Code of Practice

Upstream Polyethylene Gathering Networks - CSG Industry

Companion Paper CP-11-001

Condition Assessment

Rev 1

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Contents

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Preface

Companion Papers have been developed by the Working Group responsible for the APGA Code of Practice for Upstream PE Gathering Networks – CSG Industry (the Code) as a means to document technical information, procedures and guidelines for good industry practice in the coal seam gas (CSG) industry.

Since 2008, the development of the LNG export industry based in Gladstone, Queensland, with its related requirement for a large upstream CSG supply network of pipelines and related facilities presented the impetus for significant improvements in design and best practice approach.

The principal motivation for the initial development of the APGA Code of Practice was safety and standardisation in design and procedures and to provide guidance to ensure that as low as reasonably practicable (ALARP) risk-based requirements were available to the whole CSG industry. Accordingly, the Code is focused solely on this industry and the gathering networks using locally- manufactured PE100 pipeline. The Code is a statutory document within Queensland.

The incorporation of Companion Papers in Version 4 of the Code is intended to provide information and best practice guidelines to the Industry, allowing the Code to be limited to mandating essential safety, design, construction and operation philosophies and practices.

These documents form part of the suite of documents together with the Code and are intended to:

- be used in the design, construction and operation of upstream PE gathering networks
- provide an authoritative source of important principles and practical guidelines for use by responsible and competent persons or organisations.

These documents should be read in conjunction with the requirements of the Code to ensure sound principles and practices are followed. These documents do not supersede or take precedence over any of the requirements of the Code.

A key role of the Companion Papers is to provide the flexibility to incorporate endorsed industry practices and emerging technologies expeditiously, as/when necessary.

A related benefit is that the Companion Papers can be referenced by the wider resources industry which uses similar PE gathering networks for gas or water handling, including coal bed methane (CBM) in underground coal mines; mine de-watering; or the emerging biogas industries (agricultural, landfill, etc.).

1 Scope

The scope of this Companion Paper is to recommend a method to enable efficient determination of the condition of a PE network and to approximate remaining life. Condition Assessment is also referenced in the Code in Section 11.

A method for applying Miner's rule for assessing the capability of individual PE100 pipe compounds to withstand over-pressure excursions is also described. The method may be applied as part of an assessment of remaining life or at the design stage to predict future performance.

2 Introduction

The procedure and tests to be considered when assessing the condition of a PE100 pipe that has been in service or storage are described. It should be understood that the service life of PE100 pipes will be dependent on the actual service conditions and these might differ from those assumed when the pipeline was designed. Similarly, any service life achievable after a condition assessment will also depend up the actual conditions experienced. Accurate condition assessment is dependent on accurate records being maintained of PE pipes and their service conditions.

Stored pipes, pipes installed above ground, buried PE pipes and PE fittings are addressed. The information is equally applicable to the gathering system (i.e. PFW and gas lines), PE100 pipes associated with water treatment plants (e.g. brine transfer) and pipes for moving water between dams.

Condition assessment is generally opportunistically carried out when buried pipe is exposed for new connections, extensions or could be as the result of a failure, for example. If there are sections of the network that have been identified as having had a pressure or temperature excursion above the design limits, these locations may be excavated to remove a sample of pipe to be taken away and tested.

Condition assessment may be incorporated in IMP as part of the Operator's network integrity management strategy. It might also be implemented because:

- a pipe system is reaching the end of its design life,
- changes have been made or are to be made to the operating conditions,
- the system has been operated above the recommended service or design conditions,
- pipe has been damaged in operation by external causes,
- as part of a failure analysis, or
- a pipeline has been decommissioned and there is a prospect of using the pipe in another application.

The condition assessment of metallic fittings and risers which are part of the gathering network is not covered in detail in this paper. Condition assessment of metallic components may be required, in addition to the above reasons, due to external and internal corrosion, chemical reaction, bacterial attack, and coating deterioration.

3 Technical review

3.1 PE100 pipe failure mode

The procedure for the design of PE100 pressure pipes is described in the Code, but it is important to keep in mind the design stresses are based on ductile failure as shown the time – hoop stress – temperature regression curves generated in the laboratory according to the processes described in ISO 9080.

Unless the pipeline is operated at excessive temperatures or pressures, or deformed by excessive external loading and stresses, ductile failure will not occur in practice. Actual failure will ultimately be brittle in nature. The recommended condition assessment is therefore largely directed at those characteristics that relate to brittle behaviour.

4 Recommended process for condition assessment

4.1 Material identification

Confirm the pipe details by examining the printed markings down the length of the pipe.

In particular check the material is identified as PE100. If the pipe is marked ‘PE100’, bears the Standard Number AS/NZS 4130 and is made from a material listed in PIPA POP004 it is extremely unlikely to be made from anything other than a material complying with AS/NZS 4131. Therefore, in such cases material classification by testing is generally not necessary. However, in case of PE pipe bearing different or no marking at all, examination of material certificates and testing of material would be required to establish its properties.

PE 100 pipe extruded in the modern plants locally is generally subject to significant QA/QC on many properties, including the resin, and is traceable to time and place of manufacture.

However, couplings, valves and fittings are imported from various overseas plants so pre-installation inspection and validation is recommended good practice.

4.2 Service conditions

As discussed in Sec 3.1 ‘Failure mode’ above, review the actual service conditions and compare them with the original design to identify any areas of concern. Higher service temperatures or pressures can indicate the service life will be shorter than originally expected. Conversely, lower service temperatures or pressures can indicate the service life will be longer than previously expected. Vacuum formation can adversely affect the integrity of the pipe. Obviously, this process will be facilitated if accurate service condition records are maintained.

Generally, service conditions are most extreme at the inlets to the network being the wellsites, where the pipeline experiences higher temperatures and pressures. The severity of these conditions tend to diminish as the gas and water move further into the gathering network. The temperature decreases due to the heat sink properties of the soil surrounding the buried pipelines, and the pressure drops due to flow friction, or change of pipe size. Consequently, the highest temperature and pressure points are typically located closest to the wells.

4.3 Failure records

Examine the service/failure record for the pipeline. An increasing failure rate not attributable to third party damage or other external causes can indicate the pipeline had reached the end of its service life.

4.4 Installed conditions

Check the installed conditions in which pipeline or assembly was found, to determine if it had been stressed, overloaded or mechanically damaged. This could be by incorrect backfilling, inadequate support in the trench or on aboveground supports, or transfer of load from other adjacent pipe/assembly. Look for inadequate compaction, subsidence, trench erosion, lack of separation between the buried services and similar.

4.5 Visual examination

Visually examine whenever pipe samples are available or installed pipe is accessible to assess the extent of any mechanical damage, erosion, manufacturing defects, or surface cracks. Refer to CP-03-002: Guidelines for Acceptance Criteria of Surface Discontinuities for assessment of these features.

Pipes installed above ground, especially those with coloured jackets or stripes might exhibit cracks on the exposed surface. These indicate the pipe may be approaching the end of its service life. In case of cracks present on stripes only, it usually means that the stripe material has deteriorated due to exposure UV. If found on buried pipe, it is likely the pipe has been exposed to UV for prolonged periods during storage before installation. The possible remaining life will depend upon the depth of the cracks and the operating conditions. For example, intermittent use at low stresses might allow for continued operation, especially if the pipe is in a location where the condition can be regularly monitored. When surface cracks are only present on stripes, and not the in parent pipe, the overall integrity of the pipe might still be acceptable, provided cracking is not progressing and if this verified by integrity material testing.

Cracks on the internal wall are harder to monitor and should be taken as evidence the pipeline has reached the end of its service life, especially if failures have already occurred.

If cracks occur in the pipe wall they more commonly initiate at the inner wall than the outer wall because there is a manufacturing residual tensile stress superimposed on the hoop stress at the inner wall. At the outer wall a residual compressive stress occurs. External localised or point loads also create a higher tensile stress at the inner wall than at the outer wall.

4.6 Wall thickness

Measure the wall thickness to confirm the SDR is correct and whether any significant erosion has taken place, especially in pipelines carrying a significant amount of dry solids at high velocities and/or changes of direction (e.g. elbows and tees). Mismatching of pipe with different SDRs due to incorrect jointing practices, can create a stress raiser, leading to premature failure.

4.7 Laboratory tests

It is recommended that both a) oxidation induction time (OIT) and b) Fourier Transform Infrared (FTIR) tests are performed.

a) The OIT test provides a measure of the residual antioxidant. Oxidation of the polymer itself occurs when the antioxidant is largely depleted.

There is a substantial incubation period between the commencement of antioxidant depletion and degradation of the polymer properties. It is when the antioxidant content is largely depleted that oxidation (i.e. polymer degradation) commences. The commencement of polymer degradation does not result in immediate pipe failure but a predilection for slow crack growth. For this reason OIT cannot be used as a quantitative predictor of remaining life, but it shows whether or not there is any residual protection of the polymer against oxidation.

b) Polymer oxidation is measured by the FTIR test and reported as the ‘carbonyl index’. The carbonyl index is a measure of the increase in the carbonyl moieties such as ketone, acid and ester resulting from oxidation of the polymer chain. It is determined by comparing the ratio of the combined carbonyl peak with an internal C-H peak. The higher the value of the carbonyl index the greater the level of the polymer oxidation that will ultimately lead to failure and likelihood of a reduction in remaining service life .

c) Depending on the size of the sample available, tensile tests can be carried out to determine and reduction of hoop or longitudinal strength. Chemical attack can have a significant effect on the tensile strength of the polymers in PE100.

d) Accelerated pressure tests can be carried out to predict the performance of the material in operating conditions. They can be performed at combination of higher pressure to achieve specific hoop stress value, and high temperature (80 deg C) as specified in AS/NZS 4129 or AS/NZS 4130.

4.8 Investigation of field failures

If a pipe has failed in the field, assess whether the mode is ductile or brittle. Ductile field failures of pipe are rare and are usually a consequence of over pressurisation at the service temperature, or higher pipe operating temperatures, commonly due to exposure to solar radiation.

Brittle failures can be initiated by stress concentrations on pipe, fitting or section, due to incorrect installation (e.g. tee offtake bearing the load of other pipe installed on the top of it, with no separation); or improper welding.

Confirm the correct SDR pipe was installed; bend radius and other installation factors were in accordance with the Standards and codes. Review the construction records, including pressure testing, welding and material records, as applicable.

4.9 Welded joints

In the CSG gathering lines and associated CSG pipelines, service conditions are not expected to affect welded joints any more than the parent pipes. Nevertheless, there have been failures of welded joints due to inadequate installation practices. The performance of welded joints is largely determined by the quality achieved during construction.

4.10 Fittings

It generally expected that the condition of PE fittings in a pipeline will be consistent with the condition of the associated pipe. If fittings are to be assessed in their own right, the same processes as described for pipes can be applied. If premature failure of fittings does occur it is likely to be associated with construction problems, for example misalignment imposing higher stresses.

5 Remaining life using Miner's Rule-for temperature impacts

5.1 Variable Conditions

The methodology employed to evaluate remaining life focuses on exposure of PE100 pipe to variable operating conditions which are outside of their design limits.

For example, higher temperatures may reduce the pipe's hoop stress capacity and hence its MAOP. Although design of PE100 pipe normally allows for certain excursions, it is expected that such excursions, particularly temperature over a long period of time, could lead to accelerated loss of antioxidant and cause cumulative damage; possibly resulting in a reduced service life.

As the 'Remaining Life' for PE100 pipe is determined using empirically based calculations, the value obtained should not be used as a prediction but rather a guideline as to how susceptible a given asset (or asset type) may be to damage based on its operating history in comparison to others.

Below are the recommended technical guidelines for determination of remaining life:

- APGA CSG Code of Practice for HDPE gathering line
- ISO 13760: (Miner's rule – Calculation method for cumulative damage)
- ISO 15494: (Plastics piping systems for industrial applications – Metric series for specifications for components and the system)

Where the pipeline has been subjected to variable operating conditions and where these conditions are known, a Miner's rule analysis can be performed as described in ISO 13760. If ISO 9080 (Long term hydrostatic strength by extrapolation) data is available for the PE100 material this can be used in the analysis. Otherwise, generic data can be obtained from, for example, ISO 15494.

5.2 ISO 13760 and the Miner's Rule Principle

The Miner's rule calculates 'damage' (empirically). A material has a value which starts at 0% at the beginning of service life and accumulates until it reaches 100% at the end of the material's service life. Under constant conditions, the damage done is proportional to the duration of the 'exposure' to these conditions. The approach within ISO 13760 is to identify all credible operating temperature vs. hoop stress scenarios for a given PE pipe and obtain a service life for each, then apply an additivity rule in order to obtain the expected maximum service life.
For a period of one year, the amount of damage a PE pipe is subject to is expressed as:

$100/t_i$ %

Where t_i is the lifetime under a specified set of conditions.

Proportionality rule

If a material is exposed to attack for only part of a year (i.e. a_i % of the year), the damage is expressed as: a_i/t_i %

The proportionality rule is applied to each range of known operating conditions.

Total yearly damage (TYD)

The total amount of damage can be determined using the additivity rule:

(Eq 1) $TYD = \Sigma a_i/t_i$

Maximum Service Life

Finally, maximum service life is obtained using the equation below:

(Eq 2) $t_x = 100/TYD$

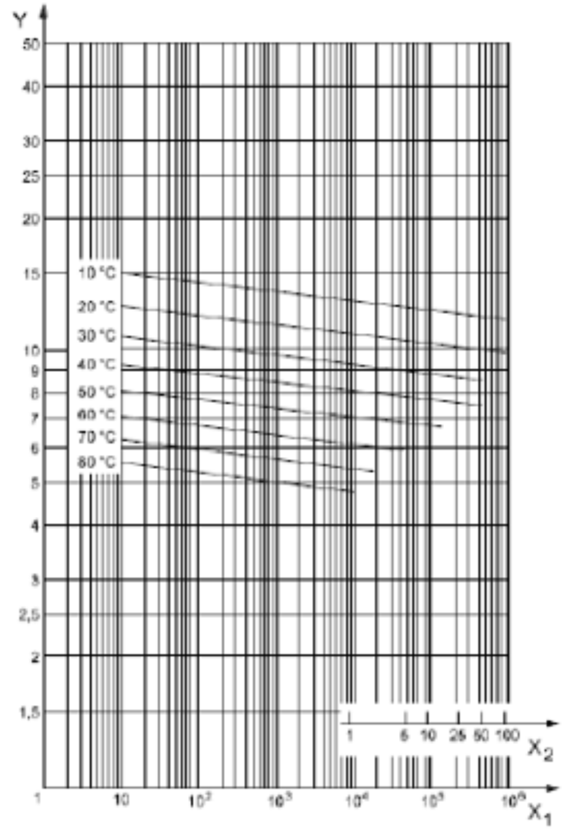
When determining the stress capability of PE100 compounds according to either the reference curves in ISO 15494 or individual compound results in accordance with ISO 9080, the material design factor f_0 of 1.25 shall be applied.

Note: In the absence of the material design factor, the calculated service life of PE100 at 20°C and an operating hoop stress of 8 MPa would be thousands of years which is unrealistic.

5.3 Applying Miner's Rule

ISO15494 contains generic material data for PE100 pipe, mainly in the form of 'hydrostatic strength curves' in which time to failure (in hours) is obtained when a temperature v hydrostatic strength/hoop stress scenario is plotted.

Figure 1 - Minimum required hydrostatic strength curves for PE 100 (Extract from ISO 15494)



Key
X_1 time to failure, in hours (h)
X_2 time to failure, in years
Y hoop stress, in megapascal (MPa)

For PE100 pipe, the hydrostatic strength curve above is also represented by the equation below:

(Eq 3) $$\log t_i = -45.4008 + 28444.7345 \times \frac{1}{T_i} - 45.9891 \times \log \sigma_i$$

Where

t_i = total time needed to cause the damage (at a given temperature)

T_i = Temperature at which the damage is caused

σ_i = Hoop stress at the time the damage was caused

In accordance with the APGA COP, Hoop Stress (σ_i) is obtained using the formula below:

(Eq 4)
$$\sigma_h = \frac{Px(SDR-1)}{2}$$

Where

P = Operating pressure at the time the damage was caused.

5.4 Establishing Service Life

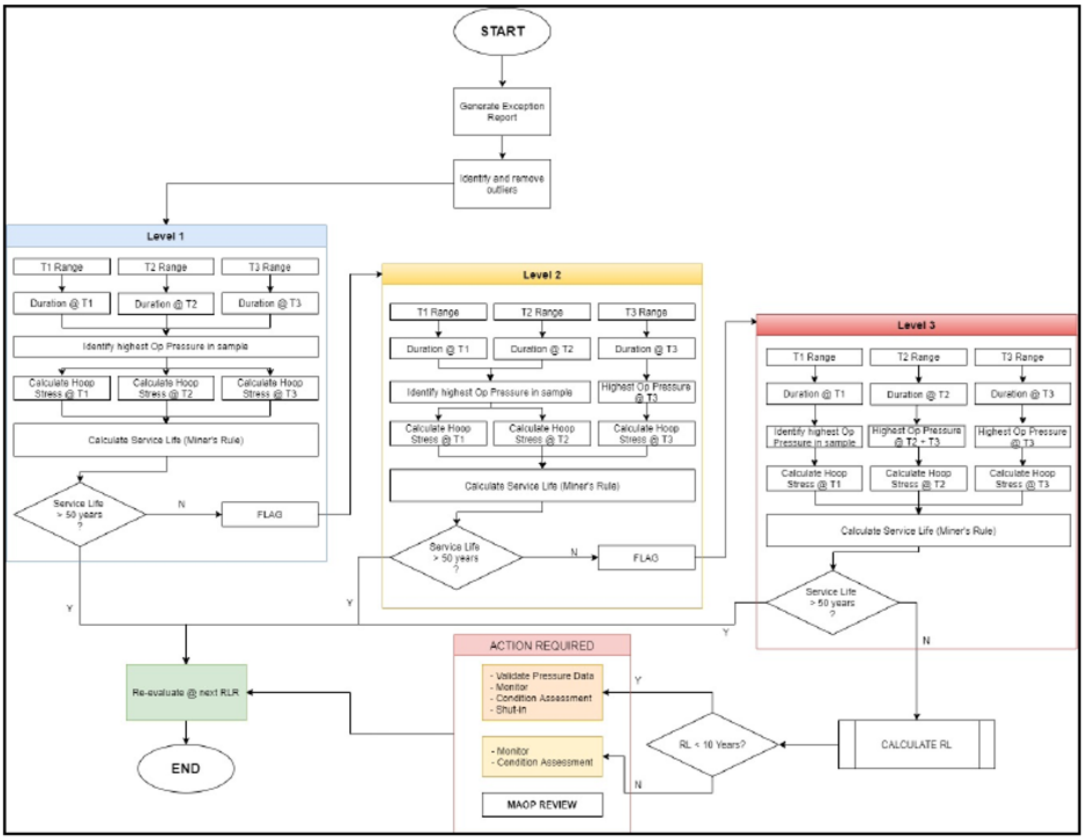
As described above, Miner's rule allows for a maximum expected service life to be determined by estimating the cumulative damage caused by the various operating envelopes to which the asset may have been subjected to. For each scenario, the following must be established:

1. Temperature
2. Hoop stress (dependent on operating pressure and SDR)
3. Duration or exposure (expressed as a percentage of operating life to date)

In operating CSG networks, temperature and pressure is typically monitored at well heads (for ease of monitoring installation), where the maximum values also occur.
Well head conditions therefore represent worst case conditions for the network.

5.5 Process Description

Figure 2 - Remaining Life Determination Process Flowchart



The process above is described in more detail within this section.

5.6 Temperature and Pressure Monitoring and Reporting

In a typical CSG company SCADA monitors, reports, and stores data on the following parameters:

1. Maximum gas temperature per day, with associated pressures
2. Maximum gas pressures per day, with associated temperatures
3. Total time in each of the 3 temperature ranges, (see next section for explanation).

Frequently CSG companies do not monitor water systems, hence gas data is representative of both systems.

5.7 Temperature Range and Duration

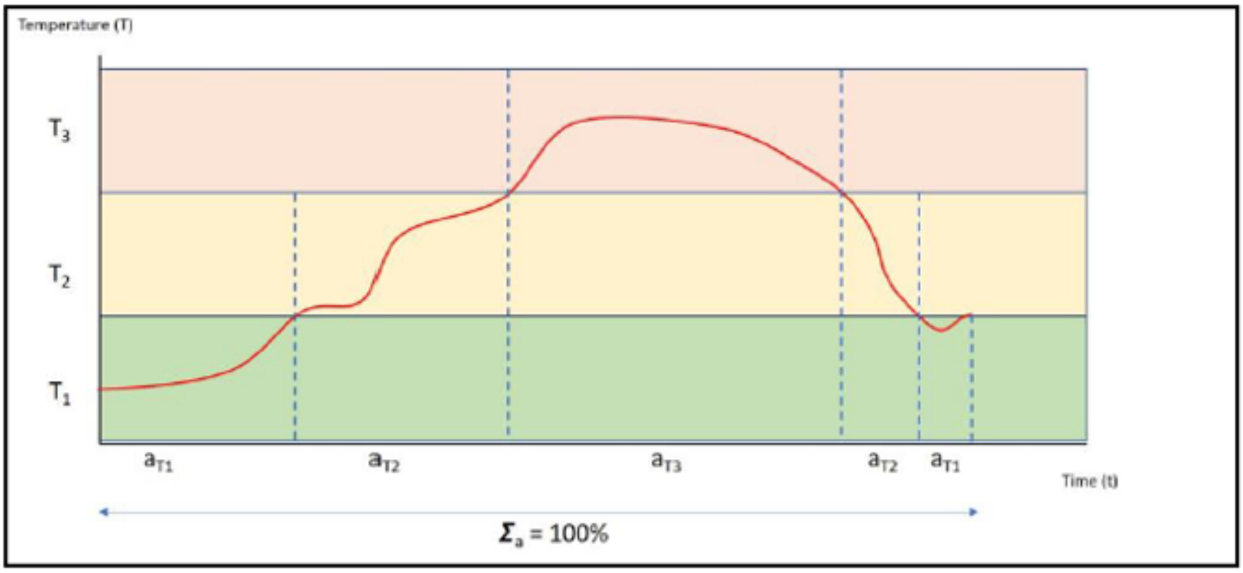
Three temperature ranges are typically established to suit expected operating conditions, (as per ISO 13760), where T1 and T2 are based on the definition of the CSG's company defined temperature excursions (typically captured in the Pipeline Integrity Management Plan) and T3 can be defined as the midpoint point between T2 and the maximum reliable reading value of field instruments.

Table 1- Temperature Excursion Ranges

Temp Range	Description	Notes
T1	T1	Design Temperature
T2	T1 to T2 range	Typical Excursion Range
T3	T3	High Excursion, (T4 – T2)
T4	T4	Max field reading value

For each of the above Ranges, a cumulative duration can be determined based on data extracted from SCADA. A typical figure can then be generated which describes excursion duration and total exposure:

Figure 3 - Temperature Excursion Duration and Total Exposure Period



Exception reports can then be generated for a network, or down to individual well to monitor its performance.

6 Provision for over-pressurization excursions in PE gathering lines- Application of Miner's Rule

PE100 compounds in general have a long-term hydrostatic strength as determined in accordance with ISO 9080, in excess of the minimum required to establish the MRS of 10 MPa.

For example, according to ISO 12162 all compounds with a long-term hydrostatic strength ≥10 and <11.2 MPa are classified as PE100. Additionally. the hydrostatic strengths at elevated temperatures are generally higher than indicated by applying the design factor for temperature f_1 to the MRS. The performance of individual compounds, over and above the minimum requirements has been used to determine their capability to withstand over-pressure excursions. The process employed to investigate the ability to withstand over pressure excursions is as follows.

1. Utilising the results of the ISO 9080 analysis (for predicting the long-term hydrostatic strength of the PE100 material by statistical extrapolation) - for the compound in question, establish the 'powerlaw' relationship between hoop stress and time to failure at the service temperature. For example, $hoop\ stress = A.time^B$
   where A and B are constants

2. Establish the hoop stress at the anticipated working pressure and over-pressure excursions.

3. Multiply both hoop stresses by the material design factor f_0, (see CoP section 4.3.6).

4. Assume the maximum duration of the possible over-pressure excursions and express as a percentage (a_0) of the total service life.

5. Calculate the hours to failure (t_0) at the operating hoop stress and temperature.

6. Calculate a_0 / t_0.

7. Similarly calculate a_1 / t_1 for the over-pressure excursion.

8. Calculate $\sum(a_i / t_i)$

9. 100 / $\sum(a_i / t_i)$ is the predicted service life, in hours, taking into account the ISO 9080 performance of the individual compound and over-pressure excursions as nominated whilst retaining the material design factor of 1.25.

10. Software 'Goal-seeking' techniques (determining appropriate input values based on desired output values) may be used to determine the maximum over-pressure excursions consistent with the required service life for the compound under examination.

11. The procedure can be repeated at various service temperatures and for multiple over-pressure levels.

7 Summary

It is not possible to precisely determine the remaining service life of a PE100 piping system. However, if the pipeline is designed, constructed, and operated in accordance with the *CSG Code of Practice for PE gathering lines*, the actual service life should exceed the design life. The design life will depend on the service temperature and pressure as shown in the CoP. Up to 30°C the extrapolation rules in ISO 9080 allow us to extrapolate to 100 years for the POP 004 listed materials; 50 years for 35° and 40°; 35 years for 45°C and so on.

Pipeline material condition assessment is a complex and comprehensive process entailing consideration of a range of factors and requires significant experience and expertise in pipe material analysis. Therefore, condition assessment is best undertaken by experienced personnel with an understanding of all aspects of PE pipelines design, construction and material properties including material characteristics, manufacturing processes, installation and operating conditions. This will ensure all relevant information is considered and also that unnecessary but potentially costly testing is avoided.

Consideration can be given to carrying out opportunistic assessments of the pipe quality during normal service. For example, if a damaged pipe must be repaired or a tie-in or other modification performed there may be an opportunity to examine the pipe or even cut out a sample piece of pipe or fitting for further material and weld quality testing.

Miner's rule can be used as a tool for investigating potential remaining service life or for determining the capability of individual compounds to cope with over pressure excursions based on their ISO 9080 performance

8 References

AS/NZS 4130, Polyethylene (PE) pipes for pressure applications

AS/NZS 4131, Polyethylene (PE) compounds for pressure pipes and fittings

ISO 9080, Plastics piping and ducting systems —Determination of the long-term hydrostatic strength of thermoplastics materials in pipe form by extrapolation.

ISO 13760, Plastics pipes for the conveyance of fluids under pressure – Miner's rule – Calculation method for cumulative damage.

ISO 15494, Plastics piping systems for industrial applications – Polybutene (PB), polyethylene (PE), polyethylene of raised temperature resistance (PERT), crosslinked polyethylene (PE-X), polypropylene (PP) – Metric series for specifications for components and the system.

PIPA POP004, Polyethylene pipe and fittings compounds.

CP-03-002 Guidelines for Acceptance Criteria of Surface Continuities