Induced currents in gas pipelines due to nearby power lines

Dejan Markovic
University of Wollongong

Induced Currents in Gas Pipelines due to Nearby Power Lines

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Dejan Markovic, BEng

School of Electrical, Computer and Telecommunications Engineering

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CERTIFICATION

I, Dejan Markovic, declare that this thesis, submitted in partial fulfilment of the requirements for the award of Masters by Research, in the School of Electrical, Computer and Telecommunications Engineering, University of Wollongong, is wholly my own work unless otherwise referenced or acknowledged. The document has not been submitted for qualification at any other academic institution.

Dejan Markovic

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Abstract

Significant voltage levels can be induced in gas pipelines due to power lines in areas where they share the same corridor, especially during a fault. These voltages can affect the operating personnel, pipeline-associated equipment, cathodic protection systems and the pipeline itself. Quite often, mitigation is required to reduce these induced voltages to levels that are safe for personnel and integrity of the pipeline. This thesis investigates and evaluates the performance and capabilities of two software packages that have been developed to calculate and manage induced voltages on pipelines, PRC and CDEGS. As it was the superior package, CDEGS and the interference analysis based on it is presented in detail.

The complete interference analysis, including steady state and fault conditions, was performed on the Young-Lithgow pipeline and power line shared corridor. It is shown that pipeline coating stress voltages in excess of levels recommended by the CDEGS procedure may exist for faults on particular power lines. Possible remedial measures are suggested.

Subsequently, the existing mitigation system on the Brisbane pipeline, employing insulating joints with permanent earths, is assessed using CDEGS. It is shown that this mitigation is sufficient in regard to controlling pipeline coating stress voltages. Touch voltages on three test points are in excess of levels allowed by IEEE recommendations, but still within levels allowed by Australian Standards.

The same pipeline layout is used to analyse the hypothetical case of a mitigation system implemented with zinc gradient control wire. While the pipeline coating stress voltages are within recommended limits, only one test point touch voltage is in excess of IEEE recommendations and again all are within Australian Standards limits.

Apart from performance, the two mitigation methods are compared in terms of cost of installation and other features. It is concluded that despite the lower costs of installation of a system with insulating joints, some other features and costs associated with maintenance of the two compared systems favoured the gradient control wire method and made it the preferred method for mitigation of induced currents in pipelines for many configurations.

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Chapter 1

Introduction

1.1 Statement of the Problem

Sharing of common corridors by gas pipelines and overhead power lines is becoming quite common. Voltages can be induced in gas pipelines due to power lines in areas where they share the corridor. These voltages can affect the operating personnel, pipeline associated equipment and pipeline cathodic protection systems. As a consequence, integrity and safety of the pipeline may be jeopardized, leading to high maintenance and repair costs to the pipeline owners. There is an industry wide need to increase the understanding of the process of interaction between power lines and nearby pipelines and the mitigation of resulting effects. For this purpose, the performance and capabilities of PRC [1] and CDEGS [2] software will be examined. There are several different mitigation strategies and this research aims to examine and compare the performance of the gradient control wire method with the method using insulating joints, when used for mitigation of induced voltages on pipelines. The results of this case study comparison may be used as a guideline for designing new pipelines in the future.

1.2 Objectives of the Thesis

The prime objective of the work presented in this thesis is to study the electrical interference taking place between power lines and two of the Agility [3] owned natural gas pipelines.

1. Specific objectives of Case Study 1, Young-Lithgow pipeline:

    - To carry out pipeline and power line interference studies using CDEGS software
    - To examine the interference at both steady state and during fault conditions and compare results with applicable Standards for compliance
    - To analyse the pipeline cathodic protection level logs

2. Specific objectives of Case Study 2, Brisbane pipeline:

    - To analyse the current pipeline mitigation design that has insulating joints by examining the interference under both steady state and during fault condition and compare results with applicable Standards for compliance
    - To develop a pipeline mitigation system design employing gradient control wire
    - To analyse the current cathodic protection system on the pipeline and design a cathodic protection system based on gradient control wire
    - To compare mitigation and cathodic protection performance and system costs based on insulating joints and gradient control wire systems

1.3 Summary of the Research Methodology

The basic research methodology flowchart is given in Figure 1.1 of which a more detailed description is given in Chapter 3.

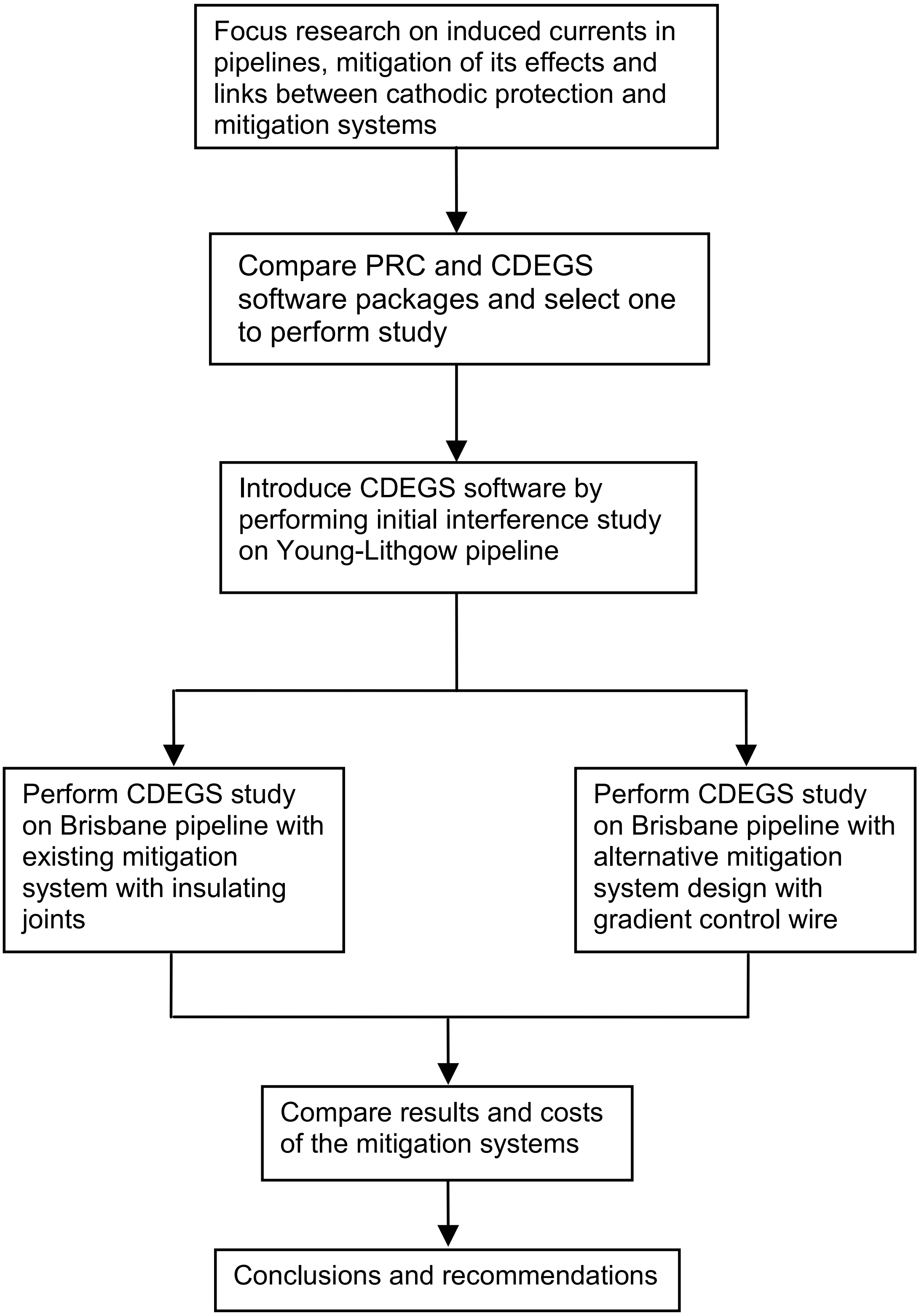

Figure 1.1: Flowchart of the research methodology

1.4 Limitations of the Study

1.4.1 Limitations of Software

This study was carried out using CDEGS software modules that are based on a circuit approach. In a circuit approach the magnetic field discontinuity at the fault location of a power line and at the pipeline ends is not taken into account. Modelled conductors are assumed to be of infinite length and parallel during computation of their parameters. The field approach (based on Maxwell equations) takes into account these magnetic field discontinuities and produces more accurate results [4]. Under remote power line fault conditions, the calculated induced potentials in the pipeline by the circuit and the field approach may differ by up to 9% for a 2 km parallel length, whereas for a long length the difference becomes negligible. In the case of a fault in the middle of the shared corridor, the circuit approach overestimates pipeline potentials by 25% for a 2 km parallel length, whereas this difference becomes very small for long corridors. It is estimated that differences resulting from the circuit approach in the case studies in this research will be very small due to the fact that corridor length in the Brisbane study is 10 km and in the Young-Lithgow study the length of the corridor is 42 km.

1.4.2 Limitations of Field Measurements

Field work included soil resistivity measurements along the shared corridors, measurements of geometrical layout between pipeline and power lines, visual inspection of pipeline and power line facilities, measurement of steady state voltages on the pipeline and cathodic protection logging. Soil resistivity measurements using the Wenner method (see Section 3.5) is the preferred method for pipeline and substation interference studies. Measurement errors when using this method are associated with:

(a) Number of readings

Instead of up to 15 different readings (as recommended in the procedure designed

and used by Safe Engineering [5]), the soil resistivity measurements were made with 4 or 5 different readings. This obviously reduced the accuracy of the final soil model, especially the accuracy of the division of the soil into a two layered model. The top layer was usually very thin (in which case the pipeline would be in the second layer) and the introduced error was estimated to be insignificant. This error does not affect inductive potential calculations in the study, whereas error in the case of conductive potential calculations may reach several tens of percent. Since the conductive component in most cases was only around 10 % of the total induced voltage, the resulting error was around just several percent of the total value.

(b) Background AC noise

It is not known how much background noise was present during the time the measurements were taken. Also, the capability of the instrument used for the measurements to filter out this noise is not known.

(c) Inter-Lead Coupling

Extra care should be taken to place the potential and current leads with a couple of metres separation between them to avoid inductive coupling. This coupling becomes a serious problem when the spacings between the electrodes reach 50 m or more. The measurements for this study were made with only up to 20 m spacings between the electrodes, hence it is estimated that the current readings were not affected.

(d) Bare Buried Metallic Structures

Care was taken to select the sites for measurements where there were no foreign objects affecting the readings. While the objects were not present on the ground surface, it is not known whether some objects were present buried at or around the location of the measurements.

(e) Instrument Error

The possible contribution to error from the instrument itself was not quantified.

(f) Accuracy of maps

The maps used for modelling the shared corridors between pipelines and power lines used a scale of 1:25000 for the Young-Lithgow corridor and a scale of 1:2500 for the Brisbane corridor. Inaccuracies in separation distances read from these maps were obviously present but it is estimated that they were minimal and did not affect the final results significantly.

1.5 Layout of the Thesis

A brief history of interference studies between pipelines and power lines, following its evolution and the current state of the theory and practice are given in Chapter 2. Special consideration is given to mitigation of interference effects, focusing on insulating joints and gradient control wire methods. Interference effects on pipeline impressed current cathodic protection systems are elaborated on.

In Chapter 3, methodologies used throughout the study are presented. Two software packages, PRC and CDEGS, used for interference analysis are described with emphasis on CDEGS. Its modules and the complete procedure of an interference study are described in detail. A brief theory highlighting the mathematical model used for interference studies is presented. Soil resistivity measurement implications and division of soil into layers are considered.

Capabilities and performance of PRC and CDEGS packages are compared in Chapter 4. Reasons for the selection of CDEGS for further work are given. An introduction into the pipeline interference analysis using CDEGS is presented by carrying out an initial study of the Young-Lithgow pipeline and power line shared corridor. A detailed description of the corridor including pipeline and power line data, soil model and computer modelling procedure is given. The analysis is carried out in relation to steady state operation of power lines, different scenarios of fault conditions and safety assessment of test points.

The procedure introduced in Chapter 4 is reapplied in Chapter 5 for the Brisbane pipeline.

The existing mitigation design employing insulating joints and permanent earths is modelled and assessed. Test point touch voltages and cathodic protection current densities are modelled and analysed. The same procedure is repeated for a hypothetical case of a mitigation system implemented with zinc gradient control wire. Performance, features and costs associated with the above two mitigation methods are compared. Conclusions, guidelines and some recommendations for future research are given in Chapter 6.

Chapter 2

Literature Review

2.1 Evolution of Prediction Methods for Induced Voltages on Pipelines

There have been several early attempts to model interference between transmission lines and buried pipelines using above-ground equations. These attempts failed because a buried pipeline differs electrically in many ways from an above-ground conductor. Other calculation procedures originally developed for calculation of induction in telephone lines were applied to buried pipelines but usually produced considerable error. Carson [6] provided equations for calculation of mutual impedance between conductors. These equations are the basis of all power line and pipeline models developed for induction calculation.

The first successful method for the prediction of induced voltages on pipelines was presented by Taflove and Dabkowski in [7, 8] and in EPRI/AGA project [9]. These authors treated the buried pipeline and its surrounding earth as a lossy transmission line characterised by a propagation constant and a characteristic impedance. A distributed voltage force function (longitudinal driving electric field) was used to model inductive coupling of the nearby power line. The model could accommodate both parallel and non-parallel orientation of the pipeline and transmission line. The pipeline sections were treated as long and short ones. The model could treat several different sections combined

together and their terminal behaviour was described by a Thevenin equivalent circuit. Overall, this model was able to treat complex features like: pipeline path changes and terminations, power line electrical discontinuities, multiple phase conductors, shield wires and adjacent ground conductors (railway tracks or other pipelines). Taflove and Dabkowski provided a formula that enables calculation of the peak induced voltages at pipeline and power line discontinuities. This formula was used and the results were compared with the field measurements conducted in the Mojave Desert in California where a 525 kV power line shared a corridor with a gas pipeline (see Section 4.1.2). Comparison showed excellent agreement which proved the accuracy of the model presented. Therefore, this model became very important and many later publications in this area cited it, or conducted further research based on this model.

The above mentioned set of papers [7, 8], together with [10, 11], were part of a jointly funded project [9] which consolidated knowledge concerning mutual interaction between power lines and pipelines with shared common corridors. The major accomplishments were:

- Development of a method for prediction of induced voltages on pipelines;
- Development of instrumentation for measurement of the longitudinal electric field due to power lines;
- Investigation of induced voltage mitigation methods and procedures for their application in practice.

The project report [9] also summarised methods for calculation of electrostatic coupling between power lines and pipelines (network solution method and voltage gradient method), power line transients coupling to pipelines (inductive and capacitive), lightning exposure and effects of induced ac voltages on pipeline and humans.

Even though the above project [9] revealed new insights, the need arose for a method that would be able to cover more complex geometries of power lines and pipelines, involving

modelling multiple power lines and multiple pipelines. The new project [12] was also completed by EPRI/AGA and its final report presented a model that could accommodate quite complex positioning of multiple transmission lines and pipelines, unbalanced currents in transmission lines, pipeline discontinuities, insulation joints placed in pipelines and multiple bonded pipelines.

There was a need to further extend the research of previous EPRI/AGA projects and a new EPRI/AGA research program [13] soon followed. As a result of this research, the computer software package ECCAPP was developed. The main advance was to include both inductive (magnetic field) and conductive (earth currents) coupling effects during steady state and fault conditions. This program calculates inductive and conductive currents on the pipeline separately and then combines them. This is an approximation as in reality an iterative method should be used which calculates first the inductive current, uses the result in calculating conductive current, then uses the calculated conductive current to calculate the new inductive current and so on. Another important difference between this program and the previous ones is that this program can accommodate in its calculation both short and long conductors at the same time. This is achieved by dividing the system into zones where field theory (Maxwell equations used for modelling short elements) or circuit element theory (used for modelling long conductors) are used exclusively. Impedances obtained this way were used to construct the computer model.

The ECCAPP computer program has been used to produce sets of curves to illustrate various aspects that may affect the inductive or conductive interference between power lines and pipelines. Those aspects include: pipeline position, pipeline section length, pipeline grounding, use of mitigation wires and transmission tower grounding.

In 1992, a new EPRI project [14] was completed and as a result the computer program CORRIDOR was developed. This program introduced some very limited possibilities for calculating fault current effects on induced voltages on pipelines. It could provide good results for inductive fault current coupling, but could significantly underestimate induced

voltages and currents on the pipeline when the conductive component of the fault current was the major contributor to the voltage on the pipeline. The way to model the sections when the pipeline and transmission line were at some angle was not well documented. In all other cases the program gave excellent results in predicting induced voltages and currents and has sound capabilities in modelling mitigation measures on the pipeline such as discrete grounds, horizontal grounding systems.

Further simplification of the methods for induced voltage prediction came from the work of Sobral [15, 16, 17]. He introduced a new "decoupled method" in modelling. Normally, modelling pipelines and power lines would take into account the effects of the influence of power line current on induced current in the pipeline and the effects of the influence of those induced currents in the pipelines back on the currents in power lines. This new decoupled approach ignored the influence of induced currents in the pipelines back on the current flow in power lines as this influence is negligible in practice. By simplifying the model like this, building a modular computer model becomes feasible, so that the program can be upgraded easily at some latter stage.

Up until 1998 all available computer programs for prediction of induced voltages on pipelines were difficult to use and required trained and experienced staff to handle modelling and calculations, especially when designing the mitigation of induced currents in pipelines. There was an overall need in the industry for a simple-to-use program for prediction of induced voltages and currents on pipelines adjacent to transmission power lines. PRC International, as a part of AGA, delivered a project report [1] with state of the art achievements in this field. The report was accompanied by a computer program with a "user friendly interface". Further details on this software package are given in Section 3.2.

Soil resistance is never uniform and is different depending on the depth where it is measured or it can vary depending on the season of the year. If the interference study is done without taking this fact into account the error in the calculated voltage could reach the magnitude of the calculated voltage. In later work by Dawalibi and Barbeito [18],

software was produced which was capable of modelling grounding conductors in multilayer soils. In a paper by Dawalibi and Southey [19], an extensive parametric study of grounding grid performance in multilayer soil structures was performed for the first time. The paper followed the behaviour of four different grounding grids depending on the grid depth and soil layer. The study provided many graphs with potential and touch voltage distribution on the grounding grid. A practical case was examined presenting how the resulting potentials on the grid vary depending on which part of the year is being considered. A top soil layer increases its resistance when it becomes frozen and yields higher and more dangerous potentials in winter time.

Safe Engineering Services [5] is a Canadian company established by Dawalibi, and is one of the most influential expert organisations in the area of pipeline and transmission line interference and grounding. In the seventies the company started developing the software package CDEGS (Current Distribution, Electromagnetic Fields, Grounding and Soil Structure Analysis) and has had ongoing improvement until the present time. It is a powerful engineering tool designed to accurately analyse problems involving grounding/earthing, electromagnetic fields, electromagnetic interference including AC/DC interference mitigation studies and cathodic protection anode analysis. A more detailed description of CDEGS is given in Section 3.3.

The two dominant theoretical approaches to calculate induced voltages on the pipelines, circuit and field theory, were examined and compared in [20, 21, 22] by Li and Dawalibi. The circuit theory approach assumes that the field lines are parallel and infinite in length, unlike the case with the field theory approach. A simple pipeline and transmission line common corridor was used in the study. The induced and conducted components of the pipeline interference potential were calculated using field and circuit models to yield a maximum difference of 15%. When the exposure length between the pipeline and the transmission line is small, the circuit theory approach gives more conservative results as it does not take into account the end effects (considers modelled lines of infinite length). By

increasing the length of exposure, the differences between the field and the circuit theory approaches become smaller.

In recent years a group of researchers lead by Dokopoulos have produced several papers [23, 24, 25], in which they developed a numerical solution for the electromagnetic field of a power line in the presence of buried conductors, using the finite element method. They model the magnetic vector potential distribution in the cross-section of a conductor. By modelling the soil as a non-homogenous medium, an excellent tool for reviewing effective and low-cost mitigation designs was developed. While the majority of previous computer models treated the pipeline coat resistance as constant and perfect, this group of authors produced a paper in which they modelled the more realistic case - a pipeline with imperfect coating resistance. Furthermore, the same group of authors developed a hybrid method for calculating the inductive interference between pipelines and faulted power lines [26]. In this procedure, the finite element method was used to calculate self impedances and mutual impedances of the elements instead of Carson's formulae. These impedances are then used in a standard circuit method for calculation of potentials on the pipeline. This way, complex situations can be solved more effectively (eg. when the earth has many layers).

2.2 Mitigation of Induced Voltages on Pipelines

2.2.1 Early Grounding Methods

The prediction method for induced voltage peaks on the pipeline presented in papers [7, 8] and research project [9] was used in another pair of papers published in the same year [10, 11] by the same authors. The predicted voltage peak values obtained were used to determine the effects of different mitigation systems used on the pipeline. The results were then confirmed by a number of field tests, proving that the method could be used in the real world. The first part of paper [10] dealt with the design issues regarding mitigating

induced voltages. These include physical positioning of the pipeline and transmission line in a way which will minimise induced voltages and different phase conductor sequencing and positioning on the power line towers. The second part of paper [11], dealt with the different types of grounding methods. Using the above computing methods, mitigation of induced voltages was examined based on different grounding locations and different grounding methods. The following mitigation methods were considered: vertical anodes, multiple vertical anodes, horizontal conductors, ground wire perpendicular to the pipeline, end-connected parallel ground wire, centre-connected ground wire, bonding to tower footings, ground mats and insulating joints.

2.2.2 Cancellation Wire

Detailed analysis of mitigation of induced voltages in pipelines by an electric field of a horizontal conductor was presented in report [12]. This method was called "Cancellation Wire". The transmission line would induce voltages in the cancellation wire which were out-of-phase compared to the ones induced on the pipelines. The cancellation wire had a common point with one end of the pipeline and ideally voltages should cancel each other. It could be positioned between pipeline and power transmission line or on the other side of power transmission line looking from pipeline. Analysis was an approximation as mutual coupling between the pipeline and mitigation conductor had been ignored. This analysis provided a preliminary solution and provided grounds for further parametric analysis. In order to obtain field measurements, a mitigation conductor (as described above) was placed at convenient places in the Mojave desert shared corridor. The results confirmed that this mitigation method is applicable in the real world. The project report also presented a simple way to predict induced voltages using a graphical method. However, further research later revealed that cancellation wire was not appropriate as it transferred dangerous voltages from one place to another (to the end of the cancellation wire that was not connected to the pipeline) and did not mitigate conductive interference.

2.2.3 Insulating Joints

Limited research has been conducted specifically on insulating joints. Insulating joints have been sporadically mentioned in a few papers and reports. EPRI project [9] states that insulating joints are used to electrically separate the pipeline from terminals and pumping systems. They are also used to divide the pipeline into sections to confine cathodic protection systems failure to single sections. Insulating joints can mitigate the AC interference effects on a pipeline by reducing the electrical length of the pipeline exposed to power lines. This way the maximum value of induced AC voltage on the pipeline is reduced as the maximum induced voltage is proportional to the length of parallel sections. It is stated that if the buried pipeline sections are longer than $2/Real(\gamma_{pipe})$ additional voltage peaks may develop at the locations of insulating joints [9], where γ_{pipe} represents pipeline propagation constant expressed in m^{-1}, and is a parameter that describes terminal behavior of the pipeline. While a long pipeline may have only two voltage peaks, the insertion of an insulating joint in the midpoint of the pipeline could cause a third voltage peak to appear at the location of the new insulator. To avoid this scenario, connection of a polarization cell across the insulating joint was suggested. This cell would represent a path for AC currents across the joint while DC currents would be blocked. In this scenario, the role of the insulating joint is reduced to DC division of the pipeline for cathodic protection purposes. As noted in the same report [9], one of the goals of the design of a shared corridor is to minimize the use of pipeline insulating joints. If such a joint is necessary, a low-ac-impedance ground cell should be placed across it.

The paper by Dawalibi and Southey [27], reiterates that the induced potential on the pipeline between two insulating joints is proportional to the length of exposure up until the characteristic length of the pipeline and that the insulating joint is subjected to a stress voltage which is double the induced peak. It suggests that if the insulating joints are inserted frequently, with smaller lengths of exposure, induced peak voltages would be smaller. Large voltages across the insulating joint can result in piercing of the insulation

and melting the pipeline metal to form a permanent weld bead across the junction, nullifying the function of the insulating joint. Fire and explosion hazards are also present due to leaks. Polarization cells or lightning arresters may be installed across the joint to guard it against these high potentials.

In addressing general pipeline mitigation, Australian Standards [28] states that by reducing the modular lengths of the exposure by insertion of insulating pipeline joints, voltage control may become more manageable, and usually at lower total cost. Application of insulating joints may be unacceptable for certain pipeline operation reasons like pressure, safety, lightning protection, segmenting cathodic protection design or telemetry requirements.

In another project [12], the Norton equivalent circuit matrix, used to model electrical conductors in a shared corridor, was adjusted to accommodate insertion of insulating joints in the pipeline. This adjustment in a mathematical model enabled modelling of insulating joints as a part of future computer models.

The report [1] describes the case of a small exposure length between the pipeline and the power line (much less than propagation length associated with the pipeline). In such a case, grounding the pipeline against the steady state induced voltages may not be effective. After grounding, the voltage peak may just shift to another location and even increase in magnitude. Effective mitigation in this situation requires insertion of insulating joints along the pipeline, protected by adequate surge suppressors for fault protection.

Another report [29] states that installation of an insulating joint in the interfered section of the pipeline reduces the maximum value of induced AC voltage which is proportional to the length of the parallel sections. The AC voltages on each side of the insulating joint have a phase shift of 180 degrees, so the voltage across the insulating joint is double the peak voltage.

CIGRE report [30] states that to be efficient in reducing the inductive influence of the power lines, insulating joints have to be installed at distances shorter than the

characteristic length of the pipeline.

One of the reasons why insulating joints should be installed on a pipeline is described in [31]. When lightning strikes in dry desert ground as found in Central Australia, it is not uncommon for lightning to propagate over the ground seeking for a good earth. A buried pipeline is very susceptible to absorbtion of some energy from the lightning. A well coated pipeline cannot dissipate energy to the ground, so its potential to earth rises. This potential may reach several hundreds of volts and the pipeline may be charged over a long distance (hundreds of km) behaving similar to a capacitor. Insulating joints are inserted between the sections of the pipeline to reduce propagation of these potentials. Surge diverters are installed at each side of the joint to divert this energy to earth and thus protect the joint and the pipeline.

Insulating joints may be divided into two categories: field fabricated that are field assembled from insulating materials, and factory fabricated which are assembled in a short section of pipe that is welded in the field to the rest of the pipeline [32]. Field fabricated insulating joints are more common but they usually come with no withstand voltage specification due to the many variables involved in the field assembly. Factory fabricated insulating joints come with voltage withstand data.

The American Code of Federal Regulations regarding pipeline isolation [33], states that a pipeline located in close proximity to power transmission line tower footings, or in other areas where fault currents or unusual risk of lightning may be anticipated, must be provided with protection against damage due to fault currents or lightning. Protective measures must also be taken at insulating devices. One of the ways to protect the pipeline is to connect it to buried galvanic anodes in the vicinity of the insulating joint. Arcing may occur across the insulating joint in the case of a power line fault or lightning, caused by generally 3 kV or even smaller voltages. Depending on the material being transported, insulating joints are classified as 'hazardous locations' and the protection device used must be listed for use in a Class 1, Div 2 hazardous location. The industry practice [34] is to

install a DC decoupler across the insulating joint in the situation where steady state AC voltage is the problem, or a surge arrester or zinc grounding cell in the situation where power line faults or lightning is a problem. In recent times, the over-voltage protector described in [32] has been used for this purpose in hazardous locations. It is a solid state component device which can be subjected to its fault current rating virtually an unlimited number of times. According to the Federal Regulation [33], it appears that it is illegal in the United States to install an insulating joint that does not short during a fault if the pipeline is located in the vicinity of power line tower footings, and other areas where fault currents and lightning can be anticipated.

2.2.4 Gradient Control Wire

Dawalibi and Southey [35, 36] offered a new cost-effective mitigation solution for both inductive and conductive interference mitigation - gradient control wire. The method consists of one or more bare zinc wires placed in backfill, regularly connected to the pipeline (typically at intervals of 150 to 400 m). In guarding the pipeline against inductive interference, gradient control wire provides grounding for the pipeline and hence lowers the absolute pipeline potential (with the respect to remote earth). These wires also raise the potential of the earth in the vicinity of the pipeline and thus reduce the potential difference between the pipeline and local earth. In this way, the pipeline coating stress voltage and touch voltages are greatly reduced. During conductive interference, the gradient control wire reduces the potential difference between the local earth and the pipeline steel by allowing current to flow between them. As a consequence, local earth potential rise due to the nearby faulted structure is lower and potentials transferred to the pipeline by this current are higher.

Gradient control wire can be made from zinc, magnesium or copper [37]. Zinc and magnesium can be directly connected to the pipeline, whereas copper cannot be as it creates a corrosion cell in connection with steel. Copper wire has to be AC coupled with

the pipeline but DC isolated. Direct bonding has the disadvantage that pipeline cathodic protection currents are intertwined with the mitigation system and instantaneous “off” potentials on the pipeline cannot be read. In the presence of some other source of DC currents in the vicinity of the pipeline, stray currents may enter the pipeline [38]. With AC couplers/DC decouplers these problems are solved.

2.3 Cathodic Protection Considerations

Under certain conditions AC induced currents on the pipeline can cause corrosion of the pipeline. Corrosion caused by AC currents are only a fraction of corrosion caused by DC currents, but in some cases it can be very dangerous for pipeline integrity.

Investigations on one German high pressure pipeline revealed that pipeline failure was caused solely by AC corrosion [39]. Studies have found that above a certain minimum AC induced pipeline current density, proposed cathodic protection levels are not enough to limit AC corrosion to acceptable levels. In those cases AC mitigation is often required to reduce AC induced voltages and prevent serious corrosion.

The Correng report [40] provides a review of the literature considering design, operation, maintenance and monitoring of cathodic protection for pipelines with AC mitigation facilities. The most important research papers that deal with AC corrosion of pipelines are reviewed in this report, including several experiments conducted by researchers in different countries and reports from the gas companies that conducted the experiments. It was common for the majority of them to find some extraordinarily quick corrosion of gas pipelines in the physical areas where pipelines were running parallel to power lines or railway lines.

The report [40] investigated the mechanism of AC corrosion (even though there is no firm agreement between scientists regarding it) and proposed that AC corrosion occurs during the positive half cycle of the induced AC current waveform. During the negative half cycle, electrochemical processes that occurred during the positive half cycle are not

reversed. The whole idea of cathodic protection comes from here, to lower the potential of the pipeline so that the most positive waveform peak lies below the corrosion critical potential that triggers these electrochemical reactions.

The report [40] also dealt with how different anodes (zinc and magnesium) can affect cathodic protection performance. Experimental results showed some cases where the corrosion rate of magnesium and zinc can shorten their effective life.

When pipelines pass near substations, power line towers or plants, they are vulnerable to fault currents introduced into the pipeline through coating holidays by resistive coupling. This issue should always be taken into account when designing a pipeline, meaning that a safe distance between the pipeline and these power system elements should be maintained.

For effective performance of cathodic protection, the protected sections have to be DC isolated to prevent loss of impressed DC currents. At the same time, pipeline elements can be severely damaged from lightning and other voltage surges and hence pipeline sections need a low impedance AC path to earth. To solve both of these requirements, a new class of devices called DC-isolator-AC-couplers are fitted to pipelines. The report lists several devices from this class: zinc grounding cell, polarization cell, isolation-surge protector, electrolytic capacitor, voltage-surge protector, metal oxide varistor and compares their performances.

The connection between varying AC induced voltage and low frequency fluctuations of the DC potential on pipelines protected by impressed cathodic protection systems is not well understood [41]. Problems arising can be:

- circulation of unidirectional current in the circuit pipeline - anode bed;
- limitation of the current supplied by the rectifiers;
- modification of the reference potential set on the rectifiers;
- rectification of AC voltage through the transformer-rectifier unit in cases where there is no special AC filter diverting AC around rectifier diodes.

It was shown how AC currents passing through the surge arrester (at times operating during high AC voltages in steady state operation) can cause significant contributions to DC potentials supplied from rectifier units.
Another study logged data for one year on a sacrificial anode protected pipeline paralleling a power line that was intermittently loaded [42]. At each of the 47 test points along the pipeline, a steel probe was installed and used for current density and potential measurements. At the end of the one year period, probe corrosion was assessed and compared with measurements. A few locations on the pipeline had high AC current densities during load periods. When the testing probe AC current density increased, the potential difference between the probe and the magnesium anode with a well coated pipeline increased, which as a consequence caused an increase in the DC protective currents. This electrochemical behavior of the probe acted favourably towards suppressing AC corrosion from induced AC voltage.

2.4 Conclusions

The literature review presented in this chapter has shown the evolution of calculation methods for AC interference between power lines and gas pipelines and methods for its mitigation. Over the years the ability to model more and more complex right-of-way situations in the field has increased. Software available for interference analysis has evolved and become more powerful and more "user friendly". CDEGS is considered to be the leading platform in the field considering its abilities and performance. One of the most significant advancements is the development of software with the capability to model multilayered soil. New powerful software has led to improved accuracy of results and new methods for mitigation of AC effects have emerged. Notably the preferred mitigation method today is the gradient control wire.
The knowledge of steady state and fault condition interference between pipelines and power lines is well established. An area of future research is transient interference and

especially the effects of lightning on the pipeline and cathodic protection systems. Arcing processes during faults or lightning need more understanding as arcing damages the pipeline coating and may even short insulating joints if they are not adequately protected. While cathodic protection of the pipelines is a very broad area covered by researchers, this literature review focused on how induced voltages in pipelines can affect cathodic protection and how problems arising from it can be rectified by AC mitigation. Even though there is evidence suggesting interaction between the AC induced voltage on pipelines and pipeline cathodic protection systems, these interactions are still not very well understood. Scientists do not agree completely on the mechanism of AC corrosion on the pipeline. It is clear that future research will have to deal further with the interaction of AC induced voltages on pipelines and cathodic protection systems of the pipeline and the AC corrosion mechanism itself.

Chapter 3

Methodologies

3.1 Introduction

In this chapter, two software packages, PRC International and CDEGS, for computing interference effects on pipelines caused by nearby power lines are assessed giving due consideration to their capabilities and performance. A brief description of the theory used for analysis of interference between pipelines and power lines is given in Appendix A.

3.2 PRC International Software

PRC International is a software package that has been developed for interference studies in relation to pipelines and power lines. The program provides many default computational functions and data entry possibilities that aid the user. It has, for instance, an inbuilt database of default transmission line parameters (depending on the voltage level) which considerably reduces the demand on the user. This program allows for both inductive and conductive modelling of transmission lines and pipelines. Up to three pipelines, five power lines and up to 80 pipeline sections can be modelled allowing for quite complex real world arrangements. However, when modelling soil, the program allows only for one layer which can lead to significant errors. It is known that in the worst case

of a multilayer soil, where the soil is modelled as a single layer, the error in the calculated induced voltages on pipelines can be as large as the size of the calculated induced voltage magnitude. Three different induced voltage mitigation methods are provided for modelling in the program. They are: discrete anode grounding, distributed anode grounding and a mitigation method where wire is placed in parallel with the pipeline and connected to the pipeline at certain intervals. The modelling is based on the fact that induced voltage peaks occur at points of electrical or physical discontinuity, which is a result of the abrupt change in the longitudinal electric field. The PRC International software package for modelling pipelines and adjacent power lines is a tool designed to discriminate between cases where no further consideration is required and cases where the use of a more powerful and complex computer program or consulting services are required.

3.3 CDEGS software

3.3.1 Introduction

CDEGS is a well regarded software package used for the analysis of electrical induction and conduction problems occurring in non-uniform three-dimensional lossy environments (eg. air and soil) when time-harmonic currents are injected into various points of the network of arbitrarily located conductors in that environment [2, 5]. The package consists of several independent modules designed to solve different problems.

3.3.2 Modules

RESAP

RESAP is used to compute equivalent earth structure computer models based on measured soil resistivity data. It produces a soil structure which closely matches the data or generates simplified approximate models with a number of layers as specified by the user. These soil models are used to analyse grounding systems, pipeline interference and

cathodic protection systems.

MALZ

MALZ module is used for frequency domain analysis of buried conductor networks. It is very useful for modelling coated conductors such as pipelines in the case when metallic conductors cannot be treated as to be at equipotential. The module is based on calculation of earth and conductor potentials, longitudinal and leakage current distribution in conductors etc.

TRALIN

TRALIN module is used for modelling conductor and cable parameters, electrostatic and electromagnetic induction effects of underground conductors and electric fields in air. This module is used to describe any type of distribution and transmission power lines, with any type and number of conductors.

SPLITS

SPLITS computes load and fault current distributions in every section or span of the electric power network described in the TRALIN module, whether balanced or not. It can also calculate induced voltages and currents between conductors due to both inductive and electrostatic coupling.

ROW

Right-Of-Way is an integrated software package within CDEGS consisting of the four modules described above. It allows accurate computation of voltages and currents arising as a result of electric power lines and cables (by inductive, capacitive and conductive coupling) in pipelines, railways, communication lines, whether buried or above ground. ROW can also be used to design systems to mitigate interference effects.

3.4 Typical CDEGS Pipeline Interference Study Procedure

It is very important to note that a typical pipeline interference study should consider the whole system and not just the pipeline in isolation. Induced voltages are usually not confined to the section of the pipeline that is part of the shared corridor, or only to the part of the pipeline where ownership changes. A typical study should incorporate the following tasks [5]:

3.4.1 Data Collection

A crucial first step in the analysis of the interference problems is the collection of data which often consumes a significant amount of time. It should never be underestimated as a task, as data is very often incomplete or unclear. Further questioning and field checks are usually required after collecting data. The required data can be divided into items related to the pipelines and to the power system.

Pipeline Data

1. System overview: A detailed map is required (geographical) indicating the following:
    - Pipelines under study
    - Power lines that are parallel to the pipeline (closer than 1 km from the pipeline)
    - Pipeline appurtenances like metering and compressor stations, valves and other exposed parts
    - Plants that are close to, or fed by the pipelines
    - Any insulating joints, earthing and anode beds associated with the pipeline
2. System layout: A detailed plan is required of the system which will allow any length and separation distances of all pipelines and power lines to be determined.
3. Pipeline dimensions:

- Burial depth of the pipeline
- Diameter
- Pipeline wall thickness
- Pipeline coating thickness

4. Soil Resistivity Data: Soil measurements (see Section 3.5) should be made at critical locations in the shared corridor, for example:

    - At exposed structures
    - At locations where the pipeline and power line deviate from each other, at power line crossings, at phase transposition locations etc
    - In situations where the pipeline is extremely close to the power lines, substations or other types of grounded structures

5. Electrical Data:

    - Pipeline coating resistance (from factory data) or an estimate of it from cathodic protection engineers. Scratches on the coating during installation partly reduces coating resistance
    - Anode bed dimensions, resistance, their interconnection configuration with the pipeline, and material type

Power Transmission System Data

1. Conductor Positions and Phasing

    - Power line cross sections indicating phases, earth wires, conductor spacing and heights above ground
    - Phase transpositions
    - Maps indicating transmission line routing through the shared corridor

- Power line grounding indicating the description and dimensions of tower footings
- Remote substation locations including distances from the shared corridor
- Nearby substations or power plant grounding system with distances from the pipeline, and a detailed description and layout of the grounding system

2. Conductor Characteristics

    - Type
    - Dimensions
    - Physical and electrical properties

3. Power Line Voltage/Current Data and other information:

    - Voltage
    - Magnitude and phase angle of load current
    - Maximum load and emergency loading levels
    - Maximum expected current unbalance level
    - Future expected load growth
    - Expected expansion possibilities of the power system in the future

4. Fault Current Data:

    - Fault type upon which fault levels are calculated (usually single phase to earth fault is considered)
    - Protection response times (primary and backup) for all power lines as this determines the duration of the fault
    - Fault Current Contributions: Single phase to ground fault current should be provided for several fault locations (at least three) on the power line in the

shared corridor. Precisely, one at each end and one in the middle or several along the corridor. In each case, contributions from both sides of the power line to the fault are required.

- Soil Resistivity values used in fault level calculations

5. Power Plants, Substation and Power line Grounding

   - Map showing all circuits connected to the plant or substation
   - Layout of grounding grids
   - Design value or measured value of grounding system impedances

3.4.2 Soil Resistivity Analysis

Measurements of soil resistivity are required to obtain an accurate multilayer soil model at each measuring location. A multilayered soil model is critical for conductive analysis as the error resulting from the use of a uniform soil model can be as large as the estimated conductive voltage itself.

3.4.3 Inductive Analysis

To accurately determine the interference effects resulting from electromagnetic induction, all conductors in the shared corridor should be included in the computer model. All significant physical and electrical deviations causing changes in electromagnetic fields should be included since induced voltage peaks occur in such locations. Maximum load, maximum unbalanced load and emergency load cases should be modelled. In a fault study, several faults at the most critical location should be modelled to obtain the worst case of interference [35]. Most often, the faults at the section of the power line closest to the pipeline would be the worst case fault location. For each fault, the magnetically induced pipeline potentials, the touch voltage at pipeline appurtenances and the ground potential rise near the faulted structure (required for conductive analysis) need to be computed.

3.4.4 Inductive Analysis and Fault Graphs

The inductive analysis performed ising CDEGS software results in a graph that shows the induced voltages on the pipeline. The faults are simulated at each power line tower in the shared corridor and for a certain number of towers outside the shared corridor on both ends of the pipeline. In the computer model of the pipeline, the pipeline is divided into a number of sections (section length typically corresponds to the average distance between two towers on the power line). Each section of the pipeline in the graph is associated with the highest induced voltage on the pipeline in that section, obtained as a maximum value from all simulated power line tower fault runs.

3.4.5 Conductive Analysis

Faulted towers inject current into the earth and that current raises the potential of the objects that lie in the ground close by. The model of the tower footing is energized to the ground potential rise level computed in the inductive analysis during the fault at that tower. Earth potentials are computed as a function of the distance away from the tower up to the pipeline location. For a short separation distance, only one tower may need to be modelled, but for a longer separation more adjacent towers should be modelled as the local earth potential will have contributions from injected currents to earth from the adjacent towers. If present, other metallic structures in the vicinity may influence the potential distribution and should be modelled as well. These calculations are very sensitive to soil layering. As previously mentioned, if a uniform soil is used, an error of the order of the magnitude of the calculated conductive voltage can occur and can lead to over conservative and thus costly mitigation solutions. If in the proximity of the pipeline there are no other energized buried conductive structures, the local soil potential (just outside the coating of the pipeline) will be equal to or almost equal to that of the remote earth, and the pipeline coating stress voltage will consist only of its inductive component.

3.4.6 Total Pipeline Coating Stress Voltage

Total pipeline coating stress voltage is obtained when its inductive and conductive components are vectorially added. In reality the phase angles of the inductive and conductive components of pipeline coating stress, step and touch voltages, in the vicinity of a fault at a given power line tower, are such that the magnitudes of the inductive and conductive components can be added together, with little loss of accuracy [5].

3.4.7 Safety Analysis

In a similar fashion to computing the total pipeline coating stress voltage, the touch and step voltage at any pipeline appurtenance have to be assessed. The computed touch voltages are then compared with the applicable Standards [28, 43]. The aim of these Standards is to limit the current through the human body (in the case a connection with the pipeline is made) during a fault on the power line to levels that will not cause heart ventricular fibrillation. In general, if touch voltages comply with the Standards, step voltages would comply as well.

3.4.8 Mitigation Design

At pipeline appurtenances, touch and step voltages need to be reduced to the levels given in the Standards [28, 43], usually by means of a gradient control grid. Also, mitigation is applied to the pipeline to reduce the pipeline coating stress voltages to levels that are safe for the coating applied. The most common mitigation methods are lumped grounding, cancellation wire, insulating joints and gradient control wire. The mitigation system has to be included in the computer model of the shared corridor and the interference study repeated until mitigation objectives are met.

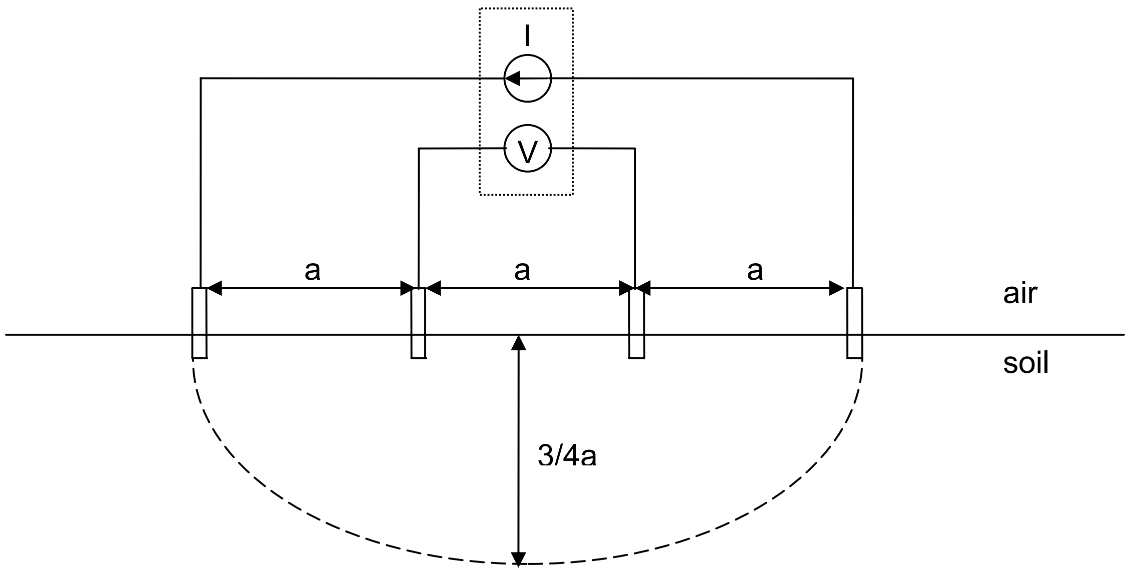

Figure 3.1: Soil resistivity measurement - Wenner method

3.5 Soil Resistivity Measurements

Results from interference studies between the power lines and the pipeline are very dependent on the accuracy of the soil resistivity model used in the study. This is especially true for the calculations of the conductive part of the total pipeline potential and conduction associated touch voltages and pipeline mitigation performance. Measurements of the soil resistivities in the shared corridors were attempted at regular intervals and at sites where it was estimated that changes in the physical layout of the corridor would produce significant amount of induced voltages on the pipeline. The Wenner method employing four pins was used for measurements. The two outer electrodes were used to inject current into the ground and the two inner electrodes were used to measure earth potentials. All four electrodes were placed in a straight line. The apparent resistance is directly readable from the instrument ($R = V/I$). Approximating the current electrodes by hemispheres, the soil resistivity is then obtained by:

$$\varrho = 2\pi Ra \ \Omega - m \tag{3.1}$$

where a is the spacing between the electrodes as shown in Figure 3.1. By using this method, the soil resistivity approximately at a depth of three quarters of the distance between two electrodes can be assessed. During field measurements, soil resistivity samples were taken for five different spacings between electrodes, with a maximum spacing of 20 m. This data was then analysed in the RESAP module of the CDEGS software package. As the output of the RESAP module, a two layer computer soil model was established for each of the sites where soil resistivity was measured. The final soil resistivity computer models for both shared corridors are given in Appendix C.

3.6 Monitoring of Cathodic Protection Potentials

In order to successfully assess cathodic protection operation, it is important to know the pipeline potential levels at all times. On impressed current cathodic protection systems, this data is used to determine whether the rectifier is supplying enough current to keep the pipeline potential within the range required for polarisation. As a part of this project, long term monitoring of these pipeline potentials was attempted on the Young-Lithgow pipeline. The monitoring equipment was installed in two metering stations located at the start and at the end of the pipeline and power line shared corridor. The intention was to monitor cathodic protection potential levels and see how they changed over a long period of time. At certain times, these levels drop below the required values and the exact time and date when this happened was to be noted. At the same time, additional logging equipment was supposed to be installed at the termination substation of the power line sharing the corridor with the pipeline. By having the exact time and date when cathodic protection levels were outside limits, the intention was to look for events on the power line and identify possible causes for cathodic protection level drops. Unfortunately, permission from the power utility to install loggers in the substation was not obtained, so no logs from the required power line are available.

The logs obtained from the cathodic protection in the two metering stations on the

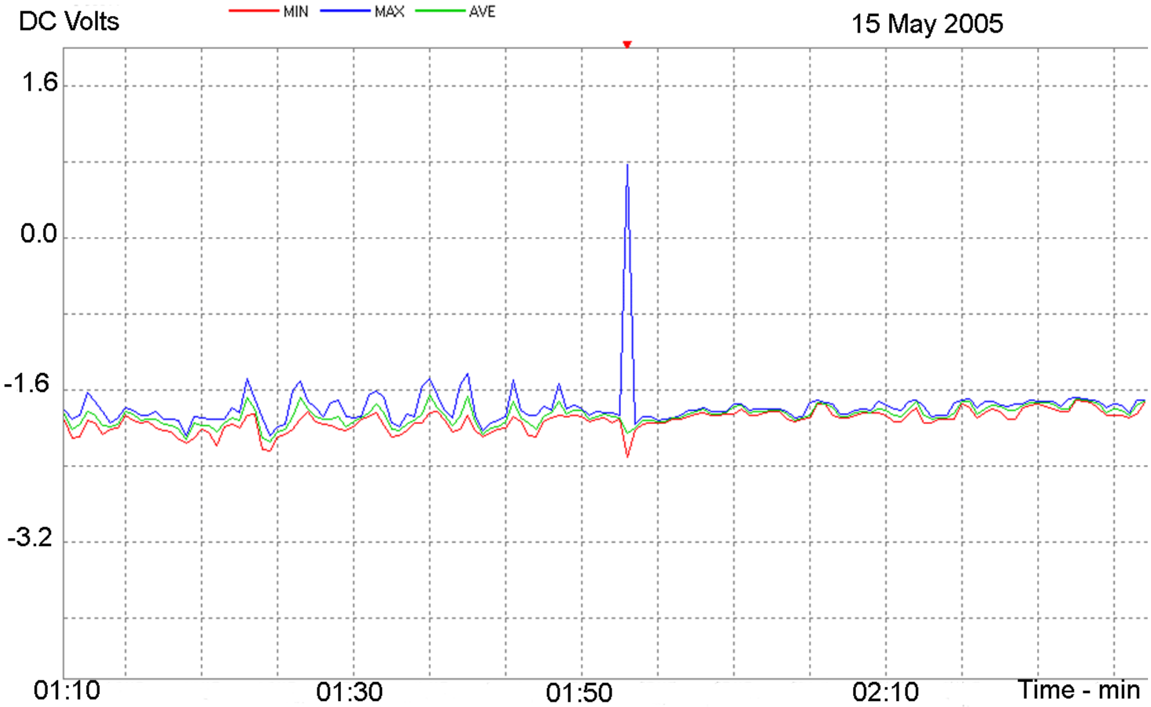

Figure 3.2: Cathodic protection levels logs at Brewongle on Young-Lithgow pipeline

Young-Lithgow pipeline were available for a period of nine months. A sample of the logs is given in Figure 3.2. This shows an instance of which the cathodic protection level was briefly above zero, much higher than it was supposed to be. The reason will remain unknown, due to the lack of data from the power line substation. It should be noted here that due to certain technical difficulties, the cathodic protection interruptors were not installed between the rectifiers and the pipeline. Consequently, the logged values were so called ON potentials and cannot be used to verify properly the polarisation level of the pipeline. Proper polarisation can be assessed only immediately after the rectifiers are switched off, when the so called OFF potential is measured. Two main criteria for pipeline polarisation are:

- OFF pipeline potential more negative than -850 mV or
- OFF pipeline potential at least 100 mV more negative than the depolarized potential [49].

By looking at the pipeline potential peak in Figure 3.2, it can be concluded that there was an event on the cathodic protection or pipeline itself that disrupted the cathodic protection output for a moment. Adequate analysis of cathodic protection performance could be possible if logged pipeline potentials were measured while the rectifier was off and if they were compared with logs from the power line substation. Completion of this research will be left as a recommendation for the future, provided that logging of required data becomes possible.

Chapter 4

Comparison of PRC and CDEGS Software and Introduction to Interference Analysis using CDEGS

4.1 CDEGS and PRC Software Comparison

Two software packages, PRC and CDEGS, were available for use in this project. Before selecting the more appropriate package for computations, the features of both packages were carefully examined and compared. The two studies on pipeline and power line shared corridors described in the project report [9] were revisited for this purpose. Based on published data, the geometry of the shared corridor was established and the steady state AC induced voltages on the pipeline calculated. Finally, comparison with original calculations and field measured values were made (see Sections 4.1.1 and 4.1.2).

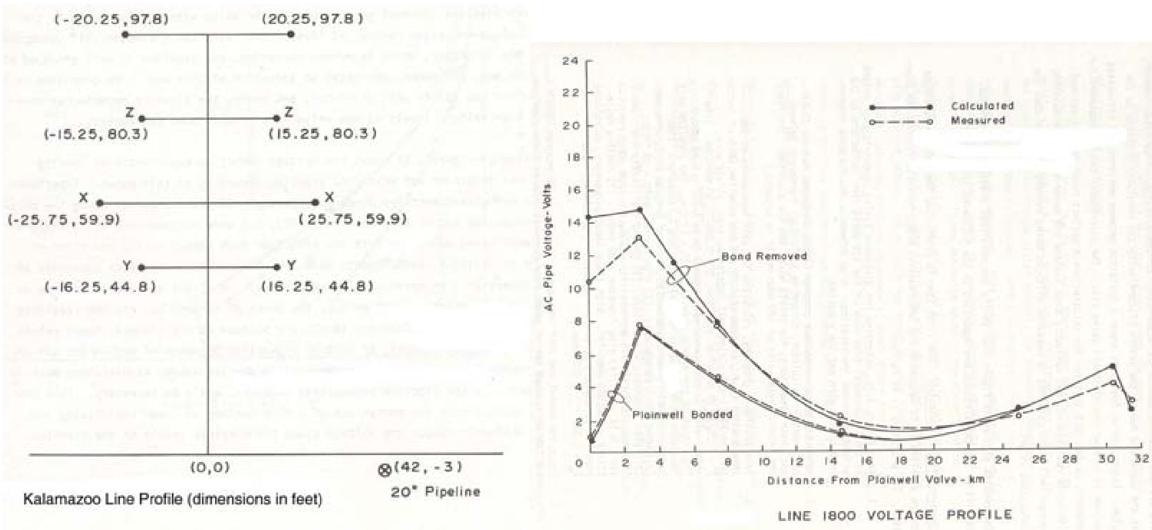

Figure 4.1: Kalamazoo pipeline - corridor profile and steady state potentials

4.1.1 Consumer Power Company, Kalamazoo Line 1800 Pipeline Case Study

Line 1800 is a 20 inch diameter gas transmission line located north of Kalamazoo, Michigan. It ran approximately south to north for a distance of 31.1 km, starting at the Plainwell valve site and terminating at the 30th Street valve site at the north end. The pipeline shared the corridor with two 345 kV three-phase circuits on a common double circuit vertical tower. The power line began sharing the pipeline in the corridor at a distance 3 km north of the Plainwell valve site and left the corridor approximately 1 km south of the 30th Street valve site, paralleling the pipeline in the corridor for 27.1 km. The average power line and pipeline profile in the region where they run in parallel is shown in Figure 4.1. Both ends of the pipeline terminate with an insulating joint (at distances 0 km and 31.1 km) with grounding cells installed across the insulating joints. A survey of the pipeline and the insulating joints revealed that the grounding cell at the 30th Street valve site (31.1 km) was partially shorted. This meant in practice that the pipeline was electrically connected with the two pipelines that exist on the other side of the insulating joint. Bonding the insulating joint did not make any difference to the pipeline potential and currents. Therefore, this end of the pipeline was considered in the

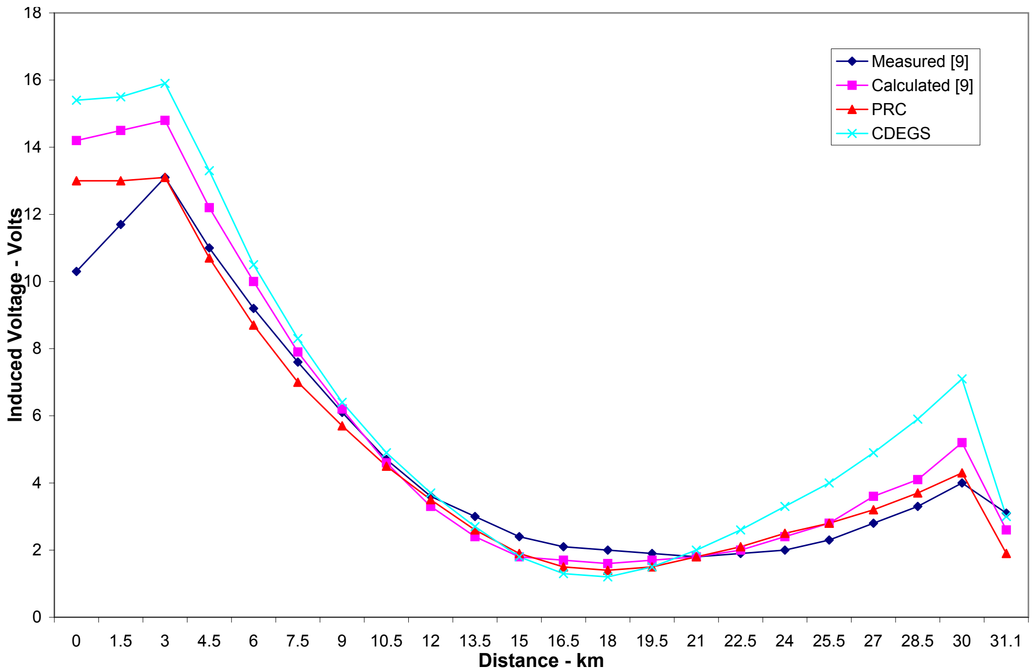

Figure 4.2: Kalamazoo pipeline with insulating joint removed - steady state potentials

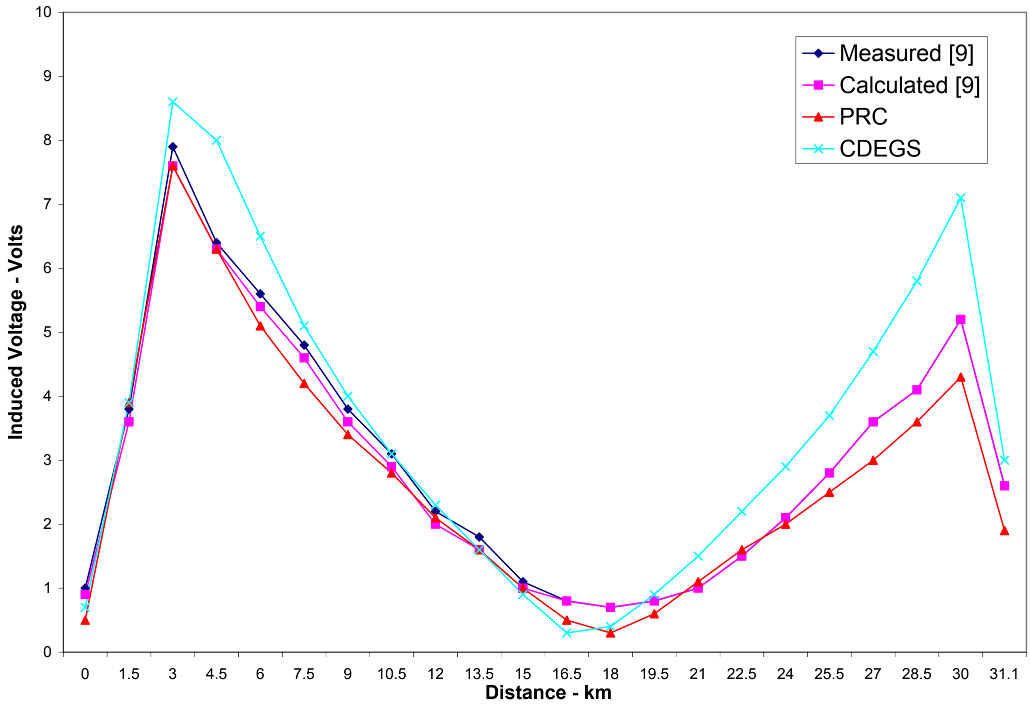

Figure 4.3: Kalamazoo pipeline with insulating joint bonded - steady state potentials

study as not terminated with an insulating joint. The impedance seen on the other side of the insulating joint was provided [9]. This load impedance was calculated as a parallel combination of the characteristic impedances of the two pipelines on the other side of the insulating joint and was (0.4+j0.314) Ω. At Plainwell (0 km), on the other side of the insulating joint there was a good grounding system connected to the pipeline that was connected to the Line 1800 pipeline. Measurements showed that the impedance to ground behind the insulating joint was (0.15+j0) Ω. Field measurements and calculations reported in the Project [9] were done with two different pipeline insulating joint configurations. Firstly, the case where the Plainwell end (0 km) was terminated with the insulating joint (bond removed) was examined. In the second case, the grounding cell (bond) across the insulating joint was closed and the measurements and the calculations repeated (in this case 0.15 Ω was modelled at Plainwell (0 km)). The currents used in the study were 50 A, soil resistivity 400 $\Omega - m$, pipe diameter 20 inches and coating resistance 27870 $\Omega - m^2$. The calculated pipeline voltage profiles reported in the project is shown in Figure 4.1. The calculation of pipeline potential for both of the above mentioned configurations of the Plainwell insulating joint was repeated using the PRC and CDEGS software packages. The comparisons of the results are shown in Figure 4.2 in the case of the Plainwell side terminated with the insulating joint (grounding cell - bond open) and in Figure 4.3 in the case Plainwell side is not terminated with the insulating joint (with grounding cell - bond across the insulating joint). These graphs show a very good agreement between the PRC and CDEGS calculated steady state pipeline potentials and the potentials presented in the Project report [9]. It can easily be observed on these graphs that the induced potential peaks on the pipeline occur at distances 3 km and 30 km. These are exactly the two points where the power line joins and leaves the shared corridor.

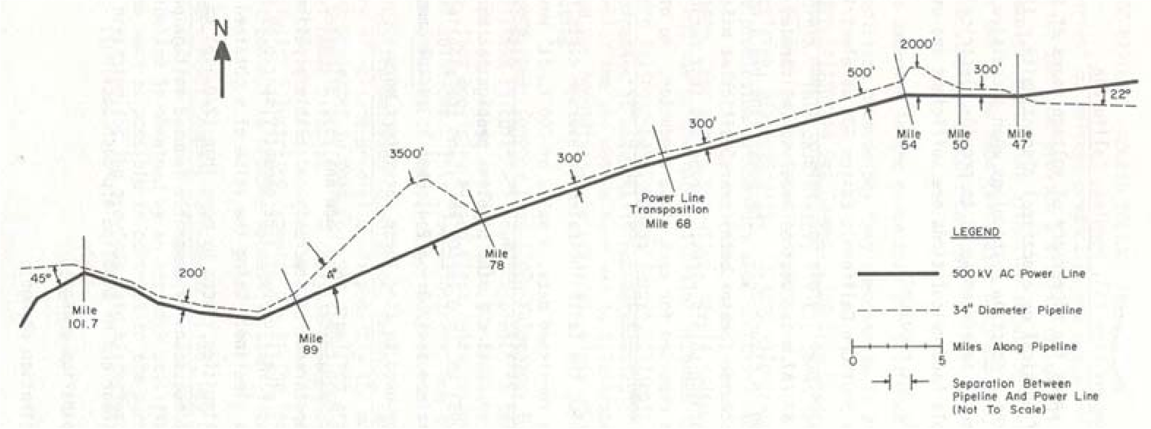

Figure 4.4: Mojave desert pipeline - shared corridor geometry

4.1.2 Southern California Gas Company Line 325 Needles, Mojave Dessert Pipeline Case Study

The shared corridor shown in Figure 4.4 in the Mojave desert is very well known to pipeline interference engineers, as it has been used as an example for power line and pipeline interference studies in many published papers. The power line, owned by Southern California Edison Company and rated at 500 kV, shares the corridor with the Southern California Gas Company 34 inch pipeline. Power line and pipeline meet at point 47 (47 miles west of Needles) and part at point 101.7. The power line is a single horizontal circuit with single point grounded lightning shield wires. It is transposed once at point 68. The power line load reported by the study was 700 A, soil resistivity 400 $\Omega - m$, and assumed average pipeline coating resistance is 65000 $\Omega - m^2$.

In the EPRI project [9], the voltage calculations were done using nodal analysis. Basically, four isolated different voltage peaks were predicted and their appearance corresponded with the location of electrical or physical change of parameters of the elements in the shared corridor. The results are shown in Figure 4.5. The measurements were not complete but the remaining parts of the final curve were supplemented from a previous survey made by the pipeline owner utility. The calculations of the steady state pipeline

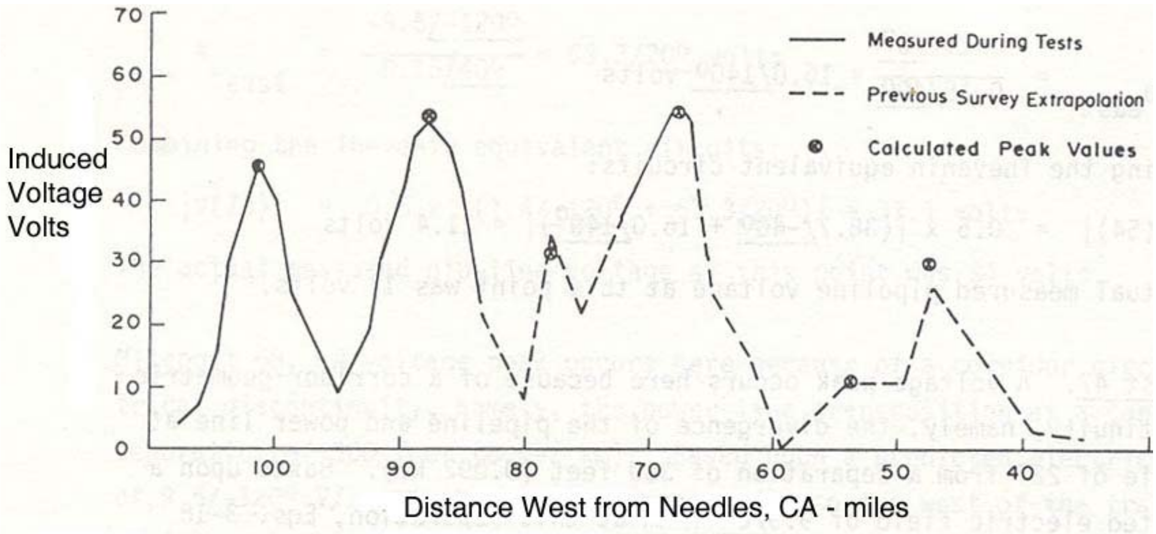

Figure 4.5: Mojave desert pipeline - steady state potentials

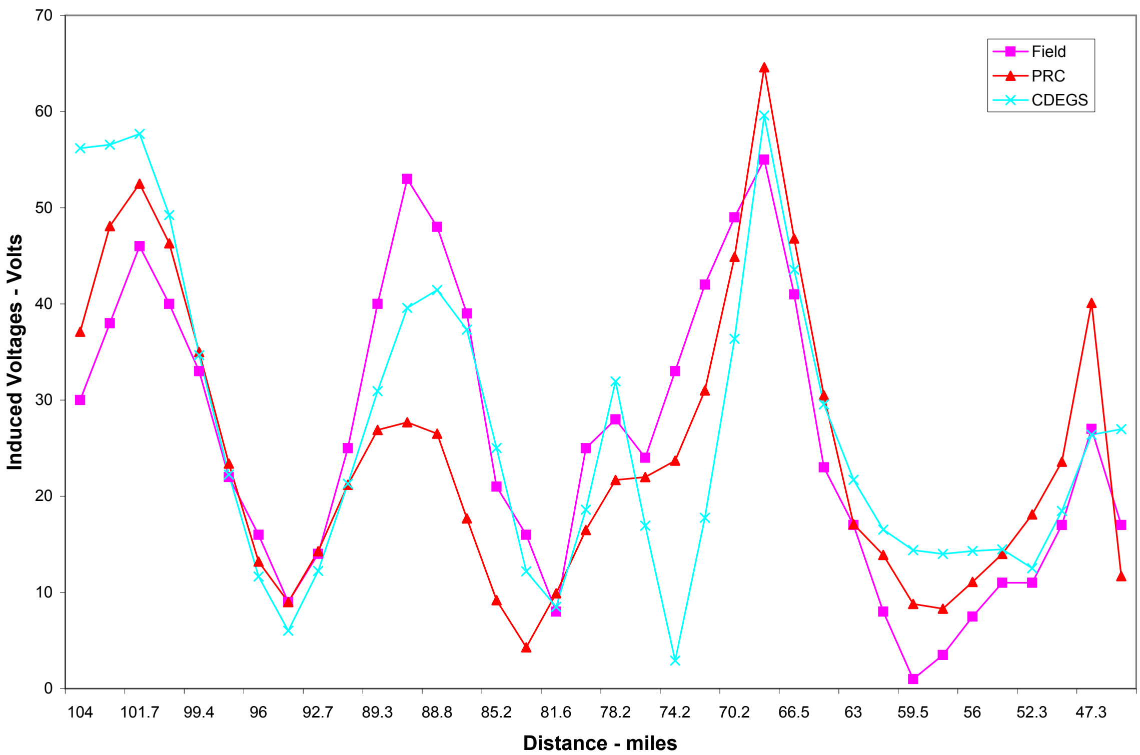

Figure 4.6: Mojave desert pipeline - comparisons of steady state potentials

potential for the above corridor were repeated using the PRC and CDEGS software.
The steady state potentials were relatively high because of the significant length of the shared corridor as the pipeline potential is proportional to the length of exposure. The comparison of the results is shown in Figure 4.6 where four isolated induced voltage peaks can be seen. CDEGS gave a higher potential at point 104 than the PRC program and much higher than what was reported in the EPRI report [9]. The terminating impedance at this end was not known and hence the end at point 104 was modelled with no extra termination impedance in CDEGS (which means a very high terminating impedance by software default) leading to a higher pipeline potential. The first voltage peak appears at point 101.7, where the power line enters the shared corridor. The second peak appears at point 89 where the pipeline veers away from the power line at a certain angle. A slightly lower peak appears at point 78 where the pipeline moves closer to the power line again. The highest steady state potential appears at the location of the power line transposition at point 68. The last steady state potential appears at point 47, the location where the pipeline changes the side on which it runs along the power line. All these peaks were predicted very accurately with CDEGS. Prediction of these pipeline potentials with PRC was quite accurate as well, with the exception of the peak at point 89.
While this experiment in Mojave desert was predominantly conducted in order to experimentally prove the methods for prediction of induced voltages on pipelines, results should be compared with acceptable values from Standards. NACE Standard RP0177 [44] states that only 15 V of induced AC voltage on pipeline is allowed in steady state. This means that some sort of mitigation was required on Mojave pipeline. Project [9] presented several experimental mitigation methods applied on the Mojave pipeline. It is not known which method was selected as a final solution.

4.1.3 Features of CDEGS and PRC Packages

The PRC package has a much smaller scope in assessing induced voltages on pipelines than CDEGS. Its main disadvantage in comparison with CDEGS is that it cannot take into account the multilayered structure of the soil. There are also limitations in the scope for designing mitigation structures for pipelines. CDEGS is much more flexible in this regard. The PRC interface only accepts real numbers for impedances, whereas CDEGS accepts complex numbers. Based on the above description, CDEGS was chosen as the preferred software package to carry out the present study.

4.2 Introduction to CDEGS: Young-Lithgow (YL) Pipeline Case Study

A complete CDEGS interference study was first performed on the Young-Lithgow shared corridor. This corridor allowed relatively easy access to the Agility's [3] pipeline and its facilities and to the power line. Its complexity and the possibility of incomplete mitigation made it very convenient for a complete pipeline and power line interference study using CDEGS software.

4.3 Description of the Corridor

The Young-Lithgow pipeline is 212 km long and kilometre markers are used throughout the study to identify locations along the pipeline. Insulating joints electrically separate sections of the pipeline from terminal facilities and pumping systems. They were used here to limit leakage of cathodic protection currents to a single section (resulting from the use of two insulating joints) in the case of the pipeline developing a contact with other structures. In the case of the failure of the cathodic protection unit, the extent of unprotected pipeline is limited to only one affected section. On the Young-Lithgow pipeline, insulating joints are located at point 120 and at the end of the pipeline at point 212. The corridor where the pipeline runs parallel to a number of power lines exists

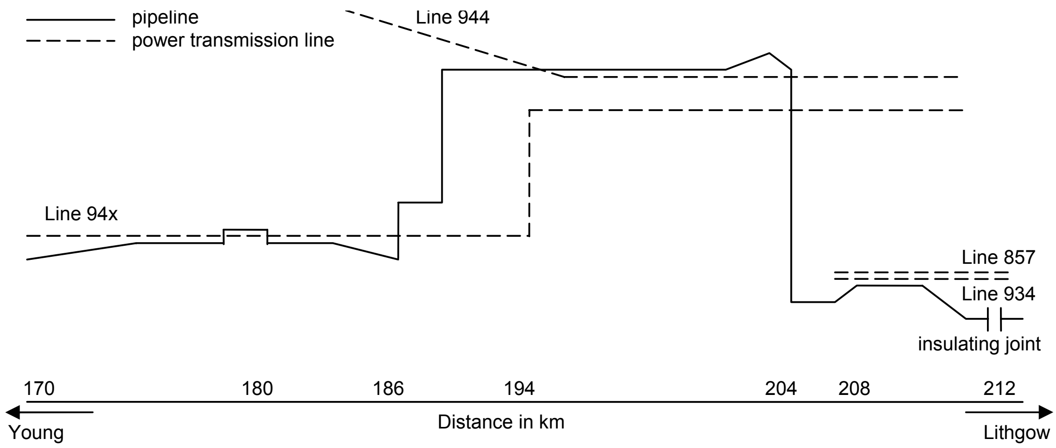

Figure 4.7: Young-Lithgow pipeline - physical layout of the shared corridor (not drawn to scale)

between points 170 and 212, and only this 42 km segment was part of this study, as shown in Figure 4.7. In analysing this segment of the pipeline, three sections were identified as being in a high risk zone for induced AC voltages from nearby power lines. These sections are 170-186, 194-204 and 208-212 respectively. During the analysis, all three sections were analysed together as the influence of one section on another must not be neglected.

4.3.1 Pipeline

The pipeline is made of steel with a 168.3 mm outer diameter and 4.8 mm wall thickness. The pipe specification is API 5L X46. This is a standard pipe grade specified in API (American Petroleum Institute) specification 5L. The applied coating on the pipeline is high density polyethylene known as yellow jacket. The coating resistance of 83600 $\Omega - m^2$ corresponds to a coating in a very good condition and was used in the study. An average depth of the pipeline of 2 m below the ground surface was used throughout the calculations. There are 32 test points (where AC induced voltages on the pipeline and AC current densities in the pipeline can be measured) along the 42 km length of the pipeline.

4.3.2 Existing Pipeline Mitigation

The final 42 km section of the Young-Lithgow pipeline (inside the shared corridor) is protected against fault conditions on the power lines with two surge diverters located at the gas metering station at Brewongle Road (point 170) and the gas metering station at Lithgow (point 212). The pipeline surge diverter (part No. AE137X) was manufactured by CorrPro [45] and has a continuous rating of 40 A AC-RMS. Its fault ratings are 3.5 kA, 0.5 s. One side of the surge diverter is connected to the pipeline and the other is connected to a galvanized steel conductor buried at 0.6 m depth and placed around the metering station. Point 212 of the Young-Lithgow pipeline terminates with an insulating joint. Its purpose is to electrically isolate the high pressure pipeline that comes from Young from the gas metering station and the network of a low pressure pipelines on the other side of it. It also has a role to contain DC cathodic protection currents on the pipeline and prevent their leakage to the network of low pressure pipelines. Metering stations at points 170 and 212 are equipped with a steel gradient cable to keep touch voltages inside the metering station area to allowable levels. Test points along the pipeline have no gradient control mats installed.

4.3.3 Power Lines

In the vicinity of the pipeline between points 170 and 212, there are four power lines that are of interest for this study. Their voltage levels are 132 kV and 66 kV, and relevant details of these power lines are given in Appendix D, Table D.1.

4.3.4 Computer Modelling Procedure

Due to the complexity of the layout of the pipeline and the power lines encountered along the corridor, the computer model contained many approximations. Available schematics from Agility did not show the power lines. However, they are shown in topographic maps with a scale of 1:25000. These maps were used to estimate distances between the pipeline

and the power lines in the shared corridor. Some of these maps were printed before the pipeline was built, so the exact location of the pipeline was carefully drawn on the topographic map, using coordinates of the pipeline available from the schematics provided by Agility.

4.3.5 Soil Resistivity

Field measurements of soil resistivities at selected sites along the shared corridor were carried out using the Wenner method. The data was then processed using the RESAP module, an integrated part of the CDEGS software, which is used for interpretation of field soil resistivity measurements. The output of RESAP provides a two layer computer soil model for each set of measurements. Along the last 42 km of the Young-Lithgow pipeline (the length that is of interest in this study), the landscape consisted mostly of cleared farmland. The measured soil resistivities are average for this type of soil and (almost as a rule) the top layer has a higher resistivity, which slowly drops with depth. The results are presented in Appendix C, Tables C.1 and C.2.

4.4 Existing Mitigation System

4.4.1 Steady State

The first step of a pipeline interference study is to undertake a steady state analysis. During steady state, the inductive component of the interference is the only one affecting the pipeline. The computer model established by CDEGS (as explained above) could be altered appropriately to accommodate different mitigation grounding configurations that can exist on a pipeline. There are three cathodic protection units placed along the final 42 km of the Young-Lithgow pipeline that are part of this study and each of them has a connection to earth through a capacitance with an impedance of 4 Ω at the power frequency. The steady state potential was measured on all test points that existed on the

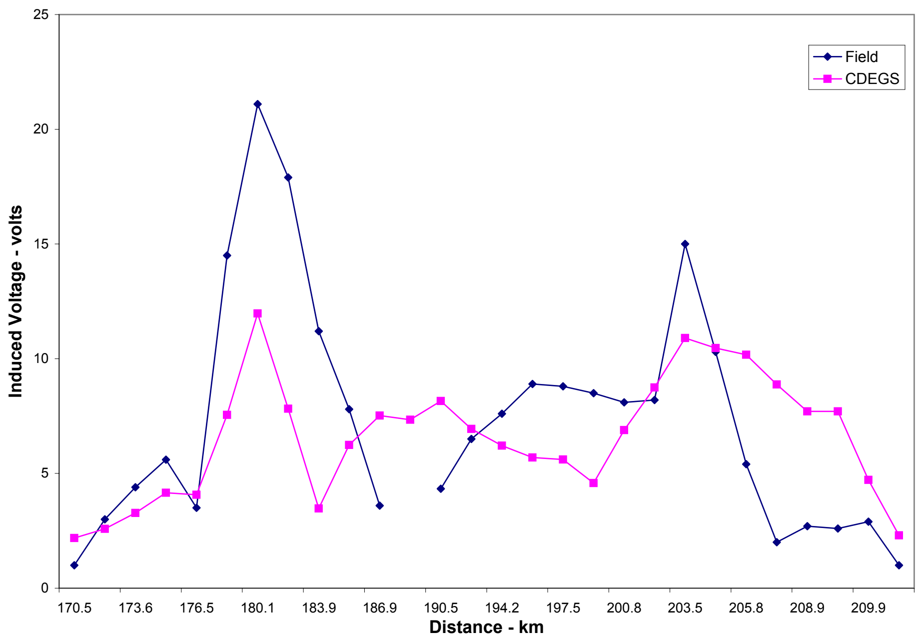

Figure 4.8: Young-Lithgow pipeline - steady state potentials

pipeline and a pipeline voltage profile was obtained. During these measurements two cathodic protection units at points 170 and 212 were connected to the pipeline. Therefore, the computer model had 4 Ω impedance connected to earth at those points. The cathodic protection at point 203.5 was disconnected. The steady state pipeline profile on the pipeline was compared with the computer calculations and the results are shown in Figure 4.8. From this, it can be seen that the overall levels of induced steady state voltages predicted showed significant difference at point 179, where power line conductor transposition occurs. There could be several reasons as to why there is no close agreement between the calculated voltages and the measured levels.

- There were many approximations made of the real position of the power line and the pipeline while developing the computer model. They never ran exactly in parallel and the angle between them changed frequently.

- The particular shared corridor was very complex, containing one pipeline and four different power lines.

- During the period of measurements of the currents at all test points along the pipeline, the currents in the power line may have changed. The logs obtained from the power utility showed half hour readings, and on the day of measurements sharp jumps in current (from 260 A to 325 A) were noticed in the half hour interval during which measurements took place.

- Current logs obtained had just one value for all three phases. The induced voltage on pipelines is very sensitive to any unbalance in the power line circuits. Even small unbalance can create high induced voltage peaks on the pipeline.

- Soil resistivities were measured at certain sites along the corridor. They do not generally change gradually and sometimes can change abruptly, which can lead to an induced voltage peak on the pipeline. It is possible that some abrupt changes of soil resistivity exist in the areas where pipeline induced voltages were not predicted accurately by the CDEGS computer model.

Prediction of steady state potentials on pipelines and obtaining close agreement with field measured levels is a sensitive issue, affected by many factors. In the case of Young-Lithgow pipeline, further investigations into the above mentioned factors, especially at point 179, are required in order to obtain closer agreement with field measured levels. It should be noted here that according to Australian Standard 4853 [28] the maximum allowed induced voltage on the pipeline in the steady state is 32 V. Therefore, there is no need for any additional mitigation of induced voltages on the Young-Lithgow pipeline in the steady state. The current densities in the pipeline were not measured. Therefore, an assessment of the possible existence of pipeline AC corrosion could not be made.

4.4.2 Faults - Inductive Component

The shared corridor contains four different power lines and faults were simulated on all four of them. The power utilities that owned the power lines in the shared corridor

supplied the fault levels at the substation busbars where the power lines terminated. From the parameters and geometry of the power lines, their zero and positive sequence impedances were calculated (see Appendix B Section B.1) which enabled approximate calculation of fault levels at any fault location along any power line(see Appendix B Section B.2). The calculated components for the required faults on power lines in the Young-Lithgow shared corridor are given in Appendix D Table D.1.

It was mentioned earlier that surge diverters exist at two locations in the shared corridor (at points 170 and 212). Faults were simulated with two possible configurations regarding the insulating joint at location 212: with the pipeline terminating with the insulating joint and with the insulating joint bridged. It was assumed that in the case of a fault both surge diverters would be conducting as the induced voltage at their locations would always exceed the operating voltage of the surge diverter. When a surge diverter conducts, the pipeline coating stress voltage at the surge diverter location is reduced to a very small value (in this case at points 170 and 212). The inductive component of coating stress voltage peak on the pipeline is dependent on the location of the fault on the power line. Line 94x is located in the first part of the length of the corridor that was of interest in this study (see Figure 4.7). As seen from Figure 4.9, high induced voltages on the pipeline exist in this area. These high voltage levels gradually drop towards the Lithgow end of the pipeline. The highest value found was 3205 V, observed at point 185.

When a fault on the line 944 is modelled, the highest inductive component of coating stress voltage appeared at a point more towards the Lithgow end of the pipeline, in the area of the corridor where this line is present. From Figure 4.10, it can be seen that the inductive component of the maximum coating stress voltage of 5076 V appeared at point 195.8.

The power line 934 is present at the very end of the shared corridor and consequently, the inductive component of the maximum coating stress voltage of 2058 V appeared at the point 209.8, as can be seen in Figure 4.11. The inductive component of the maximum coating stress voltage arising from the faults on the 66 kV power line 857 was around 800

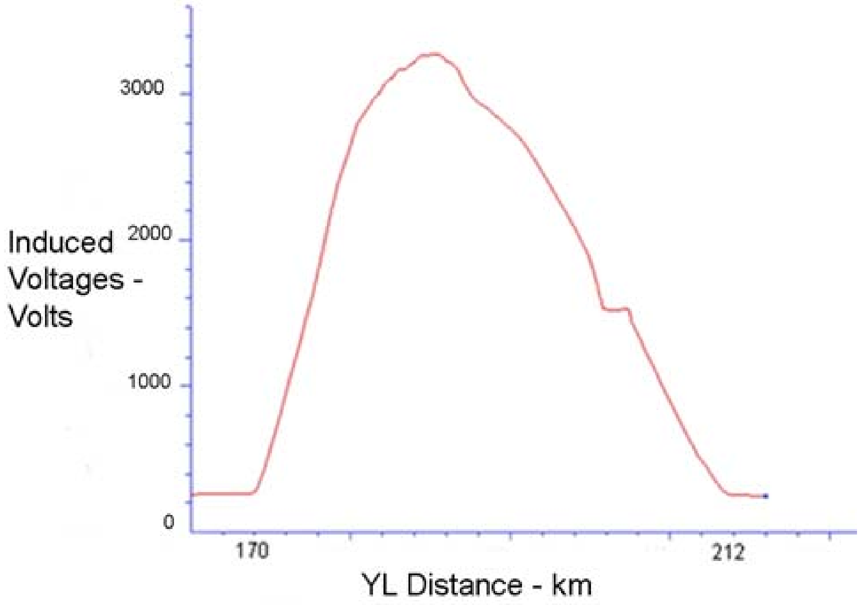

Figure 4.9: Young-Lithgow pipeline - inductive component of coating stress voltage for faults along power line 94x

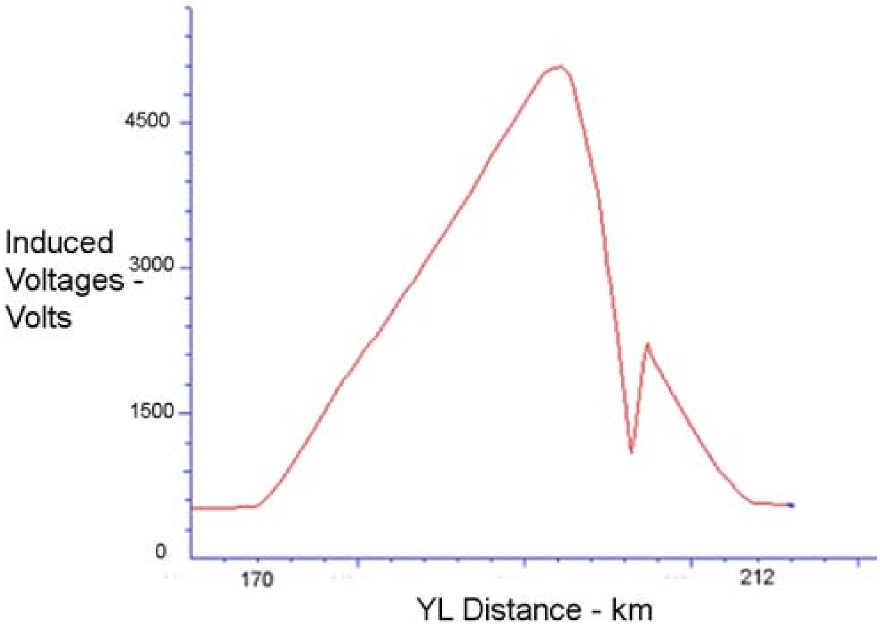

Figure 4.10: Young-Lithgow pipeline - inductive component of coating stress voltage for faults along power line 944

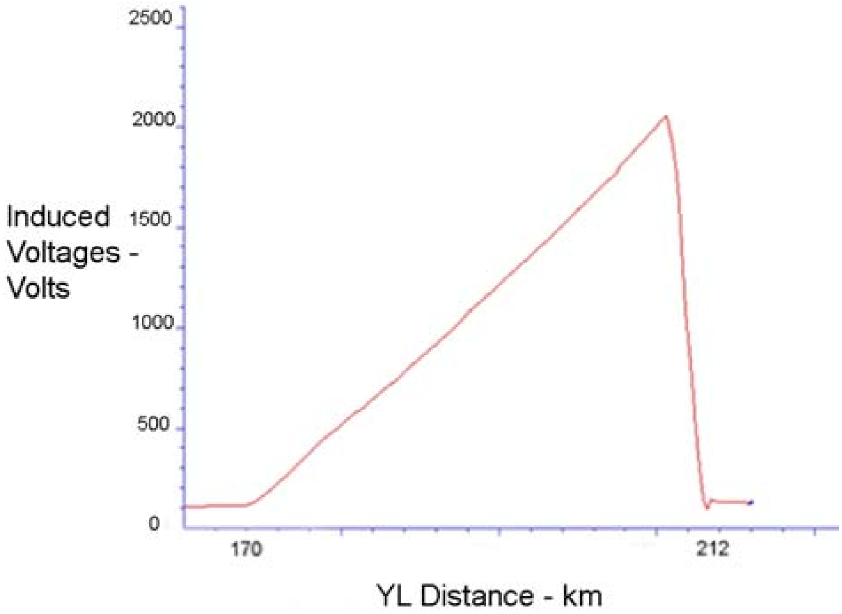

Figure 4.11: Young-Lithgow pipeline - inductive component of coating stress voltage for faults along power line 934

V and is not presented on a graph. Its influence on the pipeline was significantly lower than the influence of the 132 kV line 934. Line 857 is further away from the pipeline and operates at lower voltage level. As line 934 is located between the pipeline and line 857, line 934 acts as a pipeline shield for faults on line 857.

4.4.3 Faults - Conductive Component and Total Pipeline Coating Stress Voltages

Selection of power line towers for simulation of a fault that yields the highest conductive component of pipeline coating stress voltage was based on pipeline and power line separation and on locations where abrupt change in electromagnetic coupling occurred. Total pipeline coating stress voltage was obtained by adding the conductive and inductive component of coating stress voltages. As mentioned in Section 3.4.6, the angles of these two components are such that their scalar addition to obtain the total coating stress voltages did not introduce a significant error to the final result. In Table 4.1, total pipeline coating stress voltages are presented for the following faults simulated: (a) at the

beginning of the distance where pipeline and power line shared the corridor, (b) at the location of the tower inside this distance that yielded the worst case and (c) at the end of this distance. The length of power line 934 which shares the corridor with the pipeline is very short and the worst case is actually at the beginning of shared distance making points (a) and (b) in this case common (for this reason, results for point (b) are not shown in Table 4.1).

Faulted Line	Fault Location	YL Distance (km)	Inductive Voltage (V)	Pipeline Separation (m)	Conductive Voltage (V)	Total Coating Stress (V)
94x	(a)	170	274	650	6.7	280
	(b)	179.5	2511	30	185	2696
	(c)	185	3205	29	400	3605
944	(a)	195.8	5076	300	142	5218
	(b)	200	3051	30	958	4009
	(c)	203.5	209	29	1407	1616
934	(a)	209.3	2058	35	227	2285
	(c)	212	133	470	32	165

Table 4.1: Young-Lithgow pipeline - total pipeline coating stress voltages

By considering the values in the last column of Table 4.1 (the total coating stress voltage on the pipeline at selected locations), it is seen that there are several locations where the total coating stress voltage is above 3 kV. The worst case is 5218 V. It can be noted that total coating stress voltages at the beginning and at the end of the shared corridor are much lower than the levels that are encountered in the middle of the corridor, especially with regard to voltages arising from faults at power line 944. The existence of surge diverters at the beginning and at the end of the shared corridor suppressed total coating stress voltages in their vicinity. Line 944 had very high fault levels for faults in the corridor because its terminating substation is very close (Wallerawang is only about 3 km from the shared corridor, see Appendix D Section D.1). Also, there was no mitigation in the middle of the shared corridor to reduce these high coating stress voltages. The Safe Engineering pipeline interference procedure [5] states: “Coating stress voltages should not

exceed 5 kV or, preferably, 3 kV, otherwise the coating may be damaged and accelerated corrosion will result. In severe cases, the pipeline wall can be damaged by arcing. If necessary, design mitigation to reduce these stress voltages". These limits are further elaborated in [46]. The highest calculated pipeline coating stress voltage on the Young-Lithgow pipeline from a fault on line 944 of 5218 V at point 195.8 required further consideration for additional mitigation measures around its location. It should be noted here that these coating stress voltages were calculated for uniform coating with no coating holidays. Since the coating on the actual pipeline presumably had some coating holidays, its resistance to earth would be lower than the resistance which assumes pipeline coating without holidays. Therefore, the calculated coating stress voltages would be slightly lower, depending on the current state of the pipeline coating. It was estimated that the coating on the Young-Lithgow pipeline was in a very good condition and reduction of total coating stress voltages would be low (for instance, not more than a couple of hundred volts).

4.4.4 Safety Assessment of Test Points

There are 32 test points along the pipeline shared corridor. Touch voltages were assessed only on two test points, the ones that were at the most critical locations in the corridor, points 180.1 and 203.5. The other test points in the shared corridor are at the locations that inhibit much less interference from the power lines leading to lower touch voltages. The analysis of the test point at pipeline location 180.1 revealed that in the case of a fault on a local power line tower, the touch voltages would be significantly in excess of the maximum safe touch voltage. This was mainly due to the fact that the pipeline mitigation consisted only of earthing at the gas metering stations at points 170 and 212. There was no other mitigation installed in between points 170 and 212. Figure 4.9 shows the distribution of pipeline potential during the fault on the line 94x. It can be seen that there are high potential levels in the middle of the pipeline shared corridor. These voltages could become touch voltages at pipeline appurtenances, and they are so high that almost any

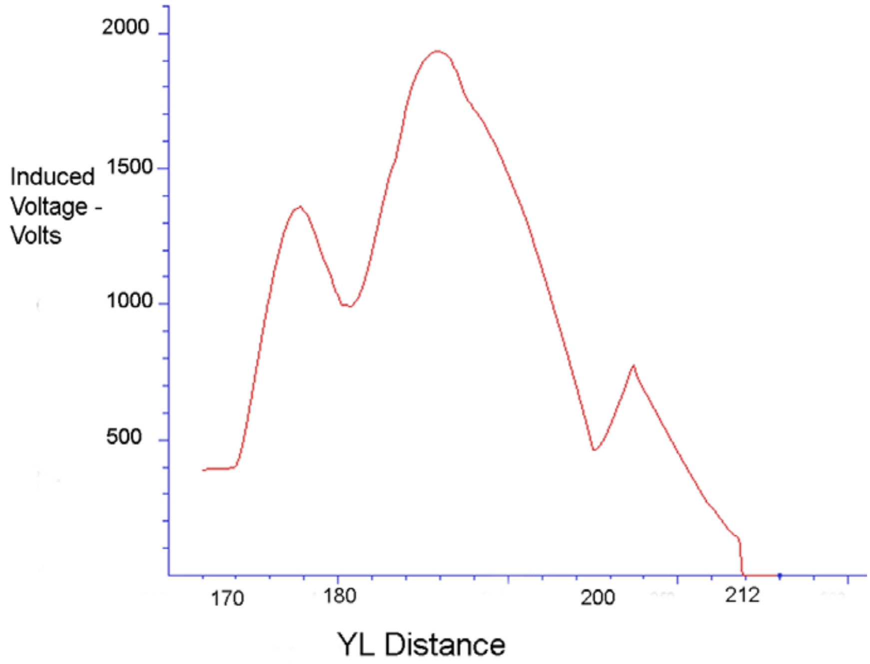

Figure 4.12: Young-Lithgow pipeline - inductive component of coating stress voltage for faults along power line 94x - with extra grounding at points 180.1 and 200

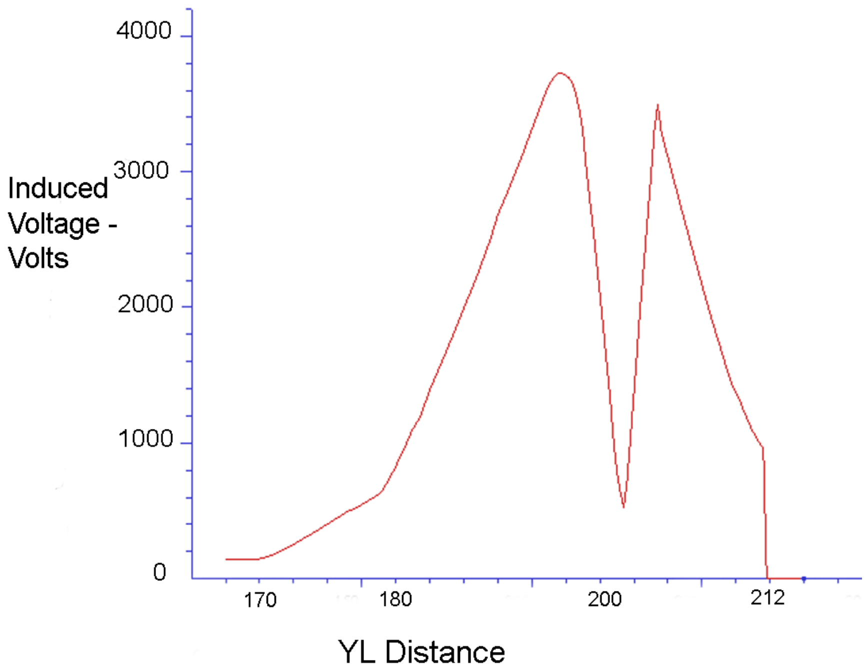

Figure 4.13: Young-Lithgow - inductive component of coating stress voltage for faults along power line 944 - with extra grounding at points 180.1 and 200

action at the test point gradient grid would not lower them sufficiently to comply with safe levels. Installing two extra grounding anodes with an impedance of 2.5 Ω at points 180.1 and 200 would reduce pipeline potential levels, as shown in Figure 4.12 for faults at power line 94x and in Figure 4.13 for faults at power line 944. Installation of these two earthing points along the power line would be just a first step in searching for an adequate test point mitigation design that satisfies safety criteria. Any reduction of the induced voltages on the pipeline by installing mitigation systems would result in the reduction of the touch voltages at the test points. Further analysis of mitigation of touch voltages at test points would depend on the objectives of the proposed mitigation. The pipeline and test point mitigation on the Young-Lithgow pipeline is not elaborated here. However, a detailed test point safety analysis and mitigation design procedure is given in Section 5.5.5.

4.4.5 Cathodic Protection

Along the length of the shared corridor between points 170 and 212, there are three impressed current system cathodic protection units. They are positioned at points 170, 203.6 and 212. As explained in Section 3.6, pipeline DC potentials were logged for nine months but could not be used in the study as they were measured while the rectifier systems were on.

4.5 Conclusions

The performance of two software packages, PRC and CDEGS, was compared along with their abilities for interference studies. A complete interference analysis between a pipeline and several power lines in a shared corridor using CDEGS software was presented. The analysis revealed a total pipeline coating stress voltage during a fault in excess of 5000 V in the middle of the considered shared corridor. Test points along the pipeline revealed touch voltages in the case of power line faults well in excess of the safe limit due to the fact that there are no mitigation systems installed at test points and on the pipeline. It

was shown that two extra 2.5 Ω grounding anodes on the pipeline at points 180.1 and 200 could reduce the peak pipeline coating stress voltage to a level below 5000 V.

Chapter 5

Assessment of Two Mitigation Methods: Brisbane Pipeline Case Study

5.1 Introduction

The subject of this case study is Agility's [3] Brisbane to Roma natural gas pipeline. The section of interest for interference study exists between Collingwood Park and Ellengrove metering stations (hereafter, called the Brisbane pipeline) that shares a corridor with a Powerlink [47] power line. Among several different mitigation design options, a design including six insulating joints and associated higher impedance earthing was chosen by Agility and implemented on the pipeline. CDEGS interference analysis was carried out in relation to both the existing mitigation design and an alternative hypothetical pipeline mitigation design employing the popular gradient control wire method. Results obtained using both mitigation system designs are analysed and compared.

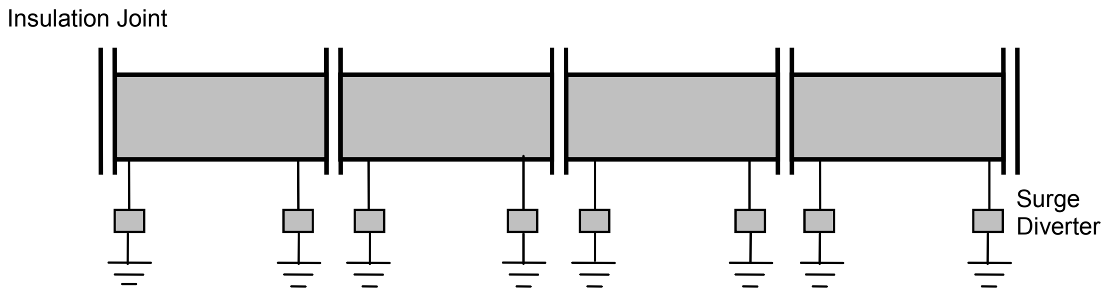

Figure 5.1: Mitigation system with insulating joints

5.2 Mitigation Methods

5.2.1 Mitigation with Insulating Joints

The use of insulating joints is illustrated in Figure 5.1. Insulating joints divide the pipeline into several electrically isolated parts so that induced voltages cannot reach high levels. Local ground is then connected to the pipeline at each side of the insulating joint. Each earthing electrode is connected to the pipeline through a surge diverter, which operates only when the voltage on the pipeline is higher than its breakdown level. With this method, the pipeline is protected from stray currents that can cause corrosion and cathodic protection currents are prevented from leaking out. The combination of insulating joints and permanent earths can be quite an effective way of mitigating AC voltages on the pipeline. However, there are several drawbacks of this method which are discussed in Section 5.6.

5.2.2 Mitigation with Gradient Control Wire

Mitigating induced voltages on pipelines with gradient control wire has been the most recently developed method (see Section 2.2.4). The method involves one or two zinc wires buried in parallel with the pipeline, with regular electrical connections to the pipeline. An example of the use of two wires is illustrated in Figure 5.2. The connections with the pipeline should be made through surge diverters, as in the case of insulating joints. Two

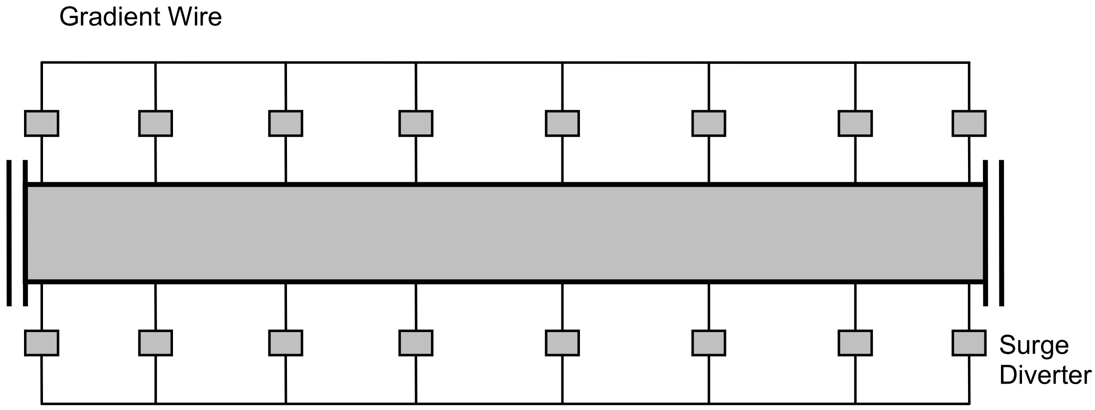

Figure 5.2: Mitigation system with gradient control wire

insulating joints are also present at the start and at the end of the pipeline. It is compulsory to electrically isolate the pipeline from the rest of the pipeline network if the rest of the network operates on different gas pressure level or belongs to a different pipeline owner. Gradient control wires provide grounding to the pipeline in relation to inductive interference. They also raise the potential of the local earth, reducing the touch and coating stress voltages. In relation to conductive interference, these wires reduce the potential difference between the pipeline and local earth by allowing the current to flow between them [36].

5.3 Description of the Corridor

Figure 5.3 shows the 9.3 km long section between Collingwood Park and Ellengrove metering stations of the Brisbane to Roma pipeline. Along this distance the pipeline shares the corridor with a double circuit vertical steel tower power line. The separation between the pipeline and power line towers varies, but is generally around 30 m. For about 2 km along this corridor the separation is only 10 m. The shared corridor is in an urban area and neighboring suburban streets provided access points. Considering the length of the corridor and the fact that the pipeline has been built in a such a way that it crosses beneath power line in places, thus changing the side it runs along the power line, it

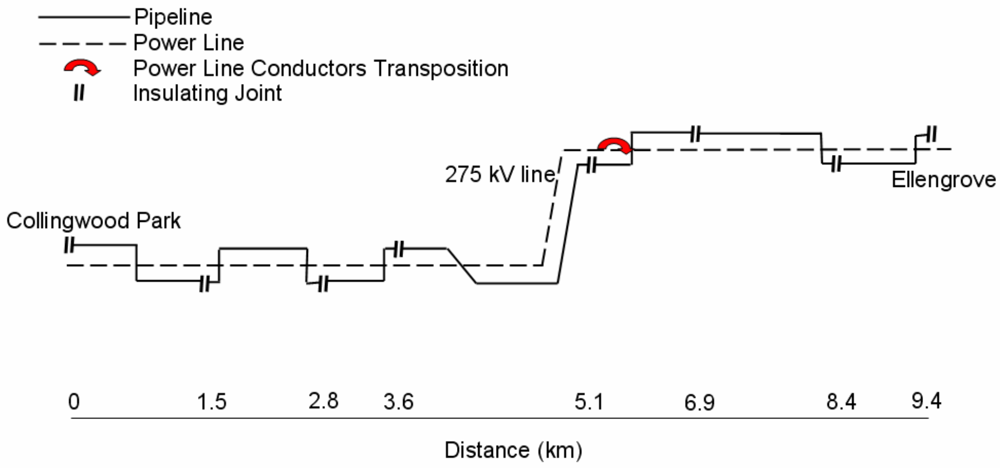

Figure 5.3: Brisbane pipeline - physical layout of shared corridor (not drawn to scale)

is expected that significant levels of induced AC voltages would appear on the pipeline during faults on the power line.

5.3.1 Pipeline

The pipe specification is API 5L X60 in accordance with American Petroleum Institute specification 5L. This is a standard pipe grade specified in API (American Petroleum Institute) specification 5L. The pipeline is steel with a 406 mm outer diameter and 9.5 mm wall thickness. Applied coating on the pipeline is high density polyethylene (yellow jacket). Pipeline was built in 2001 and it is estimated that pipeline coating is in a very good condition and hence, the coating resistance of 83600 $\Omega - m^2$ was used in the study. The average depth of the pipeline is around 1.5 m below the ground surface.

5.3.2 Existing Pipeline Mitigation

The existing mitigation design involved eight insulating joints, one at each metering station (at distance of 0 km and 9.3 km) and six additional insulating joints placed at approximately equal distances along the corridor. In addition, at the location of each insulating joint there were two permanent copper earth rods placed one at each side of the

insulating joint. These permanent earths were designed to have an impedance of less than 10 Ω. Copper in direct contact with pipeline steel can create an electrochemical combination that is prone to corrosion. To avoid this and to avoid possible interference of earth rods with the pipeline cathodic protection system, earth rods are connected to the pipeline through a surge diverter. They will be electrically connected to the pipeline only during a fault on the power line.

5.3.3 Power Lines

The power lines are owned by Powerlink [47] in Queensland. Their ratings, protection speeds and other relevant data are given in Appendix D Table D.2. Footing resistances of each power line tower along the shared corridor are given in Table D.3. The data required to model the towers themselves (for example the physical dimensions of conductors and their type) were supplied by Powerlink.

5.3.4 Computer Model

A common computer model of the entire 9,3 km of the shared corridor was used to study both the existing mitigation design with insulting joints and the alternative mitigation design employing gradient control wire. The pipeline schematics obtained from Agility [3] were used to prepare a computer model of the corridor. These schematics were very useful as they contained the precise layout of the power lines that share the corridor with the pipeline and exact locations of the towers. The computer model was developed with as few approximations as possible, modelling all significant bends on the pipeline and modelling power line towers exactly at their positions and hence higher accuracy levels can be expected.

5.3.5 Soil Resistivity

This section describes the process used to determine soil resistivity, taking Powerlink's earthing installation data sheets (which included description of the soil in the shared corridor) as a starting point. The soil was described as sandstone, sandy, clay or a combination of these. In areas where sandy soil is a top layer, measurements uncovered a high soil resistivity, about 1300 $\Omega - m$. The areas with sandstone or clay as a top layer had much lower soil resistivity measurements, around 200 $\Omega - m$. There was a site, around tower No. 2240, where no readings were obtained during measurements. This area was very sandy which increased resistances around the current electrodes of the Wenner method measuring set (see Section 3.1). The minimum current required to obtain a reading on the measuring set could not be injected into the soil. The pattern on all other measuring sites was top layer with higher soil resistivity, dropping to lower values as soil resistivity was measured deeper down into the ground. The RESAP module of CDEGS software calculated a two layer computer soil model using each set of measurements. The shared corridor was divided into several regions based on the different soil models. The soil resistivity measurements and calculated multilayered soil models are presented in Appendix C Table C.3.

5.3.6 Approximate Calculation of Induced Potentials on Pipeline

In order to verify the results obtained from the CDEGS study on the Brisbane shared corridor, a simple formula given in [28] was used to calculate the expected pipeline potentials during fault on the power line. Longitudinal induced voltage between the two ends of the exposed section will be equal to:

$$E = C * I * l * K \tag{5.1}$$

where

E = induced voltage on pipeline, V

C = coupling factor (mutual impedance per unit length), Ω/km

I = power line fault current, A

l = shared corridor length, km

K = shielding factor ($0 < K < 1$)

The procedure for determination of C, I, l and K is summarised in [48]. For the shared corridor the shielding factor K obtained from Powerlink is 0.91. The shielding factor is applicable when the overhead earth wire carries a portion of the fault current which reduces the electromagnetic field, thus acting as a shield. The coupling factor or mutual impedance was obtained from the nomogram presented in Appendix E Figure E.1. If the average separation between the pipeline and the power line in the shared corridor is taken as 35 m and the average soil resistivity at the depth at which the pipeline is buried as 30 $\Omega - m$, the value for mutual impedance from the nomogram is 0.175 Ω/km. The fault current in the pipeline in the worst case scenario is 7700 A, as explained in Appendix D.4.2. With this value, equation (5.1) gives 11400 V as a rough estimate of the worst case induced voltage on the pipeline. The highest inductive component of pipeline coating stress voltage calculated with CDEGS is around 7200 V with no mitigation applied. The difference between results from (5.1) and CDEGS arises as the former assumes straight conductors whereas the pipeline and the power line change their directions frequently (accounted for in CDEGS model). It should be also noted here that this rough estimate method assumes perfect pipeline coating, which yields higher calculated induced pipeline voltages. CDEGS calculations, on the other hand, take into account leakage currents through coating imperfections leading to lower and more realistic calculated induced voltage on the pipeline. On the whole, it can be assumed that the induced voltage calculated using equation (5.1) and CDEGS agree to a resonable degree.

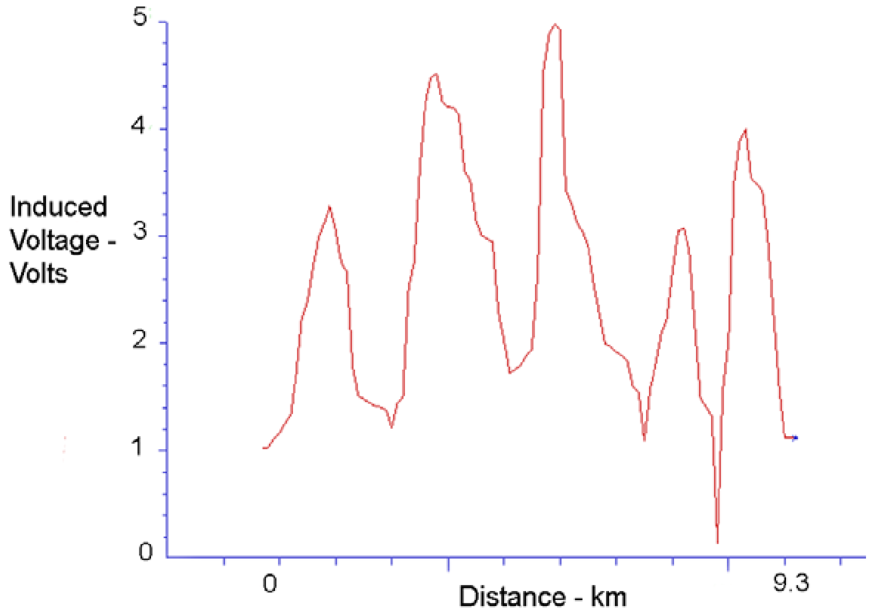

Figure 5.4: Brisbane pipeline with no insulating joints - steady state potentials

5.4 Existing Mitigation System with Insulating Joints

In the first stage, a complete pipeline interference study on the Brisbane pipeline was carried out by modelling the existing mitigation system. The steady state pipeline potentials, coating stress voltages during a fault (consisting of inductive and conductive component), test point safety and cathodic protection system were studied in order to obtain results that will be compared with those obtained from modelling the alternative mitigation system using gradient control wire.

5.4.1 Steady State

Induced voltages on the pipeline during steady state operation of the power line have been assessed by modelling three different configurations of insulating joints on the pipeline. In the first case no insulating joints were modelled, and the corresponding results are presented in Figure 5.4. In the second case two insulating joints were modelled at the termination points of the pipeline (points 0 and 9.3 km) as the pipeline should always be

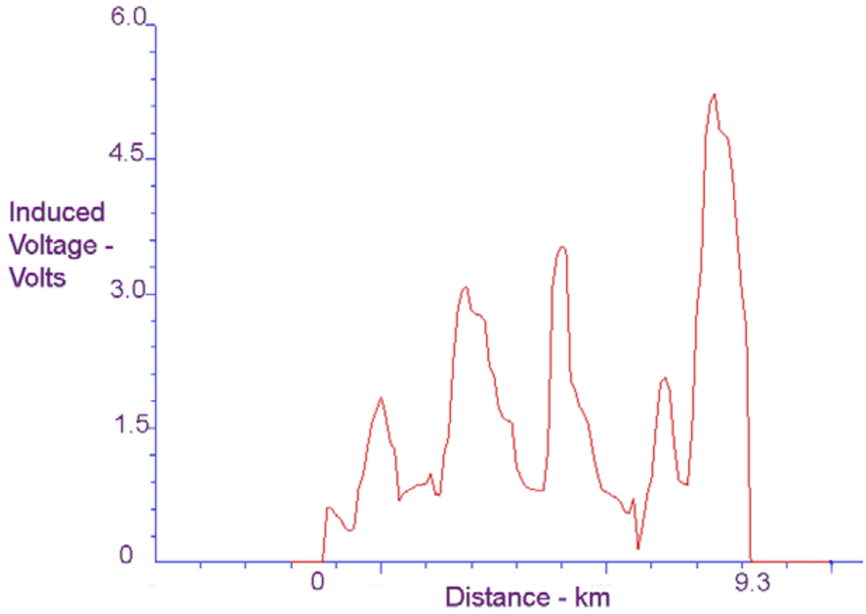

Figure 5.5: Brisbane pipeline with insulating joints at termination points - steady state potentials

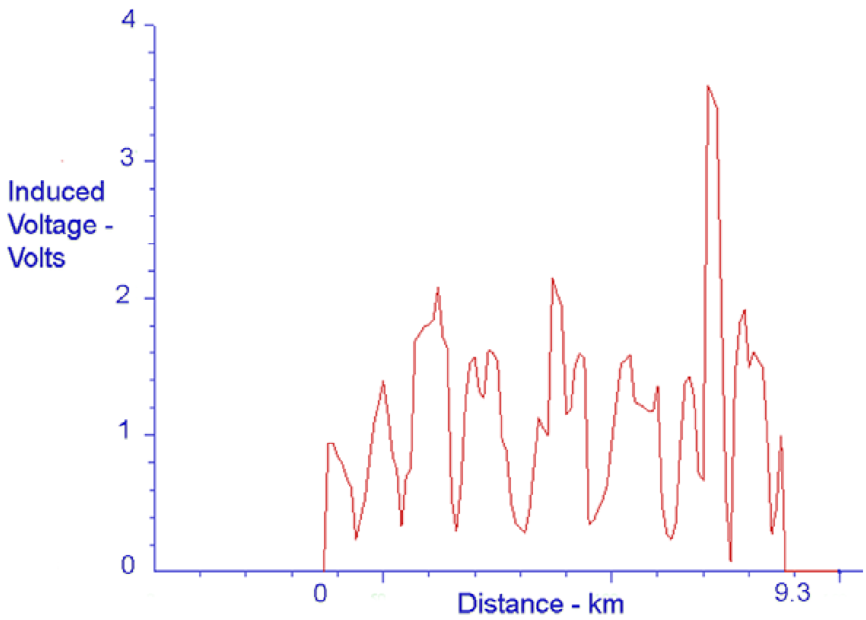

Figure 5.6: Brisbane pipeline with 8 insulating joints - steady state potentials

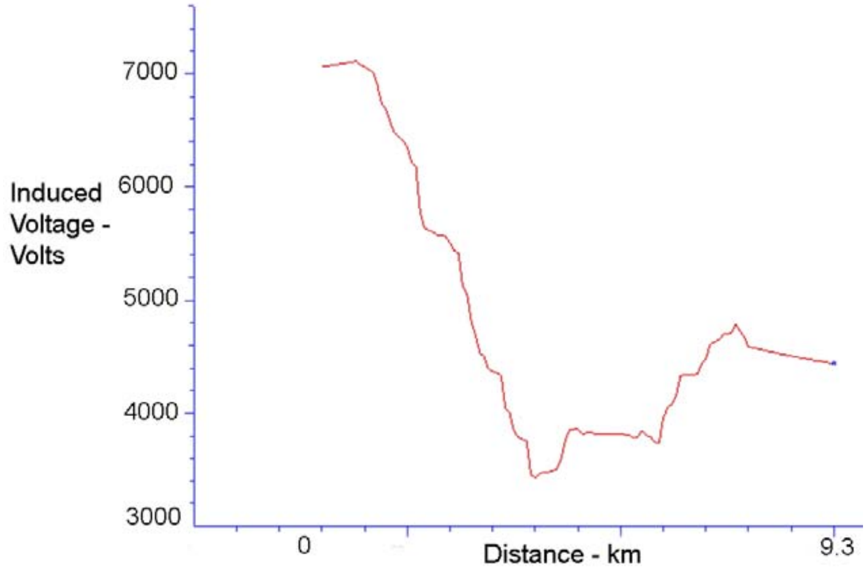

Figure 5.7: Brisbane pipeline with no insulating joints - inductive component of coating stress voltage for faults along power line 817

electrically insulated from the rest of the pipeline network, regardless of what type of mitigation system is applied on the pipeline. The reasons are: (a) to prevent cathodic protection currents leaking further along the pipeline and (b) the rest of the pipeline network could operate at different gas pressure or could belong to a different pipeline owner. Corresponding results are illustrated in Figure 5.5. The results of the third case are illustrated in Figure 5.6 and represent the steady state induced voltages on the pipeline in the case of a total of eight insulating joints modelled on the pipeline which corresponds to the existing configuration. As can be seen from all three graphs, the maximum steady state induced levels are around 5 V. This value is well within the allowed values by the Standard [28], which means that there is no need for any further mitigation of steady state potentials on the pipeline. The assessment of possible pipeline AC corrosion could not be made because current densities in the pipeline were not modelled.

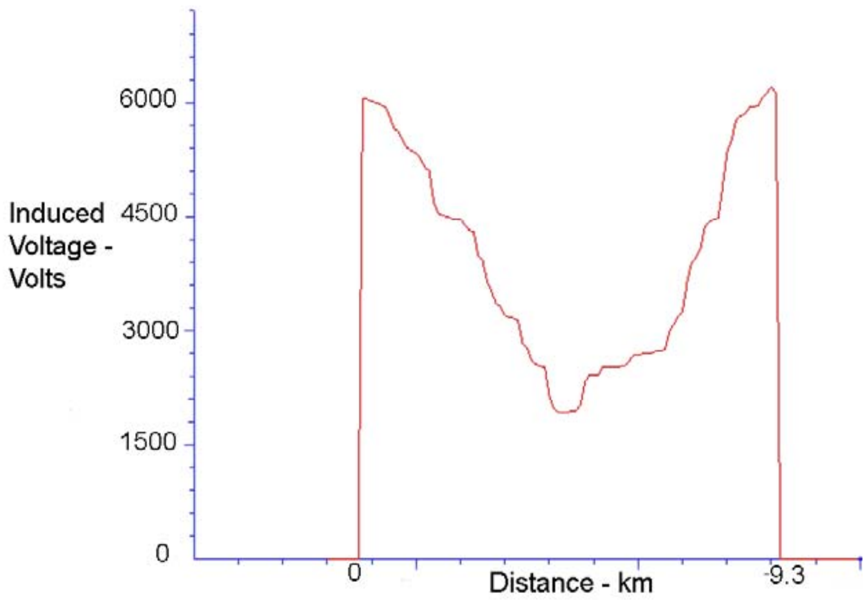

Figure 5.8: Brisbane pipeline with insulating joints at termination points - inductive component of coating stress voltage for faults along power line 817

5.4.2 Faults - Inductive Component

Faults were modelled at each power line tower in the shared corridor (procedure given in Appendix D.4.1) and graphs were plotted as per Section 3.4.4. The inductive component of pipeline coating stress voltage for the scenario where no mitigation is present on the pipeline is shown in Figure 5.7. Quite high and unacceptable voltage levels appear on the pipeline during the fault in this case. For example, over 7000 V would be induced at one end of the pipeline. This clearly demonstrates the need for induced voltage mitigation on the pipeline. The results obtained with insulating joints modelled at the two termination points of the pipeline (Collingwood Park at point 0 km and Ellengrove at point 9.3 km) are shown in Figure 5.8. Around 6000 V is induced at each end of the pipeline.

In the next modelling scenario, in addition to two insulating joints at termination points, six insulating joints located between the two termination points were included to match the existing pipeline configuration. The coating stress voltages on the pipeline are greatly reduced as can be seen from Figure 5.9. The length of the common coupling of each of

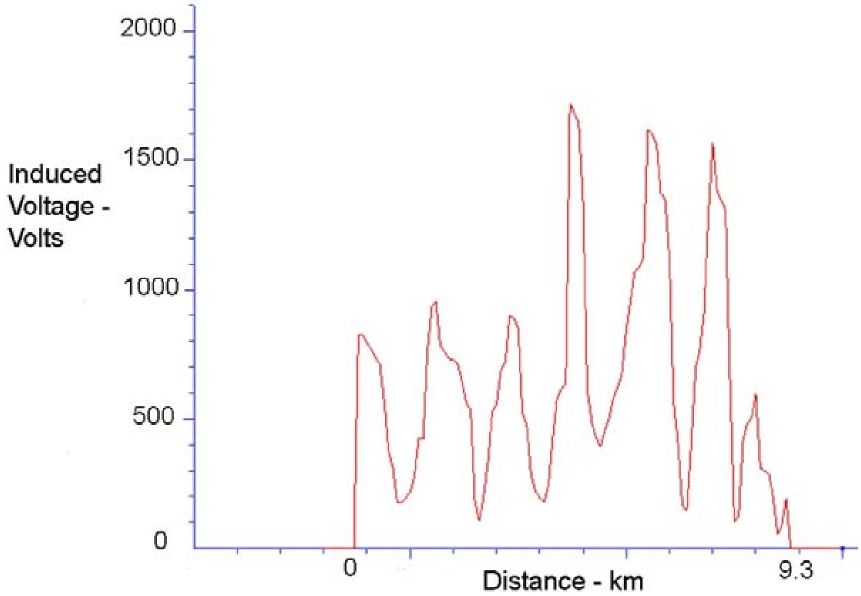

Figure 5.9: Brisbane pipeline with eight insulating joints - inductive component of coating stress voltage for faults along power line 817

these seven sections of the pipeline with the power line is now much shorter than in the case without insulating joints. Since induced voltages on pipelines are directly proportional to the length of common coupling, induced levels are now lower, at around 1500 V maximum. According to the installation details sheet, permanent earth electrodes are connected to the pipeline at each side of each insulating joint. Permanent earth electrodes have been designed to have less than 10 Ω impedance to the earth. Once this value was included in the computer model, the inductive component of pipeline coating stress voltage levels obtained are shown in Figure 5.10. In the case of frequently placed insulating joints along the pipeline, placement of earth electrodes at insulating joint locations does not seem to reduce the maximum coating stress voltages on the pipeline. While the levels are lower at locations of the earth electrodes, the coating stress voltage levels in between two insulating joints have increased. While the potential is reduced at the location of the earth electrodes, it rises further away from them. This is a consequence of the "balloon effect", as stated in [9].

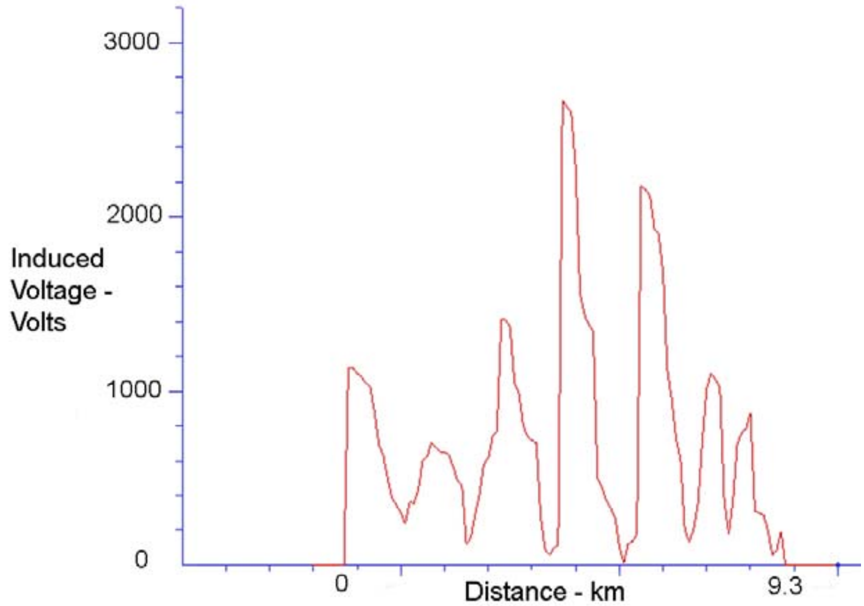

Figure 5.10: Brisbane pipeline with eight insulating joints and permanent earths - inductive component of coating stress voltage for faults along power line 817

5.4.3 Faults - Conductive Component and Total Pipeline Coating Stress Voltages

To obtain the stress voltage to which the pipeline coating would be subjected in the case of a power line fault, it is necessary to calculate the conductive component and add it to the inductive component. In reality, there is a small phase angle between the two components, so adding them arithmetically represents a conservative approximation. The conductive component of the pipeline coating stress voltage has a strong relationship with the separation distance between the faulted power tower and the pipeline. The fault study was repeated for faults on all towers in the shared corridor. Inductive and conductive components and total coating stress voltages are given in Table 5.1, where it is seen that all total coating stress voltages are well below 5 kV. This level corresponds to the allowable coating stress voltage for polyethylene used to make the yellow jacket coating that is used on the pipeline [5]. This means that the pipeline is well protected against high coating stress voltages with the existing mitigation system.

Tower No.	Distance (km)	Inductive Voltage (V)	Pipeline Separation (m)	Conductive Voltage (V)	Total Coating Stress (V)
2226	0.03	262	21	923	1185
2227	0.48	141	50	437	578
2228	0.86	267	40	200	467
2229	1.32	364	40	528	892
2230	1.71	97	40	664	761
2231	2.15	221	40	450	671
2232	2.58	520	5	1647	2167
2233	2.97	148	30	117	265
2234	3.15	214	30	189	403
2235	3.38	394	30	315	709
2236	3.80	405	12	394	799
2237	4.26	685	12	602	1287
2238	4.75	834	10	764	1598
2239	5.14	1109	55	420	1529
2240	5.58	390	28	875	1265
2241	5.92	374	28	189	563
2242	6.28	603	10	1023	1626
2243	6.72	1285	10	1882	3167
2244	7.26	406	10	1513	1919
2245	7.70	451	10	650	1101
2246	8.07	660	10	960	1620
2247	8.53	74	30	451	525
2248	9.03	232	30	605	837

Table 5.1: Brisbane pipeline with insulating joints - total pipeline coating stress voltages

5.4.4 Safety Assessment of Test Points

Touch Voltages (TV)

Touch voltages need to be assessed at points where contact between operating personnel and the pipeline or pipeline appurtenances can be made. In this shared corridor, critical locations where contacts may take place are inside the fenced metering stations at the start and at the end of the corridor and at test points along the corridor. Test points are located on the ground surface, on top of each insulating joint. Each test point consists of an internal terminal with wiring, placed inside a grounded metal box laid on a concrete base. There are one or two surge diverters mounted inside the box depending on test

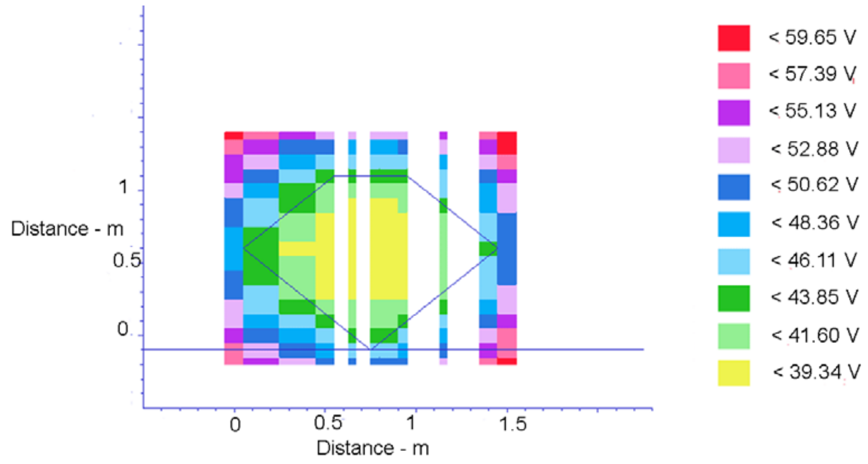

Figure 5.11: Brisbane pipeline with insulating joints, test point 1, fault at 2226 - conductive touch voltage distribution

point location and its function. Wiring includes connections to the pipeline, surge diverters, ground rods on both sides of the insulating joint, a corrosion probe and an earth mat. The earth mat is made of galvanized steel and placed at a depth of 0.6 m in the ground. The earth mat has a square shape with a 1 m side. One corner of the square mat is notched to accommodate the placement of the test point enclosure. Connection between the earth mat and the pipeline is made through a surge diverter, which means that it is only active during the fault. This arrangement exists to prevent interaction between the pipeline cathodic protection system and the earth mat. The protection speed on the power line is 80 ms primary and 250 ms backup. The calculations of touch voltages were based on a 50 kg body mass according to "IEEE guide for safety in AC substation grounding" [43]. Total touch voltage on the ground surface was calculated by arithmetically adding the inductive and the conductive components together. The soil resistivity of the ground surface used in these calculations was the soil resistivity of the top layer in the soil resistivity computer model used (see Appendix C Table C.4).

For a given shape of the test point earth mat, the calculations have shown that the highest touch voltage appears on the surface above the earth mat in the area of the conductor corner (both left and right corners) as illustrated in Figure 5.11 for test point 1.

Normally, the person working in front of the test point terminal would stand right in front of it. The assumption is that it is possible to touch the terminal and stand on top of the left or right corner of the mat. For this reason, those points were used throughout the study as a location of worst case touch voltages. The location on the surface of the earth mat where the highest conductive and inductive touch voltages appear are the same for any other test point along the shared corridor. The results for all test points were compiled and presented in Table 5.2. The maximum allowed touch voltages were

Test Point	Corridor Distance (m)	Faulted Tower	Inductive Component (V)	Conductive Component (V)	Total TV (V)	Max TV allowed (80 ms) (V)	Max TV allowed (250 ms) (V)
1	165	2226	106	51	157	454	302
		2227	161	38	199	454	302
2	1520	2229	249	57	306	993	660
		2230	315	57	372	993	660
3	2775	2232	418	46	464	948	630
		2233	656	9	665	416	277
4	3611	2235	238	25	263	392	260
		2236	527	10	537	416	277
5	5200	2239	625	46	671	392	260
		2240	870	79	949	993	660
6	6895	2243	850	75	925	948	630
7	8351	2246	454	24	478	948	630
		2247	605	32	637	948	630
8	9300	2248	110	19	129	948	630

Table 5.2: Brisbane pipeline with insulating joints - test points touch voltages

calculated according to IEEE recommendations taking a body weight of 50 kg [43]. These touch voltages are very dependent on the soil resistivity of the top layer in a given layered soil model. Different maximum touch voltage values for the same test point in Table 5.2 occur when a different soil models were used for modelling faults at two adjacent towers, thus affecting calculated value of the test point touch voltage. It can be seen from Table 5.2 that touch voltages exceed the maximum touch voltages allowed by IEEE recommendations [43] at these three locations: (a) touch voltage at test point 3 arising

from the fault on the power line tower number 2233, (b) touch voltage at test point 4 arising from the fault on the power line tower number 2236 and (c) touch voltage at test point 5 arising from the fault on the power line tower number 2239 .

Compliance with the Australian Standard

Clauses 5.2, 5.3 and 5.4 in the applicable Australian Standard 4853 [28] deal with risk assessment and touch voltage limits on pipelines. Category A presents limits for the pipeline and its ancillaries accessible to public and unskilled staff and Category B presents touch voltage limits for pipelines with restricted access. Since the test points are enclosed in the test point box and pipeline connections are wired to the local terminal inside the box, test points are considered as Category B equipment. The touch voltage limit for Category B equipment for a power line fault lasting less than one second is given as 1000 V (both AC and DC). Touch voltage limits calculated according to the IEEE method, shown in Table 5.2, in all cases are lower then 1000 V. These limits were calculated for faults lasting 80 ms and 250 ms. Therefore, these limits are comparable with the Category B limit given in the Standard [28]. If this Standard [28] was applied to the test point touch voltages calculated using the IEEE method, all test points in the shared corridor would comply with the Standard. Touch voltage limits as calculated based on the IEEE method [43] are much more elaborate as soil resistivity and time duration of the fault at each test point location are taken into account, which is not the case in the Australian Standard [28].

Recommendations for Test Points

The three test point touch voltage levels which did not comply with the IEEE safe touch voltage recommendations can be reduced below the allowed levels with certain actions. If these touch voltages were to be reduced before the pipeline and test points were built, the best solution would have been to improve the gradient control mat by inserting more

conductors across it to produce a mesh. If that is not sufficient, additional anodes could be placed at the corners of the gradient control mat (mesh). Since the pipeline and test points already exist, the most appropriate action would be to dig out the ground on top of the earth mat to a depth of 150 mm and fill this space with crushed rock which will significantly increase the total impedance in the circuit through which the body current flows. Once this 150 mm top layer of crushed rock is established, the soil resistivity in the area has very little influence on the calculation of allowed safe touch voltages. The resistance of the top layer resulting from crushed rock is dependent on the type of the rock used and the grade to which it is crushed. A very common value for the resistivity of the crushed rock soil layer used for calculations is 3000 $\Omega - m$. With a very conservative value of 2000 $\Omega - m$, based on IEEE calculations, a maximum touch voltage of 1095 V is obtained for fault duration of 80 ms and 727 V for fault duration of 250 ms. By looking back at the results in Table 5.2, it is seen that by covering the soil in front of the test point with a 150 mm layer of crushed rock, existing touch voltages can be reduced to levels below maximum allowed by IEEE calculations [43].

5.4.5 Cathodic Protection

Installed System

A sacrificial anode cathodic protection system protects the pipeline from corrosion. The presence of eight insulating joints along the shared corridor divided the pipeline into seven electrically separated sections. An independent sacrificial anode cathodic protection system exists in each section. Each system consists of an anode bed with ten magnesium anodes (with dimensions 1.5 m x 65 mm x 65 mm and type WM8). Each anode is connected with an insulated copper wire to the cathodic protection terminal box. The insulated copper cable that is connected to the pipeline also comes to the terminal box and is bridged to the cable emanating from cathodic protection anodes.

Computer Modelling

The existing cathodic protection system on the Brisbane pipeline was modelled with a few approximations. First of all, the pipeline was not modelled with existing corners and curves. Instead a straight pipeline was modelled with an equivalent length. The whole system was divided into seven sections and their lengths were modelled to match existing section lengths. Soil resistivity is not uniform along these sections, both horizontally and vertically. The CDEGS module used for cathodic protection modelling, MALZ, is able to model multilayered soil, but it can only accept one multilayered soil model per section between two insulating joints. These sections are on average 1.5 km long and there may be several significant changes in soil resistivity along that distance. Therefore, one soil model for each section was chosen, the model which most closely matched the given description of the soil. Generally, the soil model that covered the longest distance in a given section was chosen for calculations. Sections three and four had several different types of soil according to the description of the soil given in a pipeline schematic supplied by Agility [3], however no soil resistivity measurements were made in these two sections. The best option seemed to be to use a uniform soil model with a resistivity of 200 $\Omega - m$. In section five, measurements of soil resistivity did not yield any reasonable readings, as explained in Section 5.3.5. Since the description of soils in this section from the Agility [3] schematics suggested that large portion of the soil is clay and sandstone (which in general has a lower resistivity), it was decided to model section five to cover the two scenarios, a lower resistivity situation and a higher resistivity situation. The final soil resistivity model for the whole pipeline used for modelling the cathodic protection system is shown in Appendix C Table C.4.

Objectives of Modelling

As an inherent part of a pipeline cathodic protection system design, determination of pipeline current density requirements is usually based on operating experience with soil

similar to what exists in the corridor. These current density requirements are set as a target and the design should answer how many anodes are needed to meet these requirements and lift pipeline potential to the required value. Seven separate cathodic protection systems have already been designed and built on the Brisbane pipeline, which are in operation. In this case the objectives are to model the cathodic protection system of the existing configuration, examine the current density in the pipeline and the pipeline potential.

Parameters

The natural potential of pipeline steel with respect to a copper sulfate electrode is -0.55 V which exists on the pipeline when no cathodic protection is applied. Once the current starts flowing through the system the pipeline steel potential rises and the pipeline becomes polarised. It is assumed that the pipeline is cathodically protected if this polarised potential becomes more negative than -0.85 V. The CDEGS MALZ module has a feature known as "working potential of the steel" which has been designed specifically for cathodic protection modelling to describe the polarisation state of a conductor. In this study, it was set to -0.55 V for the initial state and -0.85 V for a polarised state. The current density requirements in an initial state are higher than those in the polarised state. This is the reason as to why each cathodic protection system (in each section) was modelled in two different polarisation states. The higher non-polarised current densities can be used quite conservatively for the calculation of life expectancy of electrodes. Current density demand in the system is very dependent on the state of the pipeline coating. With higher coating resistances of the pipeline less current is needed to polarise the pipeline steel. That being the case, the cathodic protection modelling was done with two values of pipeline coating resistance 83600 $\Omega - m^2$ as is the case when the coating is in excellent condition and 18600 $\Omega - m^2$ as is the case with old, deteriorated coating.

Results

	Coating resistance			
	$18600\ \Omega - m^2$		$83600\ \Omega - m^2$	
	Polarisation state			
Section	Pre-polarised	Polarised	Pre-polarised	Polarised
1	47.2	31.3	10.8	7.2
2	41.9	28	10.5	7.0
3	33.7	22.4	9.9	6.6
4	26.9	17.4	9.1	6.1
5a	43.6	29.1	10.6	7.1
5b	24.2	16.0	8.9	5.9
6	43.0	28.7	10.5	7.0
7	44.9	29.9	10.7	7.1

Table 5.3: Brisbane pipeline with insulating joints - cathodic protection current densities ($\mu A/m^2$)

The results of the calculation of pipeline current density and pipeline potentials in all seven cathodic protection sections are given in Table 5.3. In all cases the pipeline potential is around -1.45 V, which is more than enough to make pipeline cathodically protected. Columns corresponding to the initial state are characterised with higher current demand. In reality, after a certain period of time, the pipeline becomes polarised (equivalent to a capacitor that gets charged) and current (current density on the pipeline) drops. According to operating experience (data from previous pipeline surveys), current densities in the range of 1 $\mu A/m^2$ are required to keep the pipeline polarised. The exact value varies depending on the season and wetness of the soil. The calculated current densities shown in Table 5.3 are comparable with the previous pipeline survey measurements.

5.4.6 Costing

The costs given are rough estimates for the mitigation system on the pipeline. These include cost of material and estimates of the labour cost required for installation. These costs are the actual costs obtained from Agility staff. The actual costs for installation of insulating joints were not obtained. Even though these labour costs would not be

significant, in order to complete the mitigation costs and present them in a way that would be comparable with the appropriate costs of the gradient control wire mitigation system, they were assumed to be $20,000.

- insulating joints: $60,000
- permanent earth anodes: $60,000
- installation of permanent earth anodes: $30,000
- installation of insulating joints: $20,000

leading to a total cost of $170,000.

5.5 Alternative Mitigation Design with Gradient Control Wire

In the second part of the Brisbane shared corridor study, the alternative mitigation system for the pipeline using gradient control wire was designed. All input data required for computer modelling of this mitigation system were the same as in the case of insulating joints. One bare zinc wire was placed in the pipeline backfill at the same depth as the pipeline itself, at 1.5 m, and 1.5 m horizontally away from the center of the pipeline. Plattline II Standard (12.7 mm x 14.3 mm) zinc gradient control wire [50] was assumed in calculations. The connections between the pipeline and zinc wire were made approximately at the locations of the power line towers. In addition, two insulating joints were placed at the beginning and the end of the line to electrically isolate the pipeline from the rest of the pipeline network.

5.5.1 Steady State

Steady state analysis of AC interference between the power line and the pipeline revealed very low induction levels, in the range between 0 and 6 V, as shown in Figure 5.12. It is seen that the levels fall well within the limits given in the Standard [28].

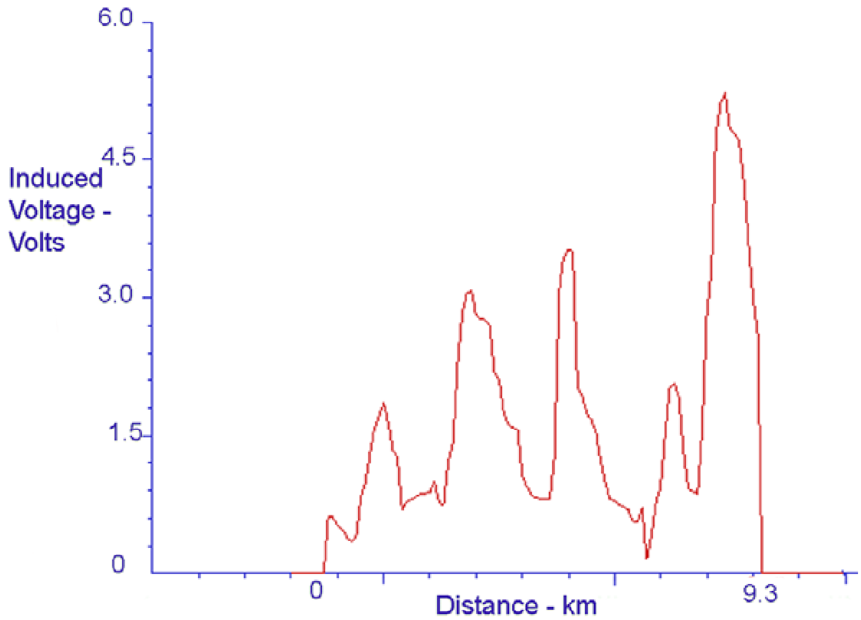

Figure 5.12: Brisbane pipeline with gradient control wire - steady state potentials

5.5.2 Faults - Inductive Component

Faults were simulated at each tower in the shared corridor. The maximum inductive coating stress voltages on the pipeline is around 1000 V, as shown in Figure 5.13.

5.5.3 Faults - Conductive Component and Total Pipeline Coating Stress Voltages

The conductive analysis has been carried out with faults applied at all towers in the corridor. In the areas where separation between the pipeline and the power line is relatively small, higher pipeline coating stress voltages are noticed as expected (see Table 5.4). The total coating stress voltage obtained by adding the inductive and conductive components is also given in Table 5.4. It can be seen from the table that total coating stress voltages on the pipeline are well below the values allowed for the polyethylene coating on the pipeline (5 kV). In general total coating stress voltages obtained with the use of gradient control wire mitigation are much lower than in the case of insulating joint mitigation.

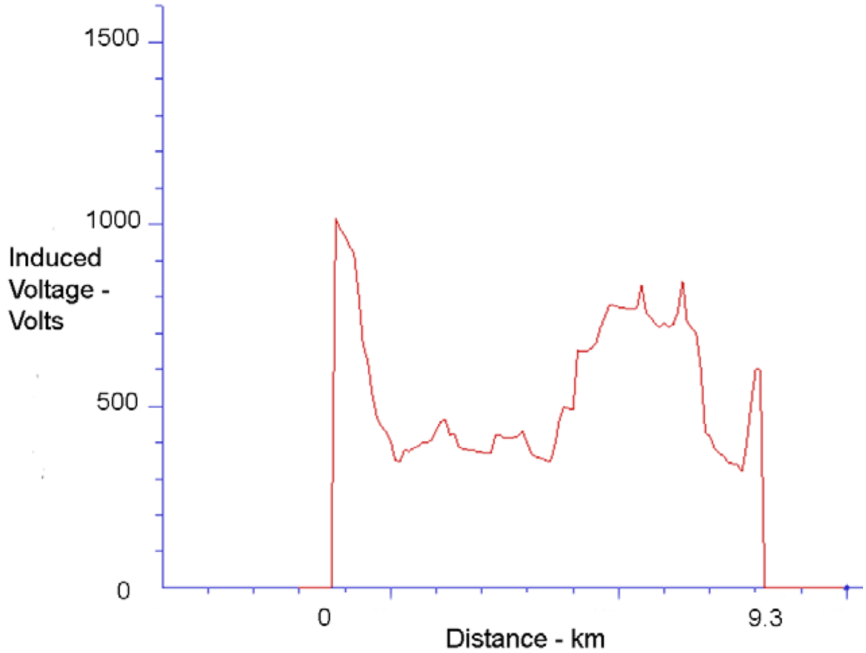

Figure 5.13: Brisbane pipeline with gradient control wire - inductive component of coating stress voltage for faults along power line 817

5.5.4 Considerations in relation to Fault at Tower 2243

The highest conductive and total coating stress potential in relation to both mitigation methods are noted for tower number 2243, which requires explanation. According to the data supplied by Powerlink (see Appendix D Table D.3), this particular tower has much lower tower footing resistance (0.5 Ω) compared to the tower footing resistance of its two adjacent towers (3 Ω and 1 Ω). As a consequence, in the case of a fault to earth on the power line, considerably more current would flow to earth through tower 2243 than through its two adjacent towers. The power line and pipeline separation in this part of the shared corridor is only 10 m, and hence the pipeline coating stress voltage in the proximity of tower number 2243 is the highest in the corridor.

Tower No.	Distance (km)	Inductive Voltage (V)	Pipeline Separation (m)	Conductive Voltage (V)	Total Coating Stress (V)
2226	0.03	289	21	530	819
2227	0.48	12	50	172	184
2228	0.86	219	40	33	252
2229	1.32	377	40	91	468
2230	1.71	463	40	129	592
2231	2.15	425	40	81	506
2232	2.58	382	5	445	827
2233	2.97	421	30	19	440
2234	3.15	417	30	65	482
2235	3.38	430	30	134	564
2236	3.80	398	12	90	482
2237	4.26	498	12	135	633
2238	4.75	652	10	377	1029
2239	5.14	776	55	141	917
2240	5.58	833	28	171	1004
2241	5.92	744	28	72	816
2242	6.28	729	10	244	973
2243	6.72	845	10	548	1393
2244	7.26	600	10	375	975
2245	7.70	406	10	142	548
2246	8.07	364	10	226	590
2247	8.53	317	30	86	403
2248	9.03	322	30	113	435

Table 5.4: Brisbane pipeline with gradient control wire - total pipeline coating stress voltages

5.5.5 Safety Assessment of Test Points

Touch Voltages (TV)

With the gradient control wire, locations of test points could be arbitrary, but to enable comparison with the insulating joint mitigation system, the test points were designed at exactly the same locations as before. The calculated test point touch voltages are given in Table 5.5. As it can be seen, only the calculated touch voltage at test point 5 from the fault at power line tower number 2239 is higher than the maximum allowed touch voltage calculated by the IEEE methods [43] taking into account a body weight of 50 kg. All test points comply with the Australian Standard [28].

Test Point	Corridor Distance (m)	Faulted Tower	Inductive Component (V)	Conductive Component (V)	Total TV (V)	Max TV allowed (80 ms) (V)	Max TV allowed (250 ms) (V)
1	165	2226	108	27	135	454	302
		2227	201	27	229	454	302
2	1520	2229	257	10	267	993	660
		2230	267	2	269	993	660
3	2775	2232	261	13	274	948	630
		2233	257	9	266	416	277
4	3611	2235	198	10	208	392	260
		2236	261	15	276	416	277
5	5200	2239	434	94	528	392	260
		2240	497	10	507	993	660
6	6895	2243	501	21	522	948	630
7	8351	2246	191	4	195	948	630
		2247	240	7	247	948	630
8	9300	2248	278	29	307	948	630

Table 5.5: Brisbane pipeline with gradient control wire - test point touch voltages

Recommendations for Test Points

The only excessive touch voltage associated with gradient control wire mitigation system is at test point 5 resulting from a fault at power line tower number 2239. To derive recommendations concerning this excessive touch voltage, the test point mitigation system was altered gradually, with a number of modifications pursued. It should be noted that this touch voltage can be reduced either by improving the test point gradient grid or by placing an extra layer of crushed rock on the ground surface in front of the test point box. In the case of insulating joints, correction of test point touch voltages was proposed by adding a layer of crushed rock on the earth surface over the gradient grid. This is the more reasonable scheme for correction of test point touch voltage in the case when the mitigation system already exists. Its correction by adding anodes to the gradient grid requires additional excavation and is more appropriate in the case of new installations. Mitigation with gradient control wire is an alternative design (hypothetical case in which pipeline mitigation system does not exist), and hence preference should be given to

installation of additional anodes to the gradient grid.

The typical process of designing test point gradient control grid which will sufficiently reduce the touch voltage to safe levels involves several iterations. After each mitigation iteration step, the gradient grid impedance (or shunt impedance connected to the pipeline in a computer model) is updated and a new inductive fault potential is calculated for the gradient control grid connection point. Following this, both the inductive and conductive component of the touch voltage are recalculated and the total level is compared with the maximum allowed touch voltage calculated using the method recommended by IEEE [43]. In the first attempt, two extra conductors were placed across the mesh in two directions (mesh conductors cross each other at an angle of 90 degrees). Secondly, an option with five extra conductors was attempted. When the space for placing extra conductors in the mesh was exhausted, three one metre long electrodes were placed at the edges of the gradient control mesh and buried vertically in the ground. And finally, the last iteration which included seven of those electrodes proved to be sufficient to reduce the touch voltage in front of test point 5 below the maximum touch voltage calculated using the IEEE method [43]. The evolution of the design process is illustrated in Table 5.6.

Gradient Mesh	Mesh Impedance (Ω)	Pipeline fault potential (V)	Inductive Component (V)	Conductive Component (V)	Total TV (V)	Max TV allowed (80 ms) (V)
frame	46	770	434	94	528	392
mesh 2x2	41	766	371	88	459	392
mesh 5x5	40	766	362	86	448	392
mesh 5x5 + 3 anodes	30	765	328	74	402	392
mesh 5x5 + 7 anodes	26	764	302	68	370	392

Table 5.6: Brisbane pipeline with gradient control wire, test point 5, faults at tower 2239 - touch voltages mitigation design

5.5.6 Cathodic Protection

A zinc gradient control wire was used for mitigation of induced voltages on the pipeline, and consequently, the cathodic protection system was modelled using the same zinc wire as the anode material. When zinc is used in the cathodic protection system, it can be safely connected to the pipeline steel without creating a corrosion cell (as is the case when copper is connected to steel). Even though a decoupling device is not necessary for zinc, it is advisable to make these connections through an above ground junction box, as it protects the pipeline from stray currents and provides access to the pipeline [51].

Computer Modelling

Since the main purpose of carrying out this analysis is to compare the performance of two different mitigation systems applied to the same shared corridor, as many parameters as possible were kept the same in modelling both mitigation systems. The exception was soil resistivity in modelling cathodic protection. In the case of the system with insulating joints, there were seven sections where different soil models were applied. In the case of the gradient control wire system, the whole system had to be modelled in one file and therefore only one soil model could be used (a restriction imposed by the MALZ module of the CDEGS software). Calculations on the complete cathodic protection system were done three times with three selected soil models. Details of these soil models are given in Appendix C Table C.5.

Results

The calculated pipeline current densities are given in Table 5.7. These show compliance with the polarisation criteria (see Section 5.4.5), since the calculated pipeline potentials are always more negative than -0.85 V. Since the cathodic protection system based on zinc gradient control wire does not exist, there is no operating experience or pipeline survey to confirm that the calculated current densities have the ability to satisfactorily

	Coating resistance			
	$18600\ \Omega - m^2$		$83600\ \Omega - m^2$	
	Polarisation state			
Section	Pre-polarised	Polarised	Pre-polarised	Polarised
1	2.8	1.3	0.6	0.3
2	2.8			0.3
3	2.8			0.3

Table 5.7: Brisbane pipeline with gradient control wire - cathodic protection current densities ($\mu A/m^2$)

polarise the pipeline. It should be noted here that the polarised pipeline potentials calculated in this case are much higher (less negative) than in the case of a mitigation system with insulating joints (around -1.1 V). The calculation revealed that zinc wire can supply a current density of 0.6 $\mu A/m^2$ in the pre-polarised state and a current density of 0.3 $\mu A/m^2$ in the polarised state. While these current densities can polarise the pipeline, it can be observed that the values are lower than in the case of the insulating joint mitigation system. The reason is that the magnesium anodes (-1.45 V) used in the system with insulating joints have a higher natural electrochemical potential than zinc (-1.1 V). Despite the ability of the zinc gradient control wire to sufficiently polarise the pipeline, material used for mitigation of the power line AC interference should not be used for cathodic protection of the pipeline. Over time, the anode electrodes get depleted which affects their impedance. This fact is in line with recent recommendations from the industry that independent cathodic protection systems should be installed in addition to the gradient control wire mitigation system [38, 37]. In this situation AC couplers/DC decouplers or surge diverters (see Figure 5.2) should be installed between the pipeline and the mitigation wire to protect the pipeline from stray currents and prevent leakage of cathodic protection current (the anode material for cathodic protection would have separate connections with the pipeline). As an example, Dairyland Electrical Industries [51] offers a new range of products such as the polarisation replacement cell (PCR) and steady state decoupler (SSD), which may be effectively used for decoupling the pipeline

from the mitigation system.

5.5.7 Costing

The costing of the installation of a single gradient control wire along the whole length of the shared corridor is difficult. Very little or no information exist in relation to installation of any such mitigation systems in Australia and the cost estimates given here are based on current information available from the United States.

Plattline II Standard (12.7 mm x 14.3 mm) zinc gradient control wire [50], was quoted for US \$1536 per reel (a reel is 152 m long). Approximate labour costs for installation of the gradient control wire were obtained from [52]. On average, one operator and the ploughing machine required for soil preparation would cost US \$6/ft. It is assumed that these costs would be the same in Australia in A\$. About an extra five workers are needed during the installation. A team like this can install between 1500 and 2500 ft per day even in rocky soil. The length needed for 9.3 km or 30500 ft of zinc gradient control wire, costed at US\$95,200 or A\$127,000. Installation would cost 30,500 ft * A\$6 = A\$183,000. If installation of 2000 ft per day is assumed, the total length of 9.3 km or 30500 ft would take 15 days to complete. In that case the extra 5 workers working 8 hours a day for 15 days would require 600 working hours. If a rate of A\$50 per hour is taken, the total would be around A\$30,000. Therefore, a rough estimate of the costs of the mitigation system would be:

- single gradient control wire 9.3 km: \$127,000
- installation of gradient wire: \$183,000
- extra labour: \$30,000

leading to a total cost: \$340,000.

5.6 Comparison of the two mitigation systems

5.6.1 Costs

The basic cost analysis included the cost of materials and the minimum estimated labour costs necessary for installation. The results revealed that the basic cost for the mitigation system using insulating joints would be around \$170,000 and the corresponding basic cost for the system with zinc gradient control wire would be around \$340,000. It should be noted once again that these costs are rough estimates and that they are particular to the pipeline and corridor considered. The results may differ for different corridor configurations. Some of the costs originate from different countries and are not directly comparable. There could be additional issues which may have an influence on the cost estimates. The most important aspect is that the overall cost of the mitigation system is just a fraction of the total cost of the pipeline, gas metering stations and pipeline appurtenances, which runs into tens of millions of dollars. Therefore, consideration should focus on adequate performance and possible costs of maintaining the mitigation system and not just on the cost of mitigation itself.

5.6.2 Mitigation

The mitigation system with gradient control wire has superior performance compared to a system with insulating joints (as seen from Figures 5.2 and 5.1). The coating stress voltages on the pipeline were lower (1000 V maximum) than those in the case of the insulating joint system (2600 V maximum). The induced voltage distribution curve was more uniform as mitigation was applied along the whole length of the pipeline, not only at certain locations (insulating joints) as in the case of the insulating joint system. The system with the gradient control wire had one test point touch voltage higher than IEEE recommendations, compared to three test points on the system with insulating joints.

5.6.3 Maintenance and Repair

Gas pipelines with insulating joints are more complicated in relation to maintenance. The insulating joints can be shorted during operation (this case has already been reported in the field and in the literature, see Section 4.1.1). Insulating joints are tested only in the laboratory, and thus, their performance in the field during faults or lightning cannot be predicted. Sealing and installation of the joints may be difficult and may lead to future leaks. Repairs on a system with gradient control wire can be done without interrupting the flow of gas in the pipeline. For repairs on insulating joints, the flow of gas through the pipeline has to be interrupted, incurring high costs to the pipeline owners. The use of insulating joints for mitigation of induced voltages in pipelines is diminishing in favour of more modern techniques such as gradient control wire.

5.6.4 Cathodic Protection

The additional cathodic protection system in the case of insulating joint mitigation provided higher current densities to the pipeline than the zinc in the case of the gradient control wire. An additional cathodic protection system is recommended in the case of gradient control wire mitigation schemes. If surge diverters are used to connect gradient control wire to the pipeline, the method used for mitigation of induced voltages on pipeline has no direct influence on the choice of the pipeline cathodic protection system. In that case, the system with sacrificial anodes installed on the pipeline with insulating joint mitigation can be applied in conjunction with gradient control wire mitigation.

5.6.5 Pipeline and Mitigation System Decoupling

Quite often there is a requirement to protect the pipeline from stray currents and to prevent leakage of cathodic protection DC currents. The entry point for a stray current is the mitigation system connected to the pipeline. That is the reason why AC couplers/DC decouplers or surge diverters should be installed between the pipeline and its mitigation

system. The insulating joint system has this decoupling implemented through surge diverters. In the case of gradient control wire, apart from surge diverters, other types of AC couplers/DC decouplers may be installed, for instance the modern Solid-State Decoupler. Also, installation of decouplers enables the use of alternative materials for gradient control wire such as copper. When considering decoupling between the pipeline and its mitigation system there is little difference between insulating joints and gradient control wire systems. Detailed design is needed to determine the number of decoupling devices for each mitigation system.

5.7 Conclusions

Two separate pipeline and power line interference studies were carried out and the results were presented. Two different methods of AC induced voltages mitigation (insulating joints and gradient control wire) were applied on the same pipeline and the results were used for comparison. Comparison revealed that the use of the insulating joints was the cheaper method. The costs of both methods are relatively small compared to the costs associated with the rest of the pipeline and its metering stations. The superior performance of gradient control wire and its advantages during maintenance and possible repairs makes it a preferred method for mitigation of AC induced voltages on the pipeline considered.

Chapter 6

Conclusions, Guidelines and Recommendations

6.1 Conclusions

As a major contribution of this project it was shown that an induced voltage mitigation system employing gradient control wire has significant benefits compared to systems with insulating joints (based on computer simulations of two pipeline mitigation systems in an existing corridor). Despite the lower costs of systems with insulating joints, their weaker performance and much higher costs in relation to cases of shorted or leaking joints, makes induced voltage mitigation design with gradient control wire superior. Canada and US almost exclusively use gradient control wire method on new pipelines requiring mitigation. There is indication that Australia is increasingly following this industry practice.

The other contribution was the interference analysis performed on an existing corridor which revealed the possibility of high pipeline coating stress voltages in excess of recommended values during particular power line faults. A possible way of reducing these voltages below recommended values by earthing the pipeline at critical points was given.

6.2 Guidelines on How to Choose an Appropriate Mitigation Method

The superior performance of gradient control wire over insulating joints determined from this study, makes gradient control wire a preferred method for AC mitigation on any new corridor with serious AC interference problems. The insulating joints method should only be pursued in the case where demands for cathodic protection currents are high and therefore the pipeline needs to be divided electrically into several separate sections. Usually this is the case when large stray currents enter the pipeline from neighboring sources. If AC interference levels are not so high and the demand for mitigation is low, installation of gradient control wire may not be necessary and may be an unjustified expense. Mitigation design in such cases should explore separate grounds at the most critical locations, as that may be sufficient to lower AC potentials to permitted levels. In any case specialised software is needed to precisely calculate mitigation requirements and assist in selecting the most appropriate option which is very dependent on each particular case.

Regarding cathodic protection systems on the pipeline, the question is which system to install: impressed current or sacrificial anode system. A sacrificial anode system is usually adequate for any low current requirement application. Impressed current systems are more likely to be implemented on long or large pipelines, or whenever high resistivity soil or some other factor demands higher current levels.

6.3 Recommendations for Future Research

While there has been a significant level of research on the performance of pipeline mitigation systems in the steady state and during fault conditions, little is known about their performance during lightning strikes. Optimisation of the pipeline mitigation system for lightning is a direction for future research. Attention should also be paid to coupling effects between pipelines and power lines during transients. Arcing arising from the

conductive component of fault current is a danger for the pipeline coating. Its mechanism is not very well known and deserves to be on a list for future research. Arcing can also occur across insulating joints both during power line faults and lightning strikes. More knowledge is needed on how these arcs can affect insulating joints once they are installed in the field. At the moment some tests are being carried out by manufacturers of insulating joints. These tests seem to be inadequate as they are performed in the laboratory conditions, which can be substantially different from the conditions in the field. Arcing towards pipelines can also occur from power system ground networks. The type of damage that can be inflicted on the pipeline is not well known.

Some research is needed regarding the connection between AC induced voltage and low frequency DC potential fluctuations in cathodically protected pipelines, as this is not well understood. There is also a lack of consensus about the exact mechanism of AC corrosion of steel (it is evident that AC corrosion can occur on pipeline with otherwise satisfactory cathodic protection levels). There are two hypotheses that need further clarification. The first one advocates that DC polarisation of the pipeline is somehow affected by AC induced potentials. The other one centres on the irreversible nature of the corrosion reaction ($2Fe = Fe^{2+} + 2e^{-}$) which occurs only during the positive half cycle of the AC current waveform.

Appendix A

Brief Theory of Pipeline and Power Line Interference

A.1 Calculations of Induction Levels

The following procedure is generally used as the basis for calculation of induction levels on a pipeline [7]:

1. From the physical layout of the shared corridor, determine the appropriate distances and locations of the relevant elements.

2. Using Carson's equation (or an alternative), determine the longitudinal electric field (LEF) driving the pipeline along its complete length.

3. Using electrical and physical parameters, determine the propagation constant and characteristic impedance.

4. Develop a pipeline circuit model and solve for the induced voltage and current levels.

The equivalent circuit of the pipeline is shown in Figure A.1. Each pipeline length increment dx is described by its source voltage increment $E_x dx$ (where E is the LEF)

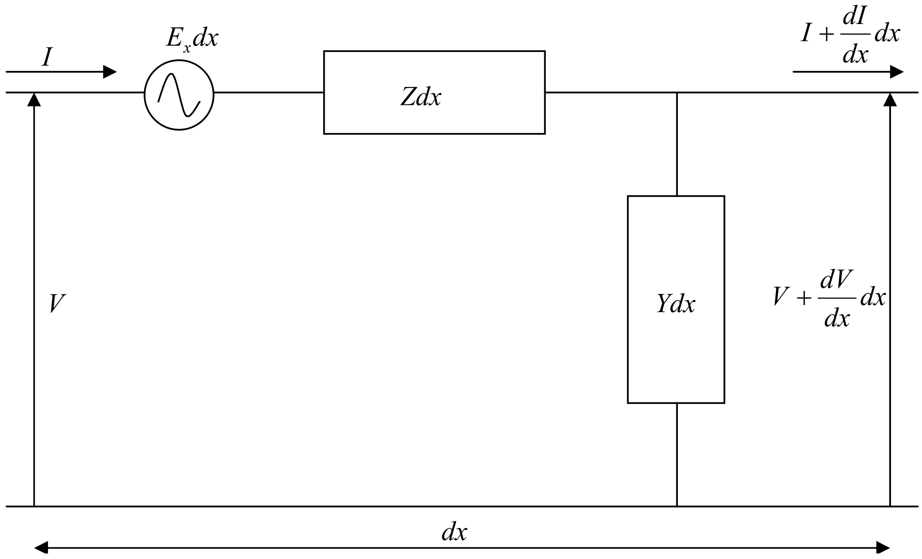

Figure A.1: Equivalent pipeline circuit (increment)

which has the dimensions of electric field strength (V/m), and impedance Z and admittance Y per unit length. The corresponding differential equations for voltage (V) and current (I) along the incremental length dx of the pipeline circuit model are as follows:

$$\frac{dV}{dx} = E - IZ \tag{A.1}$$

$$\frac{dI}{dx} = -VY \tag{A.2}$$

Equations A.1 and A.2 can be rewritten as second order differential equations:

$$\frac{d^2V}{dx^2} - \gamma^2 V = \frac{dE}{dx} \tag{A.3}$$

$$\frac{d^2I}{dx^2} - \gamma^2 I = -YE \tag{A.4}$$

where

$$\gamma = \sqrt{ZY}\ m^{-1}$$

is the pipeline propagation constant. The general solution for the current and voltage induced in a grounded pipeline for an electromagnetically coupled distributed excitation E is then:

$$I\left(x\right) = \left(K_1 + P\left(x\right)\right)e^{-\gamma x} + \left(K_2 + Q\left(x\right)\right)e^{\gamma x} \tag{A.5}$$

$$V\left(x\right) = Z_0\left[\left(K_1 + P\left(x\right)\right)e^{-\gamma x} + \left(K_2 + Q\left(x\right)\right)e^{\gamma x}\right] \tag{A.6}$$

where:

$$Z_0 = \sqrt{\frac{Z}{Y}}\ \Omega$$

represents the pipeline characteristic impedance, and

$$P\left(x\right) = \frac{1}{2Z_0}\int_{x_1}^{x} e^{\gamma s}E\left(s\right)ds \tag{A.7}$$

$$Q\left(x\right) = \frac{1}{2Z_0}\int_{x}^{x_2} e^{-\gamma s}E\left(s\right)ds \tag{A.8}$$

$$K_1 = \varrho_1 e^{\gamma x_1}\frac{\varrho_2 P\left(x_2\right)e^{-\gamma x_2} - Q\left(x_1\right)e^{\gamma x_2}}{e^{\gamma\left(x_2 - x_1\right)} - \varrho_1\varrho_2 e^{-\gamma\left(x_2 - x_1\right)}} \tag{A.9}$$

$$K_2 = \varrho_2 e^{\gamma x_2}\frac{\varrho_1 Q\left(x_1\right)e^{\gamma x_1} - P\left(x_2\right)e^{-\gamma x_1}}{e^{\gamma\left(x_2 - x_1\right)} - \varrho_1\varrho_2 e^{-\gamma\left(x_2 - x_1\right)}} \tag{A.10}$$

ϱ_1 and ϱ_2 are transmission line reflection coefficients resulting from the termination conditions of the pipeline and are defined by:

$$\varrho_1 = \frac{Z_1 - Z_0}{Z_1 + Z_0} \tag{A.11}$$

$$\varrho_2 = \frac{Z_2 - Z_0}{Z_2 + Z_0} \tag{A.12}$$

where Z_1 and Z_2 are pipeline termination impedances at two ends. This solution has to be further developed and solved by inserting the termination conditions into the equations. The above equations primarily consider coupling during the steady state operation of a power system. In addition to inductive coupling, resistive (conductive) coupling through

the earth must be considered when determining fault coupling levels, a methodology which can be found in Sobral [15, 16].

A.2 Calculation of Metallic Pipeline Electrical Parameters

When software packages CDEGS and PRC are used for pipeline induction studies there is no need for manual calculation of pipeline parameters. They are done by software automatically. If the calculations were to be done manually, mathematical formulas are presented below. The formulas were taken from [30].

A.2.1 Symbols Used

f = frequency (Hz)

$\omega = 2\pi f(rad/s)$

μ_0 = magnetic permeability of the air $= 4\pi * 10^{-7} H/m$

μ_r = relative magnetic permeability of the pipeline

ρ = soil resistivity (Ωm)

ρ_p = resistivity of the pipeline

ρ_c = resistivity of the pipeline coating

ε_0 = electrical permittivity of the air $= 8.85 * 10^{-12} F/m$

ε_r = relative permittivity of the pipeline coating

ε = electrical permittivity of the soil

δ_c = thickness of the pipeline coating (m)

D = diameter of the pipeline (m)

h_p = depth of buried pipeline (m)

a = radius of the pipeline (m)

a' = equivalent radius (m) of buried pipeline

$a' = \sqrt{a^2 + 4h_p^2}$

A.2.2 Pipeline Series Impedance

For buried pipelines pipeline series impedance (Ω/m) can be calculated as:

$$z = z_{int} + \frac{\omega\mu_0}{8} + j\frac{\omega\mu_0}{2\pi} ln \frac{1.85}{a'\sqrt{\gamma^2 + j\omega\mu_0\left(\frac{1}{\rho} + j\omega\varepsilon\right)}} \tag{A.13}$$

where z_{int} represents pipeline internal impedance (Ω/m) that can be calculated as:

$$z_{int} = \frac{\sqrt{\rho\mu_0\mu_r\omega}}{\pi D\sqrt{2}}(1+j) \tag{A.14}$$

A.2.3 Pipeline Admittance

Pipeline admittance ($1/\Omega m$) for below ground pipelines can be calculated as:

$$y = \frac{\pi D}{\rho_c\delta_c} + j\omega\frac{\varepsilon_0\varepsilon_r\pi D}{\delta_c} \tag{A.15}$$

A.2.4 Pipeline Characteristic Impedance (Ω)

$$Z_c = \sqrt{\frac{z}{y}} \tag{A.16}$$

A.2.5 Pipeline Propagation Constant ($1/m$)

$$\gamma = \sqrt{zy} \tag{A.17}$$

A.2.6 Characteristic Length of Pipeline

$$\lambda = \frac{1}{R(\gamma)} \tag{A.18}$$

where $R(\gamma)$ is the real component of γ.

Appendix B

Fault Current Components

B.1 Calculation of Power Line Zero Sequence Impedance for a Single Circuit Horizontal Tower With Two Earth Wires

Given below is a practical example demonstrating the calculation of zero and positive sequence impedances for a horizontal circuit tower (see Figure B.1) that is used on the 132 kV power lines that share the corridor with the Young-Lithgow pipeline. The procedure for the following calculation was derived from the ABB Electrical Transmission and Distribution Reference Book [53]. Diameters of phase conductor D_{aa} and earth conductor D_{gg} are respectively:

$$D_{aa} = 0.021\ m \qquad D_{gg} = 0.0098\ m$$

Distances between conductors are:

$$D_{ab} = 4.6\ m \qquad D_{bc} = 4.6\ m \qquad D_{ca} = 9.6\ m$$

$$D_{af} = 3.03\ m \qquad D_{ag} = 7.05\ m \qquad D_{bg} = 2.87\ m$$

$$D_{fg} = 4.4\ m \qquad D_{sa} = D_{aa}\ m$$

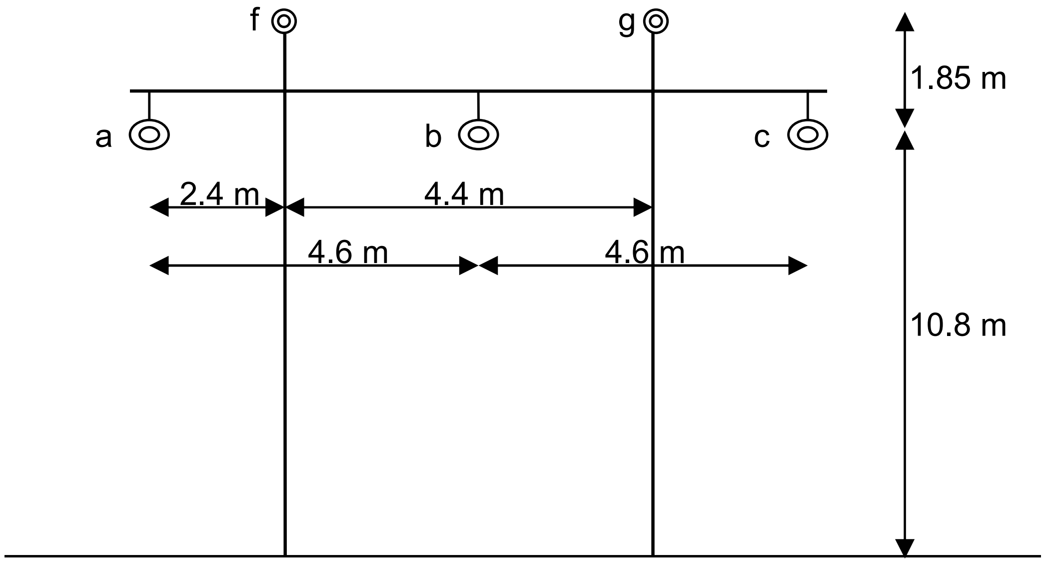

Figure B.1: Single circuit horizontal tower dimensions

Equivalent spacing or geometric mean distance of earth conductors is:

$$D_{sg} = \sqrt{D_{gg}D_{fg}} = 0.207\ m \tag{B.1}$$

Equivalent spacing or geometric mean distance of phase conductors is:

$$D_{eqa} = GMD = \sqrt[3]{D_{ab}D_{bc}D_{ca}} = 5.796\ m \tag{B.2}$$

Equivalent circuit spacing (takes into account distances between phase and earth conductors) is:

$$D_{eqg} = \sqrt[3]{D_{af}D_{ag}D_{bg}} = 3.945\ m \tag{B.3}$$

The constant K is defined as:

$$K = 2\pi * 50[Hz] * 2 * 10^{-7}[H/m] * 1000[m/km] = 0.0628\ \Omega/km \tag{B.4}$$

Resistance of the ACSR Lemon phase conductors per unit length is:

$$r_a = 0.155\ \Omega/km$$

Resistance of the SC/GZ 7/0.128 earth conductor per unit length is:

$$r_g = 4.1\ \Omega/km$$

Inductive reactance due to both internal flux and that external to the conductor to a radius of 0.3048 m is:

$$x_a = K \ln\left(\frac{1}{D_{sa}}\right) = 0.242\ \Omega/km \tag{B.5}$$

Inductive reactance corresponding to the flux external to 0.3048 m radius of the conductor and out to the center of two remaining phase conductors:

$$x_d = K \ln(D_{eqa}) = 0.110\ \Omega/km \tag{B.6}$$

Power line positive and negative sequence impedances are given by:

$$z_1 = z_2 = r_a + j\,(x_a + x_d) = 0.155 + j0.352\ \Omega/km \tag{B.7}$$

Zero sequence resistance and reactive inductance of a power line are related quantities and they will be considered simultaneously. Zero sequence resistance and inductive reactance factors r_e and x_e were taken from Table 7 in Chapter 3 of [53]. They are dependent on frequency and soil resistivity, and when 50 Hz and 300 $\Omega - m$ were used, the values read from the above table are:

$$r_e = 0.148\ \Omega/km$$

$$x_e = 1.589\ \Omega/km$$

Reactance factors x_g and x_{dg} are calculated as:

$$x_g = K \ln\left(\frac{1}{D_{sg}}\right) = 0.0989\ \Omega/km \tag{B.8}$$

$$x_{dg} = K \ln(D_{eqg}) = 0.0861\ \Omega/km \tag{B.9}$$

Zero sequence self impedance of the three phase conductors is:

$$z_{0a} = r_a + r_e + j\left(x_a + x_d - 2x_d\right) = 0.303 + j1.611\ \Omega/km \tag{B.10}$$

Zero sequence self impedance of the two earth wire conductors is:

$$z_{0g} = 3\frac{r_g}{2} + j\left(x_e - 3x_{dg}\right) = 6.298 + j1.886\ \Omega/km \tag{B.11}$$

Zero sequence mutual impedance between phase conductors as one group of conductors and the earth wires as the other group of conductors is:

$$z_{0ag} = r_e + j\left(x_e - 3x_{dg}\right) = 0.148 + j1.331\ \Omega/km \tag{B.12}$$

Hence, the power line zero sequence impedance is:

$$z_0 = z_{0a} - \frac{z_{0ag}^2}{z_{0g}} = 0.54 + j1.477\ \Omega/km \tag{B.13}$$

B.2 Calculation of Fault Current Component

In vast majority of cases single line to ground faults give rise to relatively high fault current levels leading to highly unbalanced electromagnetic fields. These unbalanced fields are major contributors to induced voltages on pipelines.

The fault current component calculations presented here correspond to a single phase to ground fault at an arbitrary point along the power line. Figure B.2 shows a simplified

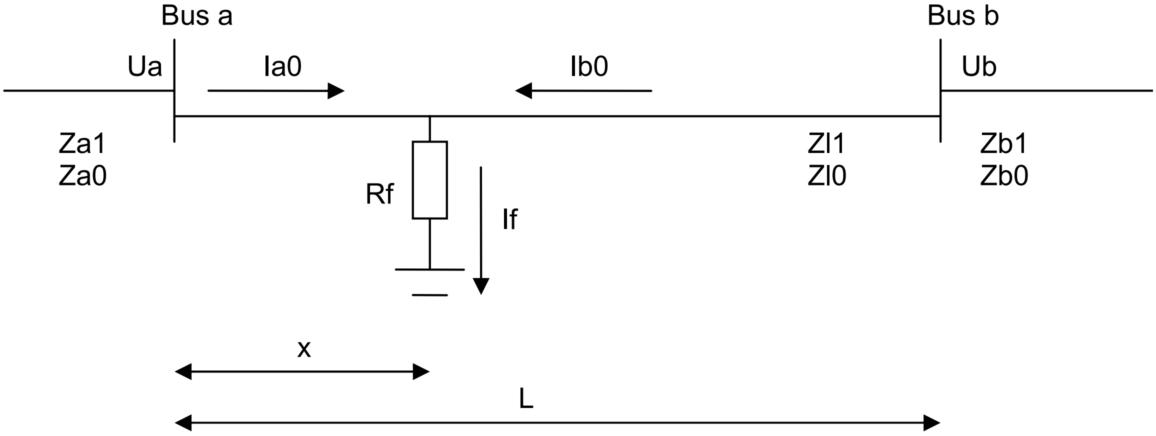

Figure B.2: Simple system illustrating left and right fault current components

power system consisting of two busbars (substations) and a power line connecting them. Contributions to the total short circuit current from each bus, ie. left and right component, are required for a complete fault interference analysis between the power lines and the pipeline in the shared corridor. The calculations presented below are based on the following assumptions:

- The faulted line interconnects two otherwise not connected subsystems
- Equivalent transfer impedance between the substations a and b is much greater than the source impedances of buses a and b

Parameters in Figure B.2:

Z_{a1} - positive sequence impedance of source a

Z_{a0} - zero sequence impedance of source a

Z_{b1} - positive sequence impedance of source b

Z_{b0} - zero sequence impedance of source b

Z_{l1} - positive sequence impedance of power line

Z_{l0} - zero sequence impedance of power line

I_{a0} - zero sequence fault current due to source a

I_{b0} - zero sequence fault current due to source b

R_f - fault impedance

I_f - total fault current

U - system voltage ($U = U_a = U_b$)

x - distance to the fault location from source bus a

L - total length of power line between buses a and b

For the system shown in Figure B.2 the single phase to ground fault current is given by the expression:

$$I_f = \frac{\sqrt{3}U}{2Z_p + Z_0 + 3R_f} = 3(I_{a0} + I_{b0}) \tag{B.14}$$

where

$$Z_p = \frac{(Z_{a1} + xZ_{l1})(Z_{b1} + (L - x) Z_{l1})}{Z_{a1} + Z_{b1} + LZ_{l1}} \tag{B.15}$$

$$Z_0 = \frac{(Z_{a0} + xZ_{l0})(Z_{b0} + (L - x) Z_{l0})}{Z_{a0} + Z_{b0} + LZ_{l0}} \tag{B.16}$$

Zero and positive sequence impedances of sources a and b, Z_{a1}, Z_{a0}, Z_{b1} and Z_{b0} are usually available from the appropriate power utility. Once Z_{l0} and Z_{l1} (see Section B.1) are calculated, the left and right components of the fault current can be computed as per the following equations:

$$I_{a0} = \frac{I_f}{3} \frac{(Z_{b0} + (L - x) Z_{l0})}{Z_{a0} + Z_{b0} + LZ_{l0}} \tag{B.17}$$

$$I_{b0} = \frac{I_f}{3} \frac{(Z_{a0} + xZ_{l0})}{Z_{a0} + Z_{b0} + LZ_{l0}} \tag{B.18}$$

Appendix C

Two Layer Computer Soil Model

C.1 Young-Lithgow Corridor Soil Model

Field Measurements			Two Layer Computer Soil Model		
YL	a	R	Layer	Depth	Soil Resistivity
km	m	Ω	No.	m	$\Omega - m$
170.5	2	4.66	1 (air)	infinite	infinite
	5	0.99	2	0.22	60.7
	10	0.36	3	infinite	30.4
	15	0.33			
	20	0.31			
178.1	2	15.1	1 (air)	infinite	infinite
	5	4.4	2	0.21	181.7
	10	2.9	3	infinite	185.7
	15	2.8			
	20	2.7			
179.6	2	28	1 (air)	infinite	infinite
	5	2	2	0.218	354.8
	10	-0.6	3	infinite	52.45
	15	0.6			
	20	0.6			

Table C.1: Young-Lithgow pipeline - field measurements and corresponding computer soil model, Part 1

Field Measurements			Two Layer Computer Soil Model		
YL	a	R	Layer	Depth	Soil Resistivity
km	m	Ω	No.	m	$\Omega - m$
180.3	2	37	1 (air)	infinite	infinite
	5	2.4	2	0.21	466.7
	10	0.9	3	infinite	65.7
	15	0.7			
	20	0.5			
182.5	2	54.7	1 (air)	infinite	infinite
	5	24.7	2	0.21	687.4
	10	15.1	3	infinite	938.2
	15	13			
	20	10.4			
203.2	2	21.2	1 (air)	infinite	infinite
	5	4.85	2	0.21	272.3
	10	2	3	infinite	143.9
	15	1.5			
	20	1.04			
203.6	2	29.3	1 (air)	infinite	infinite
	5	6	2	0.24	363
	10	0.9	3	infinite	17.78
	15	0.5			
	20	0.1			
204.1	2	45	1 (air)	infinite	infinite
	5	18	2	0.23	605.2
	10	7.2	3	infinite	351.7
	15	4			
	20	1.9			
210.1	2	32.5	1 (air)	infinite	infinite
	5	3.7	2	0.26	413.1
	10	1.2	3	infinite	55.5
	15	0.7			
	20	0.3			
212	2	62.9	1 (air)	infinite	infinite
	5	15.7	2	0.24	790.4
	10	3.6	3	infinite	63.5
	15	1.5			
	20	0.35			

Table C.2: Young-Lithgow pipeline - field measurements and corresponding computer soil model, Part 2

C.2 Brisbane Corridor Soil Model

Field Measurements			Two Layer Computer Soil Model		
Distance	a	R	Layer	Depth	Soil Resistivity
m	m	Ω	No.	m	$\Omega - m$
25	1	62.9	1 (air)	infinite	infinite
	2	14.6	2	2.0142	292.1
	5	2.9	3	infinite	44.07
	10	1.2			
	20	0.3			
700	1	19.4	1 (air)	infinite	infinite
	2	2.6	2	0.78	214.66
	5	0.3	3	infinite	7.86
	10	0			
	20	0.1			
5200	1	27.6	1 (air)	infinite	infinite
	2	10.56	2	3.15	164.05
	5	3	3	infinite	21.4
	10	0.48			
	20	0.19			
5880	1	467	1 (air)	infinite	infinite
	2	?	2	infinite	2932
	5	?	3		
	10	fault			
	20	fault			
9270	1	196	1 (air)	infinite	infinite
	2	28.4	2	1.12	1306.3
	5	3.2	3	infinite	33.27
	10	1.3			
	20	0.2			

Table C.3: Brisbane pipeline - field measurements and corresponding computer soil model

C.3 Brisbane Corridor Soil Model for Cahtodic Protection Calculations with Insulating Joints

Insulating Joint	Section	Length	Two Layer Soil Model			Uniform Soil
			1st Layer	1st Layer	2nd Layer	
m		m	m	$\Omega - m$	$\Omega - m$	$\Omega - m$
1520	1	1520	0.78	214.66	7.86	
2775	2	1255	0.78	214.66	7.86	
3611	3	836				200
5200	4	1589				200
6895	5a	1695	3.15	165	21.4	
	5b	1695	2	2800	200	
8351	6	1456	1.12	1306.03	33.27	
9300	7	983	1.12	1306.03	33.27	

Table C.4: Brisbane pipeline with insulating joints - soil model used for cathodic protection calculations

C.4 Brisbane Corridor Soil Model for Cahtodic Protection Calculations with Gradient Control Wire

Number	Two Layer Soil Model			Uniform Soil
	1st Layer	1st Layer	2nd Layer	
	m	$\Omega - m$	$\Omega - m$	$\Omega - m$
1	2.8	292.1	44.07	
2	2.6	2800	200	
3				200

Table C.5: Brisbane pipeline with gradient control wire - soil model used for cathodic protection calculations

Appendix D

Power Line Data

D.1 Young-Lithgow Corridor Power Line Data

Table D.1 describes the power lines in the Young-Lithgow shared corridor (power line parameters and corresponding fault data). CDEGS required fault levels at three different locations for each power line. Fault levels were available only at power line termination substations. Additional calculations were performed to obtain fault levels at the start, in the middle and at the end of the shared corridor. For each power line, zero sequence impedance had to be calculated, as it was not available from the data sheets. Calculations for a typical power line tower found in the corridor were presented in Appendix B.1. Based on this, left and right components of the fault current at the required point along the power line were calculated, as given in Appendix B.2. The final results are presented in Table D.1.

Line	94x	944	934	857
Voltage (kV)	132	132	132	66
Load (A)	325	200	320	280
From	Panorama	Orange	Wallerawang	Wallerawang
To	Wallerawang	Wallerawang	Hawkesbury	Lithgow
Owner	Transgrid	Transgrid	Integral	Integral
Total Distance (m)	58100	72900	81000	12000
Substation to Corridor	21000	35800	5000	5000
Shared Corridor Length	33500	33500	4000	4000
Corridor to Substation	3600	3600	72000	3000
Phases	3	3	3	3
Earth Wires	2	2	2	2
Tower	horizontal	horizontal	horizontal	horizontal
Phase Conductor	Lemon ACSR	Coyote 0.125”	26/0.100 SCA	Lime 30/3.5 ACSR
Earth Wire Conductor	SC/GZ 7/0.128	SC/GZ 7/0.128	SC/GZ 7/0.128	SC/GZ 7/0.128
Prim. Protection (ms)	80	80	80	
Backup Protection (ms)	400	400	400	
Fault 1				
Power Line Distance (m)	21000	63000	5000	5000
Fault Level (A)	4654	7461	10289	6717
Left Component (A)	2614	1005	9490	4554
Right Component (A)	2039	6456	798	2163
Fault 2				
Power Line Distance (m)	30500	67000	7000	7000
Fault Level (A)	4804	9583	8863	6347
Left Component (A)	1875	848	7973	3705
Right Component (A)	2928	8735	890	2642
Fault 3				
Power Line Distance (m)	45200	69300	15000	
Fault Level (A)	5420	11650	5981	
Left Component (A)	1463	722	4832	
Right Component (A)	5229	10928	1149	

Table D.1: Young-Lithgow power line data

D.2 Brisbane Corridor Power Line Data

Both circuits in the Brisbane corridor share the same towers. There are two earth wires on each tower. The fault levels were obtained only for one of the two circuits which is satisfactory since the construction details of both power line circuits are similar.

Line	804	817	
Voltage (kV)	275	275	
Load (A)	630	630	
From	Swanbank	Blackwall	
To	Loganlea	Belmont	
Owner	Powerlink	Powerlink	
Total Distance (m)		50000	
Substation to Corridor	8700	15300	
Shared Corridor Length	8200	8200	
Corridor to Substation		26500	
Phases	3	3	
Earth Wires	1	1	
Tower	vertical	vertical	
Phase Conductor	2 x Goat	2 x Goat	
Earth Wire Conductor	SC/GZ 19/0.08	SC/GZ 19/0.08	
Prim. Protection (ms)	80	80	
Backup Protection (ms)	250	250	
Fault 1			
Power Line Distance (m)		15300	
Fault Level		Magnitude (A)	Degree
Left Component (A)		10600	-84.5
Right Component (A)		2800	-82.5
Fault 2			
Power Line Distance (m)		20000	
Fault Level		Magnitude (A)	Degree
Left Component (A)		8460	-83.81
Right Component (A)		3290	-82.53
Fault 3			
Power Line Distance (m)		23500	
Fault Level		Magnitude (A)	Degree
Left Component (A)		7700	-83.7
Right Component (A)		3700	-82.7

Table D.2: Brisbane power line data

D.3 Brisbane Corridor Power Line Tower Footing Resistances

Tower Number	Footing Resistance (Ω)
2227	2.5
2228	0.5
2229	2.0
2230	2.5
2231	4.0
2232	2.0
2233	1.5
2234	3.5
2235	1.5
2236	1.0
2237	0.5
2238	1.5
2239	2.0
2240	1.5
2241	3.5
2242	3.0
2243	0.5
2244	1.0
2245	3.5
2246	2.5
2247	2.5

Table D.3: Brisbane power line tower footing resistances

D.4 Estimation of Fault Current Components

D.4.1 Location of Power Line Faults

Fault analysis requires knowledge of the fault levels on the power line at three different locations: in the middle and at both ends of the shared corridor. The worst case fault, which is a single phase to earth, was studied. When the electricity network is supplied from both sides (non-radial networks), contributions to the fault current from the left and the right side of the faulted phase must be known. In the case of the Brisbane pipeline, the power line fault levels and their components were supplied for a fault in the middle of

the shared corridor and for one location outside the shared corridor on both sides. These three available fault levels were graphed and connected with an exponential curve simulating the reduction of fault levels as one moves away from the supplying substation. The shape of this curve was taken from a graph in a CIGRE publication [30]. From this curve, the fault levels at both ends of the shared corridor were approximated. Once the three estimated fault current components are supplied to the program, CDEGS automatically models faults at any other location (power line tower) inside the corridor.

D.4.2 Worst Case Scenario Fault Current Components

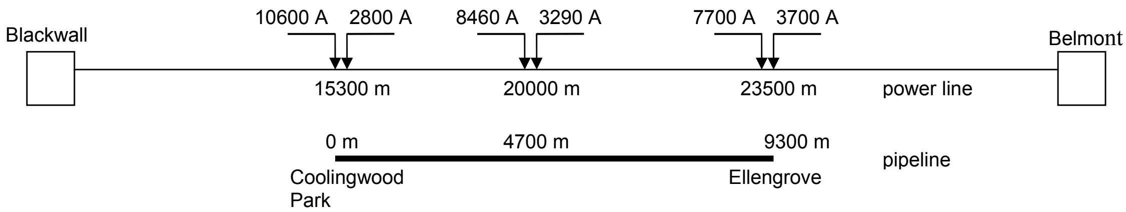

Figure D.1: Brisbane power line - left and right fault components for selected faults

Left and right components of the fault current used for the fault study in CDEGS are given in Table D.2. They were obtained using the procedure described in D.4.1. Illustration of these fault current components is given in Figure D.1. It can be seen that the highest current level is around 10600 A. But that is a left component of a fault occurring at the left end of the shared corridor meaning that there would be no coupling between that current and the pipeline during the fault. The right component of 2800 A, which would flow through the corridor in that case, would be the current involved in coupling. The worst case scenario for induced voltage on the pipeline would be the fault on the right side of the corridor. In that case the component of the fault current, which in this case is 7700 A, would flow through the shared corridor and would be involved in coupling.

Appendix E

Nomogram

E.1 Nomogram for Calculation of Mutual Impedance

This nomogram for calculation of mutual impedance between two coupled conductors was taken from [48]. It is a rough estimate based on soil resistivity and separation between the conductors. The impedance read from the nomogram is in Ω/km.

Please see print copy for Figure E 1

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