The Ingagane pipeline, which feeds the Ingagane Power Station from the Chelmsford Dam, could play a vital role in the supply of water to Newcastle and its surrounding communities. During 1996 Eskom handed over the Ingagane pipeline to the Umzinyathi Regional Council, and in doing so entrusted the Council with the responsibility of maintaining and operating the pipeline.

PIPELINE MAINTENANCE

by Craig Botha, Paradigm Projects

From available records it has been estimated that the pipeline was laid between the years 1963 and 1966 and was constructed from 710mm, continuously welded, bitumen lined, longitudinally welded steel pipe. The steel wall thickness of the pipeline is approximately 8mm.

At the time of construction bitumen linings were seen as a solution to internal corrosion, and there was little idea of the dangers associated with solvent-based linings. Only during the late 1970's and early 1980's, did the inherent weakness of bitumen linings become apparent. Subsequently, their failure has become common in pipelines 20 years or older.

Paradigm Projects carried out a detailed integrity evaluation of the pipeline, including: a soil resistivity survey; coating inspection; lining inspection, a BIC survey of the soils; current drainage and stray current surveys; a groundbed survey; and an hydraulic parameter evaluation. This article will cover a number of aspects of the survey, namely the soil resistivity survey, the coating inspection, the lining inspection and the current drainage and stray current surveys.

Soil resistivity survey

The corrosiveness of soil depends on elements such as the moisture, dissolved salts, minerals, different soil types positioned next to each other and several other elements found in the soil along the pipeline route.

The resistivity of soil is inversely related to the corrosivity thereof, ie the lower the resistivity, the higher the corrosivity and visa-versa. Low resistivity often goes hand in hand with the presence of moisture and dissolved salts.

Soil resistivity measurements on site were carried out at 100m intervals, reducing to 50m intervals at low resistivity sites, along the pipeline route. The Wenner-four-electrode method was used and the resistance measured to a depth of 1,6m (average pipeline depth). These measurements were then used to calculate the resistivity.

Table 1 illustrates the classification that could be used were no stray current activity present, since stray currents have no regard for soil properties.

Resistivity (Ωm)	Corrosivity
0 - 20	Very corrosive - cathodic protection required
20 - 50	Corrosive - cathodic protection recommended
50 - 100	Mildly corrosive - cathodic protection optional
more than 100	Not corrosive - cathodic protection not required

Table 1

For purposes of the investigation the Chelmsford Dam outlet and the Ingagane Power Station were taken to be chainages 0 and 15280 metres respectively. Soil resistivity measurements were taken at 100 metre intervals along the pipeline route, reducing to 50 metre intervals at several locations to account for low resistivity readings. From the results of the survey, it was concluded that 40,6% of the soils traversed by the pipeline could be classified as mildly to very corrosive, with the balance made up of non-corrosive soils.

For purposes of the coating investigation six potentially corrosive sites were selected.

Coating inspection

The six potentially corrosive sites were selected on the premise that the pipeline would be most likely to fail in areas of high corrosivity (low resistivity) if the coating were defective. From the outset of the project, two approaches were possible:

- excavation and exposure of the pipeline coating based on soil resistivity measurements
- the direct current voltage gradient survey technique, which, without major excavations, locates coating defects along a pipeline route

The first option was adopted to determine the pipeline coating condition at relatively low cost and with a reasonable level of confidence. Trench details are given in *Table 2*. Of the six trenches inspected, only two showed signs of marginal deterioration (trenches 1 and 5); the other four (trenches 2, 3, 4 and 6) showed signs of mild to severe degradation.

It was recommended that the DCVG coating defect survey technique be implemented to pinpoint substantial defects for repair since, on completion of such a survey, it would be possible to estimate the costs of partial refurbishment of the external pipeline coating.

It was estimated from the soil resistivity and coating inspection findings that 30% of the pipeline length could require rewrapping or recoating, with a suitable protection system. However, this would only be confirmed on completion of the DCVG survey.

Lining inspection

At the outset, two lining inspection options were available to the Umzinyathi Regional Council, namely:

- tethered camera inspection at selected locations
- physical inspection at selected locations

As the cost difference between the two is substantial, it was decided that the second option be adopted to establish the condition of the internal lining. The pipeline was shut down and the necessary isolation procedures carried out to secure the safety of the personnel entering the pipeline. Members of Paradigm Projects entered the pipeline at three locations and photographs were taken inside the pipe to demonstrate the condition of the lining.

Lining failure

The bitumen (coal tar) lining used inside the Ingagane pipeline is categorised as a thermoplastic (non-convertible coating).

Chainage (m)	Description of inspection plant	Brief summary of findings
4550	Trench 1. Between SV10 & AV14	No visible signs of coating defects Bitumen brittle, with reasonable adhesion
6435	Trench 2. 10m After AV16	Visible signs of coating defects with poor coating adhesion and advanced corrosion at defect sites. Metal loss up to 3mm
8475	Trench 3. Between IV3 & SV15	No visible signs of coating defects. Bitumen brittle, with reasonable adhesion. Bitumen coating undergoing exfoliation due to root ingress
9480	Trench 4. Just before AV20	Visible signs of coating defects with poor coating adhesion and advanced corrosion at defect sites. Metal loss up to 3,5 mm
11370	Trench 5. Between AV23 & IV4	No visible signs of coating defects. Bitument brittle, with reasonable adhesion. Backfill material appears to be less aggressive
14625	Trench 6. 100m after SV21	Visible signs of coating defects with poor coating adhesion and advanced corrosion at defect sites. Metal loss up to 1mm. Root ingress and an aggressive soil environment have contributed to rapid coating failure

SV = Scour valve; AV = Airvalve; IV = Isolating valve

Table 2: Trench details of pipeline coating conditions

Disadvantages associated with this coating system are described below:

- as a coating, bitumen has relatively poor adhesion properties and under cutting corrosion can be severe
- bitumen contains plasticising agents that provide ductility. However plasticising agents are migratory and tend to 'leach' out into adjacent porous materials. The bitumen coating becomes embrittled with the loss of plasticising agent and characteristic hairline cracking occurs
- it is common knowledge that all organic coatings absorb water and that water passes through them at varying rates. Only once an aqueous phase, capable of supporting corrosion, has formed at the metal/coating interference will the corrosion reaction occur. There are several mechanisms whereby water may condense at the metal/coating interface; of these osmotic blistering is the most common
- the fluctuation of the water temperature coupled with hydrostatic surges results in the contraction and expansion of the bitumen lined surface as it is subjected to thermal/ mechanical stresses. Ultimately cracks enlarge on the bitumen surface, blisters burst and the coating fails, exposing the steel pipe to corrosive forces within the water

Figures 1 to 4 illustrate these observations: *Figure 1* shows a typical longitudinally welded length of steel pipe. The pipe is lined with bitumen as shown in *Figure 2*. The weld site chosen illustrates the catastrophic consequences of unchecked bacterial corrosion. As the bitumen lining loses its plasticiser it begins to pass water by osmosis, resulting in a positive pressure between the steel surface of the pipeline and the lining. *Figure 3* is a simplistic representation of this process.

The process of osmosis continues until the adhesive strength and mechanical properties of the ageing bitumen lining are no longer able to withstand the positive pressure and the bitumen ruptures. The bitumen may break away completely, as shown in *Figure 4*, or may crack only as shown in subsequent photographs. The findings of the lining inspection for each of the inspection sites are detailed in *Table 3* where it is evident that sulphate reducing bacteria are well established within the pipeline. *Figure 5* depicts the bitumen lining condition and the presence of sulphate reducing bacteria. The bright metal surface displayed in *Figure 6* is an indication of severe corrosion and a metal loss of 2,5mm was measured at this location.

Sulphate reducing bacteria produce H_2S as a byproduct. This is highly soluble in water, forming dilute sulphuric acid at the steel nodule interface and resulting in rapid corrosion beneath the bacterial colony. *Figure 7* graphically illustrates the make up of a typical nodule.

It is evident that sulphate reducing bacteria pose a primary threat to the life expectancy of the Ingagane pipeline and it is safe to assume that the bitumen lining has reached the end of its useful life and that it will soon be totally ineffective as a corrosion protection system. On this basis it was recommended that a suitable relining/coating system be considered to extend the life of the pipeline. The relining/ coating system should take the following into consideration:

- the throughput of the pipeline
- the downtime required to execute the relining/coating of the inside of the pipeline
- future considerations regarding water demand ie maximise the remaining life of the asset

Current drainage

A current drainage survey determines the current required to afford protection to a pipeline. This is important since the current requirements determine the size and number of transformer rectifier units and anode groundbeds for an impressed current cathodic protection system or the feasibility of a sacrificial anode system. Without an accurate knowledge of the current required for pro-

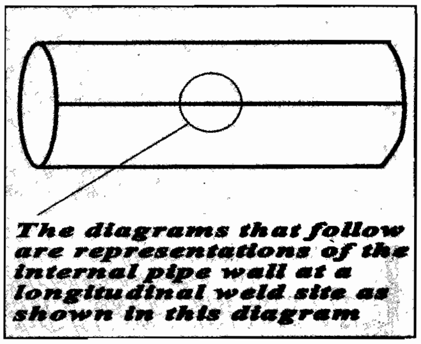

Figure 1: Typical longitudinally welded length of steel pipe

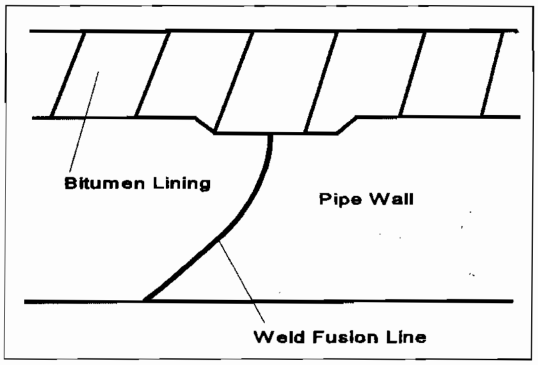

Figure 2

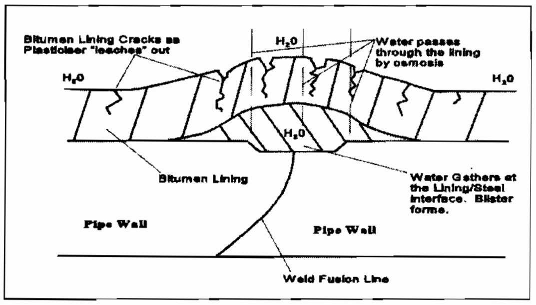

Figure 3

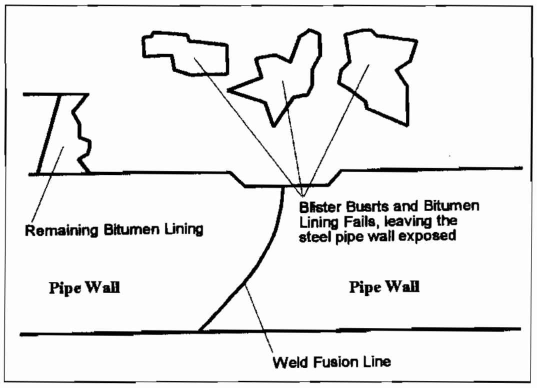

Figure 4

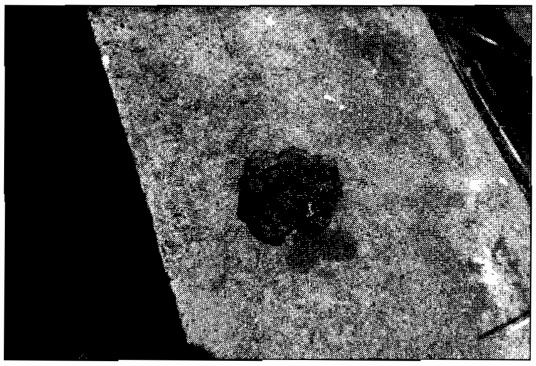

Figure 5

Chainage (m)	Description of inspection point	Brief summary of findings
4245	Main isolating valve number 1	Severe sulphate reducing bacteria colonisation. Metal loss up to 2,5mm. Bitumen lining blistering and ruptured
5685	Main isolating valve number 2	Advanced SRB colonisation. Blistering and failure of the bitumen lining beginning to accelerate
11445	Main isolating valve number 4	SRB present. Butt weld affected, blistering and rupture of bitumen lining. Metal loss of up to 3,0mm. Repaired holes.

Table 3

tection, one could over-or-under-design a cathodic protection system which would result in lack of protection or unnecessary installation requirements.

The temporary impressed current system used for this survey consisted of a portable dc power source connected to a rectifier bridge. Current was injected into the pipeline via a suitable anode and the pipe-to-soil potential was measured/ recorded along the pipeline before and after the injection of current. Results gathered during the survey included the amount of current passed, length of pipe protected, 'as-found' pipe-to-soil potentials and the shift thereof, which contributed towards the preparation of a cathodic protection design.

In the presence of stray currents data acquisition equipment is used to monitor the pipe-to-soil potentials effectively before and after current injection into the pipeline. The former practice provides a background against which the effectiveness of the current drainage survey can be evaluated.

Stray current

Stray currents flow at random in and through the soil. They could be of either alternating or direct current origin, but the latter are the cause of severe corrosion. They originate from dc-electrified railway lines or, under certain conditions, from adjacent pipelines. Traction stray currents are by far the most common, owing to the widespread nature of the rail system and because rails are not perfectly insulated from the soil, some current leaves them to enter the soil and return to the substation.

Since steel is a good electrical conductor any buried pipeline or steel structure in the vicinity will act as a parallel electrical conductor, collecting current at one end and discharging it at another point close to its source of power, thereby causing accelerated corrosion. The natural potential of mild-steel in soil is approximately -0,50V with respect to a saturated copper/copper sulphate reference electrode. Stray current activity on any pipeline causes a fluctuation in potential. Currents entering the pipe from the soil result in more negative shifts in potential, whereas currents leaving the pipe to return to earth cause the potential shift to become more positive and may even assume positive values for sustained time periods.

Stray currents flowing in the soil are difficult to measure and it is therefore common practice to measure the fluctuation in pipe potential as an indication of stray current activity. Substantial deviations from the natural potential values indicate the presence and magnitude of stray currents.

The fluctuating nature of stray currents may be attributed to the frequency and loading of rail traffic. It is therefore advisable not to use spot potential surveys under stray current conditions. Instead, digital data loggers should be used to take recordings of the pipe-to-soil potential. A stray current survey is carried out by recording the fluctuation in potential over a period of several hours.

Adjacent pipelines may also be a source of potential fluctuation, either due to their own cathodic protection systems, or because they cross or are bonded to railway lines some distance away.

Findings

The stray current and current drainage surveys were conducted simultaneously to ensure the most cost-effective procedure for data capture over the Ingagane pipeline. *Tables 4 and 5* are summaries of the recordings. From the data in *Table 4* it was evident that the Ingagane pipeline was subject to severe stray current activity, which emanated from the nearby dc traction railway line.

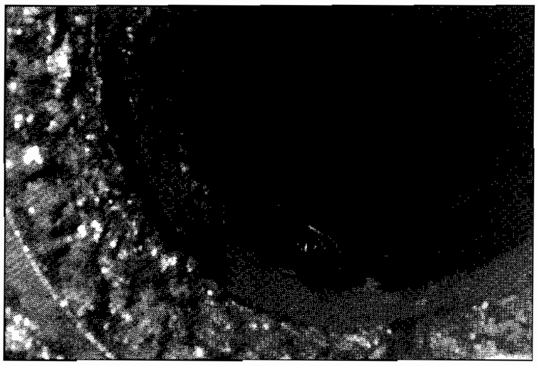

Figure 6: The bright metal surface is an indication of severe corrosion

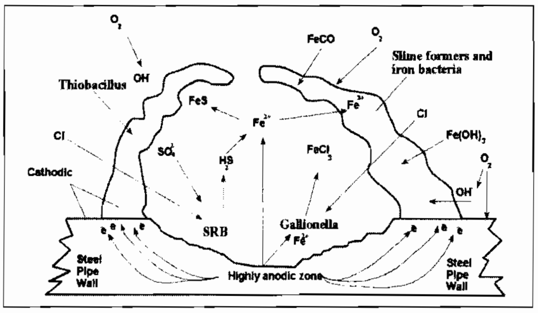

Figure 7: Processes which could occur during pitting of iron or steel with biological activity

Location	Maximum Potential (V)	Minimum Potential (V)	Mean Potential (V)	% Time Pipe Protected
TP 1	0,65	-1,51	-0,55	7,31
TP 2	0,71	-1,75	-0,51	9,23
TP 3	0,63	-2,11	-0,48	9,23
TP 5	-0,08	-2,22	-0,84	49,23
TP 6	-0,25	-0,67	-0,53	0,00
Trench 6	-0,20	-2,85	-0,83	49,47
Newcastle Offtake	-0,32	-1,46	-0,78	11,54

Table 4: Transformer rectifier 'off'

Transformer Rectifier "On"

Location	Maximum Potential (V)	Minimum Potential (V)	Mean Potential (V)	% Time Pipe Protected
TP 1	0,25	-2,10	-1,35	91,43
TP 2	0,25	-3,12	-2,10	97,27
TP 3	0,25	-3,25	-2,33	98,18
TP 5	-1,41	-3,31	-2,52	100,00
TP 6	-0,48	-1,25	-0,76	4,55
Trench 6	-1,58	-3,46	-2,35	100,00
Newcastle Offtake	-0,85	-1,65	-1,18	100,00

Table 5: Transformer rectifier 'on'

The situation was exacerbated because the pipeline passed under the railway line at approximate chainage 9400m. During the current drainage phase ie 'transformer rectifier on' the transformer rectifier output was measured as follows:

Current output : = 117 Amps
Voltage output : = 23 Volts
Pipe-to-soil potential at current injection point : = -7,5 Volts

At this level of output the Ingagane pipeline was afforded protection throughout its length. Using the above figures, it was possible to calculate the current density required to afford protection to the pipeline.

$$\text{Current density required} = \frac{\text{(drainage current)}}{\text{(Surface area of the pipeline)}} = \frac{(117\ \text{Amps})}{(\pi \times 0{,}71\text{m} \times 15500\text{m})} = 0{,}0106\ \text{A.m}^{-2} \text{ or } 10.63\ \text{mA.m}^{-2}$$

It is important to note:

- a new coating generally requires 0.01 $mA.m^{-2}$
- due to the deterioration of the coating the existing cathodic protection unit was unable to protect the pipeline throughout its length
- it was recommended that two cathodic protection units (each rated at 100V100A) be installed along the pipeline route to achieve the following: **(1)** an even distribution of current throughout the length of the pipeline and **(2)** a lowering of the current injection point potential, since constantly high potentials at the injection point could accelerate disbonding of the already fragile coating. It was further recommended that investigations be carried out in the vicinity of chainage 15500m, to ascertain the cause of 'discontinuous' potential readings

Conclusion

Although only 2% of the pipeline lining and 0,7% of the pipeline coating were inspected, the general impression was that of a failing bitumen lining and concentrated sites of failure on the external bitumen fibre coating. It was also felt that sulphate reducing bacteria would also contribute significantly to the ultimate failure of the pipeline. The rate of corrosion increases with time, placing a constraint on the time available for remedial action. Similarly defects in the external coating and a nonfunctional cathodic protection system have resulted in unchecked stray current activity on the pipeline, with up to 40% loss in wall thickness at certain locations.

A combination of the following corrosion protection techniques should be considered, since omitting one of them would result in failure of the other: cathodic protection; total relining/recoating of the inside of the pipeline; partial rewrapping/coating of the external pipeline. ■