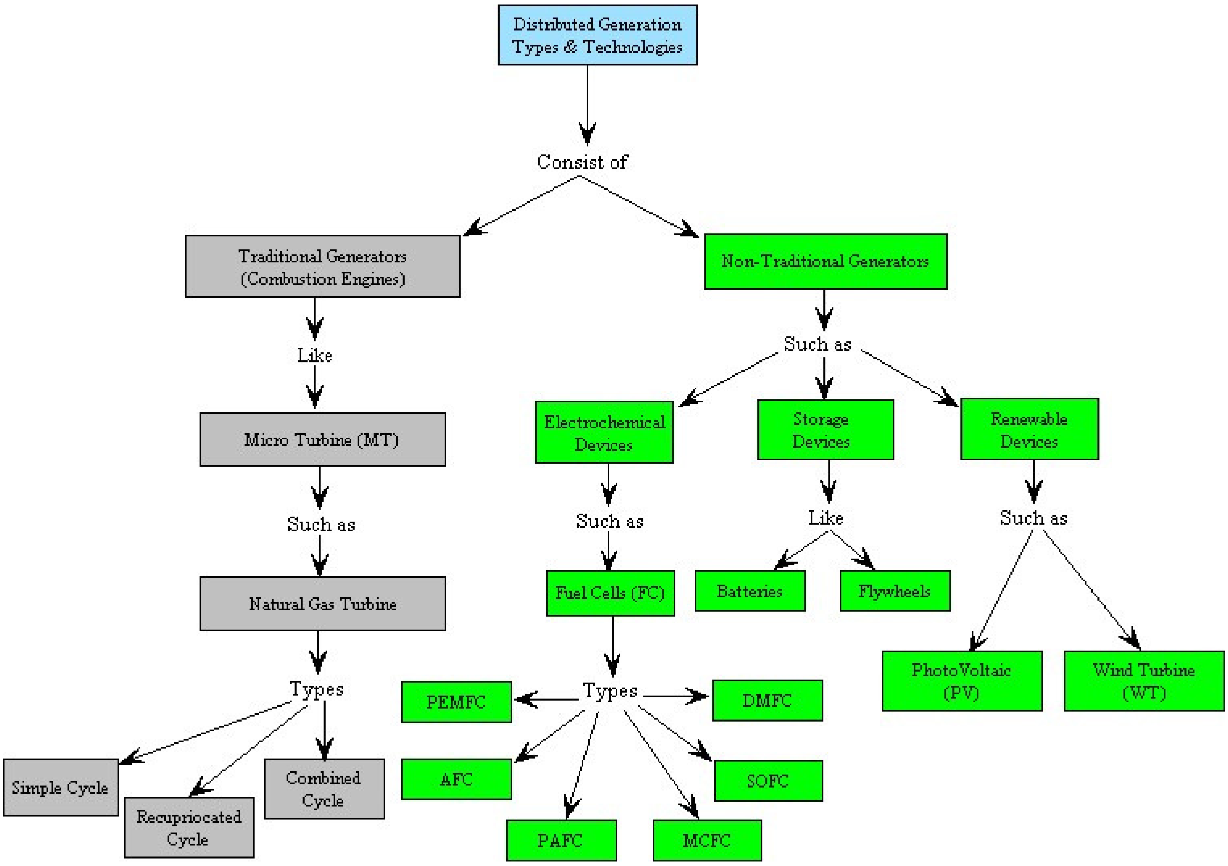


Figure 9: DG Types and Technologies (Diagram adapted from [23])

This thesis briefly discusses the different types of DG technologies. However, it focuses on one of the more utilised technologies in Ireland at the moment, CHP.

2.8 Non Traditional Generators

2.8.1 Electrochemical Devices - Fuel Cells

Discovered in the early 1840s by Sir William Grove, fuel cells are electrochemical devices which directly convert chemical energy to electrical energy without combustion [24]. Fuel cells consist of two electrodes, an anode and a cathode, with a conductive electrolyte sandwiched in between. These electrodes are coated in a highly conductive material such as platinum, to ensure they act as a catalyst for the chemical reaction. The electrolyte can range from a number of different chemicals. Normally, hydrogen is the fuel fed to the anode while oxygen is the fuel supplied to the cathode. With the aid of the catalysts present on the surface of the electrodes, the hydrogen splits into hydrogen ions and electrons. The electrons flow away from the anode into an external electrical circuit where they can make useful electrical energy.

The hydrogen ions flow from the cathode where they combine with oxygen and the electrons from the electrical circuit to form a water vapour. Depending on the type of cell, 30-60% of the energy content of the input fuel is converted to electricity; the rest appears as heat and water vapour, both of which may be utilised in other systems, such as space heating, etc. [25]

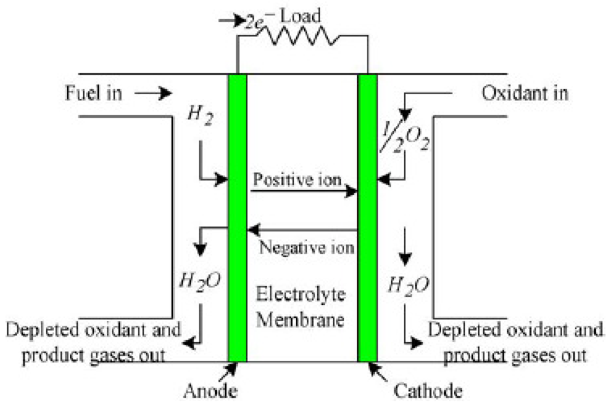


Figure 10: Principle of fuel cell operation diagram [26]

The continual advancement in fuel cell technologies means fuel cells are becoming more and more efficient as the years go by. The most obvious way to list the various types of fuel cell is by the electrolyte they use. The following is a brief description of some of the electrolytes used in today's fuel cell technology.

a) Alkaline Fuel Cell (AFC) – This type of fuel cell uses a solution of potassium hydroxide as an electrolyte and is fuelled by pure hydrogen. It can provide both electricity and water. This type of fuel cell can be up to 60-70% efficient. The major disadvantage with this type of fuel cell is the use of a corrosive electrolyte. This is the primary reason why it is not used on large scale commercial projects. This range of fuel cells are utilised primarily in the aerospace industry.

b) Proton Exchange Membrane Fuel Cell (PEMFC) - This type of fuel cell uses treated polymers that only allow the flow of positive ions. The advantage PEMFC have is they have a low operating temperature and a quick start up; however, they have an operating efficiency of 40 - 45%, which is quiet low. Also, this type of fuel cell requires a more expensive type of platinum to act as a catalyst on the electrodes. This range of fuel cells are utilised primarily in the car industry.

c) Direct Membrane Fuel Cell (DMFC) - This type of fuel cell uses solid polymers which are fuelled by a water/methanol solution. This technology is at an early stage of its development when compared with other fuel cell technologies.

d) Phosphoric Acid Fuel Cell (PAFC) - This type of fuel cell uses phosphoric acid as its electrolyte and hydrogen as its fuel. This fuel cell technology has established itself as a reliable source of electricity and heat for buildings.

e) Molten Carbonate Fuel Cell (MCFC) - This type of fuel cell uses molten lithium, sodium or potassium carbonate as its electrolyte and hydrogen as its fuel, but it can also directly run on fuels such as carbon monoxide or natural gas. Unlike the other fuel cells running on hydrogen alone, it will also produce CO_2.

f) Solid Oxide Fuel Cell (SOFC) - This type of fuel cell uses solid oxide or ceramic as its electrolyte. Similar to MCFC, it can use a variety of fuels. Both MCFC and SOFC are at early stages of their development; however, already they are proving very efficient and it is thought in years to come these two technologies may provide large scale, low emission electricity generation [24, 25, 26].

2.8.2 Renewable Devices – Photo Voltaic Panels

Photo Voltaic (PV) systems, commonly known as "solar panels", are comprised of discrete cells connected together that convert light radiation into electricity. The photovoltaic cells produce direct current electricity. Due to the fact that the utility company provides electricity using alternating current and the consumers use primarily alternating current, the electricity produced by the solar panels cannot be utilised until it is converted from DC to AC, using an inverter. By using an inverter to convert the electricity, there is an inefficient piece of equipment entering the circuit. Inverters are not extremely efficient, therefore the overall efficiency of the process is reduced. In some instances, additional power conditioning equipment may be required if the solar panel is connected to the electric grid. PV systems are on average 16% efficient; however, when discussing PV systems, energy efficiency isn't a primary concern, cost is. In most cases, it does not make sense to spend money on expensive advanced technology PV panels, when compared to using a higher quantity of less expensive PV panels.

PV generation converts light energy into electric energy without using any rotating or moving parts; it utilises a semi-conductor device similar to that used in computers. PV panels are called "cells". This is due to the fact that their output is similar to that of a battery. Each "PV cell" will produce DC current when exposed to sunlight. Usually a number of PV cells are connected in series to provide a higher voltage, or connected in parallel to create a higher current. This is referred to as a photovoltaic array or panel. PV power generation is more suited to small DC power applications than large AC power applications, such as powering machines. PV power is not suited to applications which may be required to run in either day or night time. If PV power was required at night, a method of storing the power would be required. All these difficulties can be solved and in many large scale PV power production facilities they are solved. However, this raises the cost of the PV equipment required and therefore the price of a unit of electricity produced from a PV power production facility would also be greater.

Despite the high costs associated with PV generation, PV systems offer a number of advantages:

a) They require no fuel, only sunlight. This is ideal for remote applications which require electricity, where it would be difficult to deliver fuel to site.

b) PV systems have limited environmental and aesthetic impact. They do not produce noise and do not disturb the natural water or wind flow in an area. Also PV systems do not pollute the atmosphere.

c) PV systems are more reliable than other types of power generation systems as they do not have any rotating parts, therefore there is no wear and tear.

The primary disadvantage of PV power generation must be its cost disadvantage over other power generation options, even other solar power generation options. Although PV is ideal for use in remote areas which require a low level of power, it is hard to envisage widespread use of this technology in Ireland. If further advancements were made in the manufacturing process of PV panels, then higher production yields may lower the capital cost of purchasing PV panels. This may encourage more consumers to invest in PV generation which in turn would increase the use of such a power generation system [18].

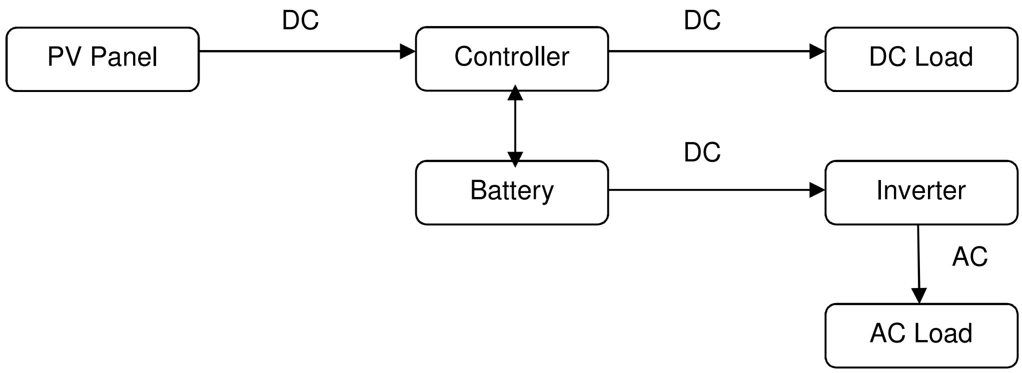


Figure 11: Principle of PV

2.8.3 Renewable Devices - Wind Turbines

Wind turbines are popular renewable sources of energy within Ireland. However, they are not largely utilised in ISDNs. One example of where wind turbines are installed in an ISDN is in Munster Joinery's facility in Ballydesmond, Co. Cork. In May 2009, a 4MW on-site wind energy project was commissioned by "Wind Energy Direct". Prior to the the installation of on-site wind energy, Munster Joinery's primary energy source was the ESB electricity supply. The Munster Joinery facility consumes approximately 26 GW hours of energy annually.

The wind turbine operates on a reasonably simple process. Wind energy turns the turbine blades and this mechanical energy is transformed into conventional electrical energy, with the aid of a wind power generator within the nacelle of the turbine. The nacelle of the turbine is the part of the turbine located on top of the tower. This contains mechanical parts such as gearboxes, cooling equipment and instrumentation. The electricity generated is then transformed to 10/20kV and distributed to a central substation. The circuit breaker upstream of this busbar is the PCC between the wind turbines and the ESB network.

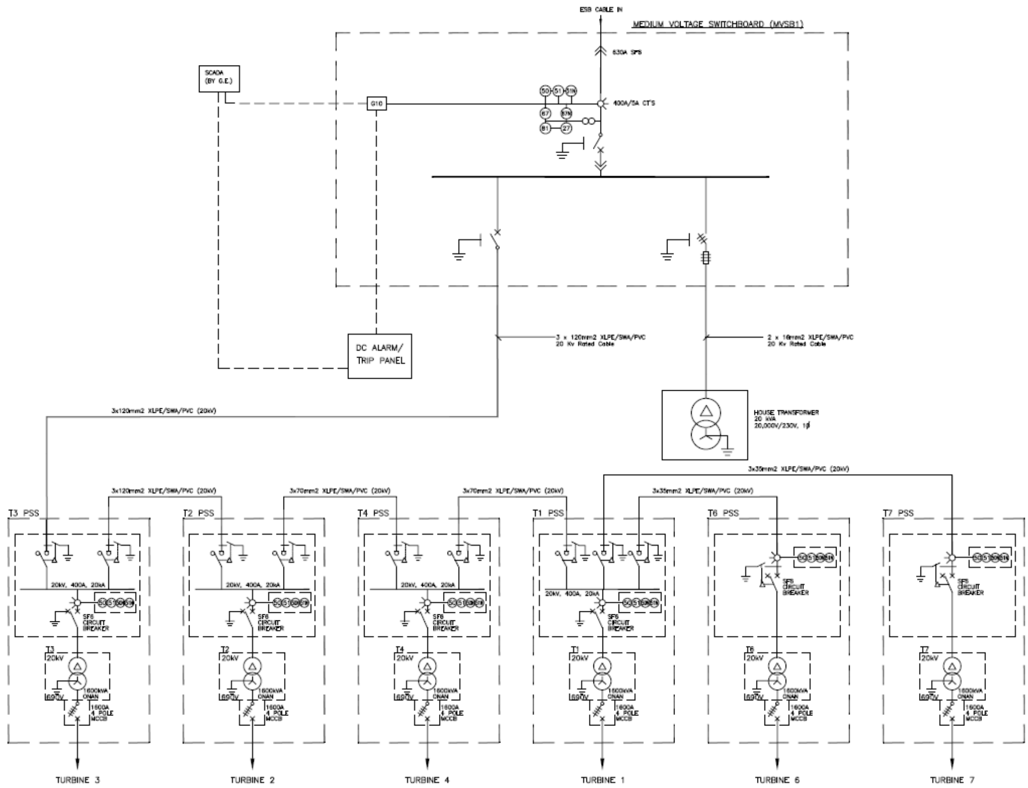


Figure 12: Single Line Diagram of a Wind Turbine Installation

The wind turbines are relatively simple yet intelligent machines. The wind turbine measures the direction and speed of the wind using instruments located at the top of the tower. This information is fed into a computer program which turns the turbine into the wind when the wind changes, or alternatively turns the turbine out of the wind if the speed of the wind is too high; this avoids the turbine from getting damaged. The blades on the turbine are designed so they can move and flex continuously, depending on the speed and direction of the wind. The turbine is also equipped with mechanical brakes, which prevent damage in high winds.

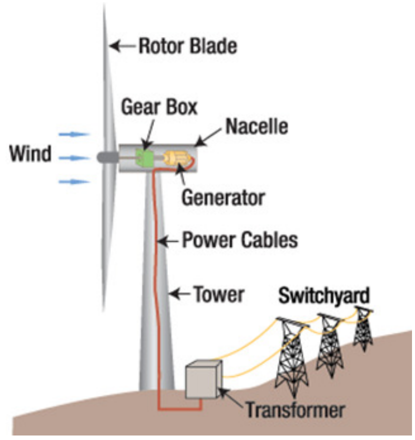


Figure 13: Parts of a Wind Turbine Installation[45]

Wind turbines are not yet used widely in ISDNs. This is largely due to the location of industrial facilities in built-up or low-lying areas, the large capital expenditure associated with such, and installation or the long payback periods also associated with such an installation. However, in limited locations where the conditions are appropriate, small scale wind turbine installations are being installed.

2.9 Traditional Generators

There are numerous ways to produce electricity. One way is by coupling a prime mover that converts mechanical energy (known as a turbine) to an electrical generator. Mechanical energy drives the turbine; magnetic energy is then created between stator and the rotor of the generator and electric energy is produced. The most common types of turbines are:

- Steam and Wind Turbines
- Internal Combustion Engines
- Diesel Engines.

The basic philosophy of each type of technology is shown below:

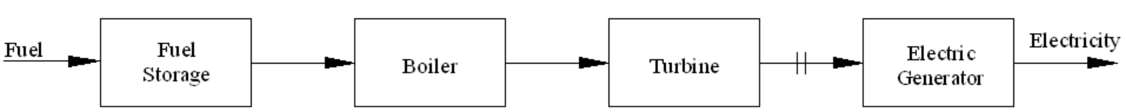


Figure 14: Steam turbine arrangement

Figure 15: Internal combustion engine arrangement

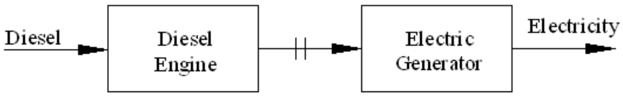


Figure 16: Diesel engine arrangement

The schemes shown above are self-explanatory. They all use a prime mover to create mechanical energy and then transform this energy from mechanical to electrical via a generator. This transformation of energy is primarily limited by the generator's current-carrying capability. There are two main types of generator, both of which may interact differently with the ISDN and local DN and both of which shall be discussed within this document [40]:

- Synchronous
- Induction.

Synchronous generators have the ability to operate at leading, lagging or unity power factor. This is important as it is a requirement of the DSO's connection agreement that DG must operate with a leading power factor. This gives the generator the ability to export watts to the ISDN and local DN, and import VARS from the local DN also [43]. A synchronous generator which operates at unity power factor produces a generator output phasor diagram as shown [41,42]:

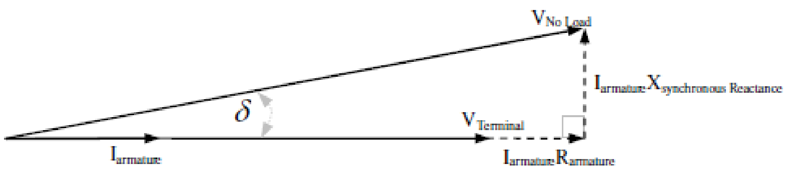


Figure 17: Generator only producing watts.

A synchronous generator which operates at leading power factor, as required by 43, produces a generator output phasor diagram as shown [41,42]:

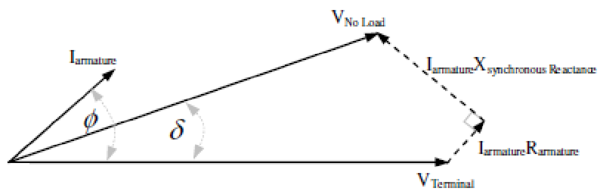


Figure 18: Generator exporting watts and importing vars.

The synchronous generator produces the electrical power. However, the generator needs to be driven by a mechanical force, namely a turbine or internal combustion engine as previously discussed. A CHP is a prime example of where turbines are directly coupled to electric generators and both heat and power are produced.

2.9.1 Combined Heat and Power - Different types / technologies

Combined heat and power, or CHP as it is more commonly known, is one of the most important distributed energy technologies in the world [16]. Security of power supply and environmental carbon footprint reduction are just two of the driving factors that are prompting engineers to investigate the integration of CHP into their industrial site distribution network. CHP is the simultaneous generation of useable heat and power in a single process utilising a single fuel source. In a CHP system, a number of fuel sources may be utilised, such as gas, oil, coal biogas or other biomass materials. Natural gas is one of the more common fuels used to drive a turbine. However, alternative fuels are increasing in popularity, such as wood, agricultural waste, peat moss and the various other fuels previously mentioned, depending on the process and the fuel’s availability in the area. This fuel is used by the CHP to provide all or part of the electric and thermal energy a facility requires at overall greater energy efficiency than if electric and thermal energy were produced separately [14]. In Ireland, CHP usually incorporates a cooling cycle also; when this occurs, the process is known as Combined Cooling and Heat and Power or CCHP. CHP systems consist of a number of individual components – prime mover (heat engine), generator, heat recovery, and electrical interconnection – configured into an integrated whole. The type of equipment that drives the overall system (i.e. the prime mover) typically identifies the CHP system. Prime movers for CHP systems include reciprocating engines, combustion or gas turbines and steam turbines. These prime movers are capable of burning a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce shaft power or mechanical energy.

In typical conventional power generation much of the total energy input is wasted. This is due to the fact that electric power production requires high temperatures. By capturing this unused waste heat from the electric power production process and reusing it to heat or cool another application, efficiencies in excess of 85% may be achieved. The higher efficiencies achieved by the CHP result in lower emissions than utilising a separate heat and power generation system. Due to the utilisation of heat from electricity production at the point of use, transmission losses are minimised and power usage of the facility producing the electricity is also reduced. Due to the utilisation of recovered heat from the power production process instead of creating heat by using separate boilers, overall savings of between 20 percent and 40 percent may be achieved [15]. Transferring the waste heat from the production of electricity over a long distance is not efficient; therefore, the CHP must be located near to the thermal load. Additional boilers are sometimes required depending on the thermal load of a facility. This would then partly negate the environmental benefits of installing the CHP. The following is a basic illustration of a packaged CHP unit, identifying the main components of the CHP.

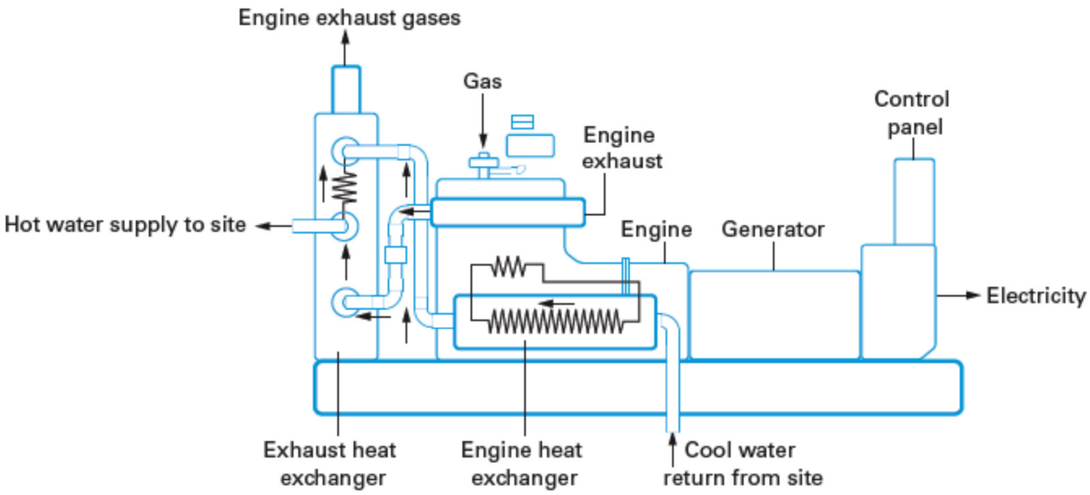


Figure 19: Basic Illustration of CHP Packaged Skid Unit [63]

Advantages of CHP include:

- The simultaneous production of useful thermal and electrical energy in CHP leading to increased fuel efficiency.
- The location of the CHP near the location of the load leads to minimal transmission and distribution losses, as opposed to a centralised generation system.

– CHP may be integrated into existing energy systems and can be installed in a greenfield site or retrofitted into an existing facility.

2.10 CHP – Turbines

The two most utilized CHP turbine options are:

— Steam turbine

— Gas-fired turbine.

2.10.1 Steam Turbine

Steam turbines are one of the most versatile and oldest prime mover technologies still in general production. Power generation using steam turbines has been in use for about 100 years, when they replaced reciprocating steam engines due to their higher efficiencies and lower costs. The capacity of steam turbines can range from 50 kW to several hundred MWs for large utility power plants. Steam turbines are widely used for combined heat and power (CHP) applications. The thermodynamic cycle for the steam turbine is the Rankine cycle.

The steam turbine consists of a steam boiler generating high pressure steam which then propels the turbine. The turbine is linked to the generator which in turn produces electric power. The drawing below shows typical arrangement of a standard back pressure steam turbine. It operates on the enthalpy difference between inlet and outlet steam. Back pressure turbines are typically used in plants which require large volumes of steam for their process.

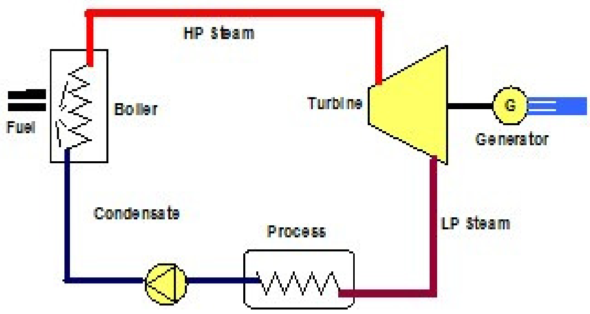


Figure 20: HP and LP Steam Turbine Cycle

Another type of turbine typically used in similar applications is an extraction steam turbine.

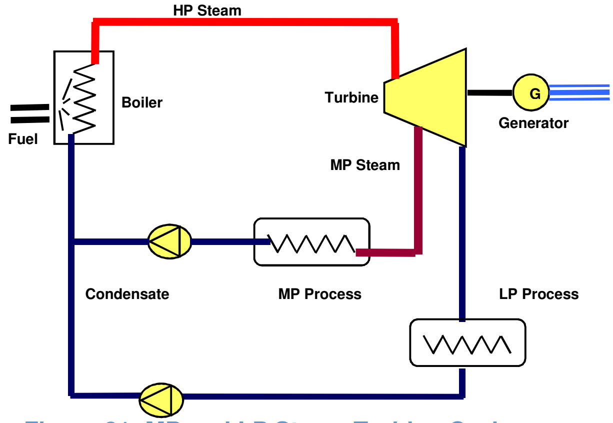


Figure 21: MP and LP Steam Turbine Cycle

Depending on various pressure (or temperature) requirements of the plant, steam is exhausted in different points of the turbine in amounts allowing satisfying process users. The turbine can be considered a multistage pressure reduction station that produces electricity as a by-product.

The advantage of steam turbines in plants with reasonably steady steam requirement is that the electricity can be considered as a by-product. Steam turbines operate at 40bar+. The main element of additional energy is for superheating and results in approximately 15- 20% additional fuel input.

The P&ID below illustrates the main system components in a gas-fired boiler steam turbine plant.

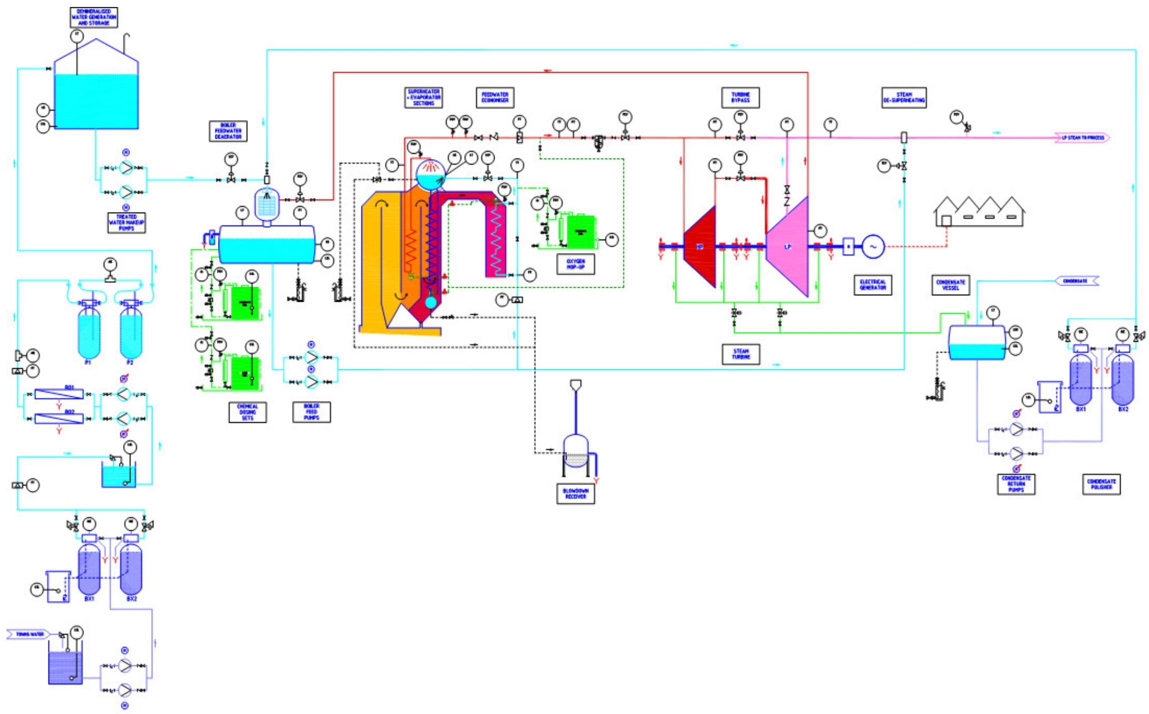


Figure 22: Main system components in a gas fired boiler steam turbine plant [64]

2.10.2 Gas Turbine and Waste Heat Boiler

A gas turbine consists of a compressor, combustion chamber and turbine. The turbine itself consists of a fixed chamber containing a series of tightly-packed blades attached to a central shaft. The fuel is mixed with the compressed air in the combustion chamber; the resultant hot gasses (500-700 ^{o}C) exit through the turbine blades and the energy within the gasses is used to rotate the turbine and subsequently the generator to produce electrical power. The turbine itself is used to drive the compressor and turbines are generally classified as single or double shafted. Compressors are generally of the centrifugal or axial type.

The hot gases post turbine can be fed directly into a Waste Heat Generator (WHG) where its heat is used to create steam. The WHG can be fitted with gas burners (supplementary firing) to increase the overall availability of steam. Turbines are available from 1MWe up to and above 100MWe; electrical efficiencies are in the range of 20 -34 %. Smaller turbines may not be economical in comparison to gas engines. Some of the advantages of GTG are; a variety of fuels can be used, small in size, low comparative cost, and high reliability. Disadvantages include noise and sensitivity to fuel quality.

The following PFD indicates the Gas Turbine cycle;

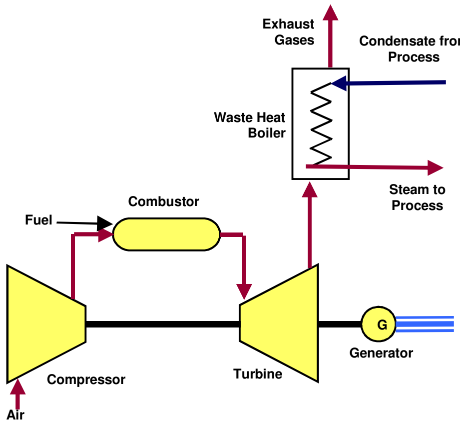


Figure 23: Process Flow Diagram for Gas Turbine Cycle

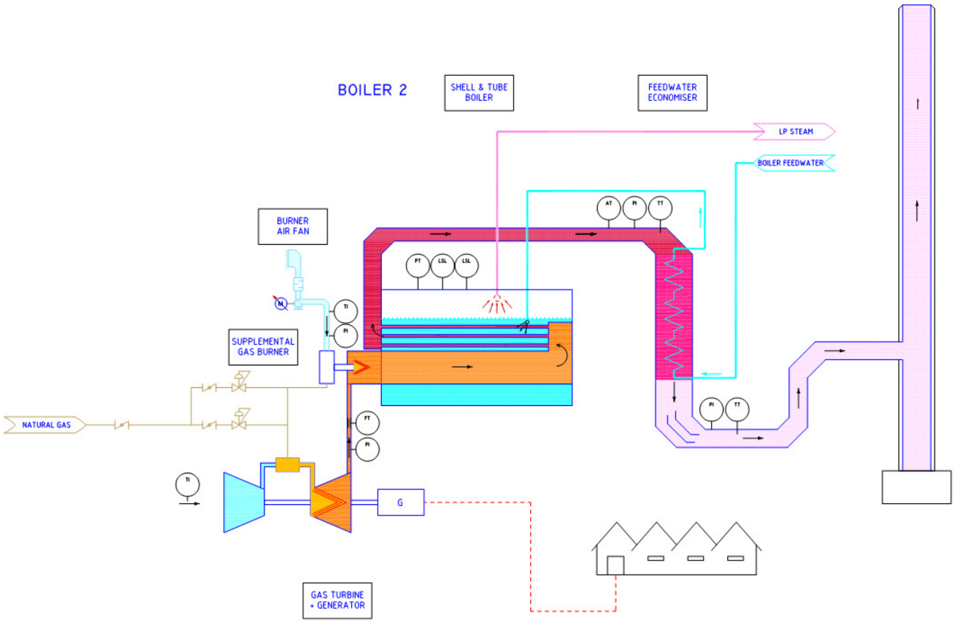


Figure 24: P&ID illustrating the main system components in a Gas turbine plant

2.10.3 Gas Engines and Waste Heat Boiler

A spark ignition engine is a machine comprising of a shaft attached to pistons housed within a series of combustion chambers. When fuel is introduced into each of the chambers, a spark from a spark plug, powered by electricity, ignites the fuel and thus moves the piston up and down which in turn rotates the shaft to which it is attached. The end of the shaft is attached to a generator from which electricity is produced. Spark ignition engines have been around since the early part of the 20th Century and since their invention have gone through numerous design changes in order to improve their cycle efficiencies. Efficiencies of up to 40% are typically achievable with modern engines.

Due to the high efficiencies and compact nature of these engines, they are the unit of choice for small scale commercial generation applications where a ready supply of gas is available. The Spark Ignition Engine is the most widely-used plant for small scale CHP applications. The technology is very well established with thousands of installations worldwide. There are a large number of operations and maintenance service providers within Ireland and the UK, and thus the use of this technology is considered mainstream. The application of engines within facilities is questionable; as discussed, engines have a large quantity of low grade heat, therefore the site demand where it shall be installed requires a quantity of low grade heat. The engines could easily satisfy the electrical and low grade heat demand. Absorption chillers require low grade heat and are often used in conjunction with gas engine CHP plants.

2.10.4 Absorption Chillers

This type of chiller uses heat energy to produce a refrigerant effect as opposed to mechanical energy, which is often provided by electric motors. Mechanical chillers work by compressing a refrigerant gas which then gets hot due to the work of compression. The compressed gas is then cooled whereupon it turns into a liquid state. The high pressure gas is then expanded through a control valve to a much lower pressure and the gas vaporises once again. In order to change state from a liquid to a gas, the fluid must absorb heat, the latent heat of evaporation. The gas therefore cools creating a refrigeration effect. The expanded gas then passes to the mechanical compressor and the cycle repeats.

Vapour Absorption Chillers use a mixture of two liquids which are soluble in each other instead of a refrigerant gas, the two most common being water and Lithium Bromide Solution. Both liquids have significantly different boiling points. The boiling point of water is directly proportional to pressure. At atmospheric pressure, water boils at approximately 100°C. At a lower pressure, it boils at a lower temperature. At 6 mm Hg absolute pressure (8 mB absolute), the boiling point of water is approx.. 4°C. When water boils and changes from a liquid to a vapour, it must absorb heat. This heat is called the latent heat of vaporisation. Similarly, when water condenses and turns from a vapour to a liquid it must reject heat. This is called the latent heat of condensation.

For an absorption chiller using the Lithium Bromide-water system, the absorption varies directly in proportion to the solution concentration and inversely to the solution temperature. Lithium Bromide (LiBr) is a water-soluble chemical and LiBr-water solution (used as a refrigerant) has an inherent property to absorb water due to its chemical affinity. Additionally, there is a large difference between the vapour pressures of LiBr and water. This means that when the LiBr-water solution is heated, the water will vaporise but the LiBr will stay in solution, which becomes more concentrated.

The absorption chilling process is powered only by the heat energy supplied to the chiller. Small units use no other external power. Larger units are provided with a small electric-powered transfer pump to circulate the LiBr-water solution.

The heat energy used as the motive force for the chilling process can be supplied in any convenient form; steam, hot water and hot gas being the most common. Like any other heat-driven process, as the heat is used, its temperature falls. This “temperature difference” enables the flow of heat energy from one process to another. The greater the temperature difference, the greater the driving force, and therefore the greater the chilling output for a given mass flow of heating media (steam, water, etc). Likewise, a minimum temperature difference is required for the process to work, below which efficiency/performance falls rapidly. Absorption chillers using LiBr-water as a refrigerant medium become increasingly ineffective with energy source temperatures below approximately 70°C. If hot water is used as the heating medium, then the practical upper limit is approximately 90°C for the supply temperature.

Figure 25: Typical image of an absorption chiller

Absorption chillers typically have a coefficient of performance (COP) between 0.6 and 0.75, depending on operating conditions and machine design. This means that for every 1,000W of energy supplied to the chiller, it will produce between 600W and 750W of cooling.

2.11 Advantages and disadvantages of Distributed Generation

With respect to the advantages of DG, there are multiple perspectives on every advantage, for example:

a. From an end user's perspective: The end user benefits greatly from the installation of DG. An end user who places great value on electricity can benefit greatly by having DG on-site; it provides an excellent back-up to a facility's imported power supply and it is highly efficient in generating heat, if a CHP unit were installed, reducing the overall energy bill for a facility. Also, if electricity is exported to the national grid from an ISDN, then the owner of the DG shall be able to charge the ESB for the use of their electricity, decreasing the payback period for the DG installation.
b. From a DSO's perspective: As Ireland has an aging transmission and distribution system, DSO's would welcome the relief DG would give the transmission and distribution system. As DG supplies loads local to where it is installed, this would then reduce the burden on transmission and distribution lines. This would allow the network load to expand to a point where it justifies upgrading the transmission and distribution system.

With respect to the disadvantages of DG, there are also multiple perspectives on every disadvantage. The main disadvantage that is associated with the installation of DG is the effect it may have on power quality. These disadvantages as well as other technical issues are discussed in depth later in this document.

2.12 Performance of a CHPC Plant

The overall performance and efficiency of a CHPC system is extremely important to ensure the installation is economically feasible. Depending on the installation and process, a CHPC within an industrial facility may be a critical piece of infrastructure as it could produce in excess of 30% of the electrical energy demand of a facility and over 90% of the chilled water demand of the facility.

As a CHPC system can simultaneously generate electrical and useful thermal energy, CHPC system efficiency is measured and expressed in a number of different ways. The following algorithm below summarises the key elements of efficiency as applied to a CHPC system incorporated in the energy supply model:

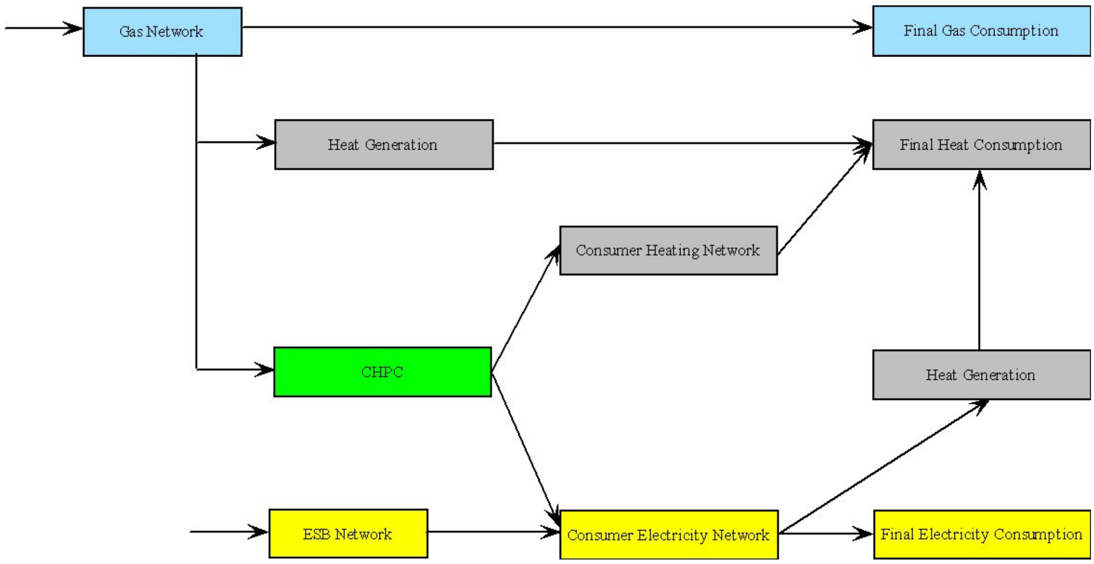


Figure 26: Energy Supply model incorporating CHPC System

For the correct performance anlaysis of the CHPC system, it is very useful to have a basic understanding of the main input and output, therefore it is necessary to design a model for an algoritm. A basic model has been developed in section 4.5 of this document. Refer to appendix 'A' for a detailed narrative on how to correctly read and decipher a flow chart.

Figure 27 indicates the primary information required to enable the reader to carry out calculations to assess three key factors in the assessment of the CHPC performance, namely, the efficiency of the system, the environmental impacts of the system and an economic analysis of the system. This flowchart can be broken down into three distinctive parts; namely, data collection, overall calculation and overall rating.

To make a differentatied rating of the CHPC performance, it is necessary to get the output data of electrical and thermal energy as well as the total running hours and costs (both capital and operational costs). The input data is given by the total annual amount of used fuel and the total running hours. With this basic data, an overall calculation under the use of the algorithm for the CHPC rating can be made.

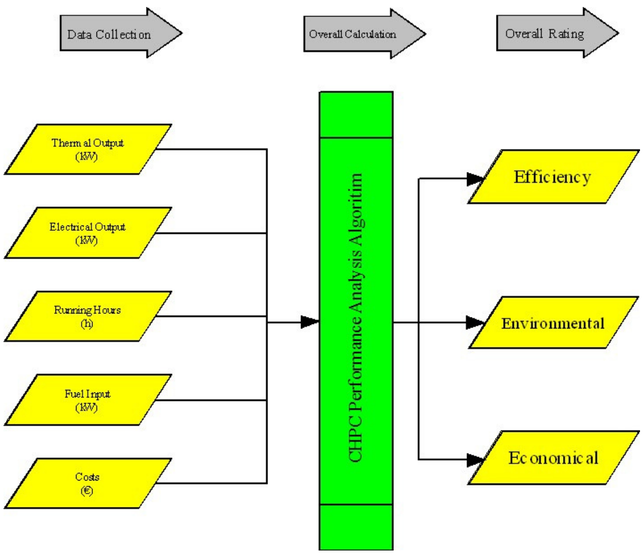


Figure 27: General CHPC Performance model overview

The initial step in the process of making a performance/rating analysis of a CHPC within an Industrial Site Distribution Network is the collection of relevant data. Generally, the data input is divided into five main sections - the thermal output (D1) and electrical output (D2), the total running hours (D3) as well as the total fuel input (D4) and the costs (D5). The thermal and electrical output can be combined giving the total energy output of the CHPC, in kW. For calculations in part two of the overall CHPC performance flowchart, it is necessary to connect various units to each other. When the total CHPC energy output (a combination of both thermal and electrical outputs) is multiplied by the running hours (D3), under the use of Transfer 1, we transform the units from kW to kWh.

The efficiency calculations can then be made with the output line D1234.

When the running hours (D3) are combined with the total fuel input (D4) in kW, we can provide the total fuel input in kWh and under the transfer 3 (CHPC in kWh), it is possible to make the other environmental calculations (D3412).

For cost data collection (D5), it is necessary to make a connection with transfer 2 (total fuel input in kWh). The running costs are divided into the fuel and maintenance costs. Gas prices are required to accurately make these calaculations. The annual running costs (operational expenditure – opex) are combined with the initial installation costs (capital expenditure - capex) to calculate the economical performance of the CHPC (D345). The higher the initial capital expenditure costs, the longer the payback period for the CHPC system. To calculate the installation costs associated with a CHPC system, it is first necessary to calculate the average monthly electrical power output. This is done by summing up the monthly electrical power output of the CHPC system and dividing the total by 12 months.

$$P_{el,avg} = \frac{\sum Nett\ Electrical\ Power\ Output}{\sum Months} \qquad (1)$$

There are multiple variables when estimating the installation costs of a CHPC system, such as location of the installation (what country the CHPC is installed in), how busy the market is, the design of the components, etc. The calculation of the installation costs can be estimated by the multiplication of the installation factor (per kW) with the average electrical plant output:

Installation Costs = Installation Costs per kW * Average Electrical Output

$$C_{Install} = C_{In,\,factor} \times P_{el,\,avg} \qquad (2)$$

Running costs (opex) are a cost which occurs throughout the lifetime of the CHPC system. The lifetime of a CHPC system can be between 20 to 25 years [61]. There are two significant running costs associated with the running of a CHPC sytem; these are maintenance costs and fuel costs. The costs can vary substantially as neither are fixed costs; one cannot accurately state what the lifetime fuel consumption of the CHPC will be as the lifetime of the CHPC system is not defined. The maintenance costs can be reasonably constant as fixed price maintenance agreements can be agreed with approporiate vendors. Typical costs for maintenance would be 0.0147 €/kWh, depending on the level of maintenance required [62]. If the electrical output is known, maintenance costs can be approximated, as follows:

Maintenance = Maintenance costs per kWh * Electrical output (kWh)

$$C_{Main} = C_{Main,\,Factor} \times P_{el,\,kWh} \qquad (3)$$

Fuel costs are dependant on the price of gas at any one time. Fuel prices are variable depending on supplier, country and/or season. Running fuel costs can be estimated by multiplying an estimated price of gas by the fuel input required for the CHPC:

Fuel Costs = Actual Fuel Price (€) * Fuel Input (kWh)

$$C_{Fuel} = C_{Fuel,kWh} \times Q_{Fuel} \qquad (4)$$

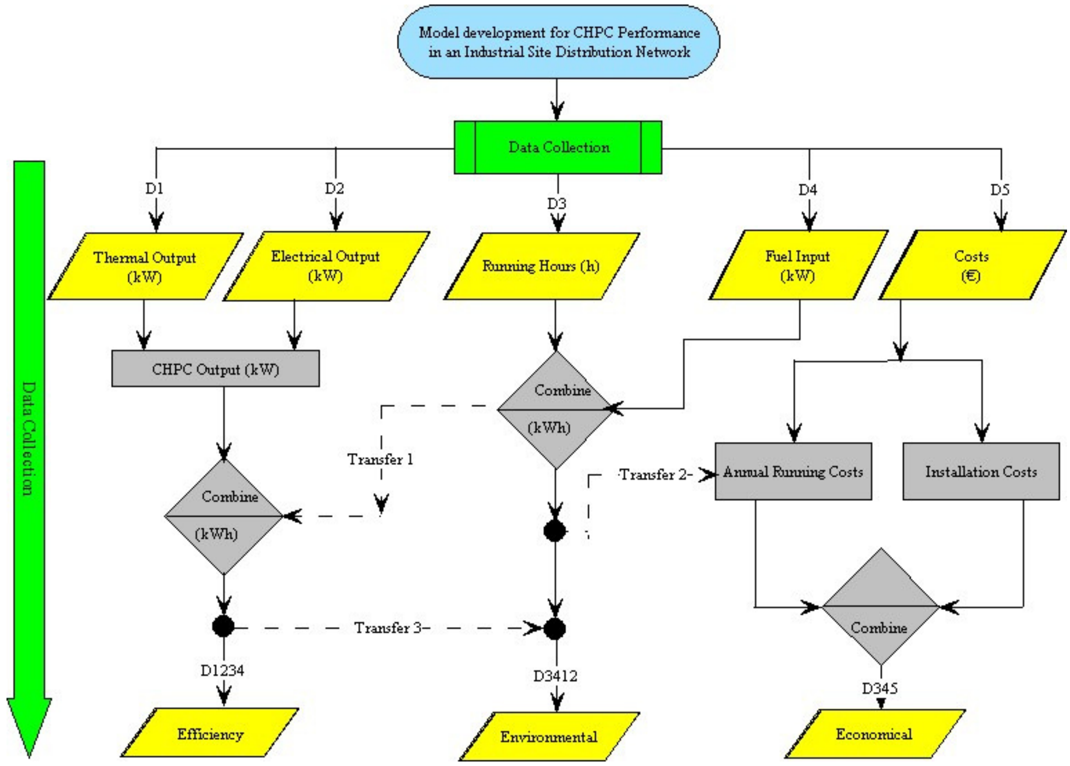


Figure 28: Data Collection Flowchart

Once the initial step in the process of making a performance analysis of a CHPC within an Industrial Site Distribution Network is completed, we can progress to the next step of the performance analysis; namely, the overall calculations.

The overall calculations are made based on the output of step one, data collection. The efficiency calculation, C1, can be made with the outcome of the line D1234. The environmental calculations can use the outcome of line D3412 and the economical calculation, which is the product of D345.

The efficiency calaculations are broken down into four sections: [54]

a) Electrical Efficiency

The electrical efficiency is based around the electrical output of the CHPC plant and compares it to the amount of fuel used to produce that electricity. To calculate the electrical efficiency, the following equation may be used:

$$\eta_{Electrical} = \frac{\sum Nett\ Electrical\ Output}{\sum Total\ Fuel\ Energy\ Input} = \eta_{P\,d,m,y} = \frac{\sum_i P_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\% \qquad (5)$$

The electrical efficiency is important for the electrical rating to ensure the CHPC system meets the basic electrical requirements of the Industrial Site Distribution Network.

b) Thermal Efficiency

The thermal efficiency is based solely on the thermal output of the CHPC plant and compares it to the amount of fuel used to produce that thermal energy.

To calculate the thermal efficiency, the following equation may be used:

$$\eta_{Thermal} = \frac{\sum Nett\,Thermal\,Output}{\sum Total\,Fuel\;Energy\,Input} = \eta_{Q\,d,m,y} = \frac{\sum_i Q_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\% \qquad (6)$$

The thermal efficiency is important for the thermal rating to ensure the CHPC system meets the basic thermal requirements of the Industrial Site Distribution Network.

c) The CHPC Total Overall Efficiency

The total overall efficiency is based on the addition of the electrical and thermal output of the CHPC plant. It is then compared to the amount of fuel used to produce that electrical and thermal energy.

To calculate the overall efficiency, the following equation may be used:

$$\eta_{Total} = \frac{\sum Nett\,Electrical\,Output \;+ \sum Nett\,Thermal\;Output}{\sum Total\,Fuel\;Energy\,Input} = \times 100\% \qquad (7)$$

$$\eta_{T\,d,m,y} = \frac{\sum_i P_{d,m,y} + \sum_i Q_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\%$$

The calculation of total system efficiency evaluates the combined CHP outputs (i.e., electricity and useful thermal output) based on the fuel consumed. CHP systems typically achieve total system efficiencies of 60 to 80% [55].

d) Heat to Power Ratio

Heat to power ratio is one of the more important parameters in a CHP system as it determines the rate of generated heat to electrical power in the single system. This calculation is important when comparing CHP plant systems. The heat to power ratio is calculated using the following equation:

$$X_{d,m,y} = \frac{\sum_i Q_{d,m,y}}{\sum_i P_{d,m,y}} \tag{8}$$

The environmental performance of the CHPC system, C2, can be estimated based on the outcome of step one, initial data collection (namely D3412). As illustrated within the flowchart in Figure 28, the environmental impact can be expressed through two different sections; namely, the efficient use of fuel and CO_2 performance.
When assessing the efficient use of fuel, one must consider two main formulae:

a) Percentage Fuel Savings.

Fuel savings compares the fuel used by the CHP system to a separate heat and power system. Positive values represent fuel savings while negative values indicate that the CHP system is using more fuel than separate heat and power generation.

$$S_{d,m,y} = 1 - \frac{\sum_i F_{d,m,y}}{\frac{\sum_i p_{d,m,y}}{EEF_P} + \frac{\sum_i Q_{d,m,y}}{EEF_Q}} \times 100\% \tag{9}$$

b) Fuel Utilization Effectiveness.

This is the CHP efficiency based on the electrical CHP output versus the net fuel consumption excluding the fuel required to produce the useful heat output. The fuel required to produce useful heat is calculated assuming a typical boiler efficiency, generally 80% [56].

The following equation may be used to calculate the Fuel Utilisation Effectiveness.

$$FUE_{d,m,y} = \frac{\sum_i P_{d,m,y}}{\sum_i F_{d,m,y} - \frac{\sum_i Q_{d,m,y}}{EFF_Q}} \times 100\% \tag{10}$$

As discussed within section 3.3 of this document, there are multiple different gaseous outputs from the exhaust of a CHPC system. One of the larger outputs is CO_2 (carbon dioxide). Before estimating the CO_2 savings, it is firstly necessary to estimate the amount of CO_2 generated by the CHPC system. Once this is calculated, the resultant value can be compared to separated CO_2 generation by a gas boiler and a power station (either coal or gas powered).

a) Percentage CO_2 Savings

The CO_2 savings compares the CO_2 production of the CHP plant to separate electrical and thermal generation by a boiler or a coal or gas power plant. The percentage CO_2 savings is calculated using the following formula:

$$S_{CO_2} = \frac{\sum CO_2\ Total\ Output\ CHP}{\sum Total\ CO_2\ Output\ Seperate\, Heat\, and\ Power} = \frac{CO_{2CHP}}{CO_{2SEPERATE}} \times 100\% \tag{11}$$

The economical analysis of a CHPC system can be estimated based on the output of the data collection (namely D345). There are a number of different aspects to be assessed when investigating whether or not a CHPC system is economically viable for a particular industrial site distribution network.:

a) To ensure the CHPC system is economically viable one must compare the costs of buying electricity from a local energy provider against the cost of generating electricity within the industrial site distribution network. The more running hours the CHPC plant accumulates, the cheaper the price of kWh energy. Therefore, the for maximum economic efficiency of the CHPC system, the system must be running as much as possible. To estimate the price per kWh, the overall cost should be summed and divided by the total annual running hours.

$$C_{install} = \frac{C_{maintenance} + C_{Fuel}}{Lifetime\, of\ CHPC\,(20\,Years)} \tag{12}$$

This, however, does not give a true reflection of the cost of energy produced by the CHPC throughout its lifetime. To calculate this, the installation cost should be divided by the lifetime of the CHPC system, in years.

$$C_{per\,kWh} = \frac{\sum Costs\,annual}{\sum Running\,Hours \times 1\,kW} = \frac{C_{installation,20\,years} + C_{maintenance} + C_{Fuel}}{t_{running\,hours\,per\,year} \times 1\,kW} \quad (13)$$

b) To determine the cost savings associated with the installation of a CHPC system, the total annual cost of the CHPC plant must be known (opex costs – both fuel and maintenance), as well as the price of electrical energy and gas from the local utility provider.

First the seperate costs of both electrical and thermal power should be calculated, as follows:

Separate overall costs = Electrical costs (€/anumn) + Thermal costs (€/anumn)

$$C_{overall\,seperate} = C_{El\,seperate} + C_{Thermal\,seperate} \quad (14)$$

Following the above calculation of the overall separate power and thermal energy costs, the CHPC overall costs should be calculated, as follows:

CHPC overall costs = Fuel costs (Cost of Fuel * Fuel input quantity) + Maintenance Cost

$$C_{CHP} = (C_{Fuel} \times Q_{Fuel}) + C_{Maintenance} \quad (15)$$

The cost savings of deploying a CHPC system within an industrial site distribution network to generate electrical and thermal energy versus separate electrical and thermal generation/purchase, are calculated as follows:

Cost Savings = Overall costs of separate generation – Overall cost of CHP

$$C_{Savings} = C_{Overall\ Seperate\,Costs} - C_{Overall\ CHP\ Cost} \quad (16)$$

Like any asset a company procures, the asset will depreciate over time. It is important to determine the depreciation of the CHPC system when calculating the payback period for such an investment. The depreciation can be calculated with annual cost savings as well as the annual spending.

The depreciation period can be calculated with the following equation:

$$Depreciation = \frac{Installation\ Costs}{\sum Annual\,Cost\,Saving - Maintenance\,Costs} \quad (17)$$

$$t_{CHP\,Dep.} = \frac{C_{install}}{C_{savings} - C_{maintenance}}$$

As previously stated, the lifetime of the CHPC is approximately 20 years and the profit calculation should be based on this time period. If, for example, a CHPC system depreciates for three years then the CHPC shall be making a profit for approximately 17 years. The overall profit can be calculated by the annual cost savings previously calculated multiplied by the total profitable years the CHPC system is in operation for. The calculation is as follows:

$$C_{\Pr ofit} = Years \;\; CHPC \; System \; is \Pr ofitable \; \times \; C_{Saving} \tag{18}$$

The following is the flowchart illustrating the second step (overall calculation) of the CHPC Performance Analysis.

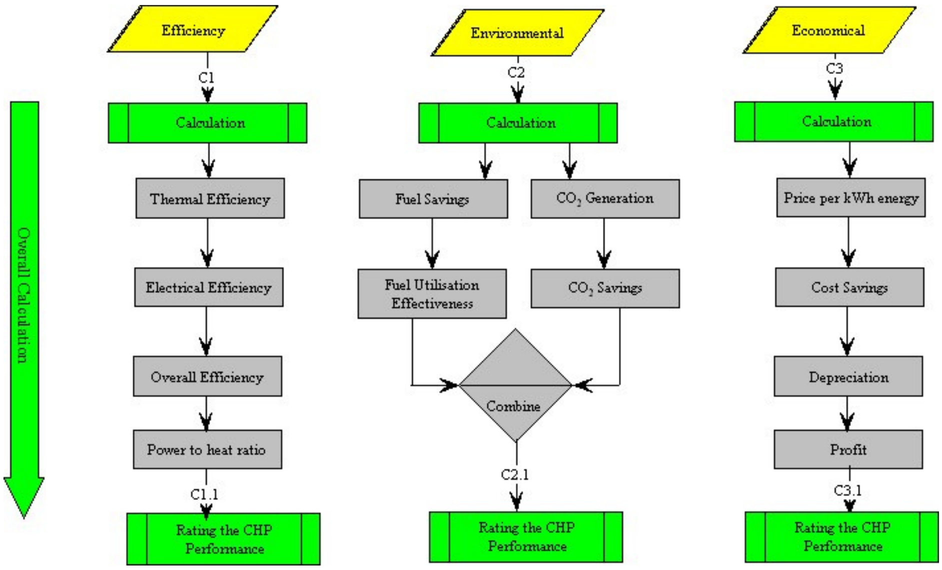


Figure 29: Data Collection Flowchart

The third and final step of the model algorithm in the analysis of the performance of the CHPC system is the rating of the CHPC system. The rating can be made based on the outcome of C1.1 (efficiency R1), C2.1 (environmental R2) and C3.1 (economical R3). When assigning a rating to the performance of the CHPC system, some key questions should be asked, such as: How is the total CHPC performance when compared to other alternative technologies? How much CO_2 is saved by employing the use of a CHPC as opposed to importing electrical and heating energy? How long will the payback period for a CHPC system be if used 24/7, 365 days a year?

Its is not feasible to accurately predict the future performance of a CHPC system as there are too many variables, such as the price of gas, electricity, changing technologies, etc., but one could make a general forecast into how a CHPC system may perform based on assumptions of running costs, etc.

The three primary steps in the process of making a performance/rating analysis of a CHPC within an Industrial Site Distribution Network can be combined into one overall algorithim and used as a roadmap for future performance analysis/rating:

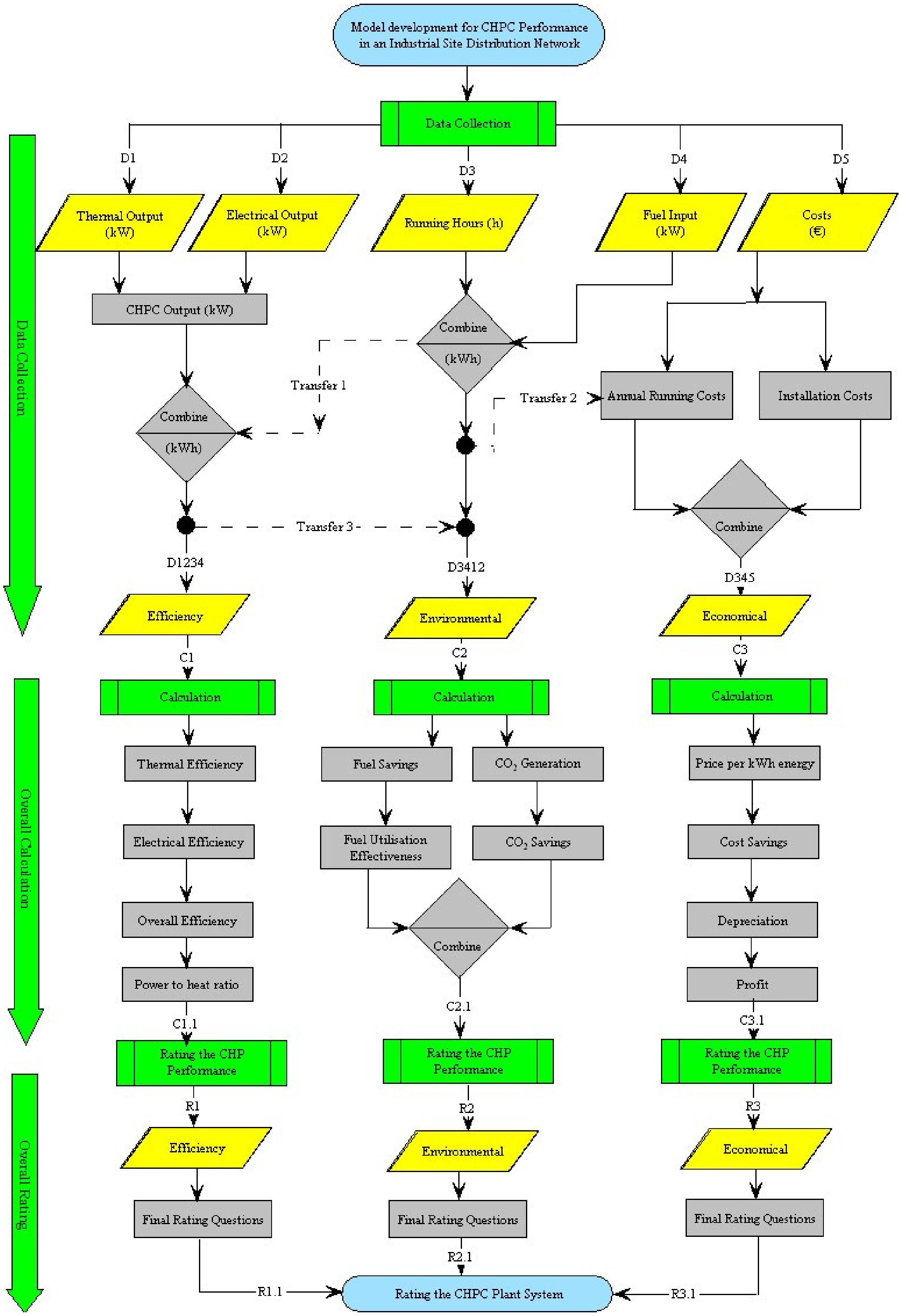


Figure 30: Model Data Collection Flowchart

2.12.1 Thermal and Electrical Output

The thermal and electrical output of the CHP plant varies throughout a year. Thermal energy generated by the CHP is used to heat water or, alternatively, heat a facility, and the electrical output is the electricity generated to support the facility's electrical loads and minimise the imported electricity from the grid. As illustrated in figure 31 below, the thermal energy is generally higher than the electrical energy due to the utilisation of better components with better efficiency and due to the thermal focus of the process at design stage.

Figure 31 illustrates the thermal output of a CHP versus the electrical output, based on the same gas input. The graph is based on data obtained from Vistakon, based on the same point in time for four consecutive months. It clearly indicates the system was designed with thermal output as the priority, as opposed to electrical output.

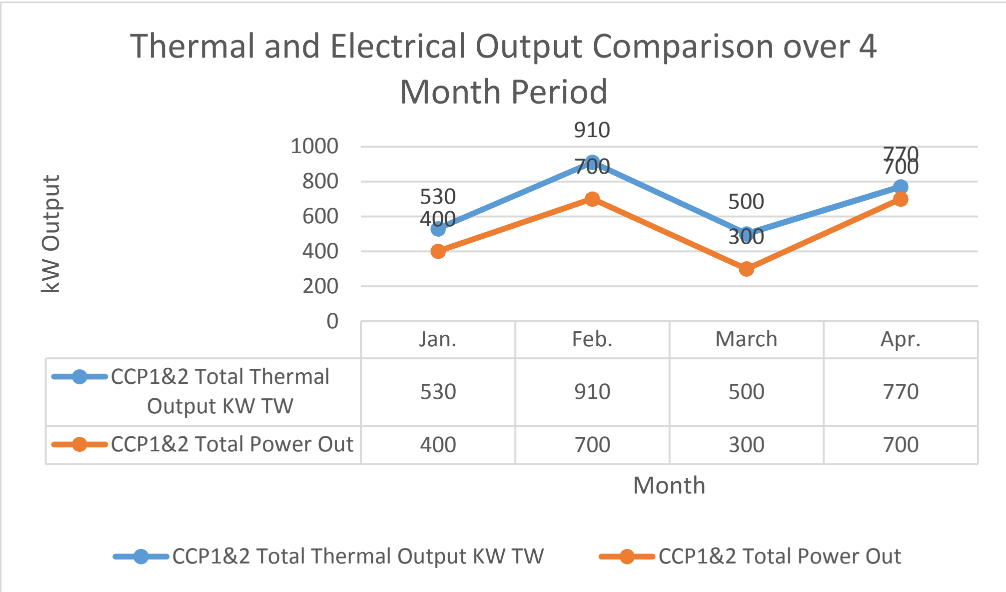


Figure 31: Thermal and Electrical Output Comparison

CHAPTER 3

3 Impact of Distributed Generation on Industrial Site Distribution Networks

3.1 Distributed generation planning

The introduction of DG into any network should be planned and evaluated from an overall strategic viewpoint. A method of modelling the impact of distributed generation on distribution networks and businesses is shown below in figure 32.

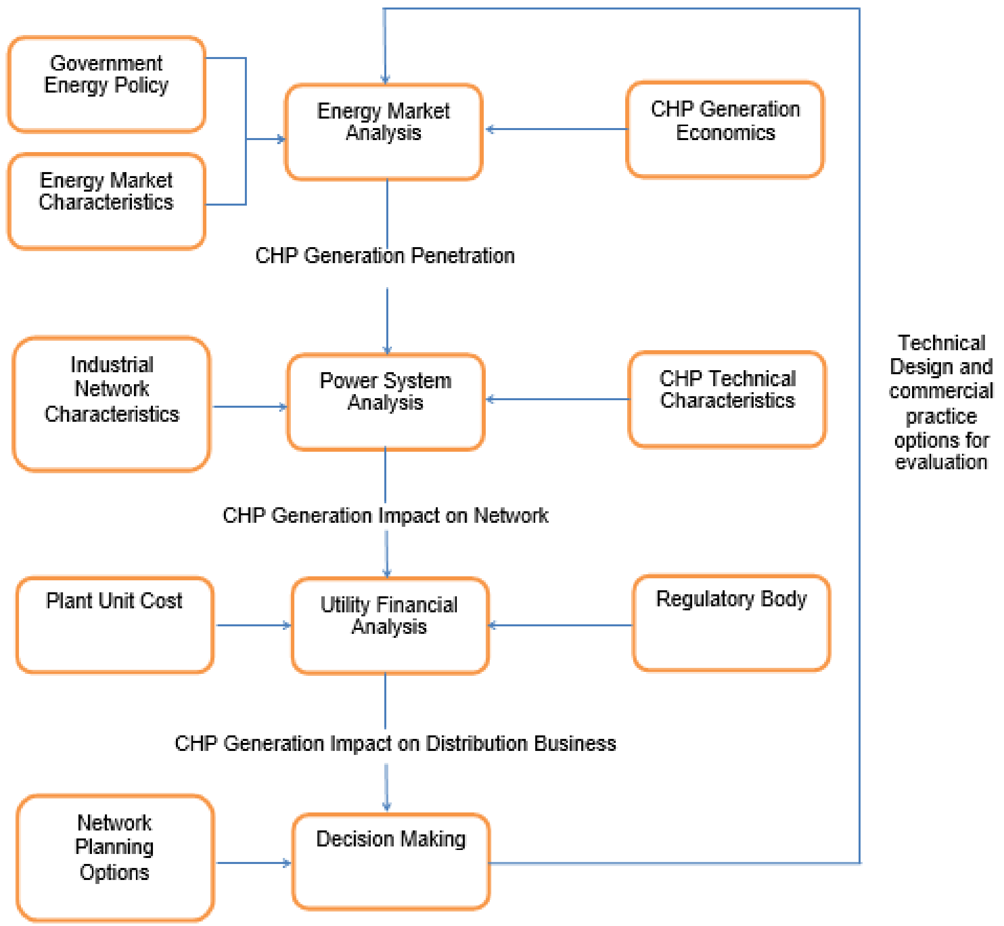


Figure 32: Strategic analysis framework for CHP generation

The first factor to investigate when planning the introduction of DG into is the "Energy Market Analysis". This considers factors such as government energy policies, energy market characteristics and DG economics. Following this initial investigation, a “Power System Analysis” has to be carried out. This integrates the industrial network’s characteristics and investigates the capacity of the existing network to accept additional power, current, etc. The technical characteristics of the CHP form an integral part of the “Power System Analysis”. This shall be discussed in greater detail later in this chapter.

The third factor to investigate is the “utility financial analysis”. This compares the plant unit cost with the profitability of a) producing heat and power for the site wide industrial network, and b) producing electrical power and exporting it to the utility company’s electrical distribution network. The results of the above analysis is collaborated and reviewed. Based on the previous analysis, a decision shall be made on whether or not to install DG. If the impact of the installation of DG was seen as positive then the project may progress to detailed design stage. However, if the impact of the installation was seen as having a negative impact on the network, an alternative scale or type of DG may be investigated.

3.2 Technical Issues - General

There have been many papers written which discuss the varying technical issues associated with the introduction of distributed generation into a distribution network. The introduction of DG into any network changes the characteristics of the distribution network, whether it is an industrial site distribution network or the national grid distribution network. There are a number of technical issues and factors which have to be addressed when connecting DG to a distribution network. These issues include:

- Fault Current Level,
- Equipment Rating,
- Voltage Rise,
- Losses,
- Power Quality (such as flicker, harmonics, etc.),
- Reliability,
- Protection,
- Power Flow.

When evaluating the effect the above characteristics has on the DN, one must look at various scenarios which could occur. Typically, these scenarios would be:

- No generation and maximum system demand
- Maximum generation and maximum system demand
- Maximum generation and minimum system demand.

3.2.1 Fault Current Level

3.2.1.1 Basic Principles of Calculation

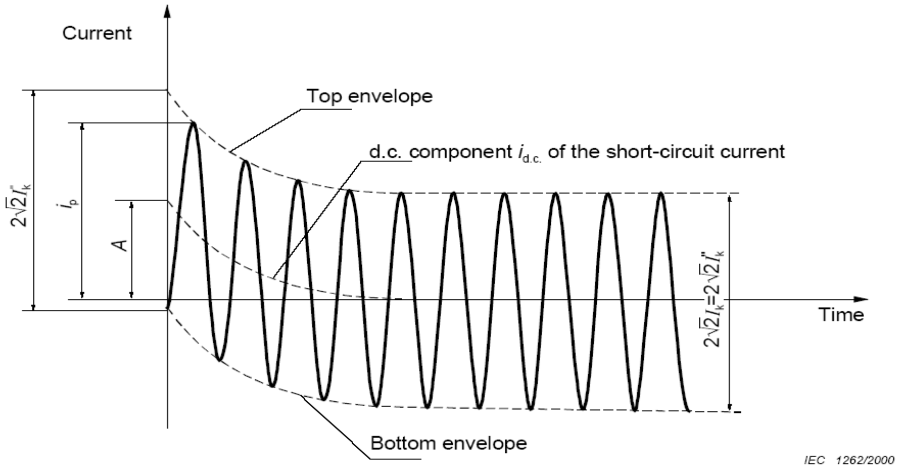
The fault current level is a critical parameter in any network. Fault currents, also known as short circuit currents, are currents which introduce both thermal and mechanical stresses to equipment installed within a distribution network. The International Electrotechnical Commission have produced a set of international standards called IEC60909, detailing the method of calculation of short circuit currents in three-phase a.c. systems. The IEC 60909 standard is divided into five parts, namely:

- IEC60909-0 *Short circuit current calculation in a.c. systems*
- IEC60909-1 *Short circuit current calculation in a.c. systems Part 1: Factors for calculation of short-circuit currents in three-phase a.c. systems according to IEC909*
- IEC60909-2 *Electrical equipment. Data for short-circuit current calculations in accordance with IEC909 (1998)*
- IEC60909-3 *Short circuit current calculation in a.c. systems Part 3: Currents during two separate simultaneous single-phase line-to-earth short circuits and partial short-circuit currents flowing through earth*
- IEC60909-4 *Examples for the calculation of short-circuit currents.*

In the aforementioned standards, the short circuit current are always considered as the sum of an a.c. symmetrical component and the aperiodic (d.c.) decaying component and all calculations are based on a nominal frequency of 50Hz.

Traditionally, a network's short circuit current level could be approximated by the vector addition of the short circuit contribution of the upstream grid from the centralised generation plant and short circuit contribution of the rotating motive power within the ISDNs. However, in recent years this has changed, as the installation of DG has meant that the total short circuit level at a point in the network is now the vector sum of all contributions from generating plant connected to the distribution network, as well as the contribution from the local generation plant within the ISDNs and the contribution from the motive loads also within ISDNs. Therefore, the most important requirements from a short circuit perspective for permitting the interconnection of DG into an ISDN or any other distribution network, is to ensure that the resultant fault level remains below the network designed value, under the worst case scenario. A distinction is made between "far from generator" faults and "near to generator" faults. Near to generator short circuit currents include a time-decaying symmetrical a.c. component, as illustrated within Figure 33, while a far from generator fault includes a constant time a.c. component. Three-phase faults are thought to provide the maximum fault current when the network neutral is earthed either directly or by small impedance. Different neutral earthing schemes would possibly lead to earth faults being the highest fault current. Maximum and minimum values for balanced and unbalanced three-phase faults need to be calculated for different reasons. Maximum fault levels are calculated for the purpose of ensuring that equipment installed within the network is adequately rated for safe operation during fault conditions. Minimum fault levels are calculated for the purpose of determining the maximum disconnection times of circuit protection devices. The maximum disconnection time is often referred to when determining the short time setting of the protection devices.

3.2.1.2 Definitions and calculations



I''_k = initial symmetrical short-circuit current

i_p = peak short-circuit current

I_k = steady-state short-circuit current

$i_{d.c.}$ = d.c. component of short-circuit current

A = initial value of the d.c. component $i_{d.c.}$

Figure 33: Example of short-circuit current [31]

As can be seen in the diagram Figure 33, the initial symmetrical short circuit power is defined as $S_k^{"} = \sqrt{3} I_k^{"} U_n$, where U_n is the nominal voltage at the short circuit location and I''_k is the r.m.s. value of the a.c. symmetrical component of a perspective short circuit. The peak i_p must be calculated to define the mechanical forces of which the installation must be able to withstand as well as determining the circuit breaker making and breaking capacity required. The value of i_p is determined by the following equation: $i_p = k \times \sqrt{2} \times I_k^{"}$, where k is the variation of the coefficient k indicated by the curve in Figure 34 as a function of the R/X or R/L ratio and is given by:
$k = 1.02 + 0.98 e^{-3R/X}$, where R and X are the real and imaginary part of the equivalent short circuit impedance Z_k at the short circuit location.

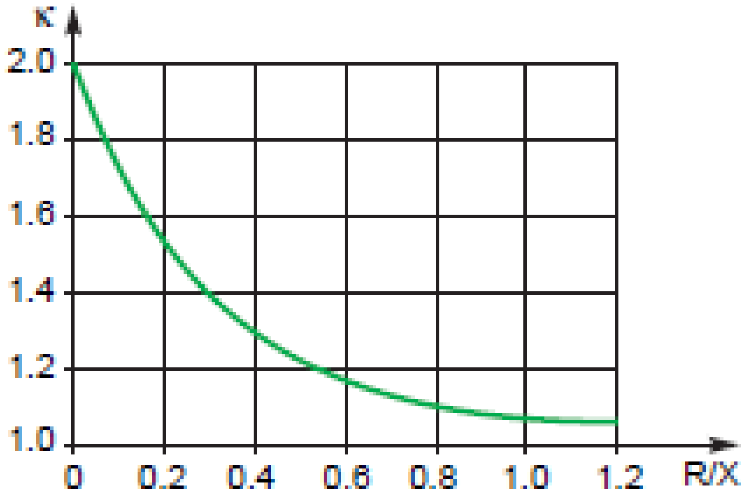


Figure 34: Variation of coefficient k depending on R/X or R/L [31]

The symmetrical short circuit breaking current, I_b, is the r.m.s. value of the integral cycle of the symmetrical a.c. component of the current, at the instant of contact separation of the first pole to open a switching device. For far from generator faults, as well as for short circuits in a meshed network, I_b is assumed equal to I''_k also, I''_k is equal to I_k, the steady state short circuit current. The steady state short circuit current is the r.m.s. value of the current after the decay of the transient components.

Calculation of the total short circuit resistance and reactance of the primary elements within a network allows the short circuit current of the network to be calculated. The sum of all short circuit resistive and reactive elements within a network is equal to the total short circuit resistance and reactance of the network. The short circuit total impedance value Z_{Tk} is given by:

$$Z_{Tk} = \sqrt{(R^2 + X_T^2)} \tag{19}$$

When Z_{Tk} is calculated, the three phase symmetrical short circuit current can then be calculated by:

$$I_{3\Phi} = \frac{cU_n}{\sqrt{3} \times Z_{Tk}} \tag{20}$$

where c is the voltage factor, which accounts for variations of the system voltage. For the maximum positive sequence fault, the value c is 1.10 and c is 1.00 for the minimum positive sequence fault. The values for c are taken from table 4.1 within IEC 60909-0.

Nominal System voltage U_n	Voltage factor c for calculation of	
	Maximal Short circuit current c_{max}	Minimal Short circuit current c_{min}
LV: 100V up to 1000V (inclusive) (IEC 60038, Table I)		
Voltage tolerance +6%	1.05	0.95
Voltage tolerance +10%	1.10	0.95
MV: > 1kV up to 35kV (inclusive) (IEC 60038; Table III)	1.10	1.00
HV: > 35kV (IEC 60038; Table IV)	1.10	1.00

Table 2: Table 4.1 within IEC 60909-0 [31]

U_n is nominal voltage at short circuit location

Z_{Tk} is the magnitude of the equivalent total short circuit impedance of the upstream network at the short circuit location.

Assuming there is no rotating motive loads, $I_{3\phi}$ may be called the steady state short circuit current and can be utilised to determine the maximum breaking capacity of the circuit breakers within the network.

If a fault occurs on the network, then upstream and downstream of the fault location may contribute to the fault, depending on numerous factors. The contribution of the upstream grid can be calculated as follows:

$$I_k^{"} = \frac{c_{\max} U_n}{\sqrt{3}(Z_Q + Z_{kT})} = \frac{c_{\max} U_n}{\sqrt{3}\left(Z_Q / t_r^2 + K_T Z_{TLV}\right)} \tag{21}$$

Where Z_Q is the impedance of the upstream network feeder at the point Q and Z_T is the impedance of the transformer. K_T is a correction factor used for the impedance of the transformer. These values may be calculated by:

$$Z_Q = \frac{cU_n}{\sqrt{3} I_{kQ}^{"}} \tag{22}$$

$$Z_T = \frac{u_{kr}}{100\%} \times \frac{U_{rT}^2}{S_{rT}} \tag{23}$$

$$R_T = \frac{u_{kr}}{100\%} \times \frac{U_{rT}^{"}}{S_{rT}} = \frac{P_{krT}}{3 I_{rT}^2} \tag{24}$$

$$K_T = 0.95 \times \frac{c_{\max}}{1 + 0.6 x_T} = \frac{P_{krT}}{3 I_{rT}^2} \; where \; X_T = \sqrt{Z_T^2 - R_T^2} \tag{25}$$

Where I''_Q is the initial symmetrical short circuit current at the Q, on the HV side, U_{kt} is the short circuit voltage of the transformer, U_{kr} is the rated resistive component of the short circuit voltage and P_{krT} is the load losses at rated current. A typical assumption of RQ/XQ is 0.1, although higher values are often encountered. U_{Rr} decreases with the size of the transformer and if not given may be given.

3.2.1.3 Fault Current – The effect of DG on the DN

DG units are typically connected to the network at low (400V) or medium voltage (10/20kV) level and therefore contribute to the total fault level of the network, as discussed. The magnitude of the fault current contribution of DG depends on the location of the DG installation in relation to the fault, the generator type, synchronous or asynchronous and the generator interface technology, directly connected or connected via an electronic interface. The following is a basic representation of a network:

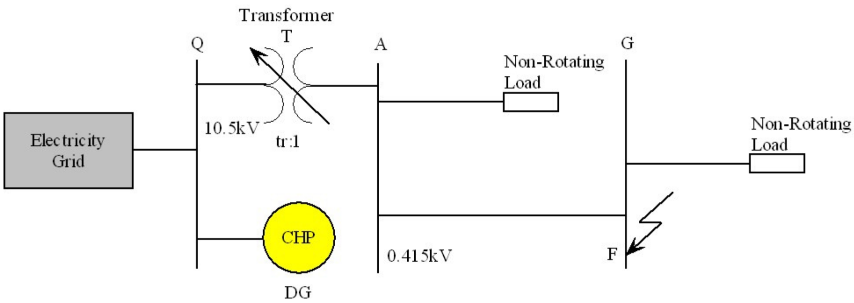


Figure 35: Basic representation of a network

The symmetrical short circuit current in the above network is calculated by:

$$I_k'' = \frac{c_{\max} U_n}{\sqrt{3}(Z_G + Z_T + Z_L + Z_R)} \tag{26}$$

Where the impedance of the generator (Z_G), the transformer (Z_T), the line (Z_L) and the reactance (Z_R) are included and refered to the voltage at the short circuit fault location, F. If the generator connected to the network was a synchronous generator, the impedance and its correction factor shall be calculated by:

$$Z_G = R_G + jX_d'' \tag{27}$$

$$R_G = 0.15 X_d'' \tag{28}$$

$$K_G = \frac{U_n}{U_{rG}} \times \frac{c_{\max}}{1 + x_d'' \sin \varphi_{rG}} \tag{29}$$

Where X"d is the sub transient reactance of the synchronous machine, can be used and K_G is the applicable correction factor from IEC 60909. For synchronous generators connected to the grid through a unit transformer, referred to as a power station unit in the IEC standard, the combined generator transformer impedance and the relevant correction factor are given by:

$$Z_S = t_t^2 Z_G + Z_{THV} \tag{30}$$

$$K_{SO} = \frac{U_{nQ}}{U_{rG}(1+p_G)} \times \frac{U_{rTLV}}{U_{rTHV}} \times (1 \pm p_T) \times \frac{c_{\max}}{1 + x_d^{"} \sin \varphi_{rG}} \tag{31}$$

with $R_G = 0.15X_d^{"}$, $P_G \; and \; P_R$ may be ignored here. The impedance of the transformer Z_{THV} is expressed at its HV side.

The following basic networks are shown for illustration purpose only. It can be seen from figure 36 and figure 37, the fault current level at the various busbars has increased when the DG is operating within the network. When the DG is disconnected from the network, it can be seen the fault current is considerably lower. In the example shown, the three-phase short circuit current is reduced by approximately 36% when the DG is disconnected.

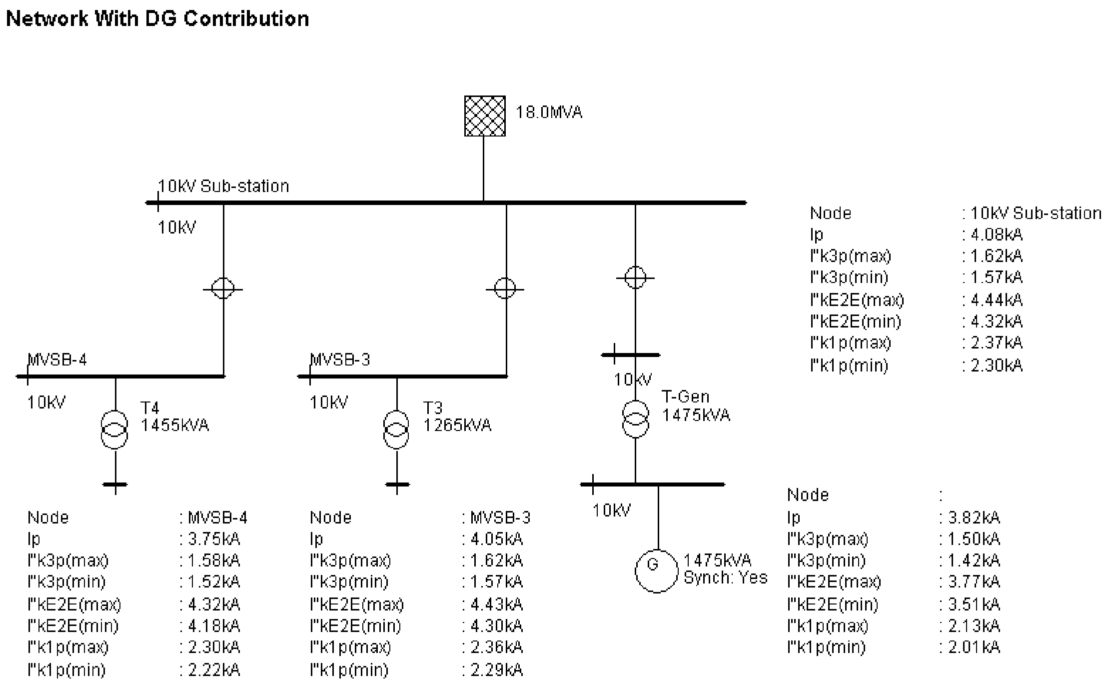


Figure 36: Network with DG Contribution

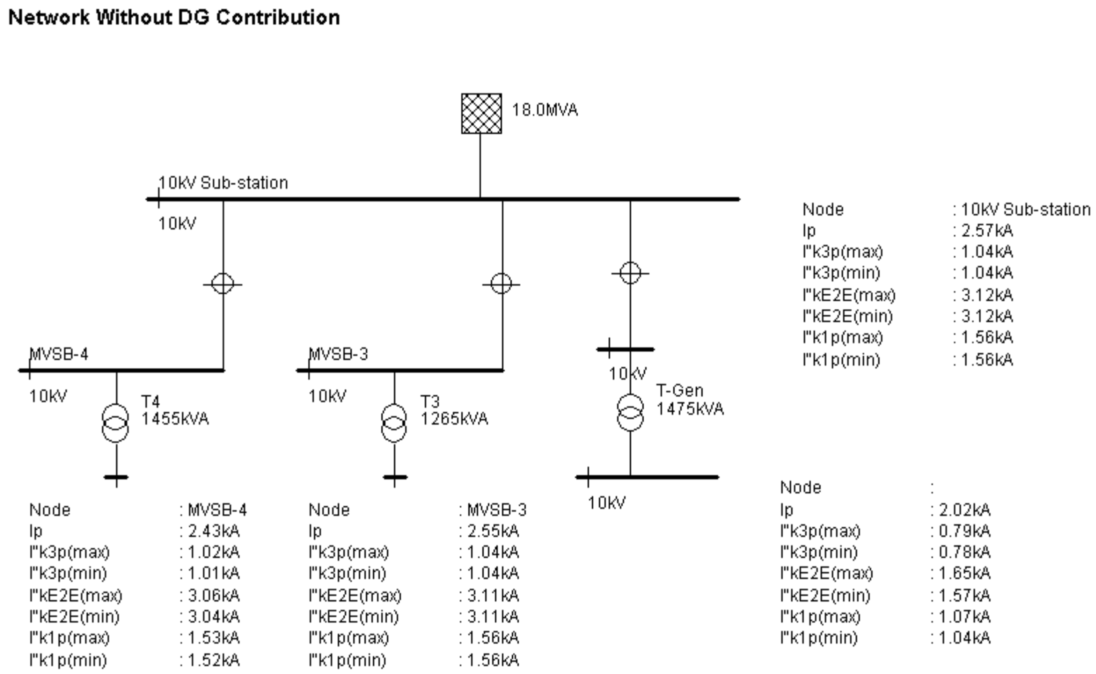


Figure 37: Network without DG Contribution

3.2.1.4 Fault Current – Generator Reactance

Due to the fact that in Ireland, the vast majority of ISDNs do not span over a large geographical area, the short circuit level within the IDSN which incorporates DG tends to be relatively high, due to the low impedance of the cables. When DG is added to an ISDN's parameters such as rated power, rated voltage, power factor, sub-transient reactance and synchronous reactance are required to calculate the impedance of the generators and in turn calculate the generator's contribution to the short circuit current. Rated voltages within one power rating may vary depending on the construction of the generator.

The sub-transient reactance of synchronous generators is typically in the range of 10-30% depending on the rated power [29]. Generator reactances are used for two different purposes; the first is to calculate the flow of symmetrical short circuit current; and the second is for use in specifications which limit the sub-transient reactance to 12% or less in order to limit the voltage distortion induced by non-linear loads. Generally, these reactance values are in per unit and may have to be converted [30]. When a fault occurs, the flow of current in the network is dictated by impedance. When a short circuit occurs within an ISDN, the fault current that flows is a function of:

- The internal voltage of the connected machines in the system (generators and motors)
- The impedance of those machines
- The impedance to the point of fault – primarily cable impedance
- The impedance of the fault, if arcing.

The generator internal voltage and generator impedance determines contribution of the generator to the fault current when a short circuit occurs. The effect of armature reaction on the generator air gap flux causes the current to decay over time from an initial high value to a steady state value, dependant on the generator reactances. Due to the fact the resistive component in the generator is negligible, for practical purposes it may be ignored and only reactance's need be considered [30]. Generator reactances, as determined by tests with fixed excitation, carried out by Cummins generators, are:

Name Importance	Symbol	Range[1]	Effective Time
Sub-transient reactance Determines maximum instantaneous current and current at time molded case circuit breakers usually open.	X''_d	.09 – .17	0 to 6 cycles
Transient reactance Determines current at short time delay of circuit breakers.	X'_d	.13 – .20	6 cycles to 5 sec.
Synchronous reactance Determines steady state current without excitation support (PMG).	X_d	1.7 – 3.3	after 5 sec.
Zero sequence reactance A factor in L-N short circuit current.	X_o	.06 – .09	
Negative sequence reactance A factor in single-phase short circuit current.	X_2	.10 – .22	

[1] Reactances shown are typical per unit values for generators ranging from 40 to 2000 kW.

Figure 38: Generator Reactance as determined by tests with fixed excitation [30]

When a three-phase symmetrical fault current occurs, a large current shall flow. This initial current is then used to determine the short circuit breaking capacity for the protection devices in the vicinity of the generator. This initial instantaneous current value (Isc_{sym}) is controlled by the sub-transient reactance (X''_d) and is expressed by voltage (E_{ac}) divided by sub-transient reactance: $Isc_{sym} = \frac{E_{ac}}{X''_d}$ [30] (32)

3.2.1.5 Fault Current – Integration

As discussed, the most important requirement from a short circuit perspective for permitting the interconnection of DG into an ISDN or any other distribution network, is to ensure that the resultant fault level remains below the network designed value, under the worst case scenario.

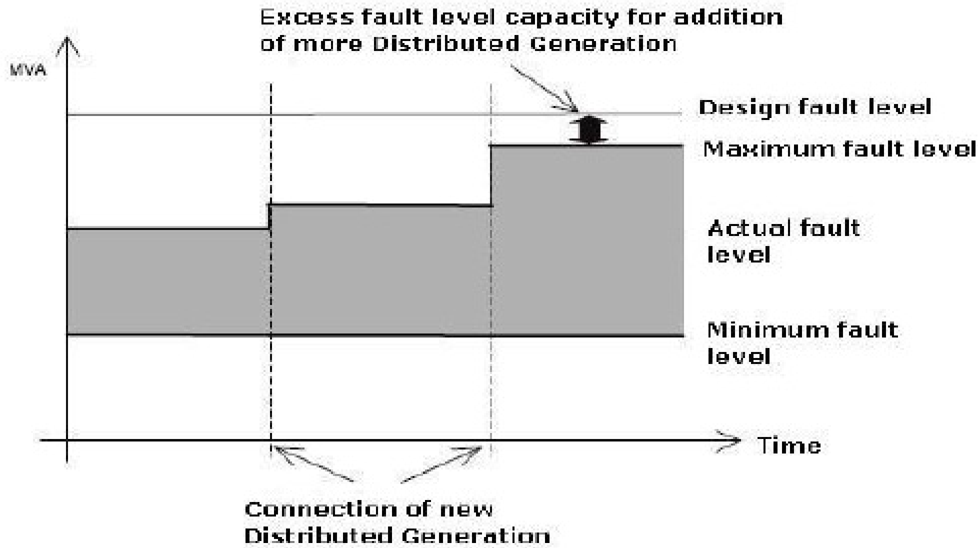


Figure 39: Fault Level Capacity with the Addition of Distributed Generation

Due to the fact that today's distribution networks, which incorporate DG, are more complex than distribution networks in the past, fault current calculations are more complex as they encompass more complex running arrangements than previously installed. The fault level contribution from DG is determined by a number of factors, including:

- The type of DG, as different types of DG contribute different fault currents
- The distance of the DG from the fault, as the increased cable impedance will reduce the magnitude of the fault current
- Whether or not a transformer is present between the fault location and contributing DG (which is often the case for voltage regulation purposes), as the transformer short circuit impedance may assist in limiting the magnitude of the fault current
- The configuration of the network between the DG and the fault, as different paths for the flow of the fault current will alter the magnitude of the fault current (due to cable impedances and other installed equipment)

- The method of coupling the DG to the network. Directly connected DG will contribute significantly higher fault currents than DG connected via power electronic (PE) interfaces.

All equipment installed within the network must have a higher short current rating than that of the combined short circuit fault current value. Protection devices are utilised to ensure the fault current does not exceed the maximum thermal withstand level of the equipment within the network. Designers of ISDNs calculate the fault current at an early network design stage to ensure they do not exceed the design limits of the network. If the fault level capacity is already high within the network then the designer may be able to specify a generator with a low X_d for use within the new DG installtion.

With the amount of DG installed within ISDNs, a number of scenarios could occur, such as:

- Failure of protection devices: A fault may occur at low voltage level within the ISDN. Due to the fact the DG is in close proximity of the fault, the impedance is low. The short circuit current may then be too high due to the combined contribution of the DG unit, the distribution network and motive loads within the ISDN. In this event, the protection device breaking capacity may be exceeded and the existing protection devices may not be able to interrupt the fault current in the ISDN or DN.
- Undetected faults: In contrast to the issue above, by introducing DG it is also possible to reduce the short circuit level to such a level where it may be too low to be detected by the protection devices.
- Disconnection of a healthy feeder: The placement of a substantial amount of DG at a short distance from a primary substation on a lightly loaded feeder, may result in the disconnection of a healthy feeder. It is possible the incorrect feeder, i.e. the feeder with the DG, is switched off incorrectly. This phenomenon is called “nuisance tripping”. Due to the fact that there is power flowing both ways to and from the substation, existing protection devices may not be intelligent enough to detect the direction of the current. The solution to this problem is to replace the existing protection devices with directional relays [31].

There are some remedial actions which may be taken to protect the network in the event of the fault level exceeding the equipment design fault current. They are:

- One solution to overcome the high fault current issue is to replace the equipment with the low fault rating or reconfigure the parts of the network where the fault current exceeds the design fault current. However, this may choose to be an expensive solution as switchgear, busbars, etc. may have to be replaced at high costs. Due to the high cost implications, designers would usually consider alternative options before this option.
- An alternative solution would be to reconfigure the busbars within the primary substations in such a way as to split the influence of the DG, therefore feeding half the feeder from one busbar/transformer arrangement and the second half of the feeder from a second busbar/transformer arrangement. This scenario would be acceptable in the normal course of events; however, in the event of failure or maintenance to one transformer then part of the DG should be taken off line, as having all DG online, would exceed the maximum allowable fault level of the network.
- Another possible solution is to install a fault current limiting device. This device shall maintain a low fault level within the network in normal operation, by creating low impedance and a low fault level in the event of a fault, by creating higher impedance.

3.2.2 Equipment Rating

When designing any electrical network, the equipment specified within the network must be suitably rated. To ensure the equipment rating of equipment within a network is sufficient, the fault rating of all current carrying equipment installed throughout the ISDN must be compared against the calculated maximum perspective short circuit current (PSCC), and also against the peak asymmetrical current. These calculated fault levels must also give consideration to the running arrangement of the distribution network. If the PSCC exceeds the equipment rating then the equipment should be replaced with appropriately rated equipment or alternatively the structure of the network should be altered. Some switchgear manufactures utilise a technique known as “cascading”. Cascading is where the upstream circuit breaker acts as a barrier against large short circuit currents. When two co-ordinated devices are used in series, the downstream devices do not have to be fully rated for the system PSCC, however, the upstream device must be rated for the system PSCC at that point. The cascading technology is employed at low voltage level only.

Equipment rating is not only associated with switchgear within an ISDN, it relates to all components of the network including cabling, transformers, etc. The equipment rating is usually described by the thermal capacity of a piece of equipment. This means the equipment is capable of carrying the power flow it is designed for without adversely effecting the equipment. Should the designed power flow of the equipment be exceeded due to the addition of distributed generation into a network, the equipment will start to mechanically fail.

The maximum allowable apparent power, S_{max} that can be fed through the ISDN components is a function of the current and voltage and can be described by:

$$Smax = |\mathrm{P} + \mathrm{jQ}|max = \sqrt{3}\mathrm{EI}max \quad (33)$$

Where:

P(W) = real component of the maximum allowable power flow

Q(VAr) = reactive component of the maximum allowable power flow

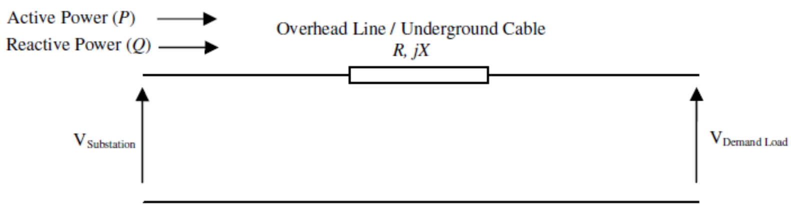
E(Volts) = voltage level on the network where a particular component is installed

I_{max} (Amps) = steady state current carrying capacity of the piece of equipment.

3.2.3 Voltage Rise and instability

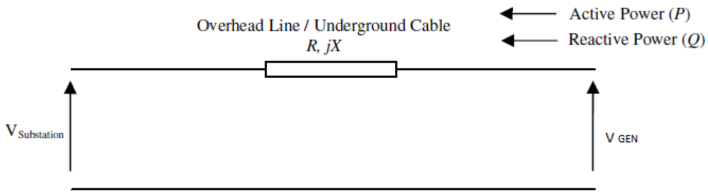
As voltage variation is a common issue within DNs, it is imperative that voltage regulation is designed into the DN during the design phase. The main objective of voltage regulation is to ensure the steady state voltage is kept within a permissible range. In Ireland, as part of the conditions governing connection to the distribution system, a voltage differential of less than +/-10% from nominal voltage is allowed [27].

A DN which has no DG and has a load a considerable distance away from a primary substation must have a higher voltage at the sending end than is required at the receiving end. This is illustrated in the diagram and formula below:



$$\Delta V = V_{Substation} - V_{Demand\ Load} = \frac{R_P + X_Q}{V_{PS}} \tag{34}$$

By connecting DG to the DN, the DN will have to operate at a higher voltage than the upstream substation if it wishes to export power. Alternatively, the DN must be able to absorb a significant amount of reactive power, as illustrated below:



$$\Delta V = V_{Gen} - V_{Substation} = \frac{R_P + X_Q}{V_{Gen}} \tag{35}$$

As discussed in [28], loads require both real and reactive power. However, reactive power causes transmission and distribution lines to heat (overload) and also causes voltage drop. Here lies the conundrum; loads require reactive power but too much reactive power has an adverse effect on the DN and causes excess heating and voltage losses. The voltage profile for a typical DG feeder connected from an ISDN to the national grid is shown in figure 40, below.

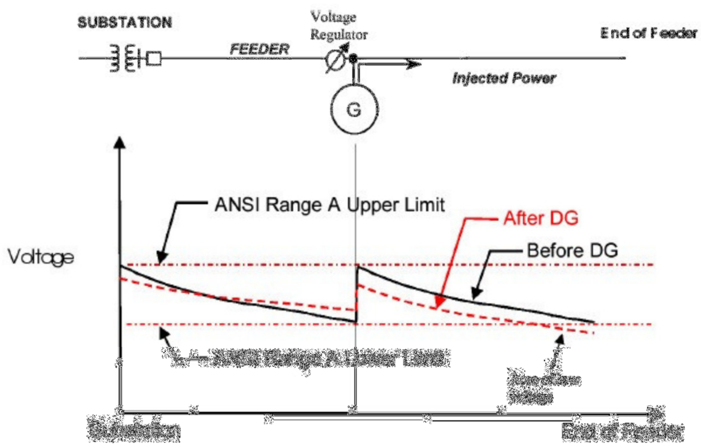


Figure 40: Voltage profile for a typical DG feeder connected from an ISDN to the Distribution Network – Note: American standard, ANSI

Another common issue with DG is the potential for voltage instability within the ISDN. Power system stability may be defined as that property of power system that enables it to remain in a state of operating equilibrium under normal conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance [53]. An ISDN is voltage unstable when voltages uncontrollably decrease, for numerous reasons, such as, reductions in site load, changes in production patterns, weather conditions (when large cooling chillers are not required), etc.

Voltage instability is generally a local problem. However, the consequences of voltage instability may have a widespread impact. The result of this impact is voltage collapse which results from a sequence of events, rather than from one particular disturbance. It leads to low profiles of voltage in part of the network. The main factors causing voltage instability include: [52]

- The instability of the power system to meet demands for reactive power in the heavily-stressed system to keep voltage in the desired range,
- Generator reactive power limits,
- Characteristics of the reactive power compensation devices,
- Load characteristics.

3.2.4 Losses

Losses are inevitable and an important factor to be taken into account when designing any type of electrical network. The magnitude of losses can vary substantially depending on the design of a network. Within a typical ISDN without DG, losses can be seen from the PCC to each individual load. With DG, an ISDN may be seen as having negative losses, if the DG is being exported to the grid. When DG is being exported to the grid, the network is operated in a different way to what it was initially intended, giving rise to bidirectional power flows. DG can act as compensation for losses similar to a capacitor; however, there is one important difference between connecting a DG unit and a capacitor to a network for loss reduction. The difference being, DG causes an impact on both active and reactive power, while the capacitor banks only have an impact on the reactive power flow. DG is particularly suited to feeders with high losses, as a small amount of DG strategically located (10-20% of the feeder load) could cause a significant reduction of losses, depending on the penetration and dispersion level [46] [32]. The penetration level can be expressed as a function of the total DG power generation over the peak load demand.

$$Penetration\ Level = \frac{\sum P_{CHP}}{\sum P_L} \times 100\% \tag{36}$$

To explain the impact of CHP on distribution, one should analyse a simple model of a single distribution network.

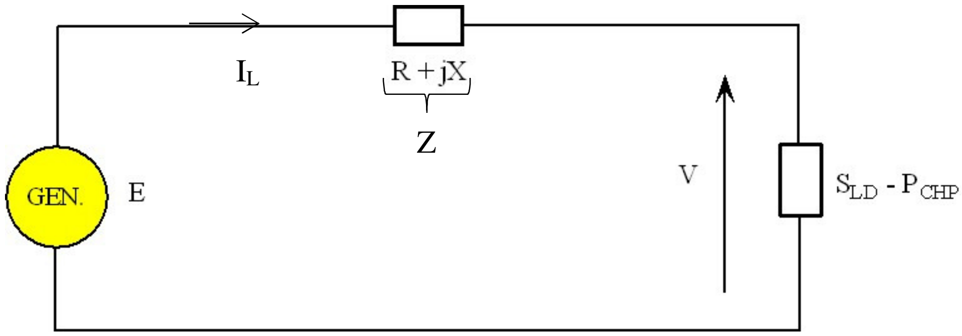


Figure 41: Simple line, load and DG model

In figure 41, E is the sending voltage, V is the receiving end voltage (to be constant at all times), I is the current and Z is the impedance of the line. If these variables are known, then the following equation can be used to calculate the losses produced in the line:

$$S_{Loss} = (E - V)I^* = (E - V)(I_{La} - jI_{Lr}) \tag{37}$$

Now assume that a form of DG such as a CHP system is connected to the load end of the line and that it is only producing active power. In that case, the new power losses are:

$$S_{Loss\,CHP} = (E - V)(I_{La} - I_{CHP} - jI_{Lr}) \tag{38}$$

The presence of CHP connected to the load feeder reduces the power loss by the following amount:

$$S_{Loss} - S_{Loss\,CHP} = (E - V)I_{CHP} \tag{39}$$

3.2.5 Power Quality

DG may have a considerable impact on the quality of power received by consumers. Several power quality issues could occur if several power sources are supplying a network. The magnitude of the impact depends on the relative size of the generator with respect to the network fault level and the X/R ratio, and the design and characteristics of the generator and prime mover installed. The effects may include:

- Steady state voltage excursions,
- Transient voltage variations (flicker),
- Phase voltage imbalance,
- Voltage waveform distortion (harmonics) [38].

3.2.6 Protection Devices

The role of protection devices within networks is to protect the equipment connected to the network from abnormal events, such as short circuits, etc., leading to dangerous situations where human life or property may be adversely affected. When designing a protection system for a network, one has to be cognisant of two key factors - reliability of the network and the security of the network. The network has to be reliable enough that when an abnormal situation occurs, the network operates in the correct way. However, the network has to be secure enough that minor events such as switching transients do not incorrectly operate the protection devices. Traditionally, industrial site distribution network protection schemes were only concerned about unidirection power flow. However, with the emergence of DG within industrial site distribution networks, bidirectional and multi-scenario protection schemes are required to adequately protect a network. Discrimination and selectivity between protection devices must be maintained to ensure the correct operation of a co-ordinated protection system. Therefore, protection studies have become a lot more complex in recent years. There are multiple solutions to help address the protection issues associated with the DSO interface between the utility network and DG, as discussed in [65].

3.2.7 Power Flow

In Ireland, distribution networks were initially designed to have unidirectional power flow, from the high voltage centralised power stations to the low voltage loads.

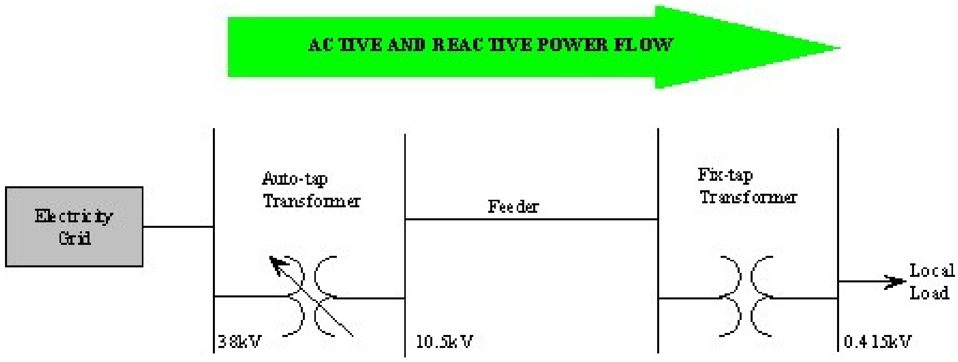


Figure 42: Network Configuration with Unidirectional Power Flow

These unidirectional networks were operated passively and had limited voltage control. Voltage control was primarily by on load tap changers at distribution transformers at PCCs with the ISDN. Typically, a large ISDN would have redundant connections to the grid. Both PCCs would form part of a ring network, which would be operated as a radial system, in order to limit the fault level and simplify the protection scheme.

With DG installed within an ISDN, the power flow is changed. If the downstream load is less than the electricity generated by the DG unit then the power flow arrangement shall be reversed and the DG unit shall export power to the grid. Thus, at some point between the ISDN and the upstream power substation the power flow shall be zero, due to the back flow from the DG on-site.

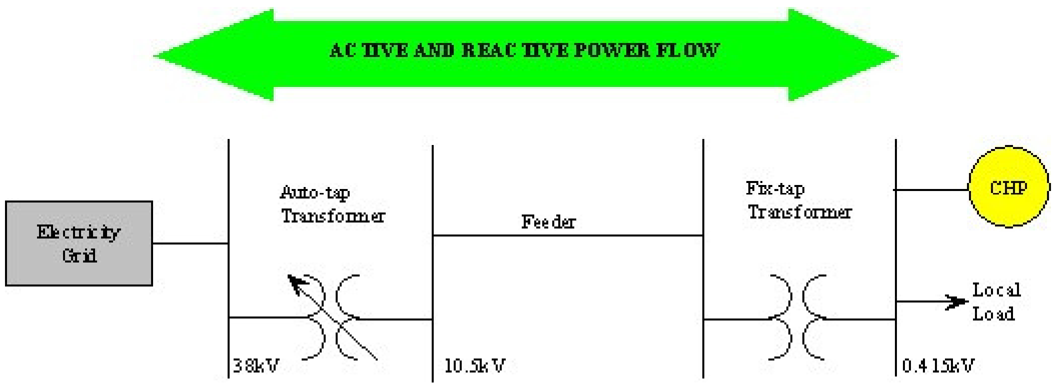


Figure 43: Network Configuration with Bidirectional Power Flow

3.3 Environmental Impact of CHP

When the environmental impacts of distributed power generation are discussed, one naturally thinks CO_2 emission as the primary impact distributed generation has on the environment. However, environmental impacts extend beyond just CO_2 emissions. Environmental factors such as noise and visual pollution, waste water, sustainability, ecology, etc. all have to be considered. When a CHP plant is being designed, the designers adhere to the following requirements:

- A high efficiency, minimum 75%, according to the definition in EC directive 2004/8/EC on the promotion of cogeneration based on useful heat demand in the internal energy market.
- A performance of the unit according to the definition of efficiency given in the Electricity Regulation Act 1999.
- Detailed calculations on the system efficiency based on high heating values (HHV) meeting the minimum electrical efficiency of the engine/generator of 43%.

3.3.1 Noise Impact of CHP

Noise emissions from the generator can be significant. Depending on the location of the generation unit, it is common practice within industry to specify a decibel (dB) level one meter away from the source of the noise, generally 80dB is specified, to be measured at one meter from the generator set. For noise simulation at a site boundary, a method allowing calculations of distance noise attenuation, recommended by Australia New South Wales EPA "Noise Guide for Local Government" 2013, is used.

Distance attenuation is the reduction of sound pressure level (SPL) in dB(A) as a function of distance. As a general rule, the SPL will decrease 6dB with a doubling of distance from a point source in the free field. For a point source such as a CHP unit, the following relationship can be used to quantify distance attenuation:

$$SPL_x = SPL_y - 20\log(d_x/d_y) \tag{40}$$

Where:

SPL_x=SPL at distance x from the source in metres (predicted)

SPL_y=SPL at distance y from the source in metres (measured)

d_x = distance in metres to location x from the source

d_y = distance in metres to location x from the source

When CHP units are installed within concrete block buildings, some attenuation of sound by buildings shall take place. The concrete block sound attenuation absorption coefficient depends on the frequency and varies between 0.25 and 0.40 (25 – 40%) [50]. The 0.25 (25%) attenuation factor is selected to simulate the worst case scenario.

The conditional planning exception requirements for CHP (SI 83 of 2007 Planning and Development Regulations and Amendment SI235 of 2008) require the noise level not to exceed 43 dB(A) at the nearest party boundary. This is one good reason to locate the CHP centrally within the site.

3.3.2 Air Emissions from CHP

One of the primary advantages of installing a CHP plant in industry is the reduction of a facilitys carbon footprint. The reduction of air emissions within a facility leads to positive public relations and contributes to Ireland's Kyoto Agreement obligations.

CHP Greenhouse Gas Impact	
Gas	*Estimated net reduction in emissions per kWh of electricity produced (g/kWh)*
CO_2	1,000
SO_2	17
NO_x	4.6
CO	(3)
CH_4	3.9

Table 3: CHP Greenhouse Gas Impact [51]

A gas fired CHP unit's primary emission concerns are related to CO_2 and NO_X gases.

3.4 Reduction in Carbon Emissions

Carbon Savings

With the implementation of a CHP system, the efficient usage of fuel can reduce the overall net production of carbon dioxide. In relation to electricity, on-site generation through the combustion of gas can have a lower carbon output per kilowatt-hour compared to the carbon produced by the generation of electricity purchased from the grid. The grid electricity has to be transmitted from remote/centralised power stations, which may be generated using less efficient means, depending on the profile of national electricity production. Coal-burning power stations would increase the carbon output per unit of grid electricity, whilst wind farm power stations would reduce this value. In addition to the financial benefit, this carbon “footprint” saving can be a key benefit of switching to CHP.

The overall carbon “footprint” saving can be calculated by comparing the carbon output of the CHP fuel consumption with the existing scenario; from fuel consumed for the heat loads (for example, steam generation, water heating and spray dryer air heating) plus the equivalent carbon from the electricity purchased from the grid. Emission factors are available for combustion of different fuels, often provided on a country by country basis. For large facilities, which have an overall installed thermal capacity in excess of 20MW, this carbon saving can be translated to a financial benefit via carbon trading.

Since 2008, such facilities are given an annual carbon allocation which is typically in the order of 80 to 90%, depending on the industry, of the carbon associated with the total annual fuel input. The remaining percentage, in terms of tonnage of carbon dioxide, has then to be purchased on the carbon market. After 2012 this annual allocation was gradually reduced and allocations may possibly be eliminated by 2020. This scheme has been introduced to reduce the overall net carbon used on-site. Where a facility has reduced their carbon usage below their allocation, they are entitled to sell the excess on the carbon market. The calculation of carbon trading differs from the approach taken to assess the overall carbon “footprint” of a facility, in that imported grid electricity is not considered for carbon trading. The grid electricity is covered by the power plant’s own carbon trading.

The installation of a CHP plant will result in an increase in overall fuel consumption. There is, however, an additional carbon allowance provided for CHP plants in order to account for this fuel increase and to make sure that the installation of CHP is not disadvantaged by the carbon trading scheme. Currently, the calculation of this additional allowance is determined on a country by country basis. For Ireland, the calculation of this additional CHP allowance is based on the carbon output from the equivalent displaced electricity from a “best available technology” (BAT) modern combined cycle gas turbine (CCGT) power plant. Currently, the carbon market price is very variable and has been fluctuating in the last year between €10 and €25 per tonne of carbon dioxide.

CHAPTER 4

4 Case Study

4.1 Background to Vistakon

This case study discusses the potential impact of the installation of DG into an existing ISDN. The energy network belongs to a contact lens manufacturing plant located in Limerick (in the South of Ireland). Vistakon Ireland is a subsidiary of Johnson & Johnson Vision Care, Inc. Established in 1995, the Limerick facility is the only Vistakon manufacturing site outside the U.S. Globally, Vistakon are the largest producer of disposable contact lenses, with ACUVUE as the leading product in the market. The facility in Limerick operates 24/7, 365 days of the year, and a constant supply of both power and chilled water is of paramount importance. The Vistakon site has over 30 production lines. These lines manufacture one-day, fortnightly, monthly and colour lenses that are shipped worldwide and utilize leading edge technologies in moulding, robotics, vision system and sterilization processes. Due to the high level of automation and accuracy associated with the lens manufacturing process, high quality power is critical to the facility.

Within the manufacturing process on-site, there is a large electrical base load to be served, approximately 9MW, and a large thermal chill load to be addressed in the form of cold water at 5ºC flow and 11ºC return, to serve process cooling requirements which is derived from a single effect hot water absorption chiller. The thermal base load of the site is approximately 2500kW steam, 500kW Low Pressure Hot Water (LPHW) and 2000kW Chilled Water (CHW). The CHPC was envisioned to address only the last of these, namely the Chilled Water.

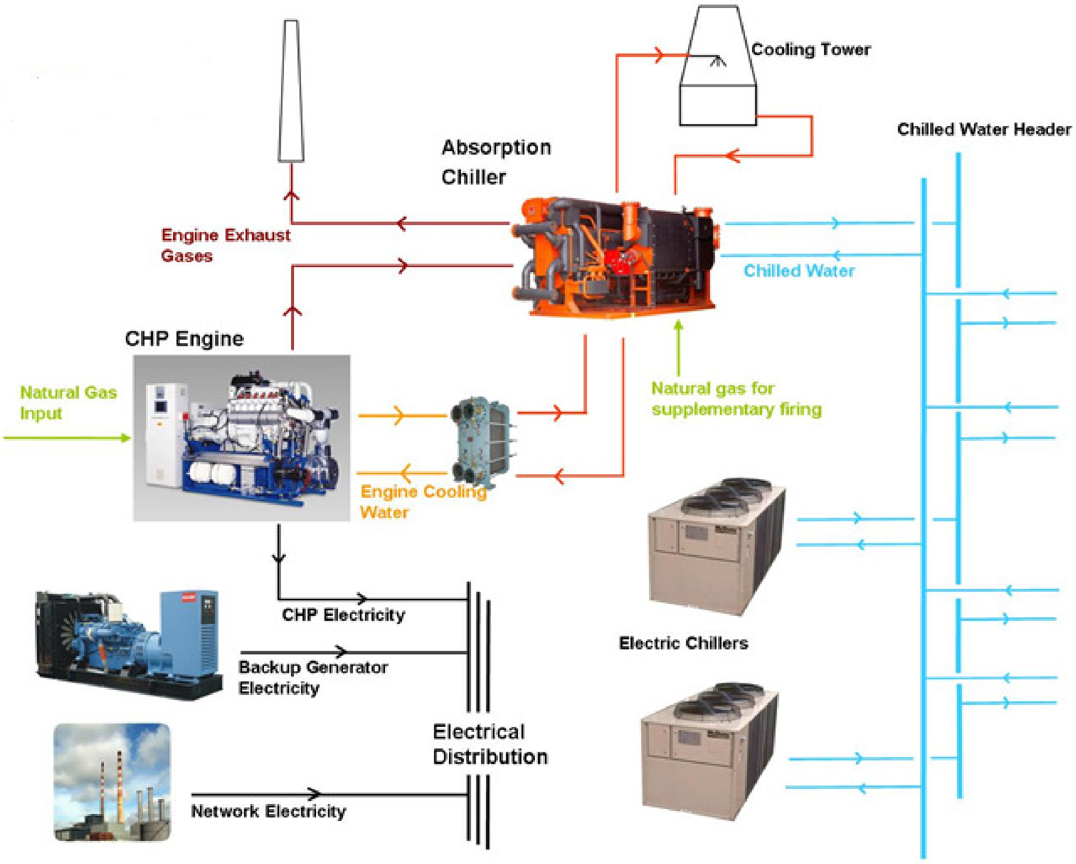


Figure 44: High level CHPC arrangement at the Vistakon facility in Limerick.

4.2 Vistakon Electrical System

The CHP in Vistakon shall generate a maximum 3.2MVA of the plant load, which is estimated at approximately 9MWe. The facility will take approximately 6MWe of the remaining power required from the utility provider (ESB). The CHPs shall operate in parallel and synchronous with the main utility supply. The introduction of the CHP allows the existing utility supply arrangement to be maximised and provide N+1 utility connection from the existing Ardnacrusha and Castletroy sources. On the CHP system side, the N+1 redundancy of supply also exists. In the event of a power outage from one leg of the utility supplies, there will be auto-change over to the alternative supply leg and full service will be maintained. In the unlikely event of complete loss of ESB service, the CHP supply would be available, subject to load shedding of non-essential and non-critical loads.

Under normal operation, the CHP will modulate between 2-3MWe to satisfy base load requirements. In production times, the load will increase beyond 3.2MVA

(CHP max) and the ESB contributes the difference. Eventually the load may reach 9MWe which could be serviced by the CHP and the ESB.

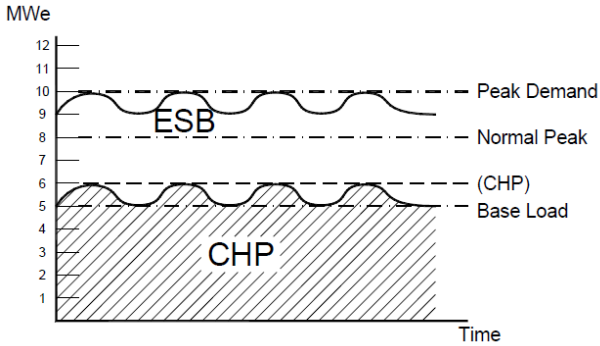


Figure 45: Electrical Load Variation at the Vistakon facility in Limerick.

As can be seen from figure 46, the Vistakon network has 9no. 10.5kV busbars and 12no. 0.4kV busbars. These 10.5kV and 0.4kV busbars are distributed across the site, at various load centres. As discussed in more detail in the following sections, the site ISDN contains 2no. 10.5kV normally open rings. These rings distribute power at medium voltage to the various load centres where it is stepped down to 0.4kV and distributed to various Main Distribution Boards (MDBs) and Motor Control Centres (MCCs). At this point, it would be also worth noting that the majority of motive power is controlled via variable frequency drives (VFDs). This arrangement means the motors do not contribute to the overall short circuit current, when a fault occurs. It has therefore been assumed that motive power contribution to a fault is negligible. It is also worth noting at this juncture that 8no. out of the 9no. 10.5kV busbars absorb power from the ISDN and 1no. (MVSB-9) 10.5kV network transmits power to the 10.5kV network. The reason for this is because MVSB-9 has 2no. CHPs connected to it, aswell as other auxillary power supplies. These CHPs generate electricity for utilisation within the Vistakon ISDN.

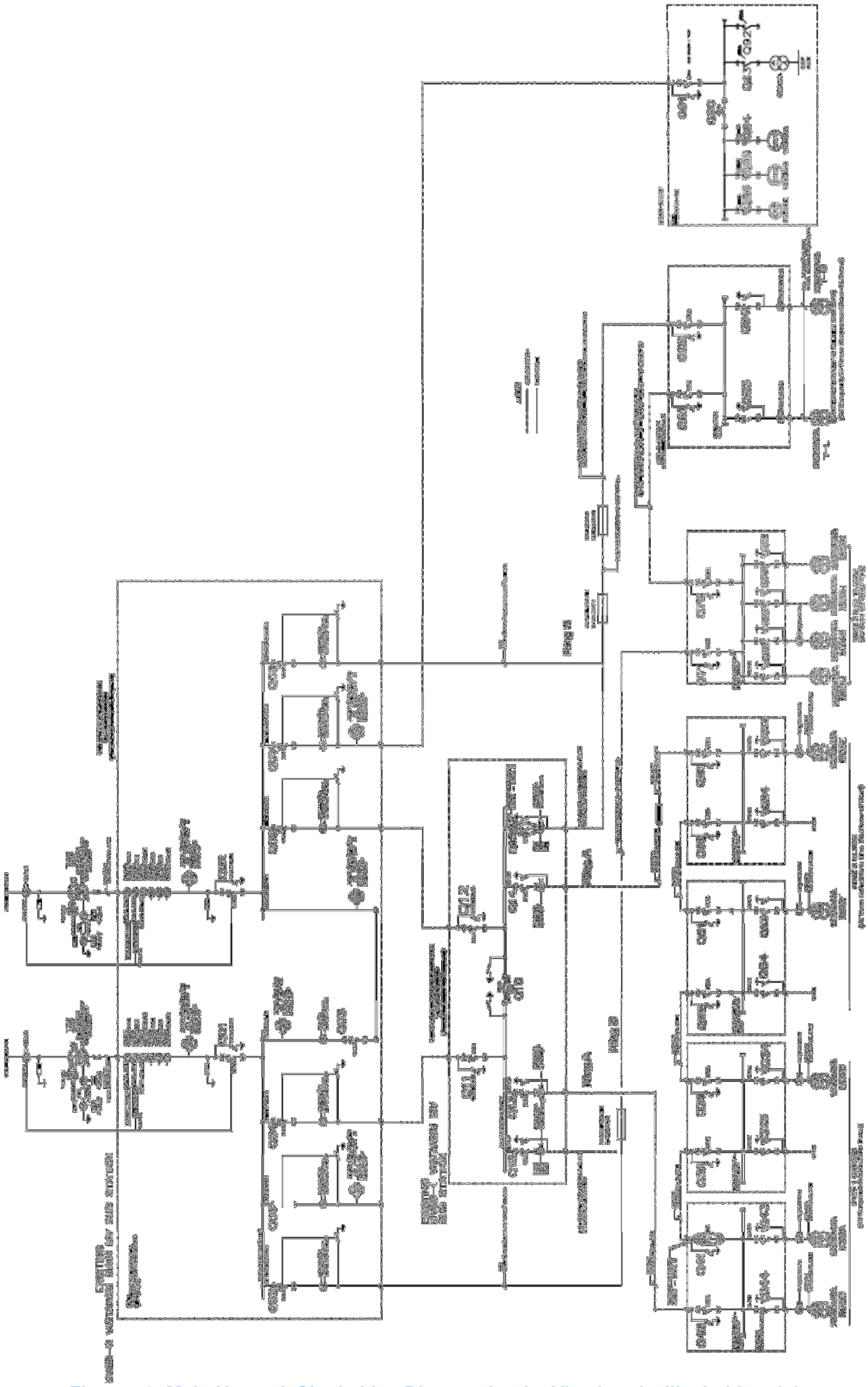


Figure 46: Main Network Single Line Diagram for the Vistakon facility in Limerick

4.3 Overview of Vistakon ISDN

As discussed in section 4.2, the Vistakon facility has 2no. 38kV overhead ESB lines supplying the ISDN; one supply is fed directly from Ardnacrusha power station to the facility, while the second supply is taken from the main Ardnacrusha to Castletroy line. The overhead lines are connected to two 38 kV +/-7%, /10.48kV, 15/18MVA oil-filled transformers. These transformers are YNyn0 winding transformers. This means the transformer has a "star" winding on the primary side, the neutral is brought out/available to an external connection. The winding on the secondary side of the transformer is also "star" connected and similar to the neutral/star point on the primary winding, the star point of the secondary winding is also available on the secondary side. In Vistakon's case, the "star point" of the secondary winding is connected to earth/grounded via a "neutral earthing resistor" (NER). The main purpose of a neutral earthing resistor is to limit ground fault currents to safe levels so that all the electrical equipment in the network is protected, at the same time letting enough current to flow to operate the protective relays that will alarm or clear the fault. As can be seen within figure 47, the star point of the primary winding on the primary side is brought out and connected to a 50VA current transformer (c.t.). This c.t. has two secondary windings, one star and one delta connected. The delta connected winding is in turn connected to a protection relay with overvoltage neutral protection (59N). If the neutrals of the primary and secondary windings are both brought out, then a phase-to-ground fault on the secondary circuit causes neutral fault current to flow in the primary circuit. Ground protection relaying in the neutral of the primary circuit may then operate for faults on the secondary circuit. Any fault current in the secondary neutral is transformed into neutral current in the primary circuit through the second transformer law [46]. It should also be noted that to comply with distribution code [48], the DG transformer winding shall be connected in star (with the star point or neutral brought out) on the higher voltage side and in delta on the lower voltage side.

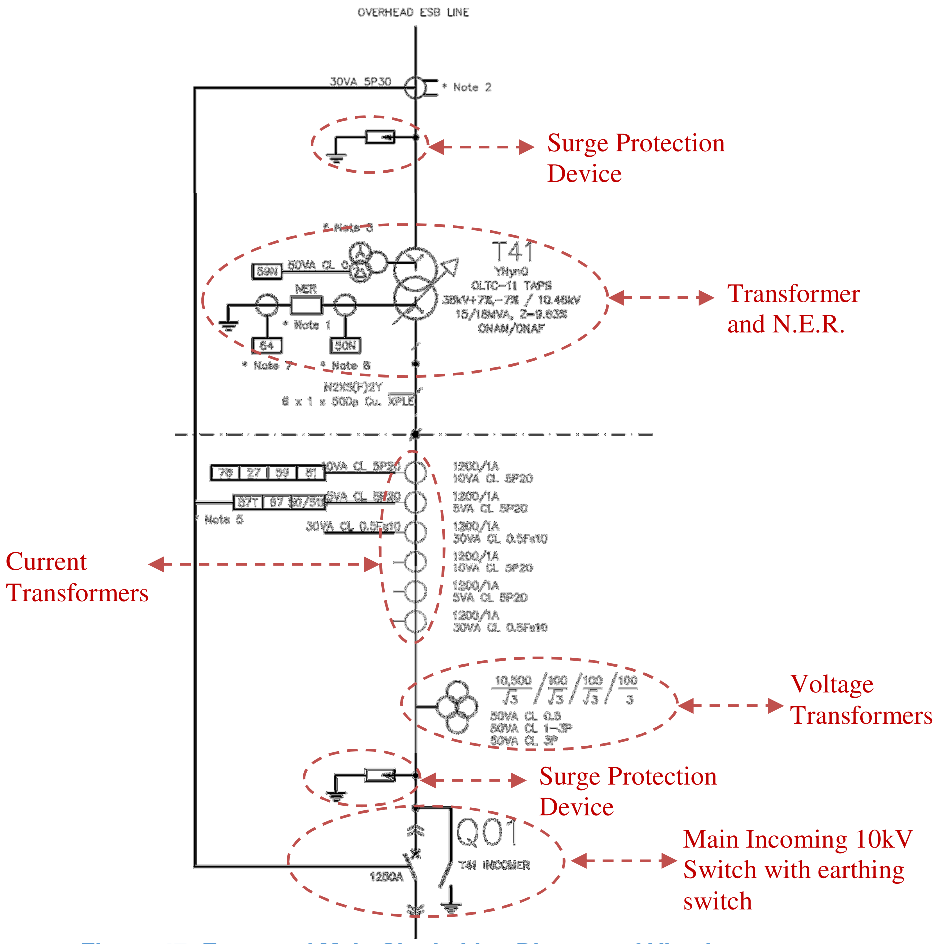


Figure 47: Extract of Main Single Line Diagram of Vistakon

The NER is a critical component of the earth fault protection scheme. It is a connection between the transformer neutral and earth. The primary reason for installing an NER is to minimise the amount of current flowing through the transformer in the event of an earth fault. NERs limit fault currents to a value that does not cause any further damage to switchgear or transformers beyond what has already been caused by the fault itself. As can be seen from the extract above, the NER is connected to a protection relay. This relay protects the circuit from a) Instantaneous Overcurrent in the Neutral (50N) and b) Ground Detector Relay (64).

The instantaneous overcurrent in the neutral protection is provided for protection against phase-to-ground faults. The neutral overcurrent protection responds to the calculated neutral current, as the sum of the phase currents: $I_N=I_R+I_S+I_T$. When configuring the protection settings for the neutral overcurrent protection, it is imperative that the neutral instantaneous protection is set higher than the maximum phase-to-ground short circuit current beyond the closest downstream device (in this case Q01) and it must also be set higher than the maximum unbalanced load current on the line. The Ground Detector Relay (64) operates on failure of the insulation of the transformer to ground. This relay only detects the flow of current from the frame of the transformer to earth or detects an earth on a normally unearthed winding or circuit.

Upstream and downstream of the transformer T41, there are a number of c.t.s installed. The upstream c.t. is a 30VA 5P30 c.t. 30VA is the accuracy power of the c.t. Accuracy power is always expressed in VA; it is the apparent power supplied to the secondary circuit for the rated secondary current and the accuracy load. 5P is the accuracy class of the c.t. The accuracy class defines the error limits guaranteed on the ratio and on the phase shift in specified power and current conditions. 30 is the accuracy limit factor of the c.t. The accuracy limit factor is the ratio between the nominal overcurrent (eg. $10I_n$) and the rated current. A protection c.t. such as this upstream c.t. must saturate sufficiently to allow a relatively accurate measurement of the fault current by the protection, whose operating threshold can be very high. A protection relay with the following protection characteristics is connected to both upstream and downstream c.t.s:

- Differential transformer protection relay (87T)
- A.C. directional overcurrent relay (67)
- Instantaneous overcurrent relay (50) and a.c. time overcurrent (51N)

For faults which occur within the windings of the oil transformer a Buchholz relay is installed but this does not completely monitor the condition of the entire transformer. Differential unit protection is installed to detect faults such as flash-over in bushings, internal winding faults, etc, within the differential zone of the transformer. The differential protection operates on the principle of comparing the primary current to the secondary current at either side of the transformer. If the imbalance is too large then it shall cause the upstream and/or the downstream breaker to operate.

A.C. directional overcurrent protection is utilised to monitor when current exceeds a certain limit in a defined direction, either imported from the ESB network or exported from the ISDN. In Vistakon’s current situation, this type of protection can be utilised if Vistakon were not allowed to export power to the ESB grid. A.C.

directional overcurrent relaying refers to the relaying which can use the phase relationship of voltage and current to determine direction to a fault, as discussed in [47].

Instantaneous overcurrent relay operates with no intentional time-delay when the current exceeds a pre-determined value. Overcurrent relays are affected by variations in the magnitude of a short-circuit which could be caused by different network configurations, such as DG exporting power or DG disconnected from the network.

Upstream and downstream of the transformer T41, there are surge protection devices installed. The role of these surge protection devices is, that in the event of a lightning strike, the lightning current would be directed to earth in a very short time.

It is also worth highlighting at this point the “earthing switches” on both Q01 and Q02. These “earthing switches” are installed in switchgear primarily near cable sealing ends, i.e. before the main switching devices - in Vistakon’s case before Q01 and Q02. All fault make “earthing switches” must be capable of conducting their rated short-time current without damage. “Make-proof” earthing switches are also capable of making the associated peak current at rated voltage. For safety reasons, make-proof earthing switches are recommended with air insulated switchgear because of possible actuations. In gas-insulated switchgear, such as the switchgear installed in Vistakons MV ISDN, the earthing of a feeder is often prepared by the earthing switch and completed by closing the circuit breaker. In this case, a separate make-proof earthing switch is not required [49].

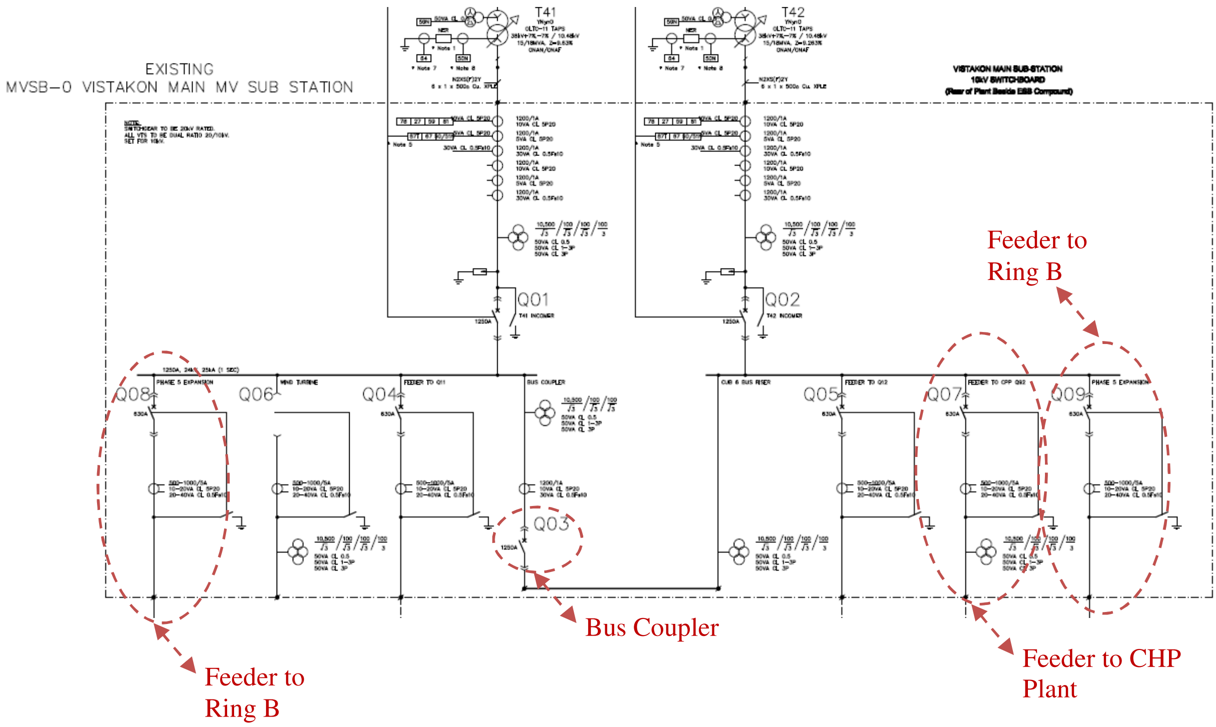


Figure 48: Extract of Main Single Line Diagram of Vistakon MVSB-0

The two main incoming 10kV switches are located within the main MV substation (MVSB-0), as shown in figure 48. Due to continuous upgrading of the ISDN there are two main boards, MVSB-0 and MVSB-1. MVSB-0 is a 1250A, 25kA, 24kV Schneider manufacture board which contains the two main incoming SF6 circuit breakers, one bus coupler and six feeder breakers; five of which are currently being utilised. Four of the five feeder circuit breakers are utilised to create two site wide 10kV rings, while the fifth feeder is connected to the CHP installation. The bus coupler in MVSB-0 is a normally closed bus coupler, which means in the event of the loss of one supply from the grid, the plant shall remain operational. Circuit breakers Q04 and Q05 supply power to Q11 and Q12 of MVSB-1. The primary function of MVSB-1 is to supply power to “Ring A”. As can be seen in Appendix B, “Ring A” comprises of four ring main units (r.m.u.s) MVSB-4, MVSB-3, MVSB-5 and MVSB-6. The normally open point of this ring is located at MVSB-4 Q41. These four r.m.u.s are ABB “Safering” units.

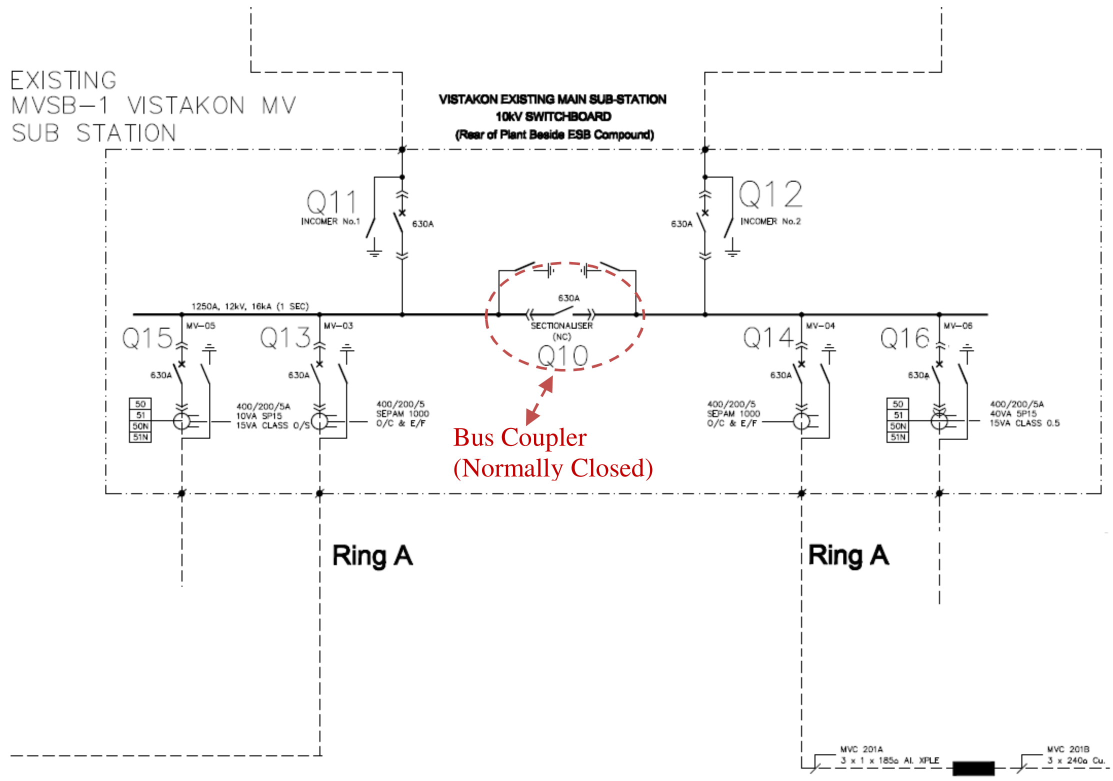


Figure 49: Extract of Main Single Line Diagram of Vistakon MVSB-1

As shown in figure 48, “Ring B” is fed from MVSB-0 via Q08 and Q09. “Ring B” consists of r.m.u.s MVSB-7 and MVSB-8. The normally open point of this ring is located at MVSB-8 Q81. Both r.m.u.s within “Ring B” are ABB “Safering” units.

Feeder Q07 of MVSB-0 appears to be a feeder breaker from MVSB-9. However, this could also be called an incoming breaker, as it supplies power onto the ISDN via this breaker. MVSB-9 is a 7 cubicle Schneider SM6, 12kV, 630A, 16kA rated board; it was supplied and installed by the CHP vendor, as part of the CHP project. This board contains 1no. 630A feeder(Q91) from the ISDN, 1no. 630A bus coupler (Q90), 3no. 630A feeder breakers for CHP units, two of which are currently utilised (Q95 and Q96), 1no. feeder (Q93) to an 800kVA transformer for auxiliary loads and 1no. spare feeder (Q92).

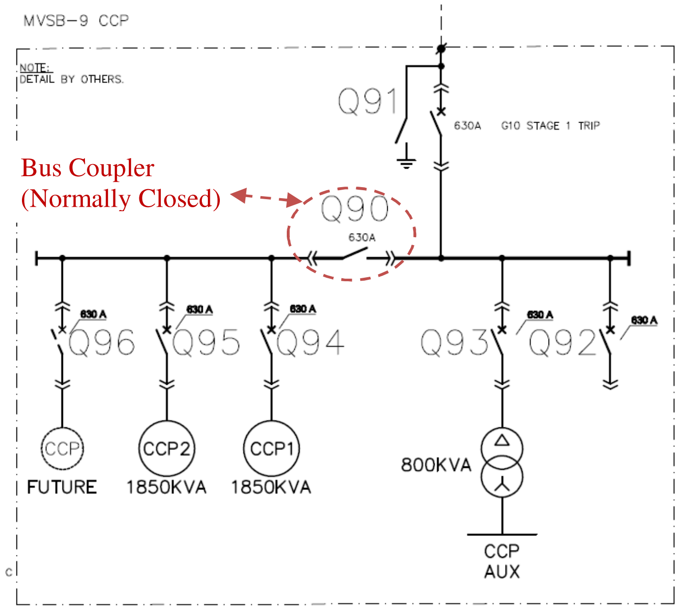


Figure 50: Extract of Main Single Line Diagram of Vistakon MVSB-9

The 800kVA transformer is located within a container adjacent to the MV switchgear (MVSB-9). The transformer is a three phase cast resin transformer, rated for 10.4kV on the high voltage side and 0.4kV on the low voltage side, at no load. The transformer has off load tap changer of +5%, +2.5%, -2.5% and -5%. The transformer's aluminium windings are naturally cooled and the transformer's vector group is "Dyn11". The transformer has PT100 sensors embedded in its winding to monitor the temperature of the windings. The 800kVA transformer is connected to the "CCP Aux" board via 1250A busduct. The "CCP Aux." board supplies auxiliary power supplies for the CHP's, pumps, lighting and power within containers, etc. This board consists of the following:

Schedule of Circuit Breakers installed within the LV CCP Aux. Board	
Breaker Size	**Load Description**
1250 Amp (NS1250 N type)	Main Incomer
630 Amp (NS630 N type)	Cooling Tower
160 Amp (NS160 N type)	CHP 1 Feeder
160 Amp (NS160 N type)	CHP 2 Feeder
160 Amp (NS160 N type)	CHP 3 Feeder (Spare)
100 Amp (NS100 N type)	Lighting Section
32 Amp (NS100 N type)	MV Section
32 Amp (NS100 N type)	LV Section
32 Amp (NS100 N type)	Spare

Table 4: Schedule of LV circuit breakers installed in Aux. CCP Board

It should be worth highlighting the location of the "CCP Aux." feeder in relation to the CHP feeders within MVSB-9. The feeders are separated by a bus coupler. The primary reason for this is, if the CHPs were out of service for any reason, such as maintenance, then the cooling towers, lighting and power within the CHP containers and other auxiliary containers could be maintained.

Due to the mixture of different vendors' switchgear across the ISDN (namely Schneider and ABB switchgear) there is also a mixture of protection relays utilised across the ISDN. The following table lists the different type of protection relays used within the 10kV network across the site.

Schedule of Protection Relays installed within the ISDN				
Breaker No.	**Relay Type**		**Breaker No.**	**Relay Type**
Q01	Sepam G88		Q90	Sepam S20
Q02	Sepam G88		Q91	Sepam S84
Q03	Sepam G88		Q92	Sepam S20
Q04	Sepam T20		Q93	Sepam T20
Q05	Sepam T20		Q94	Sepam S84
Q06	N/A		Q95	Sepam S84
Q07	Sepam G87		Q34	ABB SPAJ 140C
Q08	N/A		Q43	ABB SPAJ 142C
Q09	N/A		Q44	ABB SPAJ 142C
Q10	N/A		Q53	ABB SPAJ 140C
Q11	Sepam 2000		Q63	ABB SPAJ 140C
Q12	Sepam 2000		Q73	ABB PR512/P
Q13	Sepam 1000		Q74	ABB PR512/P
Q14	Sepam 1000		Q75	ABB PR512/P
Q15	Sepam 1000		Q76	ABB PR512/P
Q16	Sepam 1000		Q83	SEG WIC1
			Q84	SEG WIC1

Table 5: Schedule of protection devices installed within the 10kV ISDN

As well as common protection characteristics such as overcurrent, short circuit current and earth fault protection, the installation will also require G10 protection. The on-site generation of power is governed by the DNO MV network connection regulation G10. Vistakon's compliance with the G10 regulation has to be demonstrated to the DNO to obtain the generation permit. The main requirement of G10 is that in the event of a deviation in DNO supply, the genset must electrically disconnect from the supply within 500 ms. The protection settings have to be agreed with the DNO at commissioning stage. The operating philosophy in Vistakon is for the CHP's generator to run in parallel with the MV network to provide power to the site. Should a G10 event occur during parallel operation, the CHP's synchronising breaker will then be opened/ tripped by third party protection equipment to disconnect the CHP's generator from the MV network. In addition, the CHP will receive a third party signal to shut the genset down; the unit will not be re-started until the MV supply has been returned to a healthy condition. This condition as such disables Vistakon's ability to operate the facility in "island" mode. Island mode means the ISDN is powered only from the CHP generator and not the ESB grid connection.

Some protection relays have the characteristic where dual settings may be inputted to the protection device. In the event of the CHPC units being in the 'on' position, a hardwired signal may be sent to the protection relays initiating protection settings 'A'. In the event the CHPC units are in the 'off' position, no signal may be sent to the relay, therefore protection settings 'B' shall be active. A cutsheet of a typical relay is located within 'Appendix C' of this document.

4.3.1 CHP Installation

As previously discussed, the CHP units are connected at 10.4kV to MVSB-9.

The CHP installation satisfies Vistakon's base load requirements, which are approximated as follows:

	Hot Water (LPHW)	Steam	Cooling
Winter	500kW Flow 82°C Return 71°C	3500kg/hr @ 10bar	2000kW Flow 5°C to 11 °C
Summer	500kW Flow 82°C Return 71°C	3500kg/hr @ 10bar	4000kW Flow 5°C to 11 °C

*Note: Base loads are based on estimates and not measured loads

The engines used in the Vistakon packages are Jenbacher J420GS-A305 units, each rated at 1,475 kWe with two stage intercooler. The engine drives an alternator generating at 10.5kV 50 Hz.

The CHP system will be thermally led, providing chilled water and electricity proportionally to meet the site requirement, as noted above. It is envisaged the CHP system operates at its maximum duty for the majority of running hours throughout the year.

The CHP system does have the facility to de-rate its output, both thermal and electrical, should the site demand for either fall during its period of operation. As previously noted, the CHP system will offset 2950kW of site electrical based load, indicated to exceed 6MW, so both CHPs will be running at 100% output whenever there is a thermal load.

The CHP system thermal output is in the form of chilled water operating with flow and return temperatures of 5°C and 9°C respectively. The CHP system is capable of offsetting 2,048kW of the site thermal base load at 100% duty. It is envisioned that this base load will exist for the majority of the operating hours; however, should the base load reduce below this level, the CHP system will de-rate its thermal output to match the new demand.

The electrical output can be maintained during thermal de-rate with the excess thermal energy being dumped to atmosphere through the integral cooling tower system.

Primary Water Circuit

The pressurised primary hot water system recovers heat from the oil cooler, then the high temperature first stage intercooler, then the engine jacket, and finally from the engine exhaust heat recovery shell and tube exchanger up to a temperature of 105 ºC. This primary hot water is then transferred, at 11kg/s by 2no. fixed speed pumps, directly to a hot water driven absorption chiller where at full duty it is cooled to 70 ºC by the process of producing chilled water.

Control of the chiller duty for operation at part load (which is thought to be a rare occurance) or isolation of the chiller for either planned or unplanned maintenance, is afforded by a control bypass valve, operated by the chiller to modulate the hot water to the chiller.

To cater for expansion of the primary water, an expansion vessel is installed in the system. All system temperatures pressures and flows are monitored by the CHP control system.

A second thermostatic control valve operates in tandem with a plate heat exchanger interfaced with the cooling water circuit to ensure any excess heat present downstream of the chiller is dumped and the return temperature to the engine remains at 70 ºC. This exchanger is sized to ensure all of the waste heat recovered in the primary circuit is capable of being dumped if required.

The Jenbacher engine control system, incorporating the operation of a pump and internal jacket water divert valve (supplied by Jenbacher), necessitates the inclusion of a secondary low loss bypass. This allows the system to maintain a flow of primary water through the exhaust gas shell and tube exchanger while the engine is protecting itself by internally circulating the jacket water to raise its temperature as quickly as possible. Once the jacket is up to temperature and this bypass valve is open, the draw from a pump is sufficient to ensure the residual flow through is minimal and the engine will maintain a flow.

Low Grade Water Circuit

The secondary intercooler circuit is circulated at 6.2kg/s from a fixed speed pump between the engine and a dump plate heat exchanger interfaced to the cooling water circuit. This uses a thermostatic control valve to ensure the return water temperature to the engine intercooler remains at a constant 35-40 ºC.

Cooling Water Circuit

Each CHP unit will have a dedicated bank (4no.) of Watermiser Model 30 FD Axial/900 open circuit cooling towers supplying cooled water at 25 ºC. Each of these evaporative coolers requires a top-up supply of treated soft water.

The York chiller requiring this cooling water has a stated cooling water flow rate of 120 kg/s with a temperature of 25.5 ºC inlet, 30.5 ºC outlet at full duty, and a stated COP of 0.689. When supplied with 1,488kW of primary hot water, it recovers 1,024kW of chilled water. The resultant low grade waste heat load from the chiller will be 2,512kW; this will be circulated by a pump and dumped by the evaporative cooling tower modules.

The cooling water system is open circuit, meaning the cooling water that passes through the cooling towers is the same water that passes through the absorption chiller. This is the most efficient method of cooling but does require constant water quality maintenance. The cooling water is circulated by a common pump set consisting of run & standby end suction pumps.

The cooling water also flows proportionally through a primary dump plate exchanger and a smaller intercooler low grade plate exchanger.

The primary dump plate heat exchanger ensures any residual heat required to be dumped by the primary flow control valve has a route to dump. This plate is sized at 1,488kW so is capable of dumping all the heat of the primary circuit in the event the chiller is off.

The smaller intercooler low grade plate exchanger ensures the waste heat from the engine intercooler has a route to dump. This plate is sized at 114kW and is required to dump this heat whenever the engine is running.

The resultant return water to the cooling towers is 30.6 ºC, 120kg/s.

A three-way control valve is positioned between the cooling towers and the cooling water pump set affords control of water temperature entering the chiller, maintaining the temperature within the tolerance band required by the chiller during start-up and excessive cold weather.

The above text was adapted from [66].

CHP Enclosures

The CHP genset and chiller modules are enclosed by the standard "Stork" panel system, which helps attenuate the noise breakout down to 75 dB(A) at one metre.

Each module has additional airflow attenuators and a pre-fabricated GRP roof.

All doors have standard fixing closure equipment with emergency release mechanism.

4.4 Eracs Model Scenarios

4.4.1 Voltage Rise/ Drop Issue

There are a number of different scenarios discussed in this case study. The first area discussed is the potential voltage rise issue. As discussed in previous chapters, voltage rise is a potential issue when installing DG into networks, often causing lines/cables to be upgraded, etc. Table 6 shows the results of three different running arrangements. In the first arrangement, the ISDN is supplied from two utility network supplies only; in the second arrangement, the ISDN is supplied from the two utility network supplies and one CHP supply and in the final arrangement, the ISDN is supplied from the two utility network supplies and two CHP supplies. This would be the facility's normal running arrangement.

	0 CHP and 2 Grid Supplies Supplying the ISDN		1 CHP and 2 Grid Supplies Supplying the ISDN		2 CHP and 2 Grid Supplies Supplying the ISDN	
Busbar ID	**pV (pu)**	**V (kV)**	**pV (pu)**	**V (kV)**	**pV (pu)**	**V (kV)**
MVSB_0	0.999735	10.497	0.999866	10.499	0.999834	10.498
MVSB-4	0.999315	10.493	0.999446	10.494	0.999414	10.494
MVSB-3	0.997373	10.472	0.997505	10.474	0.997472	10.473
MVSB-5	0.998103	10.48	0.998235	10.481	0.998202	10.481
MVSB_0 B	0.999735	10.497	0.999866	10.499	0.999834	10.498
MVSB-6	0.998132	10.48	0.998264	10.482	0.998231	10.481
MVSB-9	0.999735	10.497	0.999999	10.5	0.999999	10.5
BUS-0008	1	38	1.000001	38	1.000001	38
BUS-0009	1	38	1.000001	38	1.000001	38
MVSD-7	0.998855	10.488	0.998987	10.489	0.998954	10.489
MVSB-8	0.998855	10.488	0.998987	10.489	0.998954	10.489
MVSB-1A	0.999605	10.496	0.999736	10.497	0.999703	10.497
MVSB-1B	0.999661	10.496	0.999793	10.498	0.99976	10.497
MDBB	0.97441	0.39	0.974546	0.39	0.974512	0.39
MDBA	0.978391	0.391	0.978525	0.391	0.978492	0.391
MDBC	0.962539	0.385	0.962676	0.385	0.962642	0.385
MDBF	0.974291	0.39	0.974426	0.39	0.974393	0.39
MDBE	0.967631	0.387	0.967768	0.387	0.967734	0.387
MDBJ	0.989424	0.396	0.989556	0.396	0.989523	0.396
MDBH	0.987209	0.395	0.987342	0.395	0.987309	0.395
MDBG	0.981828	0.393	0.981962	0.393	0.981928	0.393
MDBK	0.983405	0.393	0.983539	0.393	0.983505	0.393
MDBL	0.998855	0.4	0.998987	0.4	0.998954	0.4
MDBM	0.998855	0.4	0.998987	0.4	0.998954	0.4

Table 6 : Extracted Full Load Voltage levels at each busbar from ERACS model

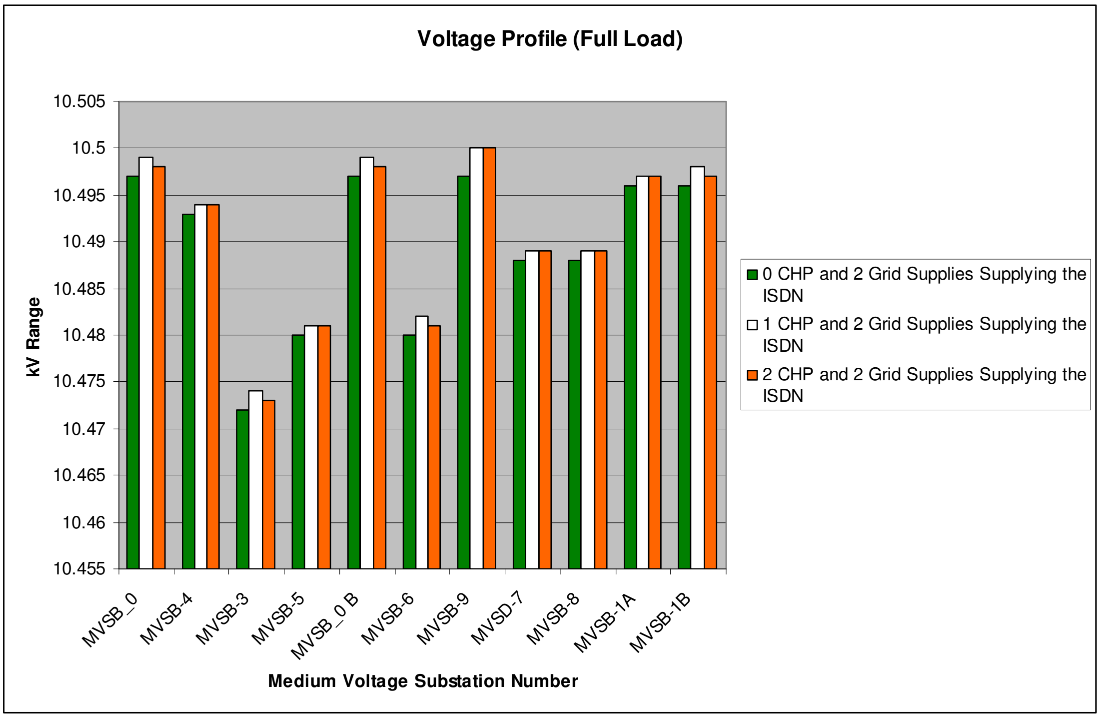


Figure 51: Voltage level fluctuation at MVSB-7 for different running arrangements

As can be seen from the table 6 and figure 51, there is no appreciable change in the voltage profile of the ISDN when the facility is running on full load and one or both CHPs are disconnected from the network. The primary reason for this is due to the size of the incoming transformers (T41 and T42). Both incoming 15/18MVA transformers are sized so one transformer can comfortably support the site load of approximately 9MW across the ISDN. Also, it should be noted the generators are configured with ERACS to be P, V power sources, which means they are constantly supply a fixed amount of power to the ISDN and a fixed voltage value to the network at all times. Another contributory factor to the low voltage fluctuation is the tap changers on the 10.5kV side of the two main transformers. Tap changers help regulate the voltage within a network. The voltage on the main busbar is monitored via voltage transformers on the main busbar. This reference voltage determines the adjustment of tap changers. The speed of tap change could be as fast as three seconds. There is no engineering issue with the current network arrangement; however, care should be taken when setting the protection devices for such a transformer as the magnetisation current may be high due to size of the transformer. To overcome the magnetisation issue, the instantaneous short circuit curret setting of the downstream circuit breaker should be set up. Also, the capital expenditure to purchase such transformers would be much higher than that of a transformer to match the load. However, installing larger transformers allows for the future expansion of the facility, therefore future proofing the design to a certain degree.

	0 CHP and 2 Grid Supplies Supplying the ISDN (20% full load)		**1 CHP and 2 Grid Supplies Supplying the ISDN (20% full load)**		**2 CHP and 2 Grid Supplies Supplying the ISDN (20% full load)**	
Busbar ID	**pV (pu)**	**V (kV)**	**pV (pu)**	**V (kV)**	**pV (pu)**	**V (kV)**
MVSB_0	0.99995	10.5	0.99995	10.499	0.99992	10.499
MVSB-4	0.99987	10.499	0.99987	10.499	0.999838	10.498
MVSB-3	0.9995	10.495	0.9995	10.495	0.999469	10.494
MVSB-5	0.99964	10.496	0.99964	10.496	0.999608	10.496
MVSB_0 B	0.99995	10.5	0.99995	10.499	0.99992	10.499
MVSB-6	0.99965	10.496	0.99964	10.496	0.999614	10.496
MVSB-9	0.99995	10.5	1	10.5	1.000005	10.5
BUS-0008	1	38	1	38	0.999999	38
BUS-0009	1	38	1	38	0.999999	38
MVSD-7	0.99978	10.498	0.99978	10.498	0.999749	10.497
MVSB-8	0.99978	10.498	0.99978	10.498	0.999749	10.497
MVSB-1A	0.99993	10.499	0.99992	10.499	0.999894	10.499
MVSB-1B	0.99994	10.499	0.99993	10.499	0.999906	10.499
MDBB	0.99513	0.398	0.99513	0.398	0.9951	0.398
MDBA	0.99586	0.398	0.99585	0.398	0.995826	0.398
MDBC	0.99301	0.397	0.99301	0.397	0.99298	0.397
MDBF	0.99511	0.398	0.9951	0.398	0.995073	0.398
MDBE	0.99391	0.398	0.99391	0.398	0.99388	0.398
MDBJ	0.99793	0.399	0.99793	0.399	0.997899	0.399
MDBH	0.99751	0.399	0.9975	0.399	0.997475	0.399
MDBG	0.99649	0.399	0.99649	0.399	0.99646	0.399
MDBK	0.99679	0.399	0.99678	0.399	0.996755	0.399
MDBL	0.99978	0.4	0.99978	0.4	0.999749	0.4
MDBM	0.99978	0.4	0.99978	0.4	0.999749	0.4

Table 7 : Extracted Voltage levels at each busbar from ERACS model

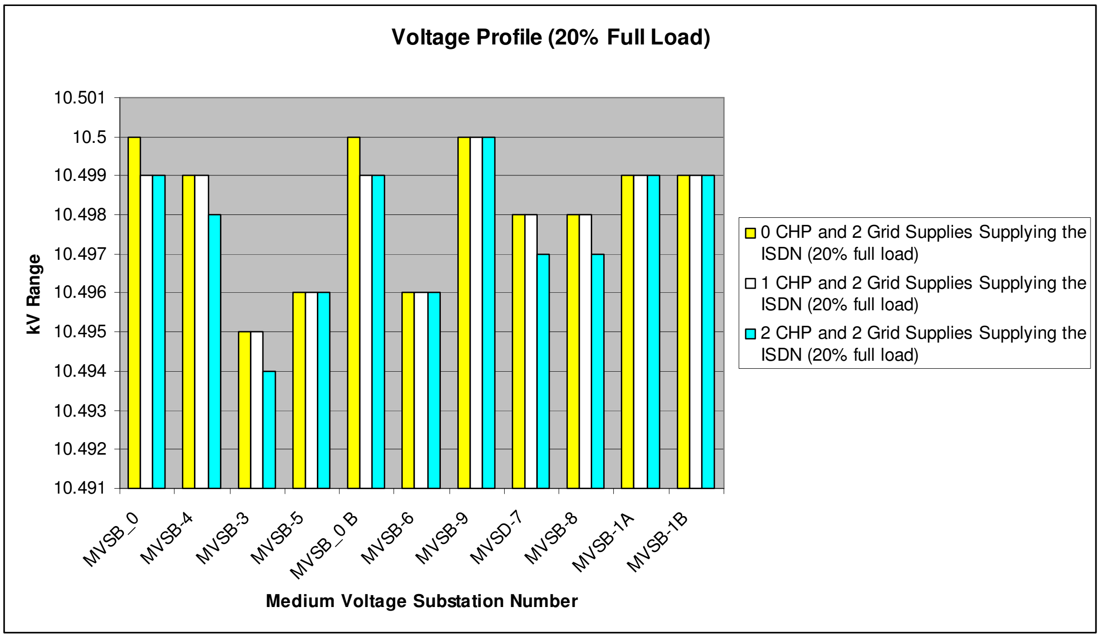


Figure 52: Voltage level fluctuation at MVSB-0 for different running arrangements at 20% full load

As can be seen from the figure 52 above, again there is no appreciable change in the voltage profile of the ISDN when the facility is running on 20% full load and one or both CHPs are disconnected from the network. This is again as a direct impact of the generous size of the incoming transformers (T41 and T42).

4.4.2 Short Circuit Issue

The second area discussed is the potential rise in short circuit current issue. As discussed in previous chapters, short circuit current rise is a potential issue when installing DG into networks, often causing switchgear, lines/cables and protection relay settings to be upgraded, etc. Table 8 shows the results of three different running arrangements. In the first arrangement, the ISDN is supplied from two utility network supplies only; in the second arrangement, the ISDN is supplied from the two utility network supplies and one CHP supply; and in the final arrangement the ISDN is supplied from the two utility network supplies and two CHP supplies. This would be the facilities normal running arrangement.

	0 CHP and 2 Grid Supplies Supplying the ISDN (100% full load)		1 CHP and 2 Grid Supplies Supplying the ISDN (100% full load)		2 CHP and 2 Grid Supplies Supplying the ISDN (100% full load)	
Busbar ID	**Voltage (kV)**	**A (kA)**	**Voltage (kV)**	**A (kA)**	**Voltage (kV)**	**A (kA)**
MVSB_0	10.5	21.5292	10.5	22.7793	10.5	24.0082
MVSB-4	10.5	20.8562	10.5	22.027	10.5	23.1736
MVSB-3	10.5	16.5594	10.5	17.2751	10.5	17.9574
MVSB-5	10.5	19.0092	10.5	19.9721	10.5	20.9047
MVSB_0 B	10.5	21.5292	10.5	22.7793	10.5	24.0082
MVSB-6	10.5	19.0726	10.5	20.0424	10.5	20.9819
MVSB-9	10.5	21.228	10.5	22.4778	10.5	23.7086
BUS-0008	10.5	5.9533	10.5	6.2841	10.5	6.6078
BUS-0009	10.5	5.9533	10.5	6.2841	10.5	6.6078
MVSD-7	10.5	20.0044	10.5	21.0786	10.5	22.1257
MVSB-8	10.5	19.9364	10.5	21.003	10.5	22.0423
MVSB-1A	10.5	21.4033	10.5	22.6385	10.5	23.8519
MVSB-1B	10.5	21.4033	10.5	22.6386	10.5	23.852
MDBB	0.4	44.3141	0.4	44.5043	0.4	44.6726
MDBA	0.4	44.3129	0.4	44.5033	0.4	44.6717
MDBC	0.4	29.0689	0.4	29.1504	0.4	29.2221
MDBF	0.4	29.289	0.4	29.3719	0.4	29.4449
MDBE	0.4	29.2956	0.4	29.3784	0.4	29.4513
MDBJ	0.4	44.1569	0.4	44.3464	0.4	44.5139
MDBH	0.4	44.1577	0.4	44.3471	0.4	44.5146
MDBG	0.4	44.1595	0.4	44.3488	0.4	44.516
MDBK	0.4	44.159	0.4	44.3483	0.4	44.5156
MDBL	0.4	44.1415	0.4	44.3312	0.4	44.499
MDBM	0.4	44.1415	0.4	44.3312	0.4	44.499

Table 8 : Extracted Full Load fault current at each busbar from ERACS model

	0 CHP and 2 Grid Supplies Supplying the ISDN (20% full load)		1 CHP and 2 Grid Supplies Supplying the ISDN (20% full load)		2 CHP and 2 Grid Supplies Supplying the ISDN (20% full load)	
Busbar ID	**Voltage (kV)**	**A (kA)**	**Voltage (kV)**	**A (kA)**	**Voltage (kV)**	**A (kA)**
MVSB_0	10.5	21.5292	10.5	22.7793	10.5	24.0082
MVSB-4	10.5	20.8562	10.5	22.027	10.5	23.1736
MVSB-3	10.5	16.5594	10.5	17.2751	10.5	17.9574
MVSB-5	10.5	19.0092	10.5	19.9721	10.5	20.9047
MVSB_0 B	10.5	21.5292	10.5	22.7793	10.5	24.0082
MVSB-6	10.5	19.0726	10.5	20.0424	10.5	20.9819
MVSB-9	10.5	21.228	10.5	22.4778	10.5	23.7086
BUS-0008	10.5	5.9533	10.5	6.2841	10.5	6.6078
BUS-0009	10.5	5.9533	10.5	6.2841	10.5	6.6078
MVSD-7	10.5	20.0044	10.5	21.0786	10.5	22.1257
MVSB-8	10.5	19.9364	10.5	21.003	10.5	22.0423
MVSB-1A	10.5	21.4033	10.5	22.6385	10.5	23.8519
MVSB-1B	10.5	21.4033	10.5	22.6386	10.5	23.852
MDBB	0.4	44.3141	0.4	44.5043	0.4	44.6726
MDBA	0.4	44.3129	0.4	44.5033	0.4	44.6717
MDBC	0.4	29.0689	0.4	29.1504	0.4	29.2221
MDBF	0.4	29.289	0.4	29.3719	0.4	29.4449
MDBE	0.4	29.2956	0.4	29.3784	0.4	29.4513
MDBJ	0.4	44.1569	0.4	44.3464	0.4	44.5139
MDBH	0.4	44.1577	0.4	44.3471	0.4	44.5146
MDBG	0.4	44.1595	0.4	44.3488	0.4	44.516
MDBK	0.4	44.159	0.4	44.3483	0.4	44.5156
MDBL	0.4	44.1415	0.4	44.3312	0.4	44.499
MDBM	0.4	44.1415	0.4	44.3312	0.4	44.499

Table 9 : Extracted 20% Full Load fault current at each busbar from ERACS model

4.5 Performance of Vistakon CHPC Plant

The overall performance and efficiency of a CHPC system is extremely important to ensure the installation is economically feasible. Based on the algorithm previously developed within section 2 of this document, we can calculate the performance of Vistakon's CHPC system.

To calculate the installation costs associated with a CHPC system, it is first necessary to calculate the average monthly electrical power output. This is done by summing the monthly electrical power output of the CHPC system and dividing the total by 12 months.

	CHP Units			2015 Downtime		
	A (Mins)	B (Mins)	Total Downtime per Month	2015 Hrs per month	2015 Mins per month	Runtime Per Month 2015
January	120	40500	40620	744	44640	48660
Febuary	630	30000	30630	672	40320	50010
March	1680	19965	21645	744	44640	67635
April	2250	60	2310	720	43200	84090
May	23820	20715	44535	744	44640	44745
June	36720	2010	38730	720	43200	47670
July	2055	6165	8220	744	44640	81060
August	585	7095	7680	744	44640	81600
September	6825	4260	11085	720	43200	75315
October	1485	42000	43485	744	44640	45795
November	2760	6030	8790	720	43200	77610
December	8235	35235	43470	744	44640	45810
Total Non Running Time	87165	214035	301200			
Total Running Time 2015 (mins)						750,000

Table 10 : Table to calculate runtime of CHP Units in 2015

	A (Average kW)	A (Run Time - hrs/month)	B (Average kW)	B (Run Time - hrs/month)	Total kWhr per Month
January	365	67	32	69	26,663
Febuary	329	162	93.44	172	69,369.68
March	314.8	383	202.29	411	203,709.59
April	260	682	367	719	441,193
May	126.7	2	194	399	77,659.4
June	51.5	75	356.24	687	248,599.38
July	345	607	294.77	641	398,362.57
August	362.7	615	300.7	626	411,298.7
September	307.78	535	331.01	649	379,487.79
October	354.9	19	18.31	44	7,548.74
November	344.14	574	313.29	620	391,776.16
December	299.33	20	76.64	157	18,019.08
Total kW hrs 2015					2,673,687.09

Table 11 : Table to calculate average Power Output (kW & kWhr) of CHP Units in 2015

	A (Run Time)	A (Average Thermal kW)	A (Average Thermal kWh)
January	67	318.6	21,346.2
Febuary	162	231.5	37,503
March	383	291.21	111,533.43
April	682	243.65	166,169.3
May	2	127.57	255.14
June	75	43.02	3,226.5
July	607	297.79	180,758.53
August	615	133.94	82,373.1
September	535	0.403	215.605
October	19	6.89	130.91
November	574	0	0
December	20	0	0
Total kW 2015	3741	1694.573	603,511.715

Table 12 : Table to calculate average Thermal Output (kW & kW hr) of CHP 'A' Unit in 2015

	B (Run Time - hrs/month)	B (Average Thermal kW)	B (Average Thermal kWh)
January	69	4	276
Febuary	172	1.03	177
March	411	0.78	321
April	719	0.715	514
May	399	1.704	680
June	687	8.76	6,018
July	641	2.139	1,371
August	626	0.706	442
September	649	0.3894	253
October	44	0	0
November	620	0	0
December	157	0	0
Total kW 2015	5,194	20	10,051

Table 13 : Table to calculate average Thermal Output (kW & kWhrs) of CHP 'B' Unit in 2015

	A (Average Gas Consumption m^3)	A (Run Time - hrs/month)	A (Average Gas Consumption m^3/hr)
January	79.85	67	5349.95
Febuary	71.68	162	11612.16
March	68.62	383	26281.46
April	58.4	682	39828.8
May	28.92	2	57.84
June	11.27	75	845.25
July	75.17	607	45628.19
August	80.25	615	49353.75
September	66.01	535	35315.35
October	77.16	19	1466.04
November	74.82	574	42946.68
December	65.39	20	1307.8
Total m^3 2015	757.54	3741	259,993.27

Table 14 : Table to calculate average Gas Consumption (kW) of CHP 'A' Units in 2015

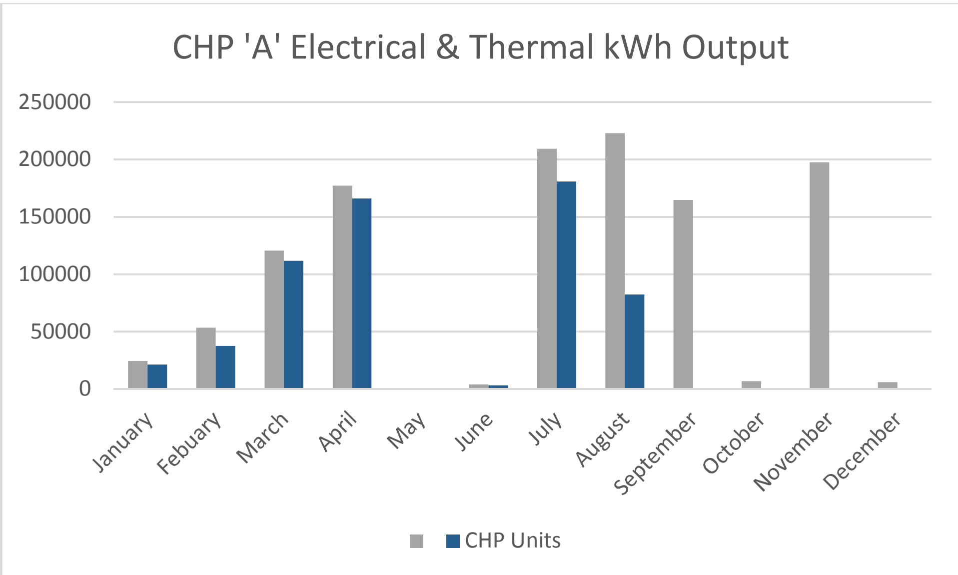


Figure 53: CHP 'A' Electrical & Thermal kWh Output

	B (Average Gas Consumption m^3)	B (Run Time - hrs/month)	B (Average Gas Consumption m^3/hr)
January	6.9	69	478.032
Febuary	19.8	172	3397
March	43.5	411	17874.39
April	79.0	719	56779.43
May	42.5	399	16961.49
June	80.7	687	55461.51
July	66.6	641	42658.55
August	67.1	626	42023.38
September	70.6	649	45812.91
October	4.0	44	174.68
November	67.6	620	41912
December	16.6	157	2603.06
Total m^3 2015	564.8	5194	326,136.432

Table 15 : Table to calculate average Gas Consumption (kW) of CHP 'B' Units in 2015

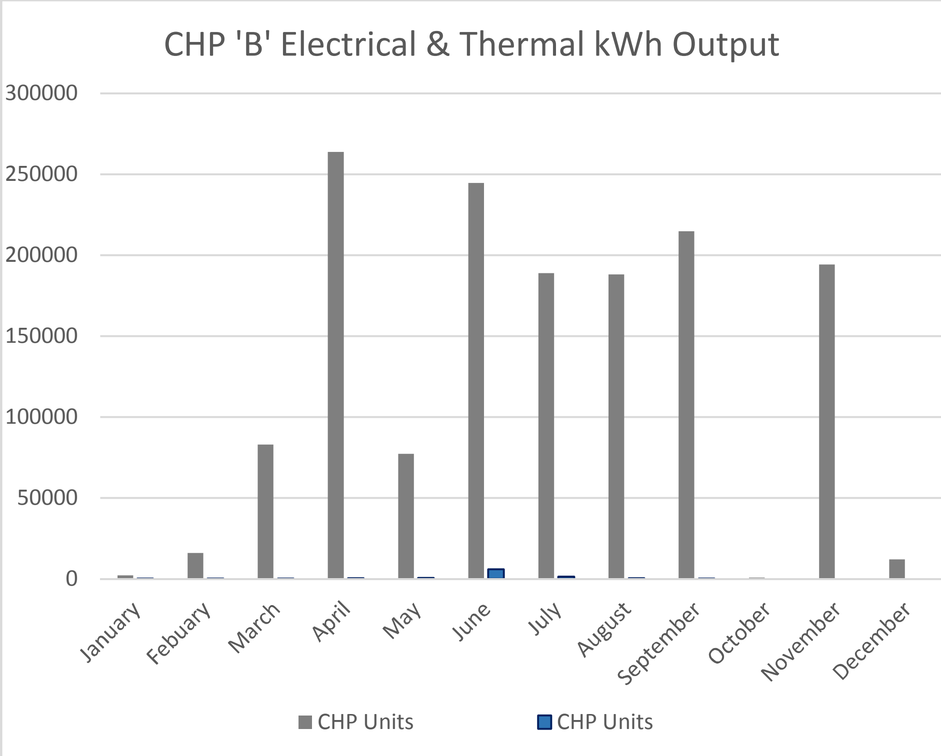


Figure 54: CHP ‘B’ Electrical & Thermal kWh Output

$$P_{el,avg} = \frac{\sum Nett\ Electrical\ Power\ Output}{\sum Months} \tag{41}$$

$$P_{el,avg} = \frac{6040.54}{12} = 503.38$$

There are multiple variables when estimating the installation costs of a CHPC system. These include the location of the installation (what country the CHPC is installed in), how busy the market is, the design of the components, etc. The calculation of the installation costs can be estimated by the multiplication of the installation factor (per kW) with the average electrical plant output:

Installation Costs = Installation Costs per kW * Average Electrical Output

However, based on a feasibility study for a similar project, the estimated cost for 1no. 2MW CHPC facility would be in the order of €3,817,582. When extrapolated and multiplied by 3.6MW, the estimated installation cost for the Vistakon installation would be in the order of :

$$\frac{€3,817,582}{2x10^3} = €1,908$$

$$\therefore €1,908\, x\,(3.6x10^3) = €6,868,800$$

Again, based on a feasibility study for a similar project, the estimated maintenance cost for 1no. 2MW CHPC facility would be in the order of €219,386.

When extrapolated and multiplied by 3.6MW, the estimated maintenance cost for the Vistakon installation would be in the order of :

$$\frac{€219,386}{2x10^3} = €109.69$$

$$\therefore €109.69x(3.6x10^3) = €394,884$$

Fuel costs are dependant on the price of gas at any one time. Fuel prices are variable depending on supplier, country and/or season. Running fuel costs can be estimated by multiplying an estimated price of gas by the fuel input required for the CHPC:

Based on benchmarked information from previous years, the average unit rate for gas over a 9 month period is 2.59902 cent per kWhr.

As the gas consumption readings obtained from Vistakon are in m^3, these should first be converted into kWhr.

Gas Consumption for CHP A = 757.54m^3

Gas Consumption for CHP B = 564.8m^3

Total Gas Consumption = 1,322.34m^3

Fuel Costs = Actual Fuel Price (€) * Fuel Input (kWh)

$$C_{Fuel} = C_{Fuel,kWh} \times Q_{Fuel}$$

$$\left(\frac{1,322.34x1.02264x39.2(calorific\ value\ assumed)}{3.6}\right)x\,2.59902 \tag{42}$$

$$=(5367.26922)\,x\,2.59902$$

$$=€13,949.64$$

The efficiency calaculations are broken down into four sections:

a) Electrical Efficiency

To calculate the electrical efficiency, the following equation may be used:

$$\eta_{Electrical} = \frac{\sum Nett\ Electrical\ Output}{\sum Total\ Fuel\ Energy\ Input} = \eta_{P\,d,m,y} = \frac{\sum_i P_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\% \tag{43}$$

Total Electrical Power Output from both CHP's = 2,673,687.09kW hr

Fuel Consumption for CHP 'A' = 2895132.525 kW hr

Fuel Consumption for CHP 'B' = 3631663.973 kW hr

Total Fuel Consumption for both CHP's = 6526796.499 kW hr

$$\eta_{Electrical} = \frac{\sum Nett\ Electrical\ Output}{\sum Total\ Fuel\ \ Energy\ Input} \tag{44}$$

$$= \eta_{P\,d,m,y} = \frac{2,673,687.09}{6,526,796.499} \times 100\%$$

$$= \eta_{P\,d,m,y} = 0.409647 \times 100\%$$

$$= \eta_{P\,d,m,y} = 40.9647\%$$

The electrical efficiency is important for the electrical rating to ensure the CHPC system meets the basic electrical requirements of the Industrial Site Distribution Network.

b) Thermal Efficiency

The thermal efficiency is based soley on the thermal output of the CHPC plant and compares it to the amount of fuel used to produce that thermal energy.

$$\eta_{Thermal} = \frac{\sum Nett\,Thermal\,Output}{\sum Total\ Fuel\ \ Energy\,Input} = \eta_{Q\,d,m,y} = \frac{\sum_i Q_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\% \tag{45}$$

To calculate the thermal efficiency, the following equation may be used:

Thermal Output for CHP 'A' = 603,511.715 kW hr

Thermal Output for CHP 'B' = 10,051 kW hr

Total Fuel Consumption for both CHPs = 6,526,796.499 kW hr

$$\eta_{Thermal} = \frac{\sum Nett\,Thermal\,Output}{\sum Total\;Fuel\;\;Energy\;Input} \tag{46}$$

$$= \eta_{Q\,d,m,y} = \frac{613,562.715}{6,526,796.499} \times 100\%$$

$$= \eta_{Q\,d,m,y} = 0.0940 \times 100\%$$

$$= \eta_{Q\,d,m,y} = 9.40\%$$

The thermal efficiency is important for the thermal rating to ensure the CHPC system meets the basic thermal requirements of the Industrial Site Distribution Network. In this case, the thermal efficiency appears to be extremely low. This could be due to a number of factors, namely:

i) Inaccurate meter measurements

ii) Low/no requirement for chilled water.

As the primary reason for a low thermal efficiency is thought to be inaccurate meter measurements, I shall assume a thermal efficiency for the installation to be in the order of 45%.

$$\eta_{Thermal} = \frac{\sum Nett\,Thermal\,Output}{\sum Total\;Fuel\;\;Energy\;Input} \tag{47}$$

$$= \eta_{Q\,d,m,y} = \frac{2,937,058.42}{6,526,796.499} \times 100\%$$

$$= \eta_{Q\,d,m,y} = 0.45 \times 100\%$$

$$= \eta_{Q\,d,m,y} = 45\%$$

c) The CHPC Total Overall Efficiency

The total overall efficiency is based on the addition of the electrical and thermal output of the CHPC plant and compares it to the amount of fuel used to produce that electrical and thermal energy.

To calculate the overall efficiency, the following equation may be used:

$$\eta_{Total} = \frac{\sum Nett\ Electrical\ Output + \sum Nett\ Thermal\ Output}{\sum Total\ Fuel\ Energy\ Input} \times 100\% \qquad (48)$$

$$\eta_{T\ d,m,y} = \frac{2,673,687.09 + 2,937,058.42}{6,526,796.499} \times 100\%$$

$$\eta_{T\ d,m,y} = \frac{5,610,745.51}{6,526,796.499} \times 100\%$$

$$\eta_{T\ d,m,y} = 0.8596 \times 100\%$$

$$\therefore \eta_{T\ d,m,y} = 85.96\%$$

The calculation of total system efficiency evaluates the combined CHP outputs (i.e., electricity and useful thermal output) based on the fuel consumed. CHP systems typically achieve total system efficiencies of 60 to 80 percent [55].

d) Heat to Power Ratio.

Heat to power ratio is one of the more important parameters in a CHP system as it determines the rate of generated heat to electrical power in the single system. This calculation is important when comparing CHP plant systems. The heat to power ratio is calculated using the following equation:

$$X_{d,m,y} = \frac{\sum_i Q_{d,m,y}}{\sum_i P_{d,m,y}} \qquad (49)$$

$$X_{d,m,y} = \frac{2,937,058.48}{2,673,687.09}$$

$$X_{d,m,y} = 1.0985494$$

The environmental performance of the CHPC system, C2, can be estimated based on the outcome of step 1, initial data collection (namely D3412). As illustrated within the flowchart in figure 30, the environmental impact can be expressed through two different sections, namely, the efficient use of fuel and CO_2 performance.

When assessing the efficient use of fuel, one must consider two main formulae:

i) Percentage Fuel Savings.

Fuel savings compares the fuel used by the CHP system to a separate heat and power system. Positive values represent fuel savings while negative values indicate that the CHP system is using more fuel than separate heat and power generation.

$$S_{d,m,y} = 1 - \frac{\sum_i F_{d,m,y}}{\frac{\sum_i p_{d,m,y}}{EEF_P} + \frac{\sum_i Q_{d,m,y}}{EEF_Q}} \times 100\% \qquad (50)$$

$$S_{d,m,y} = 1 - \frac{6,526,796.499}{\frac{2,673,687.09}{40.96\%} + \frac{2,937,058.48}{45\%}} \times 100\%$$

$$S_{d,m,y} = 1 - \frac{6,526,796.499}{6,527,556.37 + 6,526,796.62} \times 100\%$$

$$S_{d,m,y} = 1 - \frac{6,526,796.499}{13,054,353.0} \times 100\%$$

$$S_{d,m,y} = 1 - 0.499,97089 \times 100\%$$

$$S_{d,m,y} = 0.50002911 \times 100\%$$

$$S_{d,m,y} = 50.00\%$$

ii) Fuel Utilization Effectiveness.

This is the CHP efficiency based on the electrical CHP output versus the net fuel consumption excluding the fuel required to produce the useful heat output. The fuel required to produce useful heat is calculated assuming a typical boiler efficiency, generally 80% [56].

The following equation may be used to calculate the Fuel Utilisation Effectiveness:

$$FUE_{d,m,y} = \frac{\sum_i P_{d,m,y}}{\sum_i F_{d,m,y} - \frac{\sum_i Q_{d,m,y}}{EFF_Q}} \times 100\% \qquad (51)$$

$$FUE_{d,m,y} = \frac{2,673,687.09}{6,526,796.499 - \frac{2,937,058.48}{80\%}} \times 100\%$$

$$FUE_{d,m,y} = \frac{2,673,687.09}{6,526,796.499 - 3,671,323.1} \times 100\%$$

$$FUE_{d,m,y} = \frac{2,673,687.09}{2,855,473.39} \times 100\%$$

$$FUE_{d,m,y} = 0.93633760 \times 100\%$$

$$FUE_{d,m,y} = 93.6337\%$$

As discussed within section 3.3, there are multiple different gaseous outputs from the exhaust of a CHPC system. One of the larger outputs is CO_2 (carbon dioxide). Before estimating the CO_2 savings it is firstly necessary to estimate the amount of CO_2 generationed by the CHPC system. Once this is calaculated, the resultant value can be compared to separated CO_2 generation by a gas boiler and a power station (either coal or gas powered).

Percentage CO_2 Savings.

The CO_2 savings compares the CO_2 production of the CHP plant to separate electrical and thermal generation by a boiler or a coal or gas power plant. The percentage CO_2 savings is calculated using the following formula:

$$S_{CO_2} = \frac{\sum CO_2\ Total\ Output\ CHP}{\sum Total\ CO_2\ Output\ Seperate\ Heat\ and\ Power} = \frac{CO_{2CHP}}{CO_{2SEPERATE}} \times 100\% \quad (52)$$

During 2015 CHP ‘A’ operated for circa 3,741 hours and consumed 259,993 m^3/hr of gas and CHP ‘B’ operated for circa 5,194 hours and consumed 326,136 m^3/hr. In total, 6,526,796.49kWh of gas was used in 2015. With gas having a ccarbon content of 50g per kWh, this gas produced a carbon emission of 326.339,824 tCO_2.

If the same energy were supplied from separate heat and power generation plants, i.e. a standalone in-house gas fired boiler (with a typical efficiency of 80% to produce 2,937,058.42kWh of heat) would take 3,671,323.02kWh of natural gas, that would produce 183.566,151 t CO_2.

By generating on-site, the CHP plant replaces electricity that would otherwise be obtained from the national grid. 7An average emmisson from fossil fuel generating plant is estimated to be 183g of carbon per kWh produced, including an allowance for transmission losses. Generating 2,673,637.09kWh of electricity would produce 489.275,587t CO_2.

Total emission produced by separate heat and power would be:

183.566,151 t CO^2 + 489.275,587t CO_2 = 672.841,738t CO_2.

$$S_{CO_2} = \frac{\sum CO_2\ Total\ Output\ CHP}{\sum Total\ CO_2\ Output\ Seperate\ Heat\ and\ Power} = \frac{CO_{2CHP}}{CO_{2SEPERATE}} \times 100\% \quad (53)$$

$$S_{CO_2} = \frac{326.339}{672.841} = 0.4850 \times 100\% = 48.50\%$$

The economical analysis of a CHPC system can be estimated based on the output of the data collection (namely D345). There are a number of different aspects to be assessed when investigating whether or not a CHPC system is economically viable for a particular industrial site distribution network. The following is just one aspect of the economical analysis that should take place:

To ensure the CHPC system is economically viable, one must compare the costs of buying electricity from a local energy provider against the cost of generating electricity within the industrial site distribution network. The more running hours the CHPC plant accumulates, the cheaper the price of kWh energy. Therefore, for maximum economic efficiency of the CHPC system, the system must be running as much as possible. To estimate the price per kWh, the overall cost should be summed and divided by the total annual running hours.

$$C_{install} = \frac{C_{maintenance} + C_{Fuel}}{Lifetime\ of\ CHPC\ (20\,Years)} \quad (54)$$

$$C_{install} = \frac{(1c \times 2,673,687.09) + (5.8c \times 2,673,687.09)}{(20\,Years)}$$

$$C_{install} = \frac{(2,673,687.09) + (15,507,385.1)}{(20)}$$

$$C_{install} = €909,053.610$$

Based on the above calculation, the cost of the CHPC installation is in the order of €1,000,000.

Assuming:

a)1c / kwh to maintain the CHPC system

b) 5.8c / kwh per unit of gas (based on Bord Gais unit rates)

This, however, does not give a true reflection of the cost of energy produced by the lifetime CHPC throughout its lifetime. To calculate this, the installation cost should be divided by the lifetime of the CHPC system, in years.

$$C_{per\,kW} = \frac{\sum Costs\,annual}{\sum Running\ Hours \times 1\,kW} = \frac{C_{installation,20\,years} + C_{maintenance} + C_{Fuel}}{t_{running\ hours\ per\ year} \times 1\ kW} \tag{55}$$

$$C_{per\,kW} = \frac{909,053.61 + 2,673,687.09 + 15,507,385.1}{12,500 \times 1\ kW}$$

$$C_{per\,kW} = €1,527.21$$

5 Conclusion

CHPC's are playing an increasingly important role in the generation and distrubtion of electrical power. Connecting a CHPC to the distributed network creates a range of positive and negative impacts. These impacts must be limited to protect the security and quality of the power supply network. Mitigation techniques currently employed may add significant capital expenditure to a CHPC installation and may deter investment into a CHPC system within a companies industrial site distribution network.

A detailed analysis of the electrical, heating and cooling requirements of a facility should be completed prior to investing in a CHPC system. A detailed analysis of the utility companies power infastrucutre is also required, assuming the company producing power wish to export excess power to the grid. In general, the conncection of CHPC units to the power system improves the voltage profile of the power network and reduces losses. The loss reduction depends on the on the injection capacity and the network characteristics. If the network infrastructure is not adequately sized for the power injection or fault current, then local overvoltages or breaking capacity/relay protection issues may arise. Generally, networks are adequatey sized for minor power injection, however, protection relay settings may have to be updated based on increased network capacity at the point of common coupling with the distributed generation. As illustrated within the case study (section 4), where a minimal amount of distributed generation is added a minor upgrading of local protection relay settings may suffice, but where a subsational amount of distrubted generation is connected an entire protection scheme may require updating to ensure accurate tripping times and adequate discrimination between protection curves.When the level of CHPC capacity within a network rises to levels beyond that of CT's or relays within a network, the system reliability may be adversely affected. In the case of Vistakon, a specific protection relay was installed to help overcome the protection settings issue. This relay has two sets of protection settings, one for when the CHPC unit is running and one for when the CHPC unit is not running.

Before proceeding with CHPC development in a specific industrial site distribution network, a detailed study of different combination of units, connection locations, CHPC sizes, type of loads and network assessment must be completed. Some of the calaculations within this document shall assist in the assessment of such installations.

Another reason why the use of distributed generation is increasing within industrial site distribution networks, is due to the emphasis put on energy savings and reducing organisations carbon footprint, particularly during the economic recession. CHPC is a useful way of harnessing energy created within a facility and utilising it to make both power, heating and cooling energy. Such economic savings and positive impact on the environment can be seen within the case study of this document.

For companies such as Vistakon, security and integrity of power supply is critical to their operations. While unable to supply Vistakon with the full facility energy needs, the installation of distributed generation into their industrial site distribution network lessons the impact of a power outage.

6 Bibliography

1. http://www.antaisce.org/transportenergy/Electricity/History.aspx
2. Power Distribution Planning Reference Book
3. Definitions for Distributed Generation;: a revision
4. SEI "A guide to connecting renewable and CHP electricity generators to the electricity network
5. SEI "Energy in Ireland 2011"
6. Schnedier Document
7. http://www.epa.ie/whatwedo/climate/thekyotoprotocol/
8. IEEE Recommended Practice for "Electric Power Distribution for Industrial Plants".
9. Energy Efficiency: Principles and Practices by Penni McLean-Conner
10. Keane, Andrew (2007), Integration of Distributed Generation, Philosophie Doctor Thesis, Dublin Institute of Technology
11. Eirgrid, System Demand document. www.eirgrid.com
12. Alexandra von Meier, "Electric Power Systems, A Conceptual Introduction", IEEE Press
13. Eirgrid Electricity Statistics January 2013 Report http://www.eirgrid.com/media/EirGridElectricityStatisticsJan2013.pdf
14. http://www.ceere.org/iac/iac_combined.html
15. A guide to Combined Heat and Power in Ireland. SEI publication
16. "A Novel method to Determine the Best Size of CHP for an Energy Hub System", A. Sheikhi, A.M. Ranjbar, F. Safe
17. "Power Systems of the Future", M. Rabinowitz, IEEE Power Engineering Rev 2000:20 (1):5-16
18. "Understanding Electric Utilities and De-regulation" Second Edition by Lorrin Philipson and H. Lee Willis

19. www.cer.ie

20. “Power Flow Calculation in Distribution Networks containing Distributed Generation”, Yang Wenyu *12, Yang Xuying *2, Duan Jiandong*2, Wan Xiaozhonq'", Fan Yue*

21. http://electrical-science.blogspot.ie/2010/04/transformer-tap-changer.html

22. “Distributed Generation: a Definition”, Electric Power Systems Research 57 (2001), pp.195-204. Thomas Ackermann, Goran Anderson and Lennart Soder

23. El-khattam, W. and Salama, M. M. A., 'Distributed Generation Technologies, definitions and benefits', *Electric Power Systems Research*, vol. 71, 2004, pp. 119–12.

24. “Current Technology of Fuel Cell Systems” by Ali T-Raissi, Arundhati Banerjee, Kenneth G. Sheinkopf

25. “Energy Systems and Sustainability”, 2nd Edition. Editted by Bob Everett, Godfrey Boyle, Stephen Peake and Janet Ramage

26. “Renewable and Sustainable Energy Reviews 13 (2009)” by Kirubakaran et al.

27. “Conditions Governing Connection to the Distribution System” by ESB Networks. Document ref. DTIS-250701-BDW

28. “Voltage rise the big issue when connecting embedded generation to long 11kV overhead lines”, C.L. Masters , IEEE Power Engineering Journal, Vol. 16, Issue 1, February 2002

29. IEC60909-2 “Electrical Equipment – Data for short circuit current calculations in accordance with IEC909”

30. “Calculating generator reactances”, Cummins Generation White Paper, by Timothy A. Loehlein. Available at : http://www.cumminspower.com/www/literature/technicalpapers/PT-6008-GeneratorReactances-en.pdf

31. “Short Circuit Currents” by J. Schlabbach – IEE Power & Energy Series 51

32. “Impact of High Penetration of CHP Generation in Urban Distribution Networks”, by Sreto Boljevic

33. IEC60909-0 Short circuit current calculation in a.c. system

34. IEC60909-1 Short circuit current calculation in a.c. systems Part 1: Factors for calculation of short circuit currents in three phase a.c. systems according to IEC909

35. IEC60909-2 Electrical equipment. Data for short circuit current calculations in accordance with IEC909 (1998)

36. IEC60909-3 Short circuit current calculation in a.c. systems Part 3: Currents during two separate simultaneous single-phase line-to-earth short circuits and partial short-circuit currents flowing through earth

37. IEC60909-4 Examples for the calculation of short circuit currents.

38. Effects of small embedded generation on Power Quality, IEE Colloquium on "Issues in Power Quality" by N Jenkins and G Strbac

39. Kirby, Brendan and Hirst, Eric, Ancillary Service Details: Voltage Control, The National Regulatory Research Institute Columbus, Ohio, U.S. Department of Energy, December 1997. Available at: http://www.ornl.org/sci/ees/etsd/pes/pubs/con453.pdf

40. Schavemaker, Pieter and Van Der Sluis, Lou, *Electrical Power System Essentials*, Wiley, pp 27 – 70, 2008.

41. Nasar, Syed A., Schaum’s Outline of Theory and Problems of Electric Machines and Electromechanics (Second Edition), MCGraw- Hill, pages 123 - 136, 1998.

42. HydroPowerStation.com, VAR of a System Balanced by Synchronous Generator and Synchronous Motor, HydroPowerStation.com, January 2011. Available at: http://hydropowerstation.com/?tag=power-factor

43. Distribution System Operator, *Distribution Code*, ESB Networks, V2.0, October 2007. Available at: http://www.esb.ie/esbnetworks/en/downloads/Distribution-Code.pdf

44. Wind Energy Direct website. Available at: http://www.windenergydirect.ie

45. Working Wind website. Available at: http://www.workingwind.com/what-are-the-parts-of-a-wind-turbine

46. Power Transformers, Principles & Applications by John J. Winders, Jr. ISBN: 0-8247-0766-4

47. "Directional Overcurrent Relaying (67) Concepts" by John Horak

48. "Distribution Code" by ESBI Networks. Version: V2.0

49. ABB Switchgear Handbook

50. "Noise Control with Concrete Masonry" (NCMA TEK13-2A) by National Concrete Masonry Association

51. SEI "An examination of the Future Potential of CHP in Ireland"

52. "Voltage Stability Analysis of an Urban Distribution Network (UDN) with High Penetration of Combined Heat and Power (CHP) Generation" by Sreto Boljevic

53. P. Kundur: Power: System Stability and Control, New York: McGaw Hill – 1994

54. Liam Buckley, Sreto Boljevic, Michael F. Conlon, "Impact of Combined Heat and Power (CHP), Plant on Small and Medium Size Enterprise (SME), Energy Supply used as Trigeneration."

55. https://www.epa.gov/chp/methods-calculating-chp-efficiency

56. https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_appendix_a_expressing_chp_efficiency.pdf

57. http://www.smartdraw.com/flowchart/flowchart-symbols.htm

58. http://www.breezetree.com/articles/what-is-a-flow-chart.htm

59. http://www.smartdraw.com/flowchart/flowchart-symbols.htm

60. http://www.breezetree.com/article-excel-flowchart-shapes.htm
61. ETSAP, Energy Technology Network analysis program, Technology Brief E04, May 2010
62. http://www.epa.gov/chp/project-development/stage5.html
63. https://www.carbontrust.com/media/19529/ctv044_introducing_combined_heat_and_power.pdf
64. P&ID Extract from Handover documentation of confidential client.
65. Review of Embedded Generation Interface Protection (EGIP) Requirements for the Irish Distribution System, Ken Atkinson, Fergus Malone
66. Vistakon CHP Unit Handover Manual
67. IEC 60038:2009
68. Integration of Distributed Generation in Low Voltage Networks: Power Quality and Economics by Konstantinos Angelopoulos
69. https://www.wbdg.org/resources/combined-heat-and-power-chp
70. Moneypoint Ash Storage Area Development

    ESB Power Generation and Wholesale Markets, Environmental Impact Statement, QS-000132-01-R001, Date: 13/06/2014; http://www.epa.ie/licences/lic_eDMS/090151b280553f2d.pdf

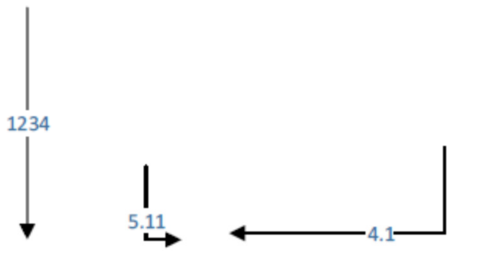
Appendix A
Flow Chart Development

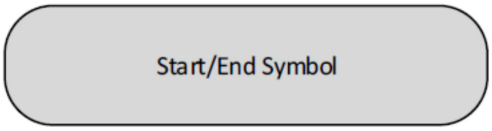
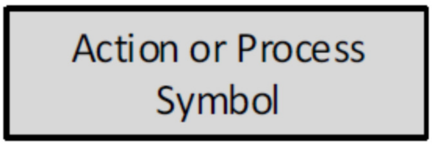
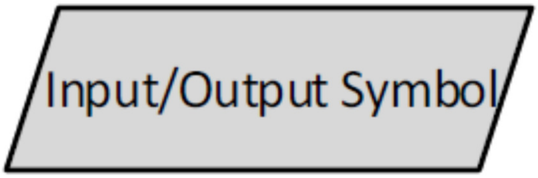
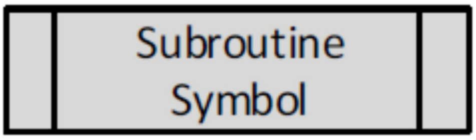
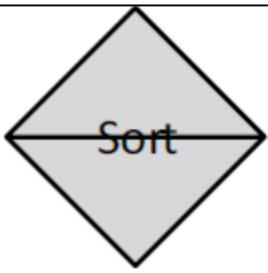
Flow Chart

A basic way to illustrate a model development for an algotritm is to use the flow chart system method. Within the engineering sector, this is a very popular way of illustrating a basic overview to a complex scenario or system.
Flow charts are made for a categorical overview of any type of process, CHPC, Power system analysis, etc. Flowcharts use special shapes or symbology to represent different types of functions as well as identifying different steps in the process. Lines and arrows indicate relationships between sequences. The type of diagram is show in a differenciated way by the symbols illustrated in reference no. 57.

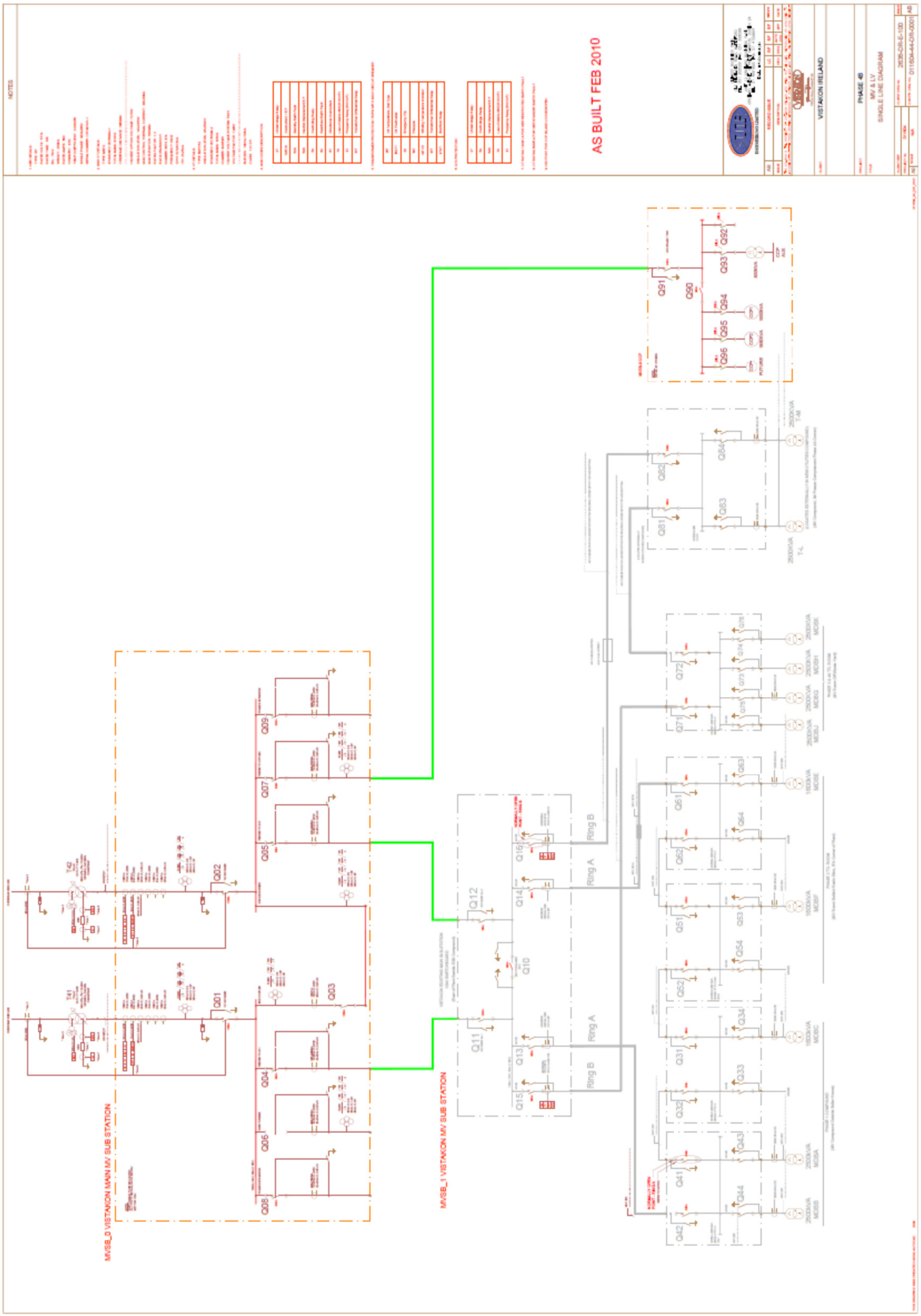
The official definition of a flow chart as stated in reference no. 58, is:
"A flow chart is a graphical or symbolic representation of a process. Each step in the process is represented by a different symbol and contains a short description of the process step. The flow chart symbols are linked together with arrows showing the process flow direction"

For a simple comprehension of the flow chart chart characterisitics, an explanation of the used symbols is shopwn in the table below. This symbology is officially used worldwide. 59, 60

Symbol	Definition
	A line is a connector that shows a relationship between the representative steps. The numbers are given connector a definition. If two arrows are combined, the numbers are connected and shown in the following arrow
	A broken connector shows the relationship between two main components (a combination of two

	sections)
	The terminator symbol marks the starting or ending point of the system. It usually contains the word “Start” or “End”.
	A box can represent a single step (“add two liters of diesel”), or an entire sub-process (“make electricity”) within a larger process
	Represents material or information entering or leaving the system, such as customer order (input) or a product (output).
	Indicates a sequence of actions that perform a specific task embedded within a larger process. This sequence of actions could be described in more detail on a separate flowchart.
	Indicates the sorting data, information, materials into some pre-defined order.

Appendix B
Vistakon Power Single Line Diagram



AS BUILT FEB 2010
VISTAKON IRELAND
PHASE 4B
MV & LV
SINGLE LINE DIAGRAM
MVSB_0 VISTAKON MAIN MV SUB STATION
MVSB_1 VISTAKON MV SUB STATION
Ring A
Ring B
Ring A
Ring B

Appendix C
Protection Relay Literature

Product Note

SACE Emax 2
Ekip Hi-Touch dual setting of protections

Data centers, hospitals, manufacturing plants, and many other facilities rely on backup generators to maintain continuity of electrical service when there is an unexpected power outage.

Due to the inherent differences between a utility supplied power source and an emergency generator the protective device current thresholds and settings that apply to the utility power may not be appropriate for the generator supplied power source.
The protective device would need to be reprogrammed or a separate protective device with different settings would need to be activated to adequately protect the generator and maintain continuity of service.

With the **Ekip Hi-Touch**, a powerful trip unit developed for **SACE Emax 2** air circuit breaker, continuity of service and selectivity can be maintained using the integrated dual setting feature.

With the dual setting feature two user selectable protective parameter sets are available; these two parameter sets are called Set A and Set B.
They are completely interchangeable and either can be configured as the default or alternate parameter set.

The dual setting feature can also add an extra level of protection against Arc Flash within a system.
When this feature is used in a switchgear, for example, it can be set to activate the second set of parameters that minimize protection delays if the switch gear door is opened. This can greatly reduce the risk of an operator being injured by an arc flash incident.
When this feature is activated it can be used to alternate between these two sets of protective parameters for:

Overload (L – ANSI 49)
Time delayed overcurrent (S – ANSI 51 & 50TD)
Thermal Memory
Instantaneous overcurrent (I – ANSI 50)
Closing on short circuit (MCR)
Ground fault (G – ANSI 51N & 50NTD)
Instantaneous ground fault (G – ANSI 50N)
Ground fault on toroid (Gext – ANSI 51G & 50GTD)
Neutral protection
Start-up function
Zone selectivity for functions S and G (ANSI 68)
Current unbalance (IU – ANSI 46)
Undervoltage (UV – ANSI 27)
Overvoltage (OV – ANSI 59)
Under-frequency (UF – ANSI 81L)
Over-frequency (OF – ANSI 81H)
Voltage unbalance (VU – ANSI 47)
Residual current (Rc – ANSI 64 & 50NTD)
Reverse active power (RP – ANSI 32R)
Syncrocheck (SC – ANSI 25, optional)
Cyclical direction of the phases (ANSI 47)
Power factor (ANSI 78)
Current thresholds
Power Controller function (optional)
2nd Time delayed overcurrent (S2 – ANSI 50TD)
2nd Instantaneous overcurrent (2I – ANSI 50)
2nd Ground fault (ANSI 50GTD/51G & 64REF)
Directional overcurrent (D – ANSI 67)
Zone selectivity for function D (ANSI 68)
2nd Undervoltage (UV2 – ANSI 27)
2nd Overvoltage (OV2 – ANSI 59)
2nd Under-frequency (UF2 – ANSI 81L)
2nd Over-frequency (OF2 – ANSI 81H)

The dual setting of protections is particularly useful in LV microgrids when they switch to stand-alone operation.

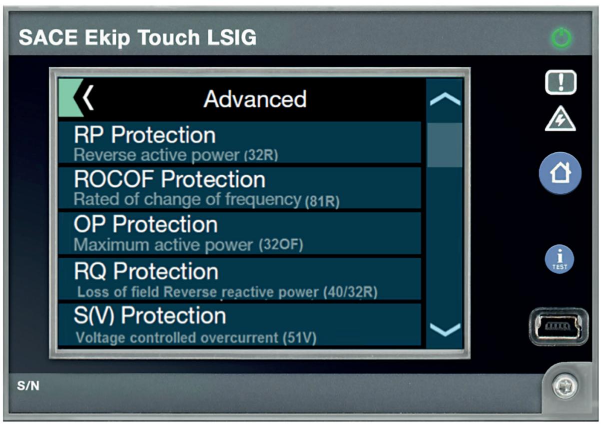
Power and productivity
for a better world™

SACE Emax 2
Ekip Hi-Touch dual setting of protections

Generator Safety

In addition to all of the powerful capabilities of the **Ekip Hi-Touch** trip unit, the **SACE Emax 2** air circuit breaker is also available with an **Ekip G Hi-Touch** trip unit.

This advanced trip unit has all of the same protective functions of the Ekip Hi-Touch trip unit but with even more specialized protective functions required by generators integrated into the **Ekip G Hi-Touch**, such as:
Voltage controlled overcurrent protection (S (V) – ANSI 51V)
2nd Voltage controlled overcurrent protection (S2 (V) – ANSI 51V)
Minimum current (UC – ANSI 37C)
Maximum residual voltage (RV – ANSI 59N)
Rate of frequency change (ROCOF – ANSI 81R)
Loss of field or reverse reactive power (RQ – ANSI 40 or 32RQ)
2nd Loss of field or reverse reactive power (RQ2 – ANSI 40 or 32RQ)
Maximum reactive power (OQ – ANSI 32Q)
Maximum active power (OP – ANSI 32P)
Minimum active power (UP – ANSI 37P)



These integrated generator protective functions can be used to replace costly and bulky external generator protective relays and wiring thus saving time and money for the equipment builder without sacrificing functionality.

For more information on how to apply Ekip G's generator protections see the "*Generators protection: Ekip G trip unit for SACE Emax 2*" white paper.

Selectivity

The dual setting feature can be used to maintain selective coordination within an electrical system. For example, if an emergency generator (backup power source) is activated because of loss of utility power from the grid, an alternate set of protection settings can be enabled automatically due to this event. The alternate settings can be optimized for the characteristics of the emergency generator which ensures the incoming supply and load side circuit breakers will remain selectively coordinated.

Under normal service conditions of the installation shown in Figure 1, the circuit breakers C are programmed to be selectively coordinated with the upstream main circuit breaker A, supplied by the utility grid, and the downstream load circuit breakers D. By switching from the utility power source to the emergency power source, circuit breaker B now becomes the upstream main circuit breaker on the supply side of circuit breakers C.

Circuit breaker B, being the main circuit breaker supplied by an emergency generator, must be set to current thresholds and tripping times that are suited to the characteristics of the generator and therefore the values of the parameter settings in circuit breakers C on the load side may not be selectively coordinated with circuit breaker B. By means of the "dual setting" function of the Ekip Hi-Touch trip unit, it is possible to switch the parameter set of circuit breakers C from a set which guarantees selectivity with circuit breaker A, to another set which guarantees selectivity with circuit breaker B.

Figure 1

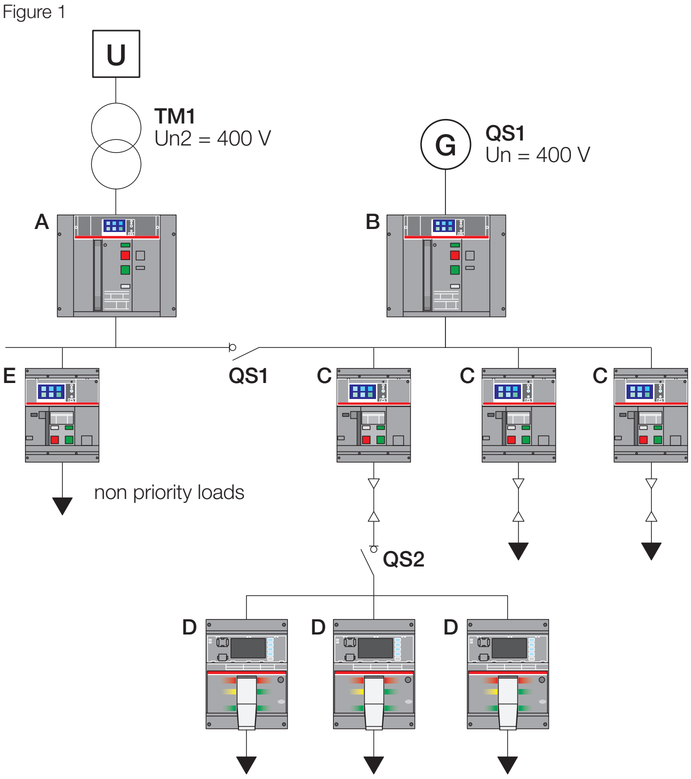
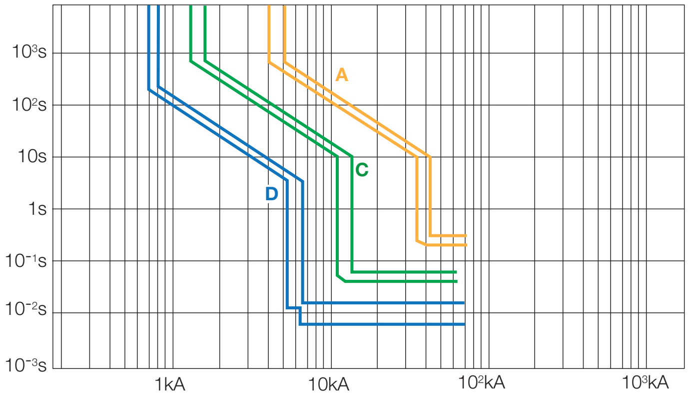


Figure 2 shows the time-current curves of the installation under normal service conditions. The current thresholds and time delay values set allow for a selectively coordinated system, no intersection of the time-current curves.

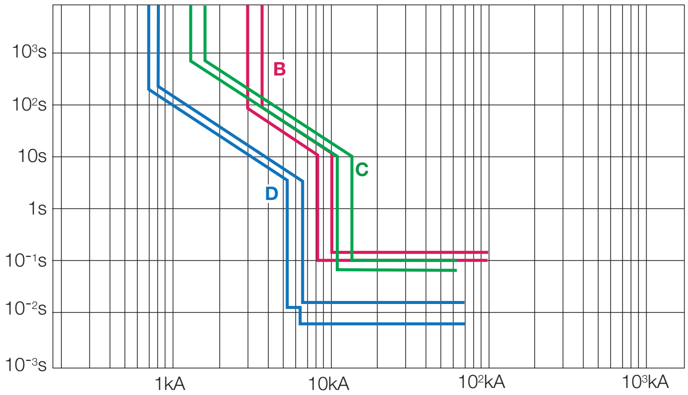
Figure 2



Time current curves

Figure 3 shows the situation in which, after switching, the power is supplied by the backup generator through circuit breaker B. If the settings of circuit breakers C are not modified, there will be no selectivity with the generator circuit breaker B.

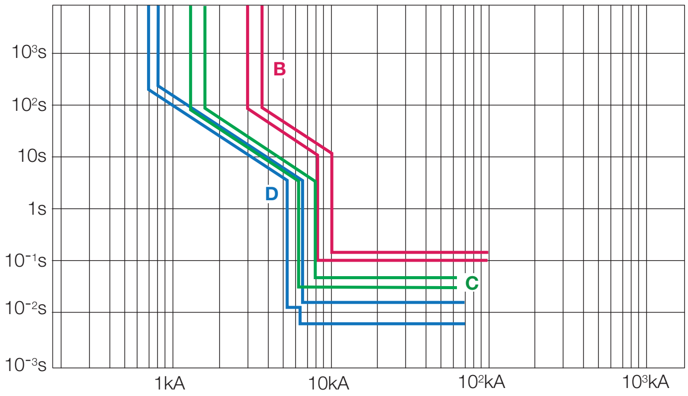
Figure 3



Time current curves

Figure 4 shows how it is possible to switch to a set of parameters which guarantees selective coordination between circuit breakers C and B by means of the "dual setting" function.

Figure 4



Time current curves

Methods to activate dual setting parameters

Activation of the alternate set of protection parameters on the Emax 2 Ekip Hi-Touch trip unit can be managed by:

– Digital input using an Ekip Signaling module;
– Communication network, by using one of the seven Ekip Communication protocols;
  - Modbus RS-485
  - Profibus
  - DeviceNet
  - Modbus TCP
  - Profinet
  - EtherNet/IP
  - IEC61850
– Directly from the Ekip Hi-Touch display;
– By a settable internal time, after circuit breaker closing

Conclusion

In an electrical installation it is very important to make sure that both personnel and equipment are protected and working under safe conditions. It is also important to make sure that your electrical system not only stays up and running during a power outage, but remains selectively coordinated for maximum continuity of electrical service. The Emax 2 Ekip Hi-Touch and Ekip G Hi-Touch trip units with dual setting feature can help make all of these possibilities a reality.

Contact us

For more information please contact:

ABB SACE
A division of ABB S.p.A.
L.V. Breakers
Via Pescaria, 5
24123 Bergamo - Italy
Tel.: +39 035 395 111
Fax: +39 035 395306-433
www.abb.com

1SDC200047L0201 - 01/2016

Power and productivity
for a better world™

Appendix D
Conference Paper

Impact of Combined Heat and Power Generation on an Industrial Site Distribution Network

Thomas Neally
Cork Institute of Technology, Ireland
Tom.Neally@pmgroup-global.com

Sreto Boljevic
Cork Institute of Technology, Ireland
Sreto.Boljevic@cit.ie

Michael F. Conlon
Dublin Institute of Technology, Ireland
Michael.Conlon@dit.ie

Abstract- **With the growing demand and cost of electric power in industrial networks, more and more companies are evaluating efficient ways to generate their own electricity. Sustainable energy and Combined Heat and Power and Cooling (CHPC) plants are seen as two ways to generate electricity on-site efficiently, depending on the application. Distributed generation (DG) plays a key role in companies reducing their maximum import capacity (MIC) hence reducing their electricity overheads. DG can be defined as electric power generation within distribution networks or on the customer side of the network. When DG is incorporated into industrial networks issues arise, this is due to the change of key parameters within the industrial site distribution network (ISDN) such as fluctuations in voltage levels, changes in short circuit levels and the operation of the network protection system during faults and disturbances. This paper studies the impact of such DG on a typical ISDN. A case study is carried out on the energy network of one of the worlds leading contact lens manufacturing facilities, located in the South of Ireland.**

Index Terms—**Combined Heat and Power, Impact of DG, Operation of CHPC, Protection Requirements**

I. INTRODUCTION

Due to the current economic climate, companies are forced to explore methods of saving money such as automation of processes, reduction of overheads etc. One large overhead for any production facility is their electricity, heating and cooling expenses. Many companies have been forced to rationalize the number of facilities, increase production in existing facilities and at the same time minimise their energy expenditure. This rationalization leads to an increase in electricity, heating and cooling requirements for the existing facilities. One option to offset the high cost of importing electricity, heating and cooling is to install a distribution generation unit and generate electricity on-site. This would involve the facility importing gas to produce electricity and utilising the waste heat from this process to cool water for the production process, on site. This process is carried out with the aid of a CHPC plant. The definition of CHPC is a small scale power generation technology that provides electric power and thermal energy at a site close a customer. [1] This paper studies the effects of the installation of DG into an existing ISDN. The energy network belongs to a contact lens manufacturing plant located in Limerick (in the South of Ireland). Vistakon Ireland is a subsidiary of Johnson & Johnson Vision Care, Inc. Established since 1995, the Limerick facility is the only Vistakon manufacturing site outside the U.S. Globally Vistakon are the largest producer of disposable contact lenses with ACUVUE as the leading product in the market. The facility in Limerick operates 24/7, 365 days of the year. The Vistakon site has over 30 production lines, these lines manufacture one-day, fortnightly, monthly and colour lenses that are shipped worldwide and utilize leading edge technologies in moulding, robotics, vision system and sterilization processes.

Within the manufacturing process on site there is a large electrical base load to be served, approximately 9MW and a large thermal chill load to be addressed in the form of cold water at 5ºC to serve process cooling requirements which will be derived from a single effect hot water absorption chiller. The thermal base load of the site is approximately 2500kW steam, 500kW Low Pressure Hot Water (LPHW) and 2000kW Chilled Water (CHW). The CHPC was envisioned to address only the last of these, namely the Chilled Water.

II. SITE DISTRIBUTION NETWORK SYSTEM OVERVIEW

The ISDN at the Vistakon facility is a robust, secure electrical network, it imports electricity from the national grid through 2 no. 38kV connections. These power supplies are taken from separate busbars at Ardnacrusha hydro electric power plant, also located in the south of Ireland. The power is transmitted from Ardnacrusha power station via an 110kV feeder to a 110/38kV substation, where it distributed to large industrial consumers at 38kV. The power supply is stepped down on-site by 2no 15/18MVA, 38/10.5kV, yNynO, star/star, step down transformers. This point is known as the point of common coupling (PCC). These transformers have an on-line tap changer of 11 taps on the secondary side. The tap changers are utilised for voltage control within the ISDN. The neutral points on the secondary winding of both 38/10.5kV transformers are brought to earth via neutral earthing resistors (NER). These transformers feed Vistakons 10.5kV Main Substation (MVSB_0), which consists of 2No. 1250A incomers, 1No. 1250A bus coupler and 6 No. 630A feeder breakers, 3 No. of which are in use, as shown in the Eracs network attached to this paper. 2 No. feeders in use feed Vistakons MV substation (MVSB_1), with the third feeder connected to the CHPC load centre (MVSB_9). There are 2 No. normally open ring main circuits distributed to substations around the site, 1 feeder of the each ring taken from the A and B side of substation busbar MVSB_1. Ring A consists of 4No. ring main units (RMU's) dispersed across the industrial site. These RMU's supply a total of 2 no. 2500kVA transformers and 3 no. 1600kVA transformers. Ring B consists of 2No. ring main units (RMU's) dispersed across the industrial site. These RMU's supply a total of 6 no. 2500kVA transformers. This ring normally acts as a radial circuit and has a normally open point located at MVSB-1. The third feeder from MVSB-0 is fed to the CHPC load centre on site (MVSB-9). This feeder breaker acts as an additional incomer, as power is generated from the CHPC units and fed into the ISDN at this point. The CHPC can run in parallel with one or both of the 10.5kV incomers. Prior to 2009 the Vistakon site had imported all of its electricity from the utility company (ESB) via the 38/10.5kV transformers however, now they have installed DG within their ISDN they need only import a fraction of their power from the local utility. This allows the site loads to be fed from a combination of utility and on-site generated power supplies. The CHPC operates in parallel with the ESB supply therefore both supplies have to operate in synchronism. A synchronisation panel and associated protection devices were installed at the site to facilitate parallel operation mode. The synchronisation panel also known as the "G10 protection panel" has to be installed as a requirement by the Distribution Network Operator (DNO). The CHPC units generate electricity at 10.5kV and distribute it to the industrial site network at this voltage. The CHPC units have a 10.5/0.4kV step down transformer located within MVSB_9 substation enclosure, this is to provide power to the auxiliary systems associated with the CHPC system. This cast resin transformer is has a rating of 800kVA. In the event of a loss of utility mains power supply the CHPC on-site must not feed into the grid network. The CHPC will carry out a controlled shut down of the plant to prevent the site operating in island mode. This situation is extremely unlikely to occur as the Vistakon site has two independent supplies from the utility company and it is unlikely both supplies would fail. For this reason, the implications of island mode are not discussed within this paper.

III. Operation of CHPC

The Vistakon facility has the ability to produce 2,950MW of electrical power at 10.5 kV. This power is generated by 2No. 1,850kVA natural gas fuelled power synchronous generators. An absorption chiller utilises the waste heat from the combustion engine to produce cold water for the production process.

Each plant consists of a gas engine which drives a synchronous generator, this generator in turn generates electrical power at 10.5kV. The gas engines on site are Jenbscher J420GS-A305 units, these are supplied by approximately 200mbar (+/- 10 mbar) of natural gas. The engines burn a mixture of natural gas and compressed air in a combustion chamber which drives a generator, which produces electricity. Each CHPC consists of a reciprocating engine that uses spark ignition (10 No. 40kV spark plugs) to produce mechanical work. Spark ignition (SI) engines use natural gas as the preferred fuel, although they can be set up to run on biogas or landfill gas. Reciprocating engines are well suited to DG applications as they are quickly started, follow load well, have good load efficiencies and are generally reliable. The gas engines drive the generators which in turn produces electricity to power the plant and chillers. These chillers cool the water to produce chilled water for the process. The CHPC unit is thermally led, therefore it provides chilled water and electricity proportionally to meet the site requirement. At 100% duty the CHPC can offset 2048kW of the site thermal base load. It is expected that this base load will be present the majority of time.

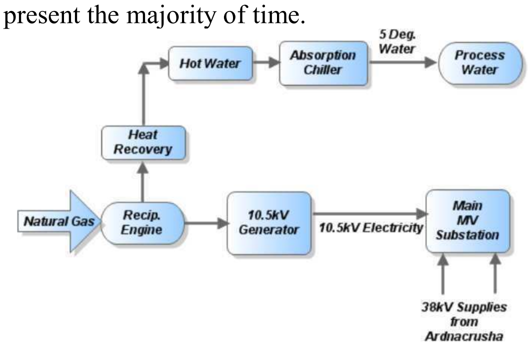


Figure 1. Illustration of Combined Heat and Power System

As shown above, the primary pieces of equipment within the CHPC process are the CHPC plant, the absorption chiller and the distribution system. The CHPC generation plant converts the natural gas input into useable electricity and heat. The absorption chiller is required for the purposes of converting the heat output from the CHPC into usable chilled water, and the distribution system for distributing the generated energy around the Vistakons site.

The CHPC plant generator is part of a skid mounted unit, the generator specification is as follows:

Generator Specification	
Type of Generation Plant	Gas Engine
Generator Type	Synchronous
Make / Version	AVR DIG 130-H4
Rated Power – kVA	1850
Power Factor	0.8
Power @ Power Factor 1.0 - kVA	1475
Full Load Current	100.7Amps
Synchronous Speed	1500 rpm 1/min
Protection Class	F
Enclosure Rating	IP23

Table 1. Generator Specification

The absorption chiller unit is also located within the CHPC container. The chiller operates with lithium bromide (LiBr) in water and uses the hot water provided by the CHPC at a temperature of approximately 80-90 degrees. The chillers have the capability of producing a cooling output of 2048kW, at a chilled water temperature of 5ºC, this represents approximately the base load CHW demand of the facility.

The single effect absorption cycle lithium bromide uses water as the refrigerant and lithium bromide as the absorbent. The process within the chiller is shown in figure 2, and is as follows: A dilute lithium bromide solution is pumped through the absorber shell and tube heat exchanger for preheating. After exiting the heat exchanger the solution surrounds a bundle of tubes which carry the hot water within the upper shell. The hot water transfers heat to the dilute lithium bromide, the solution boils sending refrigerant vapour into the condenser and leaves behind concentrated lithium bromide. This concentrated solution moves down to the heat exchanger where it is cooled. The refrigerated vapour condenses on the condenser tubes, due to the cool water passing through the tubes the heat is removed from the vapour. As the refrigerant condenses it collects in a trough at the bottom of the condenser. The refrigerant liquid moves from the condenser down to the evaporator and is sprayed over the evaporator tube. Due to the high pressure of the lower shell, the refrigerated liquid boils at approx 3.9C. As the refrigerant vapour migrates from the evaporator the strong lithium bromide solution from the generator is sprayed over the top absorber tubes. The strong lithium bromide solution pulls the refrigerant vapour into the solution, creating an extreme vacuum in the evaporator. The absorption of the refrigerant vapour into the lithium bromide solution also generates heat which is removed by the cooling water. The now dilute solution collects in the bottom of lower shell, where it flows down to the solution pump. The chilling cycle is now complete and the process begins once again. [2]

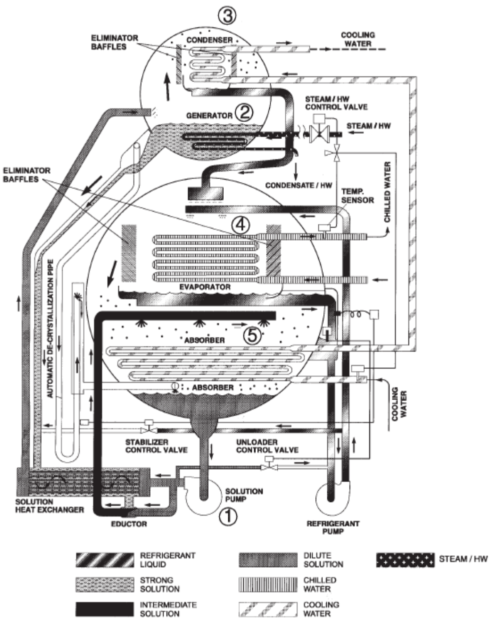


Figure 2. Internal Chiller Diagram

The CHPC is backed up by the plants original chillers. In the event the CHP can not satisfy the demand the original water cooled chillers shall operate. In the event of CHPC failure the original chillers will also operate. Steam would be produced by 3No. (1 duty/ 2 standby) gas fired boilers (each 5,000kg/hr). The LPHW is produced in various ways, a) 420kW gas fired condensing boiler, b) Steam to LPHW heat exchangers, c) 270kW LPHW generated via heat recovery compressors, d) 500kW electric heat pump taking its heat from cooling tower water. Chilled water can be produced by 5 No. on-site chiller units of varying size and capacity. There are 2No. 1470kW chillers (Duty/Standby arrangement), 2No. 1322kW, 1No. 2272kW and 1No. 2000kW.

The energy balance of a CHPC scheme located on an industrial site is formulated for each energy as follows [3]:

$$\begin{aligned} &\mathit{Electricity}:\ E_{elec} + \sum E_{CHP} = \sum E_{RE} + E_d \\ &\mathit{Exhaust\ Gas}:\ \sum Q_{CHP} = Q_{disp} + \sum Q_{CHPRB} \\ &\mathit{Steam}: \sum C_{RB} + \sum C_{HB} = \sum Q_{RS} + H_d \\ &\mathit{Cold\ Water}: \sum C_{RS} + \sum C_{RE} = C_d \\ &\mathit{Natural\ Gas}\ F_{Gas} = \sum F_{CHP} + \sum F_{HB} \end{aligned}$$

RE - Electricity Compression Refrigeration
E_d, H_d – Electricity, Heating Load
RB – Waste Recovery Boiler
RS – Steam Absorption Refrigerator
HB – Gas Fired Auxiliary Boiler

IV. Implications of Introducing CHPC into An IDSN

There are a number of implications with regards the installation of DG into an industrial site distribution network, these can be put into three main headings a) economic issues, b) environmental issues, c) technical issues. It would be common practice to carry out a feasibility study to investigate what impacts the proposed installation will have on the plant at concept stage of the project.

A) Economic Issues

When making a decision to invest large capital into a facility the client must ensure the project is economically viable. From an economic perspective two calculations that should be carried out are when assessing the viability of installing DG are i) comparison between importing electricity for 1 year against generating electricity for 1 year, ii) a payback period must be calculated and this should be within the operational lifetime of investment. When carrying out the afore mentioned calculations it is important to note that there are three shifts in the Vistakon site. The calculations below are divided up into the day shifts, of which there are two and the night shift. The reason the shifts are broken out into day and night is due to the fact it is cheaper to buy electricity from the utility company at night during low power demand than during the day when there is maximum demand on the network. The tariffs given in this paper are fictional values for confidentiality reasons. The daytime tariff is given as 0.099 euro per kW and 0.078 euro per kW for night time tariff. The price of gas fluctuates depending on a number of market conditions, I have chosen a value of 0.0259 euro per kWh as the price of natural gas. This value was an average value calculated from the cost of gas during a 21 month period between 2005 and 2007.

Electrical Power Day Shift Cost

$2950\text{kW} \times 16 \times 7 \times 50 = 16{,}520{,}000\text{kW}$ per Year

Assume 95% availability (18 days per year downtime)

$16{,}520{,}000\ \text{kW} \times 0.95 = 15{,}694{,}000$

Sub total €/kWh Tariff $= 0.099 \times 15{,}694{,}000 =$ €1,553,706 per year

Electrical Power Night Shift Cost

$2950\text{kW} \times 8 \times 7 \times 50 = 8{,}260{,}000\text{kW}$ per Year

Assume 95% availability (18 days per year downtime)

$8{,}260{,}000\text{kW} \times 0.95 = 7{,}847{,}000$

Sub total €/kWh Tariff $= 0.078 \times 7{,}847{,}000 =$ €612,066 per year

Chilled Water Production Day Shift Power Cost

2024kW is the size of the proposed chiller capable of supplying sufficient chilled water to the process on a daily basis.

$2024\text{kW} \times 16 \times 7 \times 50 = 11{,}334{,}400\text{kW}$ per Year

Assume 95% availability (18 days per year downtime)

$11{,}334{,}400 \times 0.95 = 10{,}767{,}680$

The coefficient of performance (COP) is a basic parameter used to report the efficiency of refrigerant based systems. The COP is the ratio between useful energy acquired and energy applied. In the case of Vistakon the COP of the chiller unit has been advised as 6.6. This information was given as part of the chiller handover documentation. To calculate the billable kWh one has to divide the COP into the total kWh for chilled water production: $\frac{10{,}767{,}680}{6.6} = 1{,}631{,}466.67$

Sub total €/kWh Tariff = 0.099 x 1,631,466.67 = €161,515.2 per year

Chilled Water Production Night Shift Power Cost

$2024\text{kW} \times 8 \times 7 \times 50 = 5{,}667{,}200\text{kW}$ per Year

Assume 95% availability (18 days per year downtime)

$5{,}667{,}200 \times 0.95 = 5{,}383{,}840$

To calculate the billable kWh one has to divide the COP into the total kWh for chilled water production:

$$\frac{5{,}383{,}840}{6.6} = 815{,}733.33$$

Sub total €/kWh Tariff = 0.078 x 815,733.33 = €63,627.2 per year

Total Input of Electrical Power:

$\text{Total Input } € = 1{,}533{,}706 + 612{,}066 + 161{,}515.2 + 63{,}627.2$

$\text{Total Input} =$ €2,370,914.4

CHPC Power Cost

$\textit{CHP kW Output}\ 1475kW \times 2 = 2{,}950kW$

$2950kW \times 24 = 70{,}800kW\ hrs$

$70{,}800 \times 7 = 495{,}000kW\ \textit{per Week}$

Annual Cost @ 50 weeks per year

$495{,}600 \times 50 = 24{,}780{,}000$

Assume 95% availability (18 days per year downtime)

$24{,}780{,}000 \times 0.95 = 23{,}541{,}000\ \textit{kWhrs per year}$

Total €/kWh Tariff = 0.0259 x 23,541,000 = €609,711.9 per year

This equates to the potential net savings per annum:

€2,370,914.4 – €609,711.9 = €1,761,202.5

To carry out a simple method of calculating the payback period for the investment, one must first calculate the magnitude of the initial investment. For confidentiality purposes an order of magnitude capital cost of €3,000,000 is used in this calculation.

In Vistakons case their potential payback period would be approximately: $\frac{3{,}000{,}000}{1{,}761{,}202.5} = 1.7033\ \textit{years}$

B) Environmental Issues

There are a number environmental issues associated with the production of electricity. The primary issue that is commonly identified is the emission of greenhouse gases such as CO_2. Each year the "Commission for Energy Regulation" (CER) and "Sustainable Energy Ireland" (SEAI) publish electricity emission factors. Within CER's "Fuel Mix Disclosure and CO_2 Emissions 2010" report, the average CO_2 emissions from the production of electricity between all the energy suppliers was 50 gCO_2/kWh. [4] CO_2 emission factors for electricity vary from year to year depending on the fuel mix used in power generation, for example, if there was alot of rainfall throughout a year the average CO_2 emissions would be lower because more hydro electricity would be produced and this generates a lower carbon footprint than burning fossil fuels to generate electricity. Typically, with conventional electricity generation, 60% of the input energy is lost with just 40% being transformed into electricity. [5] Also, due to the centralised generation of electricity, losses in the order of 5-7% are incurred through the transmission and distribution system, in comparison with on-site generation and distribution of electricity. In order for the CHPC plant at Vistakon site to produce 25404MWh of electrical energy and 28908MWh of thermal energy it requires 61162.6MWh of natural gas. During this energy generation by the CHPC plant 3058.13 tonnes of CO_2 emissions would be generated. If Vistakon were to purchase this electricity from the utility supplier, this would generate 3060.7 tonnes of CO_2 emissions and in addition to that, the generation of thermal energy from the on-site boiler, with an efficiency of 90%, would produce 28908MWh of thermal energy and would generate 1606 tonnes of CO_2. This means by employing the CHPC unit to generate electricity and thermal energy on-site generates a reduction of CO_2 emissions of 1608.57 tonnes of CO_2.

V. CHPC PERFORMANCE

The overall performance and efficiency of the CHPC system is extremely important to ensure the installation is economically feasible. The CHPC within the Vistakon facility is imperative as it produces approximately 30% of the electrical energy demand and over 90% of the chilled water demand of the facility. In order to evaluate the performance of the CHPC over a period of time, data was collected from the facility and extrapolated to investigate annual efficiencies and savings. The data was tabulated and the following calculations used to assess the following: Electrical efficiencies, thermal efficiencies, total efficiency, fuel utilization effectiveness, heat to power ratio, percent fuel savings and savings in the emission of greenhouse gases, according to the following expressions:[10]

Where P = Nett electrical energy output

Q = Nett thermal energy output

F = Total fuel energy input

EEF_Q = Efficiency of displaced thermal generation

i.e. typical boiler efficiency EEF_Q=90%
EEF_P = Efficiency of displaced electrical generation
i.e. typical electrical utility efficiency EEF_P=38%
(d = per day, m = per month, y = per year)

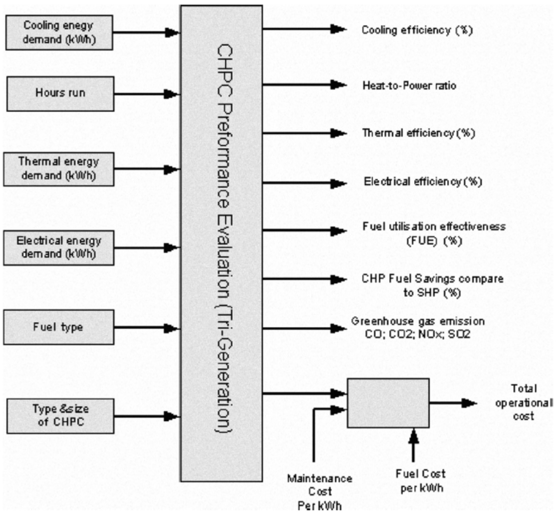


Figure 3. CHPC Tri-generation Block Diagram

A) Electrical Efficiency

$$\eta_{P\,d,m,y} = \frac{\sum_i P_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\%$$

P = 25404MWh; F = 61162.66MWh;
Therefore the electrical efficiency is 41.5%

B) Thermal Efficiency

$$\eta_{Q\,d,m,y} = \frac{\sum_i Q_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\%$$

Q = 28908MWh; F = 61162.66MWh;
Therefore the thermal efficiency is 47.2%

C) The CHPC Total Efficiency

$$\eta_{T\,d,m,y} = \frac{\sum_i P_{d,m,y} + \sum_i Q_{d,m,y}}{\sum_i F_{d,m,y}} \times 100\%$$

P = 25404MWh; F = 61162.6MWh; Q = 28908MWh;
Therefore the overall efficiency is 88.8%

D) Fuel Utilization Effectiveness

$$FUE_{d,m,y} = \frac{\sum_i P_{d,m,y}}{\sum_i F_{d,m,y} - \frac{\sum_i Q_{d,m,y}}{EFF_Q}} \times 100\%$$

P = 25404MWh; F = 61162.6MWh; Q = 28908MWh;
EFF_Q= 90%

Therefore the annual fuel utilization effectiveness is 87.4%

E) Percentage Fuel Savings

$$S_{d,m,y} = 1 - \frac{\sum_i F_{d,m,y}}{\frac{\sum_i P_{d,m,y}}{EEF_P} + \frac{\sum_i Q_{d,m,y}}{EEF_Q}} \times 100\%$$

P = 25404MWh; F = 61162.6MWh; Q = 28908MWh
EFF_Q= 90%; EFF_P= 38%
This gives a CHPC Percentage Fuel Saving of 41.3 %

F) Heat to Power Ratio

$$X_{d,m,y} = \frac{\sum_i Q_{d,m,y}}{\sum_i P_{d,m,y}}$$

P = 25404MWh; Q = 28908MWh
This gives a CHPC Heat to Power Ratio of 1.13

VI. Technical Issues of Introducing DG into a IDSN

There are many technical issues, both positive and negative in relation to the introduction of DG into an ISDN. DG may contribute significantly to the fault current, cause voltage flickers, interfere with the process of voltage control, affect the losses of the network etc. [6]

A) Short Circuit Current

The short circuit current must be calculated for each part of the network examining all possible network configurations, to determine the optimum equipment rating required to withstand or break the perspective fault current.

There are various types of short circuit current, generally 3 phase short circuit currents are the highest fault currents to flow in the event of a fault. [8] There are 2 values of short circuit current that must be investigated, maximum and minimum. The maximum short circuit current is the main design criteria for the rating of equipment to withstand the effects of short circuit currents, such as thermal and electromagnetic effects. The minimum short circuit current is needed for the design of protection systems and the minimal setting of protection relays. [7] When short circuit current faults occur damage may be caused to the insulation of cables/equipment, fire, deformation of busbars and switchgear. [8] When a fault occurs in an ISDN the fault current will converge on the fault location. The magnitude of the fault current shall depend on a number of conditions, these include the location of the fault, the further away the fault is from the generated power and the imported power the larger the impedance thus the lower the fault current, the operation mode of the system, i.e. parallel or island mode, and the type of fault, i.e. 3 phase, line to earth, etc. The normal running mode of the Vistakon facility is parallel operation of the utility supply and the CHPC installation. If a fault were to occur within the ISDN then the utility supply, CHPC generators and motive power would all contribute to the magnitude of the fault current. Initially the ISDN would have been designed to carry the fault level of the utility supply and the motive power contribution. However, due to the addition of DG the short circuit level has now been increased.

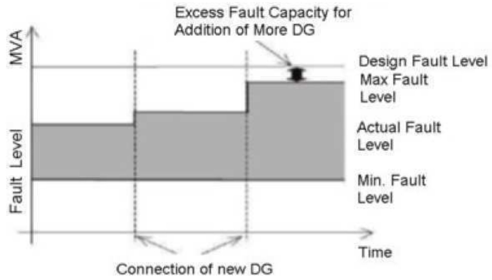


Figure 4. Diagram Depicting Additional Short Circuit Capacity

A simulation of the Vistakon ISDN was created using Eracs power system analysis software. The contribution of short circuit currents from DG can be seen within table 4. The results illustrate an increase of approximately 2.3kA to the Vistakon ISDN fault level. This has no appreciable effect to the thermal capacity of the primary MV switchgear, as this has a thermal withstand rating of 25kA, however, it may result in failure of other circuit breaking devices or conductors within the network. One contributing factor to the relatively small contribution of the generator to the short circuit is the magnitude of the sub transient reactance (X''_d) of the generator. In Vistakons case the X''_d of the generator is 0.182. A generators reactance is so large in comparison to its resistance that the resistance can be disregarded when examining at the total impedance of the generator. The amount of current that will flow as a result of a short circuit is determined by a generators reactance.

Table of Generator Reactances				
Name	*Symbol*	*Range*	*Importance*	*Approx. Time Effective*
Sub-transient Reactance	X"d	.08 to .26	Determines max. inst. current	1 to 6 cycles
Transient Reactance	X'd	.16 to .45	Determines current when breaker opens	6 cycles to 5 sec.
Synchronous Reactance	Xd	2.0 to 3.9	Determines steady state current	continuous after 5 sec.

Table 2. Diagram Depicting Additional Short Circuit Capacity

Synchronous reactance determines the steady state current, however, when a sudden change from steady state occurs, such as a short circuit, other reactance's come into play. This happens because the flux of the machine can not change immediately. Table 2 illustrates the range and importance of the primary reactances of a generator.

A full short circuit study should be carried out to ensure other electrical equipment such as power cabling and sub distribution boards are sufficiently rated to withstand this increased fault level. In addition, CHPC plants are usually connected to the network at low voltage, this is primarily driven by the capital expenditure of the CHPC unit, as previously stated, this is not the case in Vistakon.

The protection of the ISDN has to be guaranteed at all times. Traditionally protection systems assumed the power flow was from the grid down to the low voltage network in a unidirectional way. With the introduction of DG the power flows are changed. In a fault situation the DG may send power upwards on the connecting feeder, the current shall be increased by the DG and this may cause unwanted or inaccurate operation of protection devices, in some cases. One possible scenario which could occur is as follows. If a fault were to occur on a feeder fed from the same substation as the DG, the DG will contribute to the fault and feed the fault current towards the fault point. The fault current will as a result have an upwards direction on the DG feeder, which in turn will flow through the substation upstream and onto the location of the fault. If the direction of the current is not detected by the feeder relay, the DG feeder may operate unnecessarily due to the contribution of the DG. One way to overcome this mal-operation of the protection system is to introduce a more active form of protection system with some form of communication to ensure a high level of protection is maintained. [9]

B) Voltage Profile

The introduction of DG may cause local voltage levels to rise on interconnected networks. This can create issues for the generation site, the network operator (ESB Networks in Ireland) and for other power consumers within that network. Circuits supplying both power consumers and generation sites can only accommodate small amounts of export capacity. Generators connected to both 10/20kV and 38kV networks are subject to tolerances of voltage rise within the network. The following table illustrates the permitted voltage rise on the distribution network for shared and dedicated circuits.

Voltage Level	Limit for Shared Circuit	Limit for Dedicated Circuit
MV (10/20kV)	1% at POC of load share, with additional 2% at generation site	Total of 3% rise at generation site
38kV	1.5% at POC of load share, with additional 2% at generation site	Total of 3.5% rise at generation site

Table 3. Maximum Voltage Limits for Percentage Voltage Rise in Circuits

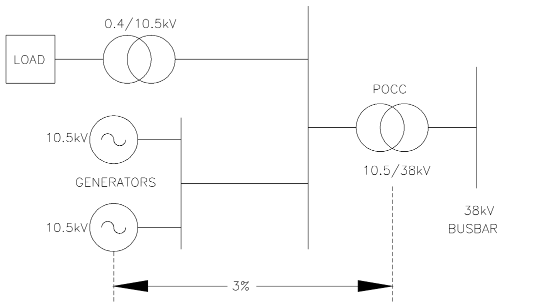


Figure 5. Illustration of Voltage Rise permitted on 10/20kV Dedicated Circuit

The DG within the Vistakon ISDN does not cause the utility companies voltage level to rise, this is due to the site not exporting electricity to the national grid. The tap changer on the secondary side of the incoming transformers monitors and controls the voltage level within the ISDN. It is evident from table 4 that the electrical system in Vistakon is quite strong, as the voltage drop across the system is minimal. This is in part due to the location and size of the main 38/10.5kV 15/18 MVA transformers as well as the steady energy demand of the facility.

VII. Protection Requirements By DNO

There are a number of requirements for the connection of DG into an ISDN by the DNO. These requirements are presented in a document entitled "Conditions Governing Connection to the Distribution System". This document is referenced in the distribution code and sets out the requirements for customer equipment at the interface between the distribution system and the customers installation, it also outlines the protection setting parameters required for such installations. The purpose of these requirements is to protect the personnel and plant of both the utility provider and the customers from any adverse effects caused by the connection of distributed generation. The protection characteristics required by the code could be summarised as being:

1. Under and Over voltage protection
2. Under and Over frequency protection
3. Directional Overcurrent protection
4. Loss of mains protection
5. Earth fault protection
6. Relay DC Supply protection
7. Trip Circuit Supervision protection

VIII. Conclusion

The integration of CHPC energy is a necessity for any company aiming to minimise their carbon footprint, assuming the site has both a constant electrical and thermal demand. The introduction of such DG has many impacts both positive and negative. Significant reduction of the CO_2 emissions from the plant as shown in the case of the Vistakon plant and reduced energy costs are the primary positive impacts. However, the positives are offset by negative impacts such as an increased short circuit level within the ISDN, which could lead to additional capital expenditure on the upgrading of site electrical infrastructure, potentially higher network voltage levels and the reco-ordination of protection relay settings within the ISDN. The case study ISDN discussed within this paper was found to have a robust, secure, ISDN and has the capacity to be expanded further if required. The sites electrical infrastructure shows the design of future planning, as the capacity in both transformer rating and the MV switchgear rating leaves room for the addition of increased DG and increased load within the network.

References

[1] Sreto Boljevic, Michael F. Conlon."Impact of High Penetration of CHP Generation on Urban Distribution Networks". UPEC 2008, Padova, Italy.

[2] York Millennium, YIA Single Effect Absorption Chiller

[3] Zhang Beilong, Long Weiding, "An Optimal Sizing Method for Cogeneration Plant ," Energy and Buiding, Science@Direct, 2005

[4] Commission for Energy Regulation, "Fuel Mix Disclosure and CO_2 Emissions 2010"

[5] SEAI, "Energy in Ireland 1990-2010 (2011 Report)"

[6] Salman K. Salman, Ibrahim M. Rida, "Investigating the Impact of Embedded Generation on Relay Settings of Utilities Electrical Feeders," IEE Transactions on Power Delivery, Vol. 16, No. 2, April 2001

[7] J Schlabbach, "Short Circuit Currents," IEE Power & Energy Series 51.

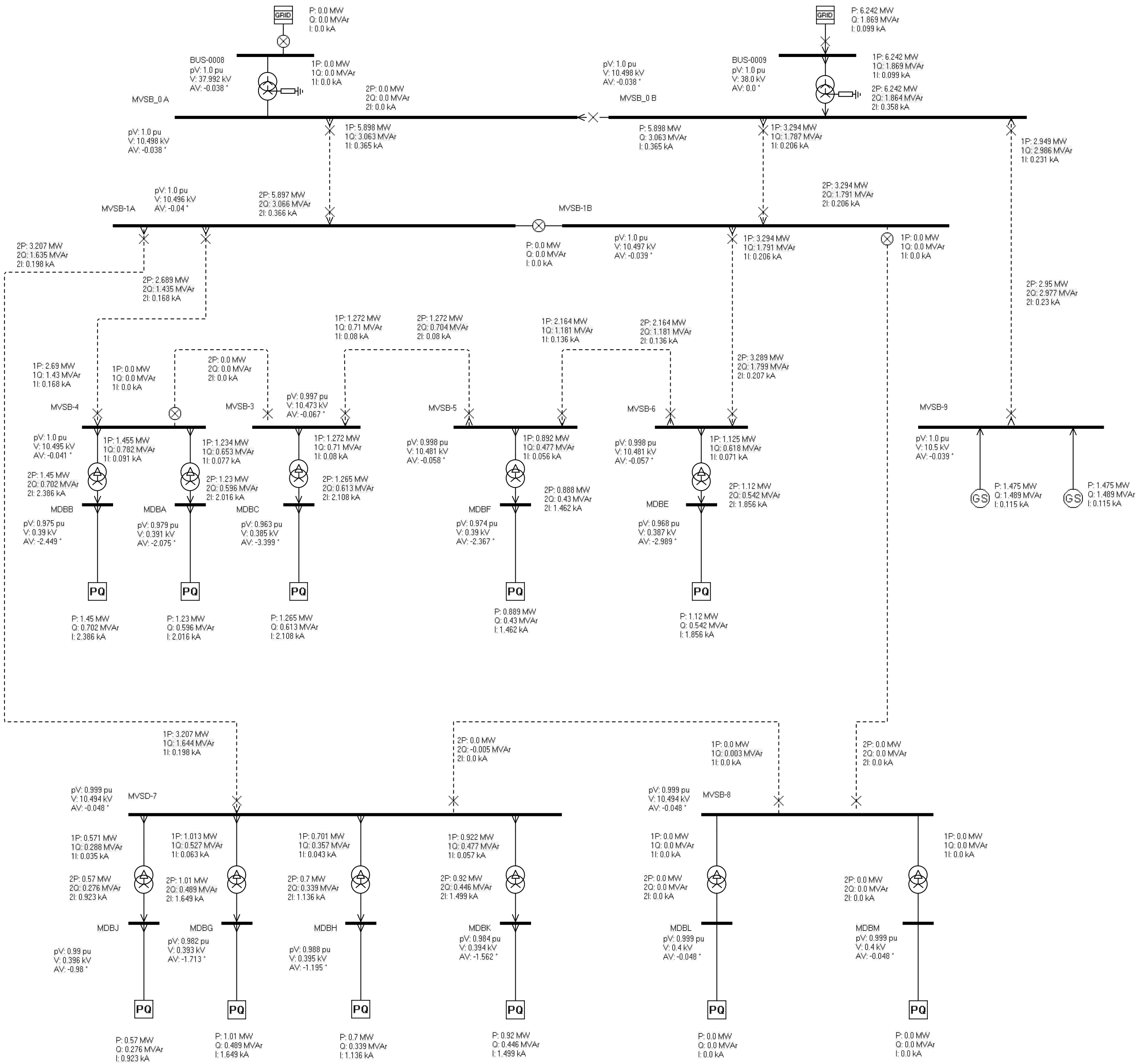
[8] B. De Metz-Noblat, F. Dumas, C. Poulain "Calculation of Short Circuit Currents", Schneider Electric Cashier technique no. 158.

[9] Sreto Boljevic, Michael F. Conlon, "Fault Current Level Issues for Urban Distribution Network with High Penetration of Distributed Generation,"

[10] Liam Buckley, Sreto Boljevic, Michael F. Conlon, "Impact of Combined Heat and Power (CHP), Plant on Small and Medium Size Enterprise (SME), Energy Supply used as Trigeneration."

Network Voltage Nom. Load	MVSB_0	MVSB_1	MVSB_3	MVSB_4	MVSB_5	MVSB_6	MVSB_7	MVSB_8
CHPC & ESB (kV)	10.499	10.499	10.494	10.499	10.496	10.496	10.498	10.498
ESB Supply (kV)	10.499	10.499	10.494	10.499	10.496	10.496	10.498	10.498
Network Voltage 20% Load	**MVSB_0**	**MVSB_1**	**MVSB_3**	**MVSB_4**	**MVSB_5**	**MVSB_6**	**MVSB_7**	**MVSB_8**
CHPC & ESB (kV)	10.494	10.493	10.47	10.492	10.477	10.478	10.491	10.491
ESB Supply (kV)	10.494	10.493	10.47	10.492	10.477	10.478	10.491	10.491
3Ph. PSCC Nom. Load	**MVSB_0**	**MVSB_1**	**MVSB_3**	**MVSB_4**	**MVSB_5**	**MVSB_6**	**MVSB_7**	**MVSB_8**
CHPC & ESB (kA)	15.465	15.4	12.75	15.304	14.13	14.164	15.105	15.066
ESB Supply (kA)	13.079	13.032	11.102	12.964	12.119	12.144	12.821	12.794
3Ph. PSCC 20% Load	**MVSB_0**	**MVSB_1**	**MVSB_3**	**MVSB_4**	**MVSB_5**	**MVSB_6**	**MVSB_7**	**MVSB_8**
CHPC & ESB (kA)	15.461	15.365	12.733	15.298	14.113	14.147	15.098	15.059
ESB Supply (kA)	13.074	13.027	11.085	12.957	12.103	12.128	12.814	12.786

Table 4. Voltage Profile & Short Circuit Results extracted from Eracs Model



Vistakon Site Distribution Network			Date: 03/05/2012	
Tel: Fax: Email:	Produced on ERACS software from ERA Technology Ltd, Leatherhead, KT22 7SA, UK	Network for Vistakon	Drn: T. N.	Chkd: S.B. Iss: T.N.
			Drg No: IE0310001-44-DR-0001	