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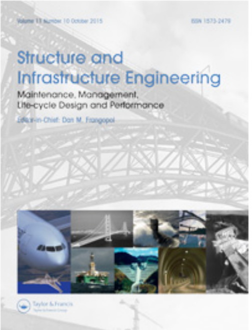

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Condition-based maintenance decision support system for oil and gas pipelines

Laya Parvizsedghy[a]*, Ahmed Senouci[b1], Tarek Zayed[a2], Seyed Farid Mirahadi[a3] and Mohammed S. El-Abbasy[a4]

[a]*Department of Building, Civil and Environmental Engineering, Concordia University, Montreal, Quebec, Canada;*
[b]*Department of Civil and Environmental Engineering, Qatar University, Doha, Qatar*

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The 2013 report card of America's infrastructure has scored the condition of oil and gas pipelines as D+ which means that such pipelines are in a relatively poor condition. More than 10,000 failures have been recorded in the US. These failures have resulted in environmental, health and property damages. Therefore, there is a definite need to give more attention to the maintenance of oil and gas pipelines. This paper develops a comprehensive model for the maintenance planning of oil and gas pipelines. The model selects rehabilitation/repair alternatives for oil and gas pipelines based on their condition during their service life. These alternatives are then used to calculate the cash flow throughout the service life of these infrastructures. The model, which uses Monte Carlo simulation and fuzzy approach to address the uncertainties in the estimation of the maintenance operation costs and the economic parameters, calculates the Equivalent Uniform Annual Worth of the identified alternatives. The optimum maintenance programmes consist of the alternatives that have the lowest life cycle cost of oil and gas pipelines. The model is expected to support pipeline operators in the maintenance decision-making process of oil and gas pipelines.

Keywords: oil and gas pipelines; life cycle cost; Monte Carlo simulation; fuzzy approach

Introduction

As a result of their lower incident rates, transportation costs and energy consumption, pipelines are suitable to transport petroleum products (Kennedy, 1993). However, the failures of oil and gas pipelines when they happen would result in significant environmental, health and property damages. The Pipeline and Hazardous Materials Safety Administration (2013) of US Department of Transportation reported the occurrence of more than 10,000 failures in its oil and gas pipeline networks. These failures caused around six billion US dollars of property damages, 380 fatalities and 1500 serious injuries and over 2.4 million barrels of hazardous materials' spillage in the environment. These statistics strongly support the development of maintenance planning tools for oil and gas pipelines.

The maintenance planning of oil and gas pipelines is not an easy task because of the complexity and high cost of maintenance operations. Moreover, the uncertainty of both the maintenance operation costs and the economical parameters (e.g. interest and inflation rates) does not permit a deterministic estimation of the life cycle cost (LCC). This fact along with the diversity of the maintenance operations makes the maintenance planning of oil and gas pipelines very challenging. This paper uses Monte Carlo simulation and fuzzy approach to analyse the LCCs of different pipeline maintenance plans. All possible maintenance operation scenarios are identified based on the forecasted condition of pipelines. The cost of the maintenance operations as well as the economic factors are then identified to estimate the pipeline LCC using Monte Carlo simulation and fuzzy approach. Finally, the best pipeline maintenance plans are determined.

Research objectives

A LCC model for oil and gas pipelines is developed herein using the following tasks:

(1) Identify the maintenance operation types suitable for oil and gas pipelines.
(2) Develop standard rules to generate possible scenarios of repair/replacement operations based on the forecasted pipeline conditions before and after the maintenance actions.
(3) Rank the generated maintenance scenarios based on their economic equivalency.

Background

Pipeline condition and risk failure assessment models

The LCC assessment of an infrastructure requires the prediction of the condition throughout its service life. Forecasting the pipeline condition allows the decision-

*Corresponding author. Email: l.sedghy@yahoo.com

makers to select and schedule the most suitable rehabilitation type. Significant efforts have been made during the last decades to assess the condition and the failure risk of oil and gas pipelines. Sinha and Pandey (2002) used artificial neural networks (ANNs) to develop a model to predict the failure probability of oil and gas pipelines. This model used eight input factors to forecast the burst pressure of pipelines. The estimated pressure is then used to forecast the remaining pipeline strength.

Dey (2003) evaluated the risk of failure of different segments of a cross-country pipeline and also developed selection strategies for the maintenance and inspection operations of these pipelines. Dey, Ogunlana, and Naksuksakul (2004) proposed a risk-based maintenance model using the analytical hierarchy process to select the most appropriate inspection technique for oil and gas pipelines. Bertolini and Bevilacqua (2006) developed a model to analyse the spill causes in cross country oil and gas pipelines using a classification tree approach. The model predicts the main source of pipeline leakage to support the decision making process during the planning of maintenance operations. Teixeira, Guedes Soares, Netto, and Estefen (2008) assessed the reliability of pipelines with corrosion defects subjected to internal pressure using the first-order reliability method. Probabilistic models (Ahammed, 1998; Caleyo, Velázquez, Valor, & Hallen, 2009; Sinha & Pandey, 2002; Zhang & Zhou, 2014) as well as deterministic approaches (Noor, Ozman, & Yahaya, 2011) were proposed to estimate the reliability and failure of oil and gas pipelines.

Ren, Qiao, and Tian (2012) developed a model to predict the corrosion rate of oil and gas pipelines using ANN. Liao, Yao, Wu, and Jia (2012) developed an ANN model to predict the internal corrosion rate of wet gas gathering pipelines. Singh and Markeset (2014) utilised probabilistic and possibilistic approaches to calculate the safe operating pressure and the probability of failure of pipelines under corrosion. Maes, Faber, and Dann (2009) developed a Hierarchical Bayes stochastic deterioration model to process the inline inspection (ILI) data considering the uncertainties of inspection data. Most of the above-mentioned studies are not comprehensive (Liao et al., 2012; Ren et al., 2012; Singh & Markeset, 2014; Sinha & Pandey, 2002) because they addressed one of pipeline failure sources such as corrosion or they were subjective (Ahammed, 1998; Dey, 2003; Dey et al., 2004). In other words, they lack the objectivity in predicting different failure types of pipelines.

Recently some researchers have developed more comprehensive models that consider other failure sources beside corrosion. Senouci, El-Abbasy, Elwakil, Abdrabou, and Zayed (2014) developed regression and ANN models to predict failure types of oil and gas pipelines. The model predicts the failure types beside corrosion, such as mechanical, third party, natural hazard and operational failures. The model was built based on historical data collected from a CONCAWE report (Davis, Dubois, Gambardella, & Uhlig, 2010). Later, Senouci, El-Abbasy, and Zayed (2014) developed a model to predict the failure types of oil and gas pipelines using fuzzy approach and compared its results with those obtained using regression and ANN models by Senouci, El-Abbasy, Elwakil, et al. (2014).

El-Abbasy, Senouci, Zayed, and Mosleh (2014) developed a model that assesses the condition of oil and gas pipelines based on several factors including 'metal loss' using both analytic network process (ANP) and Monte Carlo simulation. The model considered factors' interdependency using ANP, made decisions under uncertainty using simulation and handled decisions involving a large number of variables using integrated ANP/simulation. The model was successfully tested on an existing offshore gas pipeline in Qatar by comparing the pipeline conditions obtained using the model with the actual ones. El-Abbasy, Senouci, Zayed, Mirahadi, and Parvizsedghy (2014b) developed a model to predict the condition of offshore oil and gas pipelines based on historical inspection data that was collected in Qatar. The model used the regression technique to predict the pipeline condition and when compared with the actual condition yielded an average validity percentage above 96%. El-Abbasy, Senouci, Zayed, Mirahadi, and Parvizsedghy (2014a) developed condition assessment models using the ANN technique. The model outperformed the one developed by El-Abbasy et al. (2014b).

LCC modelling

LCC analysis is a comprehensive method that analyses the service life of projects from an economical point of view. It considers the cost of the operations that would take place during the infrastructure lifetime. On the other hand, infrastructures deteriorate during their life and therefore need to be maintained. LCC analysis is one of the methods that is applied to minimise the LCC of infrastructure. Frangopol, Kong, and Gharaibeh (2001) developed a LCC model for the maintenance planning of bridges. The net present worth of the life cycle has been estimated considering the uncertainty of the factors affecting the reliability of bridges with and without preventive actions.

Hegazy, Elbeltagi, and El-Behairy (2004) developed a management system to optimise the LCC of bridge decks. The model integrated the project and network level budget optimisation in a platform which uses Genetic Algorithms as the optimisation method. The Markovian approach was used to predict the condition of the bridge and a 'scale assessment' was developed to help in the selection of the maintenance operation type. Three levels of repair, namely, light, medium and extensive were used for the maintenance based on the bridge condition.

Shahata and Zayed (2012) proposed a probabilistic model that forecasts the breaks of water pipelines during their service life and estimates their required rehabilitation actions. The model developed several scenarios and attempted to optimise the LCC of water pipelines. Ammar, Zayed, and Moselhi (2013) developed a fuzzy model to analyse the LCC of different maintenance scenarios. The model considered the uncertainty of economical factors. However, fixed time intervals were assumed for the different maintenance operations. Gomes, Beck, and Haukaas (2013) developed a model to optimise the inspection interval of onshore pipelines under corrosion. This model used Monte Carlo simulation to optimise the total expected LCC of the pipelines. The reliability of the pipeline was considered in the optimisation of rehabilitation and inspection costs. Expected LCC included the failure cost of pipeline which has been estimated as a fixed amount. However, the failure cost is very case sensitive and can vary in a wide range due to the condition of the pipeline and the surrounding environment.

Extensive effort has been made in the development of LCC models for water pipelines as well as bridges. However, the existing models on oil and gas pipelines cannot address the requirement of operators of such pipelines. Thus, this paper intends to develop a LCC model that optimises the maintenance operations of oil and gas pipelines during their service life. This model considers various types of rehabilitation as well as the economical uncertainties that exist in the life cycle of the pipelines' operation.

Modelling techniques

Monte Carlo simulation is a powerful technique to analyse the rehabilitation alternatives of oil and gas pipelines because of the uncertainties of maintenance operation costs and economic factors (Shahata & Zayed, 2008, 2012, 2013). This stochastic simulation approach incorporates the uncertainties that exist in the input data including the cost of operations and the interest rates that should be estimated for the whole life cycle of the pipelines. It can consider the complicated behaviour of uncertain systems by generating random numbers in the probability distributions that are defined as input data. The output of the simulation is the probability distribution of the output computed for a certain number of iterations (i.e. 1000) depending on the convergence of the output function. The combination of the Monte Carlo simulation and LCC approach produces a comprehensive model which considers all possible rehabilitation alternatives as well as the input data uncertainties.

The fuzziness of both the economic factors and the maintenance operation costs reinforce the choice of using the fuzzy approach in the LCC modelling of pipelines. The fuzzy set theory, which was introduced by Zadeh (1965), assigns a membership function to the imprecise components in order to deal with their vagueness. The function defines the degree of membership of each object to a set of pairs. Different types of membership function can be assigned to the set of objects such as triangular, trapezoidal, Gaussian and sigmoid (Ammar et al., 2013). Triangular membership functions are the most commonly used functions to account for missing information.

Rehabilitation techniques and cost elements

Various types of defect may cause the failure of oil and gas pipelines. Some guidelines and repair manuals have recommended several types of rehabilitation for each defect type (BP, 2006; Jaske, Hart, & Bruce, 2006; Palmer-Jones, Hopkins, & Eyre, 2005). Table 1 summarises the recommendations of three of the most commonly used repair and replacement guidelines. The five main types of operations that are used herein are listed in Table 2. They are also briefly described in the following sections:

(1) *Regular maintenance*: This operation is usually performed annually. The monitoring system of oil and gas pipelines may include the 'Supervisory Control and Data Acquisition' System, which monitors the pressure and flow of the pipeline. The alarms may result in interrupting the pipeline work. Menon (2005) considered the annual internal corrosion inspection and the Cathodic Protection Survey as well as the extension of right of way as regular maintenance operations.
(2) *Inspection*: Inspections are necessary to monitor the condition of pipelines. Healy, Jones, Clyne, Cazenave, and Alkazraji (2004) recommend iterating ILI operations including intelligent pigs every 10 years. However, it should be more frequent for pipelines with lower condition as a result; an average interval of 7 years is considered herein for ILIs.
(3) *Remedial actions*: The coating, which is intended to inhibit pipeline corrosion, may have deficiencies, which may require repair. The repair types, which can be used for most pipeline conditions and defects, were selected herein (i.e. Type-B sleeves and bolt-on-clamps). Type-B sleeves, which are fillet-welded to the pipeline, can carry the pressure of the pipelines. As a result, they are suitable for repairing leak defects and other defect types. Bolt-on-clamps are also common types of repair (Jaske et al., 2006). These two repair types can be used for leaks, internal and external corrosion, dents, cracks and seam-weld and girth-weld defects. In fact, these

Table 1. Recommended types of rehabilitation for different types of defects.

	Type of Rehab.								
Type of defect	Grinding	Type A sleeve	Compression sleeve	Type B sleeve	Composite sleeve	Weld deposition	Bolt-on clamp with seals	Hot tapping[a]	Epoxy-filled sleeve
1. Leaks	NA	NA	NA	BP PRM API	BP (temp) API (<0.8t)	NA	BP PRM	PRM	NA
2. External corrosion	BP	BP PRM (<0.8t) API (<0.8t)	PRM (<0.8t)	BP PRM API	BP PRM (<0.8t)	PRM (<0.8t) API (min. wall > 0.8t)	BP PRM	PRM API	BP
3. Internal corrosion[b]	NA	BP (temporary) PRM	PRM	BP PRM API	BP (temp) PRM	NA	BP PRM	API	BP (temporary)
4. Dents	PRM (no smooth dents)	PRM API	PRM	BP PRM API	BP (<12.5% t) PRM	NA	PRM	PRM (only on smooth dents) API (if dent can be removed completely)	BP
5. Crack	BP PRM (<0.4t)	BP PRM (<0.8t)	PRM (<0.8t)	BP PRM (<0.8t) API	BP (after grinding) PRM (<0.8t)	PRM (<0.8t)	PRM (<0.8t)	PRM (<0.8t)	BP
6. Seam weld defect	BP PRM[c]	PRM[c]	PRM	PRM	PRM[c]	NA	BP PRM	PRM[c]	BP
7. Girth weld defect	BP PRM	NA	NA	PRM API (After grinding)	NA	PRM (after grinding)	PRM	NA	NA

Notes: BP, British Petroleum Guideline (BP, 2006); PRM, Pipelines Repair Manual prepared by USA Pipeline Research Council (Jaske et al., 2006); API, American Petroleum Institute the recommendations of which on the rehabilitation techniques are summarised by Palmer-Jones et al. (2005).
[a] Hot tapping can be applied only to defects that are small enough to be removed by the hot tap.
[b] For internal defect or corrosion make sure that it does not continue to grow beyond acceptable limits.
[c] Not proper for defects in or near ERW seam.

Table 2. Cost elements.

No.	Operation type	Details
1	Regular maintenance	Including office costs and regular annual operations of pipelines
2	Inspection	ILI Hydrostatic testing
3	Remedial actions	Recoating
4	Repair	Sleeve Type B Bolt-on clamps
5	Replacement	Hot tapping (small sizes) Replace pipe

two repair types have the least limitations in the application on various types of defects. On the other hand, sleeve type A and compression sleeves are not appropriate for leaks and girth-weld defects according to Table 1.

(4) *Replacement*: Hot-tapping is the most commonly used type of replacement (Jaske et al., 2006). The advantage of hot-tapping over other types is its applicability on in-service pipelines.

Research methodology and model development

As shown in Figure 1, the research started with a comprehensive review of previous research work on the condition assessment of oil and gas pipelines. There was a need to select a suitable model for the condition assessment of pipelines in order to predict their future condition. The pipeline condition before intervention was computed using the deterioration profiles developed by El-Abbasy et al. (2014b). The average deterioration rate was found equal to 0.14 units of condition per year. The rehabilitation techniques were selected after reviewing maintenance operation manuals and guidelines for oil and gas pipelines. The maintenance operations of oil and gas pipelines were categorised based on their type (i.e. regular maintenance, inspection, remedial actions, repair and replacement). They were further categorised based on their sizes. The impact of each rehabilitation type and size on the condition after intervention was also studied and a methodology was developed to calculate the pipeline condition after rehabilitation. The related cost data was either gathered from previous studies or calculated using available cost estimates of various repair types.

Several combinations of maintenance operation types were considered in the development of the maintenance scenarios. A set of rules were selected to define condition thresholds for the execution of maintenance operation types. Two types of plans, namely, conservative and regular were specified. The regular plans impose a set of rehabilitation condition thresholds for different operation types (e.g. coating, repair, replacement) that are lower than those imposed by the conservative ones. Thus, the

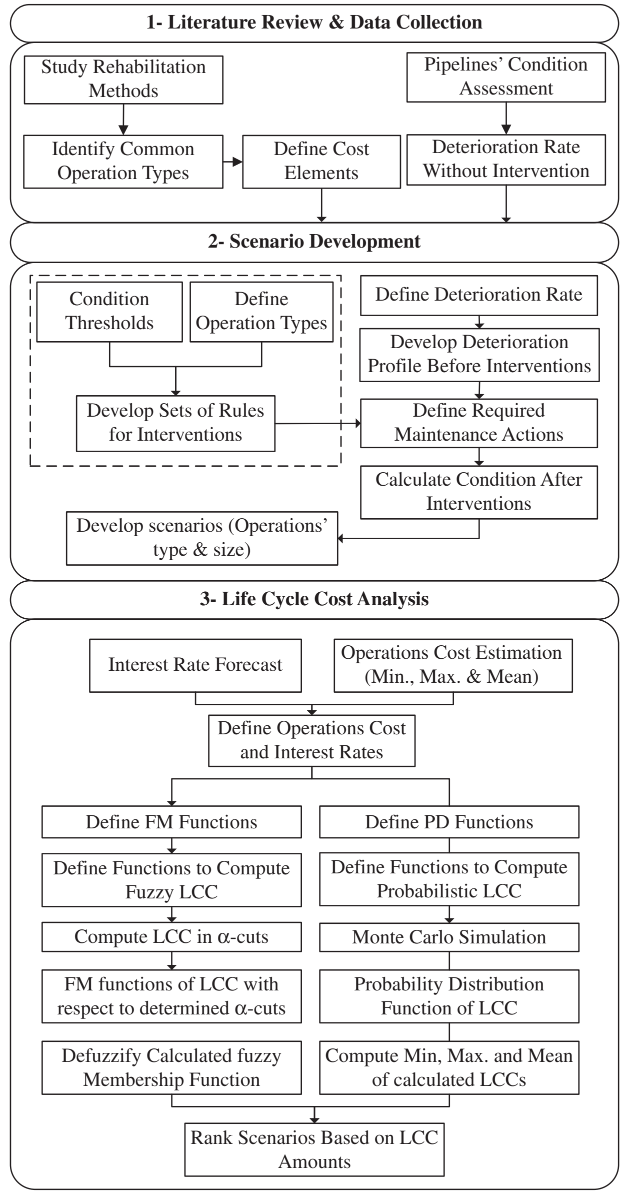

Figure 1. Model development flowchart.

conservative plans can be used for high-risk pipelines. Pipelines which carry sour or high-pressure gas are considered as high-risk. Moreover, pipelines within the densely populated areas are high-risk as a matter of safety. It is worth noting that the maintenance operations in a conservative plan start sooner compared to those in a regular one. Each plan is composed of three groups of scenarios. Each group of scenarios is composed of certain types of maintenance operations (i.e. repair and recoat) of various sizes. The condition thresholds specify the time and the type of the necessary maintenance operation. Three groups of maintenance scenarios were considered in each plan. Each scenario group consists of several maintenance scenarios based on the size of the defect.

Each maintenance scenario is defined by the following parameters: (1) scenario group; (2) size of the defect and (3) repair type (i.e. sleeves or clamps).

The required maintenance actions were forecasted by considering the condition of the pipeline before the rehabilitation action and the set of rules for each scenario group. A method was developed to calculate the condition of the pipeline after each rehabilitation type. Determining the maintenance operations and their execution time over the life cycle of the pipeline required the development of deterioration profiles after rehabilitation interventions for each scenario. Consequently, a profile defines a maintenance scenario and determines the time and type of the maintenance operations that need to be carried out each year. The collected operations' costs were then used to forecast the cash flow of the pipeline maintenance over its life cycle.

Finally, the cash flows of the maintenance scenarios were calculated using Microsoft Excel (Microsoft Group, 2010) software. Monte Carlo simulation and fuzzy approach is used to compute the equivalent uniform annual cost (EUAC) function of each maintenance scenario. The probability distribution functions of the maintenance operation costs and interest rates were defined using the software @Risk 6 (PALISADE Corporation, 2013). The probability distribution functions were used to address the uncertainties in the estimation of the maintenance operation costs and the future interest rates. The distribution functions were defined as triangular probability distribution functions. The standard parameters of triangular distribution functions are the minimum, maximum and most likely values, which were defined in the model.

After defining the distribution functions of the maintenance operation costs and interest rates, the EUAC of each scenario was calculated. For each scenario, the computations on the simulated model has been iterated for 1000 times. The distribution function that best fits the calculated EUAC amounts was determined, and the minimum, maximum and mean values of each scenario were reported. This process was repeated for each scenario. The obtained EUAC mean values were used to rank the scenarios. Finally, the scenarios with the lowest EUAC were selected as the optimum maintenance scenarios during the service life of the pipeline.

Fuzzy approach was also used to compare its results with those obtained using Monte Carlo simulation. Consequently, the maintenance scenarios used in the Monte Carlo simulation were also used to calculate the fuzzy LCC. A fuzzy membership function was used to define the cost of each maintenance operation type and determine the membership function of the operation's cost. Triangular fuzzy membership functions were used with values similar to those used in the Monte Carlo simulation model. The membership function of the interest rate was also defined using a triangular membership function. The cash flow of each scenario was computed based on the time execution and the rehabilitation size. The fuzzy membership function of the EUAC of each scenario was developed using the MATLAB 2010rb environment (Math Works, 2010). The obtained fuzzy results were defuzzified and compared with those obtained using Monte Carlo simulation. Finally, the best scenarios were selected for the maintenance works.

Size of defect

The size of defects affects the maintenance decision process of oil and gas pipelines, especially in the rehabilitation of underground and offshore pipelines. As mentioned before in the 'Methodology' section, a defect size scale was developed for each maintenance operation type (i.e. recoat, repair and replacement) based on its nature. Table 3 lists the sizes of the maintenance operation types used herein. The size of repair or replacement not only affects the cost of the maintenance technique, but also the increment of the condition, which is the improvement in the overall pipeline condition due to a maintenance action. Equations (1)–(3) estimate the condition increment of every size of recoat, repair and replacement, respectively:

$$\mathrm{CI}_{\mathrm{recoat}} = 0.5 \times (10 - \mathrm{OC}) \times \frac{S_n}{10}, \tag{1}$$

$$\mathrm{CI}_{\mathrm{repair}} = 0.7 \times (10 - \mathrm{OC}) \times \frac{S_n}{10}, \tag{2}$$

$$\mathrm{CI}_{\mathrm{replacement}} = (10 - \mathrm{OC}) \times \frac{S_n}{10}, \tag{3}$$

where, CI is the condition increment for the maintenance operation, OC is the current overall condition of a pipeline section and S_n is the size of the maintenance operation. The term '10 − OC' represents the difference between the current overall condition and the maximum condition of a pipeline, namely, '10' (i.e. condition of a newly constructed pipeline). The overall pipeline condition changes from excellent (i.e. score of '10') to extremely poor (i.e. score of '0').

Table 3. Defects size scale for various rehabilitation techniques (metres).

Size no.	Recoating	Repair	Replacement
S1	1.0	0.1	1.5
S2	2.0	0.2	2.0
S3	4.0	0.4	4.0
S4	5.0	0.8	5.0
S5	6.0	1.5	6.0
S6	8.0	2.0	8.0
S7	10.0	4.0	10.0

Table 4. Condition increments for different types of rehabilitation.

	Operation type					
Size of defect	Recoating primary condition = 8	Repair primary condition = 7	Replacement primary condition = 5	Recoating primary condition = 7	Repair primary condition = 6	Replacement primary condition = 4
S1	0.10	0.02	0.75	0.15	0.03	0.90
S2	0.20	0.04	1.00	0.30	0.06	1.20
S3	0.40	0.08	2.00	0.60	0.11	2.40
S4	0.50	0.17	2.50	0.75	0.22	3.00
S5	0.60	0.32	3.00	0.90	0.42	3.60
S6	0.80	0.42	4.00	1.20	0.56	4.80
S7	1.00	0.84	5.00	1.50	1.12	6.00

The condition increase of a recoated section is assumed equal to the 50% of the difference between the current and the maximum condition of a pipeline. The relative condition increment for repair and replacement is equal to 70% and 100% of the difference between the current and the maximum conditions, respectively. The estimated condition increments are then multiplied by the size of the maintenance operation and divided by the segment's length, which is assumed herein equal to 10 m.

Table 4 summarises the condition increase for every size of each maintenance operation in a segment of 10 m based on current overall conditions. For example, let us consider the condition increment of the recoat operation 'S1', which consists of recoating one meter in a 10-m pipeline section. Let us also assume that the current condition of the pipeline at the time of recoating is equal to 8. Hence, the difference between the maximum pipeline condition and the current condition is 2 (i.e. '10 − 8'). Therefore, the condition increment would be 0.10 (i.e. $0.50 \times 2 \times 0.10$) using Equation (1). In other words, if 1 m of a 10-m pipeline section is recoated then the condition increment would be equal to '0.1'. As a result, the condition of the pipeline section after recoating will be equal to 8.10.

Figure 2 presents a conceptual deterioration profile. For maintenance operations of the same size, recoating and repair have the smallest and largest effects on the pipeline condition, respectively. All defect sizes are repeated in all 10-m segments of the pipeline. A 10-cm size defect is repeated on all segments of the pipeline section under analysis. In a 1-km section, a 10-cm size defect is assumed to occur in each segment. The condition increment is proportional to the size of the maintenance action on the segment. As a result, the condition increment of small maintenance sizes is lower compared to those of larger maintenance sizes.

Overall scenarios

As mentioned in the 'Methodology' section, conservative and regular plans were implemented for the maintenance of pipelines. Table 5 summarised the pipeline condition

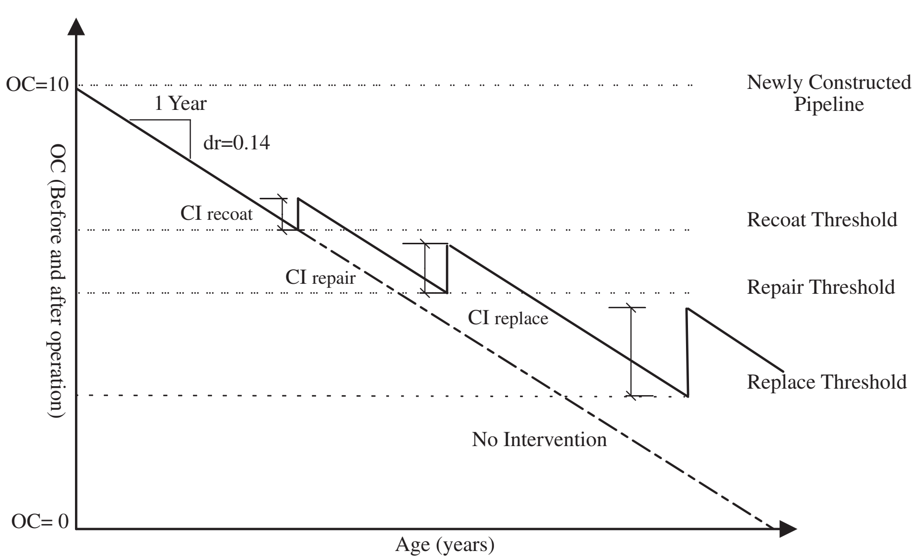

Figure 2. Conceptual deterioration profile with and without interventions.

Table 5. Pipeline condition thresholds for rehabilitation techniques.

Rehabilitation technique	Conservative plan	Regular plan
Recoating	8	7
Repair	7	6
Replacement	5	4
Replacement only	7	6

thresholds and their corresponding maintenance operation types in both plans. It is worth noting that higher pipeline condition thresholds are assigned for the conservative plan. For example, Table 5 shows that a recoating action must take place if the pipeline condition is less than or equal to 8 in the conservative plan. On the other hand, the recoating action can take place if the pipeline condition is less than or equal to 7 in the regular plan. Several scenario groups were developed based on these thresholds using various types of operations as shown in Table 6.

The first three groups (i.e. 1, 2 and 3) are based on the conservative plan while the second three groups (i.e. 4, 5 and 6) are based on the regular plan. Group 1 scenarios include the combination of remedial actions, repair and replacement under conservative thresholds. The conservative plan specifies the use of recoating, repair and replacement when the pipeline condition falls below 8, 7 and 5, respectively. In other words, the rules for Group 1 indicate that a one-time recoating is needed when the condition falls below 8.

Repair is needed when the condition falls below 7, and it is repeated every year. When the condition drops below 5, replacement is needed. In some of the scenarios, there is no need for replacement as the repair increases the condition more than the deterioration rate as a result the condition never falls under 5. The inspection is included in all of the scenarios because it is required according to the existing recommendations. Group 2 scenarios, which do not include remedial actions, contain repair and replacement with conservative thresholds. Accordingly, the rehabilitation starts with repair at a condition of seven while replacement starts when the condition falls below 5. Group 3 refers to the alternatives with repair as the major action. Finally, scenario groups 4–6 which are similar to their counterparts (i.e. Groups 1–3), are implemented under the regular plans (i.e. with lower condition thresholds).

Economic parameters

The scenario cash flow was determined using a model that was developed using Microsoft Excel (Microsoft Group, 2010). It was computed using the cost data previously described in the 'Data collection' section. The equivalent economic value of each scenario was normally computed using the net present value (NPV). However, the EUAC was used for scenarios with different service lives. The EUAC was computed by converting NPV to a uniform annual value over the service life of the pipeline.

Monte Carlo simulation was used to address the uncertainties in the cost of operations and the interest rates. Equations (4) and (5) were used to calculate the probabilistic NPV and EUAC values. To simplify the cash flow diagrams, the costs of the maintenance operations were used in constant dollars (i.e. without considering the effect of inflation) and were discounted with the forecasted interest rates:

$$\widetilde{\mathrm{NPV}} = \sum_{t=1}^{n} \tilde{\mathrm{C}}\mathrm{t}\left(P|F,\tilde{l},t\right) = \sum_{t=1}^{n} \tilde{\mathrm{C}}\mathrm{t} \times \frac{1}{(1+\tilde{l})^{t}}, \quad (4)$$

$$\widetilde{\mathrm{EUAC}} = \widetilde{\mathrm{NPV}}\left(A|P,\tilde{l},n\right), \quad (5)$$

$$\left(A|P,\tilde{l},n\right) = \frac{\tilde{l}\left(1+\tilde{l}\right)^{n}}{\left(1+\tilde{l}\right)^{n}-1}, \quad (6)$$

Table 6. Overall scenario types.

Group	Combinations of rehabilitation types	No. of scenarios	Plan type	Abbreviation of the scenarios ('*n*' shows the size of the repair or replacement and changes from 1 to 7)
1	ILI + recoat + repair + replacement	14	Conservative plan	An (sleeve are used to repair) Bn (clamps are used to repair)
2	ILI + repair + replacement	14	Conservative plan	Cn (sleeve are used to repair) Dn (clamps are used to repair)
3	ILI + replacement only	7	Conservative plan	En
4	ILI + recoat + repair + replacement	14	Regular plan	Fn (sleeve are used to repair) Gn (clamps are used to repair)
5	ILI + repair + replacement	14	Regular plan	Hn (sleeve are used to repair) In (clamps are used to repair)
6	ILI + replacement only	7	Regular plan	Jn

where $\widetilde{\text{NPV}}$ is the probability distribution function of NPV of the cash flow under evaluation, $\tilde{\text{Ct}}$ is the probability distribution function of total cost components in year t, n is the service life of the pipeline in years, $\tilde{l}$ is the probability distribution function of the forecasted interest rate during the service life of the pipeline, and $(A|P, \tilde{l}, n)$ is the probability distribution function of conversion factor from Present Worth to Equivalent Uniform Annual Worth. The probability distributions were assumed triangular due to the limited rehabilitation cost estimates.

The fuzzy LCC model was used herein to calculate the EUAC of the scenarios. The model was developed using MATLAB 2010rb (Math Works, 2010). The costs were embedded in the form of triangular fuzzy membership functions comprising the lower, medium and upper bound of the yearly maintenance operation costs. The other input was the membership function of the interest rate. This method divided the convex fuzzy sets into α-cuts, which are values between zero and one. These α-cuts were generally repeated at 0.1 intervals, and the corresponding minimum and maximum values of each interval were calculated using the membership functions.

Figure 3 presents a triangular membership function and illustrates the interval of an α-cut. It shows the reflection of the intersection of the α-cut and the triangle on the X-axis that produces corresponding minimum and maximum values. Similar values from the membership function of the interest rate were computed. The NPV was computed using Equation (7) while considering all the combinations of the obtained minimum and maximum values of costs and interest rates of the corresponding α-cut (i.e. $2 \times 2 = 4$ combinations). The lower and upper bounds of the NPV for each α-cut were calculated using the minimum and maximum of the obtained values. The obtained lower and upper bounds were converted to annual worth using Equations (8) and (9).

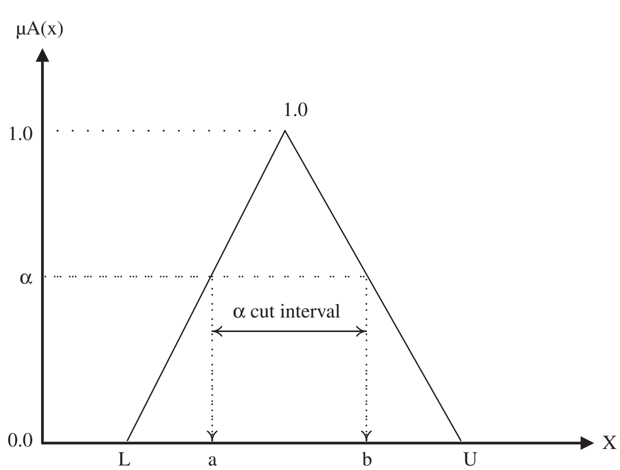

Figure 3. α-Cut of a triangular membership function.

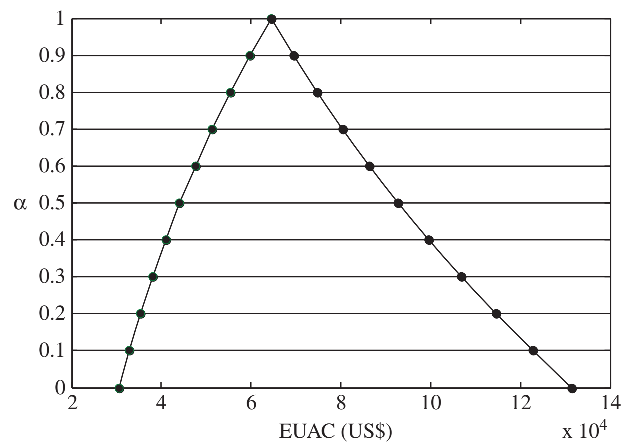

Figure 4. Fuzzy EUAC.

This process is repeated for all of the α-cut values. The obtained lower and upper bound values were used to determine the membership function of the computed EUAC values for all α-cuts. Figure 4 depicts a sample membership function that shows the calculated EUAC amounts for one of the maintenance scenarios. The obtained membership function was de-fuzzified to obtain a crisp value which represented the EUAC of the scenario. Finally, the scenarios were ranked in ascending order based on their de-fuzzified EUAC values:

$$\overline{\text{NPV}} = \sum_{t=1}^{n} \overline{\text{Ct}} \times \frac{1}{(1+\bar{l})^t}, \tag{7}$$

$$\overline{\text{EUAC}} = \overline{\text{NPV}}\left(A|P, \bar{i}, n\right), \tag{8}$$

$$\left(\overline{A|P, \bar{i}, n}\right) = \frac{\bar{i}\left(1+\bar{i}\right)^n}{\left(1+\bar{i}\right)^n - 1}, \tag{9}$$

where $\overline{\text{NPV}}$ is the fuzzy membership function of NPV of the cash flow under evaluation, $\overline{\text{Ct}}$ is the fuzzy membership function of total maintenance operation cost in year t, $\bar{i}$ is the fuzzy membership function of the forecasted interest rate during the service life of the pipeline, $\overline{\text{EUAC}}$ is the fuzzy membership function of the Equivalent Uniform Annual Cost of the scenario under evaluation and $\left(\overline{A|P, \bar{i}, n}\right)$ is the fuzzy conversion factor from Present Worth to Equivalent Uniform Annual Worth.

Data collection

An extensive literature review was conducted to gather the data for the development of the LCC model of oil and gas pipelines. The data includes the pipeline deterioration rate and the economic factors during the pipeline service life. El-Abbasy et al. (2014b) developed deterioration profiles for oil and gas pipelines for a life span of 70 years. These profiles were used herein to determine the deterioration rate, which is the yearly decrease in the pipeline condition. The deterioration rate was estimated equal to an average value of 0.14 units of the overall condition per year. However, the deterioration rate can be lower or higher than this value depending on the surrounding environment of the pipeline and the petroleum product that is transferred through the pipeline.

LCC models also require a set of economic factors such as maintenance operation costs and the interest and inflation rates. Menon (2005) detailed the most probable cost components during the construction and operation phases of gas pipelines. The research also detailed typical installation cost of pipelines with various diameters. The annual operating costs were estimated for a typical gas pipeline. Baker, Fessler, and BIZTEK Consulting (2008) summarised high and low cost per mile estimates of ILI for gas and oil pipelines. The costs were discounted using the historical inflation data published on the World Bank website (World-Bank, 2013) to convert to 2013 US dollars. The type of inspection, pipe diameter, wall thickness and pipeline accessibility may change the cost of ILIs. Repair costs were gathered from a research conducted by the US Environmental Protection Agency (EPA, 2006), which compared repair and replacement costs of a 24″ natural gas pipeline. The EPA's research has detailed the repair and replacement costs of 6″ and 24″ pipeline defects. The assumptions and cost data used in the EPA's research were used herein to estimate the cost of the different repair and replacement sizes.

The costs collected from the literature were discounted using historical inflation rates. The uncertainty in the cost estimation was also considered herein. The calculated and collected costs were considered in this study as average costs. These average cost values were then multiplied, respectively, by 0.9 and 1.15 to obtain the minimum and maximum operation costs for a 24″ gas pipeline (see Table 7). The interest rate is expressed using a distribution function based on the interest rates in the USA between the years of 1992 and 2008. The function follows a triangular probability distribution with the minimum at 3%, the most likely at 4% and the maximum at 6%.

Table 7. Cost assumptions for different size and types of rehabilitation techniques (US$).

Operation type	Minimum	Mean	Maximum
Regular maintenance			
Regular maintenance	22,500	25,000	28,750
Inspection			
ILI	3500	4000	4600
Remedial action			
Recoating S1	180,000	200,000	230,000
Recoating S2	324,000	360,000	414,000
Recoating S3	576,000	640,000	736,000
Recoating S4	630,000	700,000	805,000
Recoating S5	648,000	720,000	828,000
Recoating S6	720,000	800,000	920,000
Recoating S7	900,000	1,000,000	1,150,000
Repair			
Type B sleeve S1	353,116	392,352	451,204
Type B sleeve S2	369,021	410,023	471,526
Type B sleeve S3	400,829	445,366	512,171
Type B sleeve S4	464,447	516,052	593,460
Type B sleeve S5	575,777	639,753	735,715
Type B sleeve S6	655,299	728,110	837,327
Type B sleeve S7	973,386	1,081,540	1,243,771
Bolt on clamp S1	388,428	431,587	496,325
Bolt on clamp S2	405,923	451,025	518,679
Bolt on clamp S3	440,912	489,903	563,388
Bolt on clamp S4	510,891	567,657	652,806
Bolt on clamp S5	633,355	703,728	809,287
Bolt on clamp S6	720,829	800,921	921,059
Bolt on clamp S7	1,070,725	1,189,694	1,368,148
Replacement			
Replace S1	675,000	750,000	862,500
Replace S2	810,000	900,000	1,035,000
Replace S3	1,440,000	1,600,000	1,840,000
Replace S4	1,575,000	1,750,000	2,012,500
Replace S5	1,620,000	1,800,000	2,070,000
Replace S6	1,800,000	2,000,000	2,300,000
Replace S7	2,250,000	2,500,000	2,875,000

Model implementation

The developed models were implemented on a typical 24″ gas pipeline. The selection of the 24″ pipeline is due to the availability of the maintenance operation cost data. In order to identify the required yearly rehabilitation actions, the overall condition before intervention was computed every year for a 50-year service life of the pipeline. The calculated amounts represented the deterioration profile of the pipeline before intervention. In order to determine the condition of the pipeline before rehabilitation, the condition of the previous year was reduced by the deterioration rate (i.e. 0.14). Then, the condition was checked against the condition thresholds in each scenario's group to forecast the required maintenance work over the service life of the pipeline. If any action was necessary, the condition after intervention was increased proportionally with the size of the rehabilitation work as previously explained. The deterioration profile of the scenario was then determined. Finally, the required actions were planned and related cash flow was calculated by summing up the estimated costs of the planned maintenance works.

In each scenario group, the seven sizes of defects were used to develop several possible scenarios. As a result, 35 scenarios were built based on the regular plan and 35 based on the conservative plan. The scenario cash flow was calculated based on the estimated costs of each maintenance operation type for each size. Sample deterioration profiles of Group 1 scenarios with sleeve type B repairs are shown in Figure 5. It is clear that the condition of the pipelines never falls below five for Group 1 scenarios.

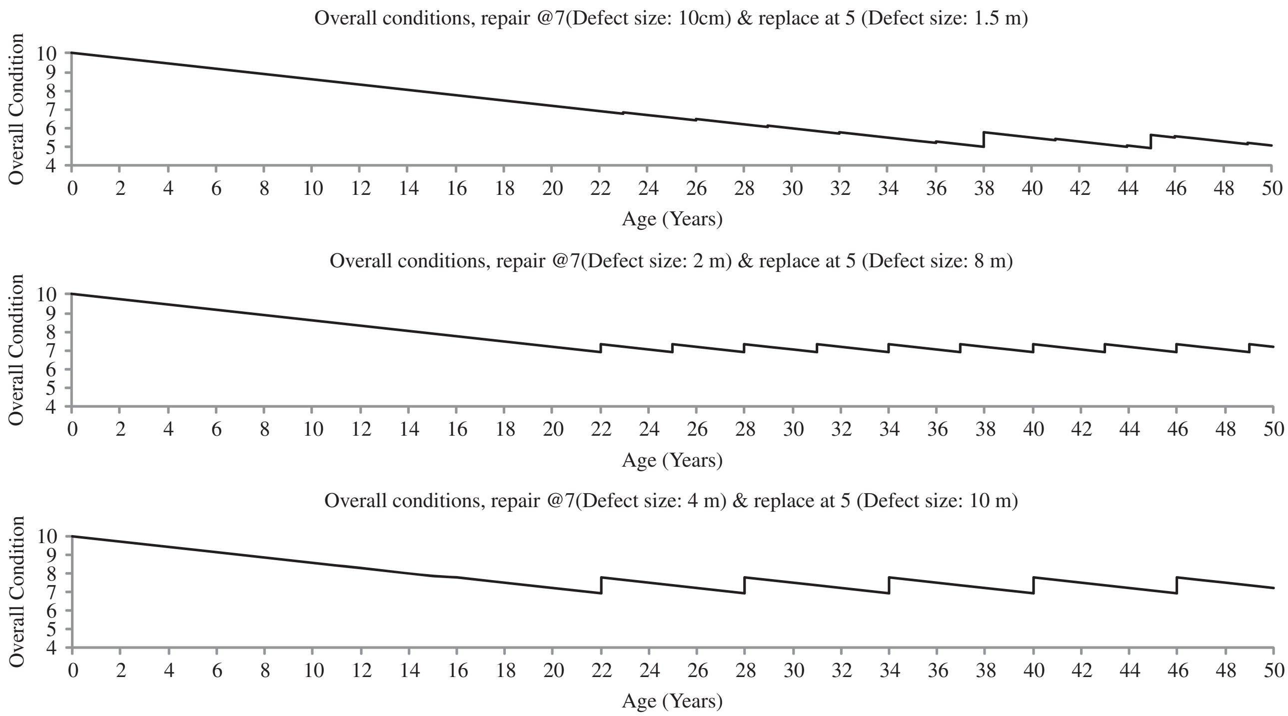

Figure 5. Sample deterioration profiles.

For clarification, let us consider an example of Group 1 scenario. As shown in Table 7, this group includes ILI, recoating, repair and replacement. The condition thresholds which determine the required maintenance actions were obtained from Table 5. The table shows that recoating, repair and replacement are needed when the condition falls below 8, 7 and 5, respectively. The condition of the pipeline before interventions during a 50-year service life was computed with the mentioned assumptions. It is clear that the recoating would be the first action to be done on this type of scenarios. Let us consider 'S1' which refers to the smallest sizes of the maintenance actions. The first required action according to the thresholds and condition of the pipeline is identified as recoating in year 14 when the condition starts to fall below 8.

Consequently, it was decided to recoat the pipeline with 'S1' type in year 14. The condition of the pipeline was calculated after this intervention using Table 5. As a result, the condition of the pipeline was increased by 0.1. The deterioration continued until the condition fell below seven in year 23. As a result, repair started in year 23. The condition after repair was calculated to be 7.02. Considering the deterioration rate and the repair thresholds, this operation was required for this scenario every year starting from year 23. The condition was then calculated after each repair for the following years.

Finally, replacement was required at year 38 because the condition fell below five. Repair continued between years 38 and 45. In year 45, the replacement was again required because the condition of the pipeline fell below 5. However, the condition did not increase above the threshold of repair. Consequently, repair continued until the end of the service life of the pipeline (i.e. 50 years). Seventy different scenarios of repair and replacement were generated to be used in the LCC analysis.

After the development of the maintenance scenarios, the probability distributions of the rehabilitation action costs were used to calculate the probabilistic cash flow of each alternative. Table 7 depicts the estimated minimum, average and maximum costs for the different maintenance operation types and sizes. In each scenario, the probability distribution functions of the maintenance operation cost and interest rate were defined. The required functions for the calculation of the EUAC were then built. Consequently, the model was used to simulate each scenario for 1000 iterations and the obtained results were recorded. The @Risk 6 application (PALISADE Corporation, 2013) was used for the Monte Carlo simulation.

The software calculated the EUAC amounts for the specified iterations. Then, it fit the best distribution function to the calculated amounts and estimated the mean, minimum and maximum of the distribution function. Figure 6 shows the distributions of the simulation-based algorithm of the model. After running the simulation for all of the scenarios, they were sorted in an ascending order with respect to their EUAC values. Figure 7 summarises the mean values of each scenario's EUAC.

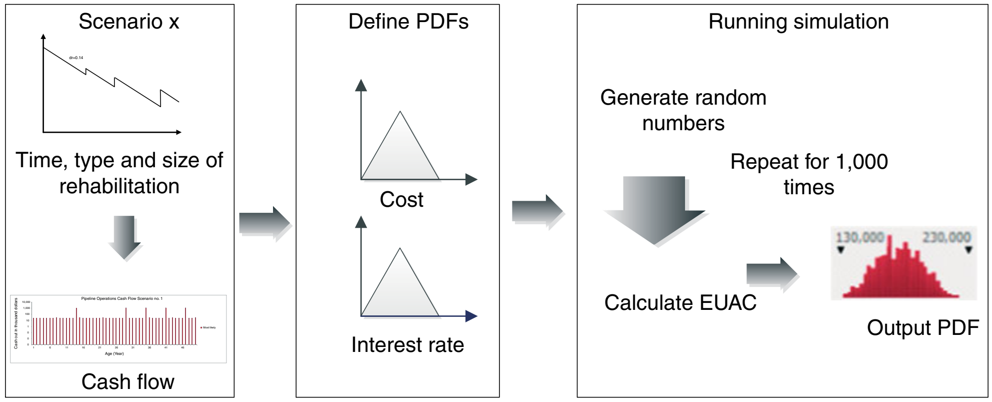

Figure 6. Simulation-based algorithm.

The fuzzy-based EUAC value of each developed scenario was calculated using the fuzzy-based model. Figure 8 compares the de-fuzzified amounts of EUAC for each scenario with its simulation-based counterpart considering the most likely and maximum EUAC values. Fuzzy-based model was more conservative than simulation-based model results. However, the results obtained using both the fuzzy-based and simulation models result in similar ranking of the scenarios. There is a significant difference between the highest and the lowest scenarios' EUAC. Table 8 summarises the top twenty scenarios that generated lower EUAC amounts using both simulation and fuzzy-based models. As shown in the Table, the lower values were mostly generated by the scenarios that combine various operation types including recoating, repair and replacement. On the other hand, scenarios with lower thresholds of maintenance generated less annual costs than the scenarios with higher and conservative thresholds.

Table 8 also illustrates that larger sizes of repair and replacement generated less annual costs. This finding supports the idea of maintaining several defects of the pipeline at the same time if technically possible. It is tried to develop the model as flexible and general as possible so the users can change the input data and adjust it based on their asset's properties. However, there are still some limitations in the model. The deterioration rate is assumed to be a fixed rate based on the properties of the pipe and the surrounding environment. This can be alleviated by considering the reliability or the actual condition of the pipelines during their service life. However, there was no other method to consider the changes of the deterioration in developing the deterioration profile.

Conclusions

A fuzzy and simulation-based LCC model was developed to optimise the maintenance cost of oil and gas pipelines

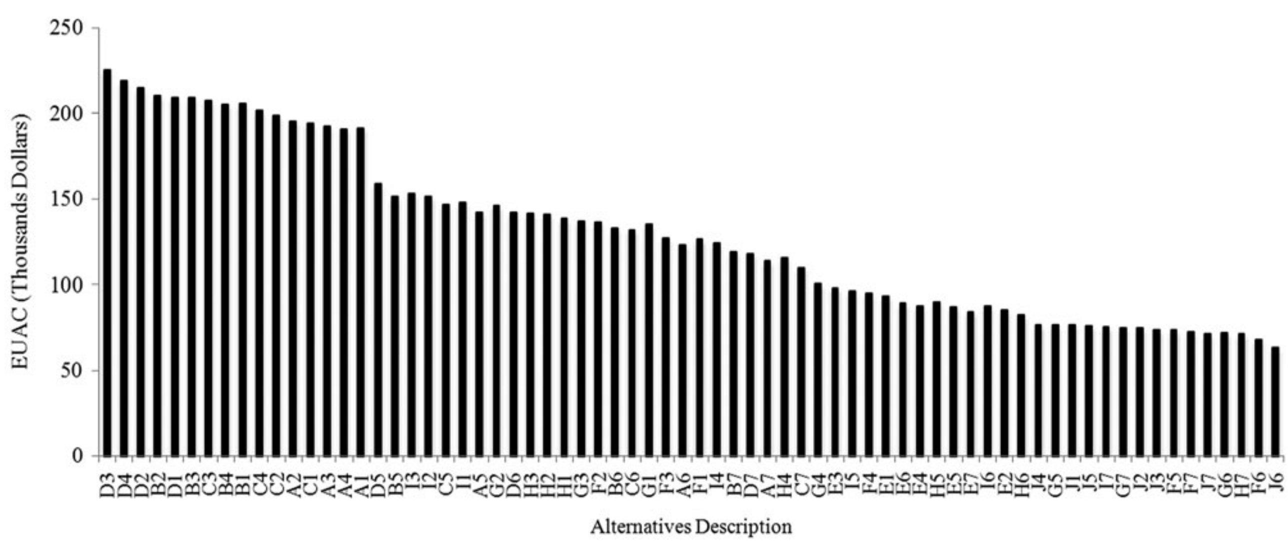

Figure 7. Simulation-based EUAC amounts (sorted based on EUAC, most likely).

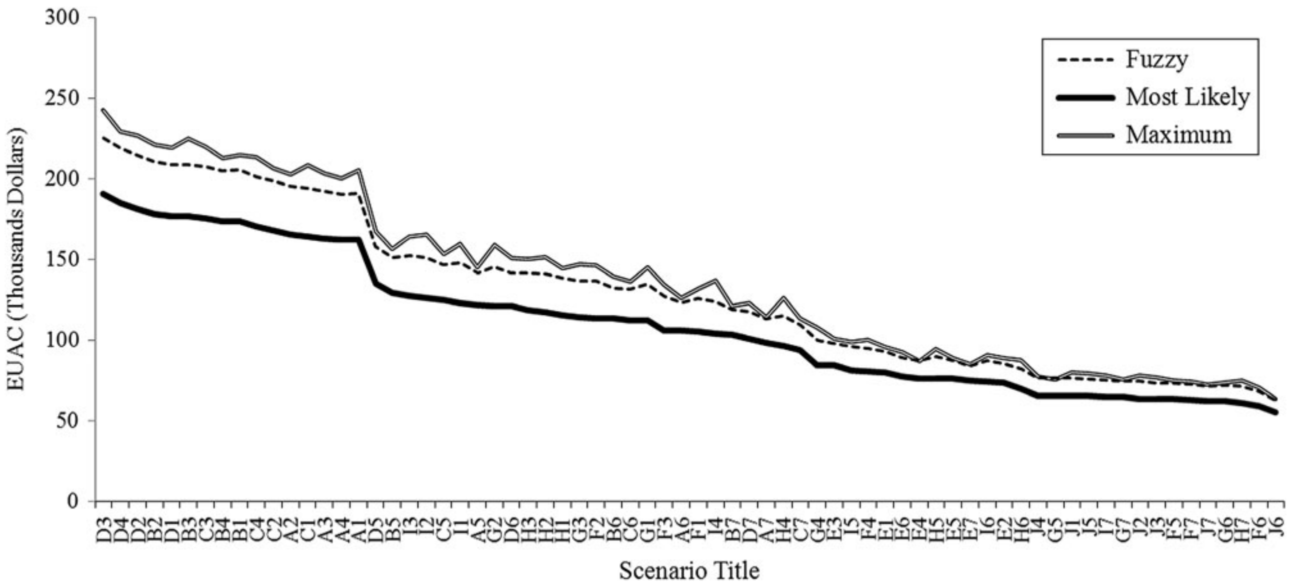

Figure 8. Fuzzy versus simulation-based EUAC amounts.

while forecasting the required actions based on condition estimation. During its service life, the pipeline condition was predicted using a fixed deterioration rate. The most common maintenance operation types were identified by reviewing existing repair and replacement guidelines and manuals. A defects' sizing scale was also developed to adjust both the cost of maintenance operations and the condition of the pipeline after interventions based on the implemented rehabilitation size.

The overall condition after intervention was calculated proportionally to the size of the repaired or replaced defects. Rehabilitation thresholds were set for different types of maintenance operations based on conservative and regular plans. The combinations of the pre-defined maintenance operation types were used to develop rehabilitation scenarios over pipeline service life. Monte Carlo simulation and fuzzy techniques were used to analyse the LCC of the scenarios due to the uncertainties

Table 8. Top 20 scenarios sorted based on simulation-based EUAC (US$).

			Monte Carlo			
Rank	Scenario title	Scenario description	Minimum	Most likely	Maximum	Fuzzy
1	J6	ILI + replace S6-2	47,441	55,149	63,630	62,927
2	F6	ILI + recoat + sleeve + replace S6-2	48,274	58,886	70,547	68,124
3	H7	ILI + sleeve + replace S7-2	48,982	61,139	74,709	71,252
4	G6	ILI + recoat + clamp + replace S6-2	52,172	62,179	73,593	72,054
5	J7	ILI + replace S7-2	53,450	62,445	72,546	71,453
6	F7	ILI + recoat + sleeve + replace S7-2	52,814	62,964	74,477	72,724
7	F5	ILI + recoat + sleeve + replace S5-2	53,084	63,423	74,764	73,543
8	J3	ILI + replace S3-2	53,082	63,467	76,892	73,653
9	J2	ILI + replace S2-2	50,876	63,748	78,257	74,568
10	G7	ILI + recoat + clamp + replace S7-2	53,863	64,631	75,744	74,812
11	I7	ILI + clamp + replace S7-2	52,341	64,676	78,436	75,495
12	J5	ILI + replace S5-2	51,095	65,184	79,664	75,990
13	J1	ILI + replace S1-2	53,225	65,448	80,278	76,610
14	G5	ILI + recoat + clamp + replace S5-2	53,884	65,688	75,654	76,357
15	J4	ILI + replace S4-2	53,522	65,752	77,700	76,513
16	H6	ILI + sleeve + replace S6-2	53,764	69,720	87,560	82,059
17	E2	ILI + replace S2-1	61,740	73,890	88,642	85,151
18	I6	ILI + clamp + replace S6-2	58,233	74,091	90,747	87,383
19	E7	ILI + replace S7-1	66,120	74,991	85,098	84,251
20	E5	ILI + replace S5-1	62,137	75,922	88,847	87,090

of the economic factors and the maintenance operation costs. These techniques were used to calculate the EUAC of each scenario. The developed model was implemented on an example of a 24″ onshore gas pipeline.

The equivalent economic value of each scenario was computed, and scenarios with lower EUAC were proposed as the optimum alternatives for the pipeline's maintenance. The optimum scenarios were mostly related to the larger sizes of maintenance operations and combinations of different rehabilitation types. EUAC values were computed using pre-defined assumptions. However, the maintenance operators should define their data to match their company maintenance operations and policies. Changing the assumptions may change the results and affect the ranking of the maintenance scenarios. There may also be some technical issues on deciding about the type and size of the repair and replacement actions. This research developed a comprehensive model that covers all these factors. Additional and specific factors should be reflected in the future case studies.

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Notes

1. Email: a.senouci@qu.edu.qa
2. Email: zayed@encs.concordia.ca
3. Email: faridmirahadi@gmail.com
4. Email: msksia@yahoo.com

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