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Reliability prediction for corroding natural gas pipelines

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ABSTRACT

This paper aims to evaluate time-dependent reliability of a corroding onshore underground natural gas pipeline system over its lifetime. The reliability analysis is segment-based, as opposed to defect-based and the pipe segment is examined with respect to external metal loss corrosion. The non-homogeneous Poisson process (NHPP) and an empirical power law model are employed for generation of corrosion defects over time and for defect growth, respectively. The time-dependent probability of failure is evaluated by employing the limit state function for burst under internal pressure. Internal pressure is modelled using a Poisson square wave process-based method (PSWP). Thereinafter, the study uses the aforementioned analysis, in conjunction with a heuristic model, in order to investigate the influence of imperfect repairs on the reliability prediction of the pipeline system. The heuristic method is known as split system approach and it is used to describe the changes in reliability of the pipeline system over its lifetime with the consideration of multiple maintenance actions. A numerical example of the described methodology is presented based on a chosen maintenance policy. A parametric study is conducted to examine the impact of instantaneous generation rate of NHPP model, PSWP model and reliability control limit on the results of the numerical application. The proposed methodology aims to assist engineers in the decision making with regard to corrosion maintenance strategies.

1. Introduction

Energy pipeline infrastructures grow about 3–4 percent a year globally. Worldwide, most energy pipelines have been in place for at least 20 years; more than 50 percent of pipelines were installed in the period 1950–1970 (Kiefner and Rosenfeld, 2012). In literature, old pipelines refer to those that were constructed prior to 1970's. These are considered to be of lower standards in terms of material and external coating systems, compared to contemporary ones. In other words, degradation is considered a normal part of the operating lifecycle of oil and gas pipelines, even for the newly built ones, as it is for many civil and mechanical structures (Mahmoodian et al., 2012; Fang et al., 2013; Zhang et al., 2017). According to statistical analysis and incident data from literature, external corrosion has been identified as the most predominant gradual deterioration process (EGIG, 2015; CONCAWE, 2015; UKOPA, 2014; AER, 2013).

According to Kishawy and Gabbar (2010), more than 50% of existing pipelines worldwide are non-detectable by in-line inspection (ILI) instruments, a term referred to literature as 'non-piggable'. Also, according to the Interstate Natural Gas Association of America (INGAA) which operates approximately two thirds of the US natural gas transmission pipeline system, only 60 percent of total miles can accommodate ILI tools (PHMSA, 2012). Even though developments in the technology of ILI tools are constant and at the same time many older lines are modified to accommodate ILI, it is considered certain that for a significant amount of upstream and transmission pipelines, ILI will remain inadequate. This regards mainly remote, rural areas' pipelines that do not pose a threat to the public safety, which also usually pose a significant technical challenge due to a number of factors (e.g., small-diameter lines; multi-diameter lines; and lines with low flow rates, complex geometry, or that serve as a single source feed to customers) (PHMSA, 2012; Leewis, 2012). As a result, alternative to ILI and maintenance plans should be at hand.

The application of the aforementioned management principles for gas pipelines that cannot be in-line inspected with the usual inspection technology (smart pigs) relies mainly on the use of historical failure data and on methodologies based on External Corrosion Direct Assessment (ECDA) as specified by the National Association of Corrosion Engineers (NACE) Standard (ANSI/NACE SP0502, 2010). Reliability prediction based on historical failure data is accomplished by assuming and defining a direct comparison among the values of each pipe segment with a reference pipeline that summarises the average conditions of the area where the

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pipeline system operates (Caleyo et al., 2008; Nessim et al., 2009). However, this method provides only relative risk prioritisation maintenance plans and is not proposed when specific information is desired (Valor et al., 2014). On the other hand, an ECDA framework will typically entail indirect inspections and selected direct examinations at bell hole locations (ANSI/NACE SP0502, 2010).

Structural reliability analysis (SRA) offers an efficient and comprehensive way of assessing the threats imposed by corrosion on the condition and operation ability of pipelines (Stephens and Nessim, 2006; Tee et al., 2015). The uncertainties involved in the manufacturing and operation processes are all incorporated in SRA by means of probabilistic approaches (Tee and Khan, 2014; Khemis et al., 2016; Li et al., 2016). The corrosion growth modelling is considered critical for the accuracy and the validity of the SRA (Alani et al., 2014; Tee et al., 2014). The corrosion growth models reported in literature can be categorised into two main groups: random-variable based and stochastic process-based models. The next step in the SRA is the application of a predictive failure model to calculate the probability of failure which is achieved by employing a failure limit state function (Valor et al., 2013; Zhou, 2011; Melchers, 2004; Tee et al., 2013). In practice, the results from the SRA are utilized for the development of safe and cost-effective integrity management strategies. The uncertainties involved in the reliability prediction, defect initiation and propagation and the effect of maintenance on the performance of the pipeline system, should all be accounted for in an accurate reliability-based maintenance management program.

Natural gas pipelines are linear assets which span long distances and can be divided into different segments with the same function but different conditions. As a result, maintenance decisions based on reliability should be made on the system level. In practice, conventional engineering asset management systems or decision support tools, are not considered adequate for linear assets like energy pipelines (Sun et al., 2014). Usually, in order to maintain the overall reliability of a system in a long period of time, decisions for preventive maintenance should be taken, based on extensive inspection and/or condition monitoring of the system (Tee and Li, 2011; Guo et al., 2013; Khan et al., 2013). However, when a pipeline system is preventively maintained, normally only part of the system gets repaired or replaced, leading to an imperfect repair for the whole system (Sun et al., 2007). Moreover, when it comes to large scale engineering systems like pipelines, it is not sufficient to decide the next inspection and preventive maintenance (PM) time, but it is also needed to estimate multiple inspection and PM times over a decision horizon, which is normally a long period. This enables decision makers to adequately plan various resources such as economics, humans and logistics.

Relevant studies of optimal maintenance schedules based on reliability have been reported in literature. Previous studies focused on either only a single defect to derive the reliability of the pipeline (Gomes et al., 2013) or required the number of defects to be known from ILI results (Lecchi, 2011; Zhang and Zhou, 2013). Hong (1999) and Zhang and Zhou (2014) used the homogeneous Poisson process (HPP) and the NHPP subsequently, to generate the number of defects on a single pipeline segment and then find the optimal interval in a periodic inspection plan. Hong (1999) estimated the probability of failure with regard to a defect-based maintenance and repair strategy, as opposed to a segment-based strategy. Zhang and Zhou (2014) did not calculate the overall probability of failure but only the optimal interval based on cost and did not consider multiple segments via system reliability.

Studies in literature referring to ECDA have so far accounted for the Bayesian updating of data relevant to uncertainties of inspection tools and active corrosion defects characteristics (Van Os and Van Mastrigt, 2006; Francis et al., 2006, 2009; Van Burgel et al., 2011). However, the above studies are considered to entail a high level of complexity in terms of their mathematical justifications and thus their applicability becomes limited. Recently, Valor et al. (2014) and Caleyo et al. (2015) proposed more applied methodologies with regard to the analysis of field gathered data from random sampling of non-piggable underground pipelines. Nevertheless, according to the NACE Standard, pipeline operators when applying an ECDA may adopt a 100 percent direct examination instead of indirect inspections and selected sampling direct examinations at bell hole locations.

Previous works that consider a system of pipe segments include De Leon and Macías, (2005); Straub and Faber (2005) and Hong et al. (2014). De Leon and Macías, (2005) studied the effect of spatial correlation on the failure probability of corroded pipelines. They concluded that the correlation degree between failure modes at two pipeline segments increases with the degree of correlation of the initial corrosion depths of defects of these segments. In addition, for a small number of segments, for instance 5, the correlation is insignificant. Straub and Faber (2005) considered system effects for the inspection planning of steel structures subjected to fatigue deterioration. The system representation was made by considering a number of ‘hot spots' in the structure, which have been distinguished as more failure prone or having higher failure consequences. However, it was marked that for corroded pipelines, in principle ‘all spots are hot' and as a result the spatial variability of the deterioration mechanisms should be exhaustively considered. Still though, the number of ‘hot spots' is expected to be very large, and therefore some level of simplification should be applied. Hong et al. (2014) studied the dependency in stochastic degradations of multiple components of engineering systems and their effect on the system probability of failure. The result indicated importance solely for parallel systems and not for series systems, like pipelines.

System reliability predictions for corroding natural gas pipelines taking into consideration imperfect repairs, have not been modelled so far in the open literature to the authors' knowledge. Various relevant methods/models have been developed for other engineering systems though. A well-established heuristic method from literature is adopted in this study, which is referred to as Split System Approach (SSA) (Sun et al., 2007, 2009). This method has the ability to link the SRA to long-term PM decision making, so that the decision can be updated by using the latest inspection and health monitoring information available. In previous works (Sun et al., 2007, 2014), SSA was implemented by adopting the hazard function which belongs to the lifetime functions and is defined based on the probability density function of the time to failure. However, the SRA allows for a clear understanding of the separate contribution of each random variable to either resistance or load, unlike the lifetime functions that summarise the combined effect of all the uncertainties on the pipeline system (Barone and Frangopol, 2014). To the authors' knowledge, SSA has never been applied before to a corroded energy pipeline system with the reliability function estimated by an SRA.

In this study, a non-piggable corroding onshore natural gas pipeline system is examined with respect to external metal loss corrosion. The corrosion process is evaluated for a number of defects on a pipe segment of 12 m. The NHPP is employed to model the uncertainties in the number and generation of defects and a well-established empirical power law model is adopted for the growth of defects with time. The reliability prediction of the segment is evaluated by the limit state for burst due to internal pressure with the uncertainties in the pressure incorporated in the analysis through a PSWP model. Afterwards, a numerical example is illustrated where a system of three identical pipe segments forming a series system is considered and the reliability prediction is evaluated. The SSA method is employed in order to model the effects of future maintenance provisions in time-dependent