USING BENCHMARKING TO OPTIMISE THE COST OF PIPELINE INTEGRITY MANAGEMENT

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ABSTRACT

This paper describes the development and application of a methodology to Benchmark the effectiveness of pipeline Integrity Management plans in preventing leaks and ruptures.

The methodology involves assessing and weighting the effectiveness of nine key integrity activities:

- Integrity plan
- Risk Assessment
- Defect assessment
- Repair method
- Spill detection
- Corrosion prevention
- In-line inspection
- Third party damage prevention
- Failure history

An operator's overall performance is benchmarked against similar operators and industry best practice. Improvement opportunities are identified and prioritised to improve the benchmarking position.

Attention is also given to the cost of the Integrity Management activities. The benchmarking methodology identifies cost optimisation opportunities whilst maintaining acceptable safety levels.

The methodology has successfully been utilised to benchmark 140,000 km of pipelines worldwide and details are provided.

1. INTRODUCTION

As in any other industry sector or function, benchmarking can play a significant role in assisting a pipeline operator to assess the effectiveness or otherwise of his current pipeline integrity management approach.

Many operators will be faced with similar questions; how does my current approach compare with code requirements or guidance?, with other operators?, is it effective and does it provide value for money?

The key aims of benchmarking pipeline integrity management activities can be summarised as follows:

- Define current industry accepted best practice for similar pipeline operations,
- Identify differences in current operating practices, procedures and processes,
- Highlight areas where significant improvements could be achieved cost-effectively
- Maintain minimum risk to safety and operations while optimising Operations & Maintenance (O&M) expenditure.

These topics are discussed in the current paper. An overview of the benchmarking approach[1] to assess the effectiveness of pipeline Integrity Management plans in preventing leaks and ruptures and its practical application in optimising the cost of pipeline integrity management is provided.

2. THE ROLE OF CODES IN RELATION TO PIPELINE INTEGRITY MANAGEMENT

2.1 International Code Review

A comparison of the integrity & maintenance procedures documented in both gas and liquid pipeline Codes was conducted [1-14]. The findings of the Code review are summarized in Table 1.

Many Codes are still prescriptive in nature, and give little direct guidance regarding how to manage pipeline integrity; therefore, simply complying with Code requirements may not in itself be sufficient to manage pipeline integrity cost effectively. For example, although it is mandatory in ANSI/ASME B31.4 to install pig traps on new pipelines (clause 434.17), there is no requirement to run intelligent pigs!

2.2 Pipeline Integrity Management Within the United Kingdom

Codes are usually documents for guidance and are not legally binding; for example, within the United Kingdom, although the majority of gas pipelines are designed to the code IGE/TD/1 [4], other Codes are permitted, but the responsibility for using other Codes lies solely with the pipeline operator, who is also legally responsible for managing and maintaining (at or below an acceptable level) any risk that he creates as a result of operating the pipeline. The legally binding requirements for gas pipeline operation are contained within the Pipeline Safety Regulations[8], which impose major requirements on pipeline operators to adopt the correct procedures to reduce the risk of system failure. The requirements are based on a goal setting rather than prescriptive approach, and were intended (in the case of gas pipelines in the UK) to give legal backing to existing safe working practices.

2.3 Pipeline Integrity Management Within the United States

Although most gas and liquid pipelines in the United States have been designed to 31.8 and 31.4 respectively since their inception, the legally binding rules for pipeline operation and maintenance in the United States are the Code of Federal Regulations (CFR) [5], and as a direct

result of the perceived poor safety record (recent failures at Bellingham and Carlsbad), public and indeed Government [6] sources have made it clear that the Regulations for both hazardous liquid and gas pipelines had to be strengthened.

2.3.1 Hazardous Liquid Pipelines

Part 195 of the CFR was amended in May 2001 for hazardous liquid pipeline systems whose total length exceeded 500 miles (the rule has since been extended to all hazardous liquid pipeline systems); two new Regulations (195.450 and 195.452) were brought in to:

i) Define and identify all high consequence areas (HCA's), i.e. areas of population density and commercially navigable waterways, and
ii) Compel operators to develop and implement written Integrity Management programs.

The above Regulations have been reinforced by a recently published standard, API 1160 [7], which is a framework document that provides guidance to liquid pipeline operators on how to manage pipeline integrity. Indeed, the foreword to API 1160 states that…..

"Although pipeline operators must comply with the pipeline safety regulations, a robust, high quality pipeline integrity management program requires more than a compliance approach to managing pipeline integrity".

2.3.2 Gas Pipelines

The Office of Pipeline Safety (OPS) has recently published[13] (in December 2003) its final rule, 49 CFR Part 192 Subpart O, regarding the integrity management of gas pipeline systems. Each operator is now required to identify "high consequence areas" (HCA), and develop an integrity management plan for each HCA. Prior to the publication of the final rule above, a non-mandatory[*] supplement to ANSI/ASME B31.8, B31.8 (S)[14], "Managing System Integrity of Gas Pipelines" was published, which includes both prescriptive and performance or risk-based approaches to developing an integrity management program. B31.8 (S) is extensively cross-referenced in the new final rule.

2.3.3 Comment

As well as the United Kingdom and the United States, this risk-based or goal-setting approach to integrity management has also been recognized in Canada[9] and Australia[10].

[*] However, it should be noted that parts of the standard are mandatory where they referenced as a requirement in the CFR Pipeline Safety Regulations

Risks must be controlled "**a**s **l**ow **a**s **r**easonably **p**racticable" (the so-called ALARP [11] principle). Certain levels of "quantitative" risk, i.e. the probability of a person becoming a casualty as a result of a pipeline failure, are broadly acceptable or unacceptable; where they are acceptable, no further action need be taken, and conversely unacceptable levels of risk cannot be tolerated under any circumstances. For intermediate levels of risk, the ALARP principle must be demonstrated, whereby all the conceivable methods of risk reduction are considered and that which achieves the greatest reduction in risk at optimal cost is selected (see Figure 1).

3. BENCHMARKING PROCESS

3.1 Benchmark Questionnaire

A questionnaire was devised, consisting of 93 questions, related to significant issues relating to pipeline integrity [1].

Nine Integrity Activities (IA's) (detailed below in arbitrary order), critical in relation to managing pipeline integrity, were identified and evaluated in the questionnaire:

- Integrity Management Planning; how operators formally plan their maintenance schedules

- Defect Assessment Methodology; which methods operators use to assess defects and make repair decisions, e.g. ANSI/ASME B31.G[15], RSTRENG[16] etc

- In-Line Inspection (ILI) policy: how do operators decide which types of inspection tools to use, at which frequency to inspect etc.

- Corrosion prevention; the methods used by operators to prevent both internal and external corrosion, methods for system monitoring etc.

- Repair method; which types of repair methods are used, e.g. cut-out, welded sleeve, composite sleeves etc.

- Use of risk analysis; how operators use risk analysis to identify high risk areas and plan maintenance accordingly

- Spill detection system and emergency planning; what methods are used to detect system leaks, what emergency plans are in place

- 3rd party damage prevention; what procedures are in place to prevent 3rd party interference

- Failure history, based on historical failure rates

To date, data has been compiled for over 21 major oil & gas pipeline operating companies worldwide. This includes over 140,000km of pipeline covering all product types. The profile of these companies is summarised as follows:

Region	North America	South America	Europe	Middle East / Asia Pacific
No of participating Companies	6	10	2	3
Total Kms	82,000	31,000	4,800	22,300
Products covered	LPG, crude oil, natural gas, gasoline refined products	LPG, crude oil, natural gas, gasoline refined products	Refined products, gasoline	LPG, crude oil, natural gas
Diameter range	4 - 48"	4 - 48"	6 - 36"	4 - 48"

3.2 Development of Benchmark Process

A Performance "League Table" was determined to compare participating operators by a combination of two factors:

i) answers to different questions in the questionnaire were subjectively awarded points using a ranking system. For example, if a company stated that it always used low-resolution inspection tools, it would receive fewer points than a company who used high-resolution inspection tools, and

ii) the IA's were weighted against each other; for example, company corrosion prevention policy was considered to be significantly more important than choice of repair method, and consequently received a higher weighting factor. The logic is that an incorrect choice in corrosion prevention policy would have far greater significance in terms of future pipeline integrity than, for example, the type of repair method utilized (assuming that the repair was correctly applied and that the method was approved by a document such as the Pipeline Repair Manual[17]).

On the above basis, a relative index for each company was calculated to rank the performance of the participant. It is highlighted that the assessment was essentially "qualitative" as opposed to "quantitative", and was conducted solely in terms of the ability of each company's maintenance strategy to reduce failure rates.

3.3 Results of the Benchmark Survey & Operator's Benchmark Position

A typical presentation of the benchmarking results is displayed in Figures 2 and 3. Figure 2 shows the relative ranking of a group of participating Operators, and Figure 3 shows the relative contribution of each of the different Integrity Activities

It can be seen that the majority of the companies who participated in the benchmark study have a benchmark ranking > 0.75, indicative of maintenance planning which complies with the guidelines laid out in API 1160 [7] and 31.8(S). This is confirmed by the respective failure rates; for example, the companies with leading positions in the benchmark survey have average failure rates over the last 10 years between 0.14 and 0.69 per 1000 km.-years. These failure rates are similar to those recorded in historical failure rate data recorded worldwide [18-23], which have been published in the open literature. These rates are shown in Table 2, from which it is concluded that the lowest historical failure rates in both oil and gas pipelines have occurred in Western Europe and Canada. Typically the failure rates are in the range 0.35 to 1.33 failure per 1000km-years.

In addition, the operators which are positioned within the upper quartile in the benchmark survey, i.e. “Top Performers”, all share a number of common elements within their Integrity Management approach & strategy – current Industry Best Practice? This will be reviewed in Section 4.

4. PRACTICAL APPLICATION OF BENCHMARKING RESULTS.

4.1 Defining Current Industry Best Practice

As a result of analysing the benchmark responses, the following generalised observations can be made:

- All companies who responded to the benchmark questionnaire comply with relevant pipeline Code requirements,

- There is a trend that companies go beyond Code requirements in developing their integrity management plans,.

By comparing the “Top Performers” with the other Operators, several key differences in terms of their pipeline integrity management strategies (and their consequences) can be identified:

- Risk-Based Inspection (RBI) approaches used to focus and schedule in-line inspection on high risk pipelines (i.e. as opposed to fixed interval inspection)
- Use of high resolution MFL and UT inspection technologies
- Estimation of future corrosion growth rates using previous inspection data to define the future integrity management strategy
- Use of advanced integrity assessment methods to make repair /rehabilitation decisions
- Effective corrosion management through measurement of CP ‘Off-Potentials’ and External Coating surveys along the pipeline Route.
- Leak detection systems in place
- Lower Pipeline Failure Rates

For any particular operator, a gap analysis from this defined Industry Best Practice can be used to identify improvement opportunities. These can be ranked and prioritised using the benchmarking methodology to improve overall ranking position.

4.2 Application of Benchmark findings to optimise O&M expenditure.

More recently, the benchmarking methodology has been extended to identify cost reduction opportunities in pipeline operation and maintenance (O&M) expenditure while maintaining acceptable safety levels.

The principle is illustrated in Figure 4 which shows annual O&M expenditure versus observed failure rates *. Based on this simple diagram, the particular approach to pipeline integrity management adopted by the selected operators can be categorised into 3 distinct Groups:

Group	Description	Highlights of Integrity Management Strategy
A	High failure rates, low annual O&M expenditure	▪ Compliance with codes ▪ Fixed interval and Price sensitivity when selecting ILI ▪ Limited use of Integrity planning tools such as RBI, advanced FFP. ▪ Varying approaches to corrosion monitoring techniques.
B	Low failures rates, high annual O&M expenditure	▪ Compliance with codes ▪ Inspection and maintenance interval based on 'fixed interval' ▪ Use of high resolution inspection technologies ▪ Repair decision based on basic code calculations, e.g. ANSI/ASME B31-G. ▪ Limited use of Integrity planning tools such as RBI, advanced FFP, data management & integration, etc. ▪ Varying approaches to corrosion monitoring techniques.
C	Low failure rates, optimised O&M expenditure	▪ Leading industry best practice. ▪ Routine use if integrated data management and RBI and inspection for inspection and maintenance planning. ▪ Use of high resolution inspection technologies ▪ Advanced FFP methods for repair decision making ▪ Quantitative risk assessment ▪ Advanced pipeline condition monitoring systems in place (SCADA, leak detection, etc.)

By combining this analysis with benchmarking, it can be demonstrated that top operators experience low failure rates, but with 30% to 70% lower annual O&M expenditure than other operators. As an example, with reference to the illustration in Figure 4, Operators 1, 2 and 7 may be compared with Operators 3 to 6.

Overall, the aim of any operator should be to achieve low (acceptable) failure rates at an optimal level of O&M expenditure, i.e. to approach the performance of Group C.

To conclude, the majority of the companies surveyed all tend to follow the same basic principles of successful Integrity Management planning. However, the top ranked Operators are those who have a formal framework plan for integrity management planning whilst also having the flexibility to

* In this example, annual O&M expenditure, $/km is calculated by dividing the annual O&M expenditure for each operator by the total pipeline network length. For the purpose of comparison in Figure 4, this is normalised with respect to the Operator with the highest annual expenditure, OP 6.

customise maintenance requirements for individual pipeline sections to follow “industry best practice”. Ultimately they also enjoy the lowest failure rates, often associated with significant overall cost savings.

It is worth noting that according to 31.8 (S), …” an integrity management program is continuously evolving and must be flexible”… that “[an operator should] take appropriate advantage of improved technologies” and that “there is no single “best” approach that is applicable to all pipeline systems for all situations.

5. CONCLUDING REMARKS.

This paper has described the development and application of a methodology to Benchmark the effectiveness of pipeline Integrity Management plans in preventing leaks and ruptures.

On this basis, an operator’s performance can be benchmarked against similar operators and industry best practice. Improvement opportunities can be identified and prioritised to improve the benchmarking position. The benchmarking methodology can also be used to identify cost optimisation opportunities whilst maintaining acceptable safety levels.

Based on data compiled for over 140,000km of Oil & Gas pipelines, the benchmarking methodology confirms that the top ranked Operators are those who have a formal framework plan for integrity management planning whilst also having the flexibility to customise maintenance requirements for individual pipeline sections to follow “industry best practice”. Ultimately they also enjoy the lowest failure rates, often associated with significant overall cost savings.

Table 1: Comparison of Code Requirements

	ASME B31.4 (Liquids)	ASME B31.8 (Gases)	ASME 31.8 (S) (non-mandatory)	IGE/TD/1 (UK)	AS 2885 (Australia)	CSA Z662-2003 (Canada)	DOT Part 195 (USA)
Assessment Method	B31.G, Safety Factor (SF) = 0.72	B31.G, Class Location dependent	B31.G or similar – Class Location dependent	To be selected by operator-	B31.G, RSTRENG or Approved method	B31.G + engineering assessment.	B31.G & RSTRENG
Repair method	Various; grinding, steel or composite sleeve, cut-out etc.	As per B31.4	As per 31.8. Additional guidance provided.	Damage and operating pressure dependent	Grinding, full encirclement sleeve or pipe replacement recommended.	Similar to B31.4	Must comply with 195.422
Integrity Plan	Written plans which should be modified based on experience.	As per B31.4	Systematic process / approach defined	Risk based, considering age & operating history	Risk based. Written safety & operating plan	Must operate & maintain system to documented procedures	Mandatory See rule 195.452
Risk Analysis	Not Considered	Not Considered	Systematic process / approach defined	Should take into account frequency and consequences of all pipeline failure modes	Required for design and operation (Code AS 2885.1)	Can be used but not mandatory	Mandatory See rule 195.452
Spill prevention	Regular patrols required to monitor activity near pipeline	Operators must have a leak survey plan	As per 31.8	Risk based.	Risk based. Leak detection system advised.	Periodic line balance + other guidance (App. E)	Leak detection system mandatory, rule 195.452
External corrosion prevention	Based on effective coating & CP. CP monitoring < 15 months, powers sources < 2 months	Similar to 31.4	As per 31.8	Based on effective coating & CP, regular monitoring, Pearson and CIPS	Based on effective coating & CP. Special surveys (Pearson, DCVG) recommended	Based on effective coating & CP & regular monitoring	As per B31.4
ILI	Not Considered	Not Considered	Guidance provided	Periodic inspection using intelligent pigs, frequency < 10 years	Previous intelligent pigs results should be considered, together with RBI	Should be considered, guidance given in Appendix D	See rule 195.452
3rd party damage prevention	Liaison with local authorities. Patrol < 2 weeks.	Patrol frequency a function of Location Class	As per 31.8	Risk based, based on operational history	Risk based. Annual patrol minimum	Must be conducted at intervals set by the operator	Patrol interval< 3 weeks, but 26 times per year
Failure history	Any failure cause should be established to prevent further incidents	As per B31.4	As per 31.8. Additional 'performance measures' identified	Detailed records of inspection, surveillance and pressures to be kept	All incidents must be recorded and investigated	All incidents must be recorded and investigated	As per B31.4

Table 2: Comparison of World-Wide Failure Rates

Region	Product	Failure Rate, per 1000 km.-years	Year
United States	Gas	1.18	1984-92
United States	Oil	0.56-1.33	1984-92
Europe	Gas	1.85	1984-92
Europe	Oil	0.83	1984-92
Western Europe	Oil	0.43	1991-95
Western Europe	Gas	0.48	1971-97
Canada	Oil & Gas	0.35	N/A
Hungary	Oil & Gas	4.03	N/A
Nigeria	Oil	6.40	1976-95

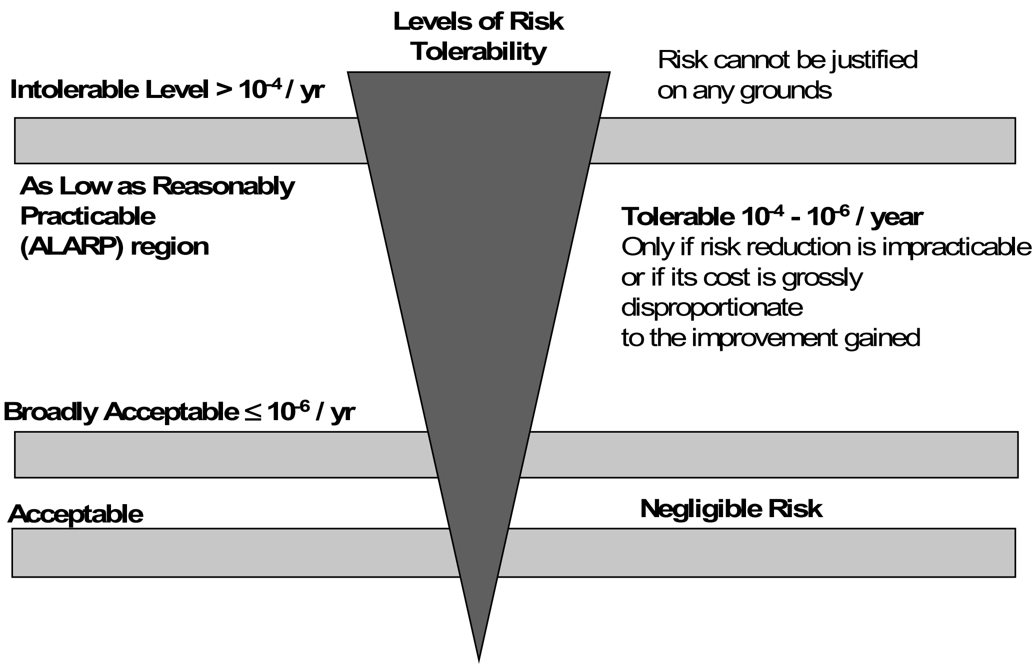

Figure 1: ALARP principle

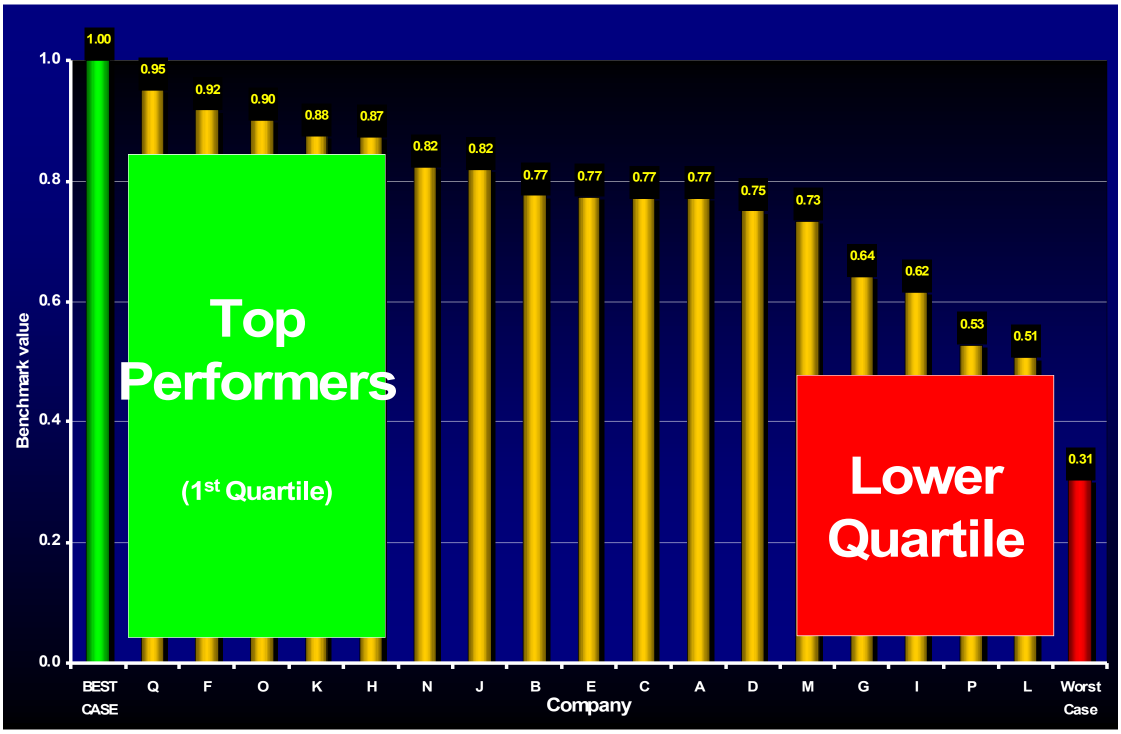

Figure 2: Benchmarking Results Relative ranking of participating companies.

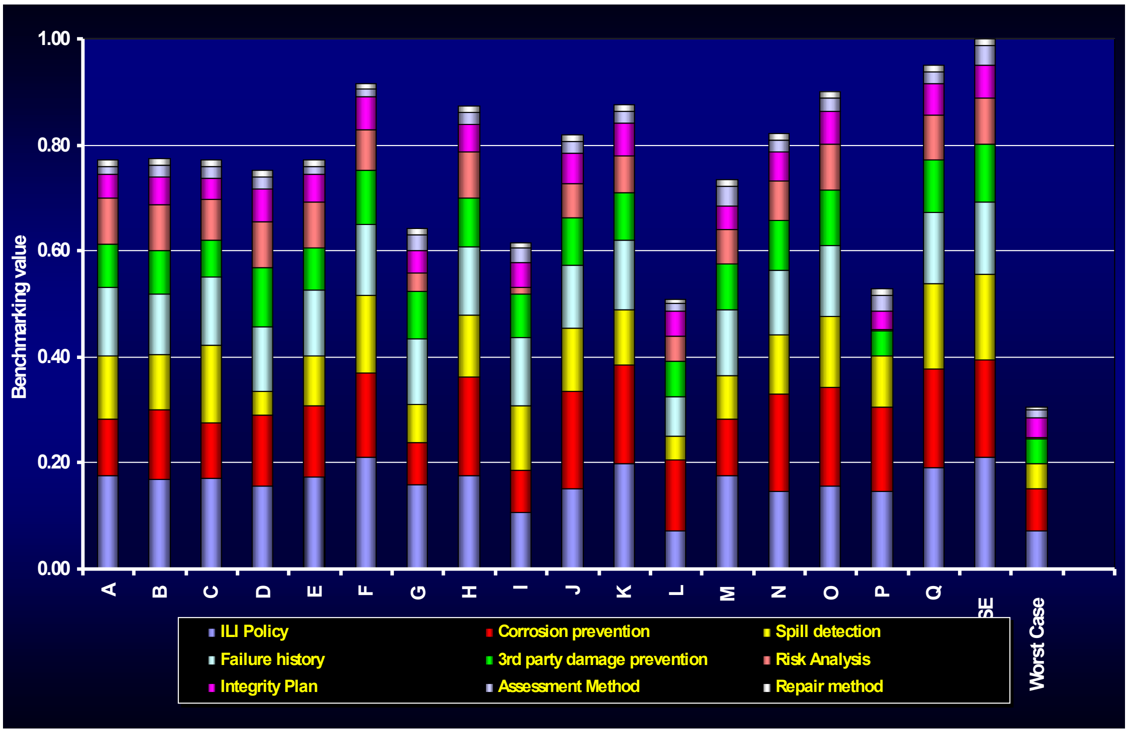

Figure 3: Relative contribution of each Integrity Activity

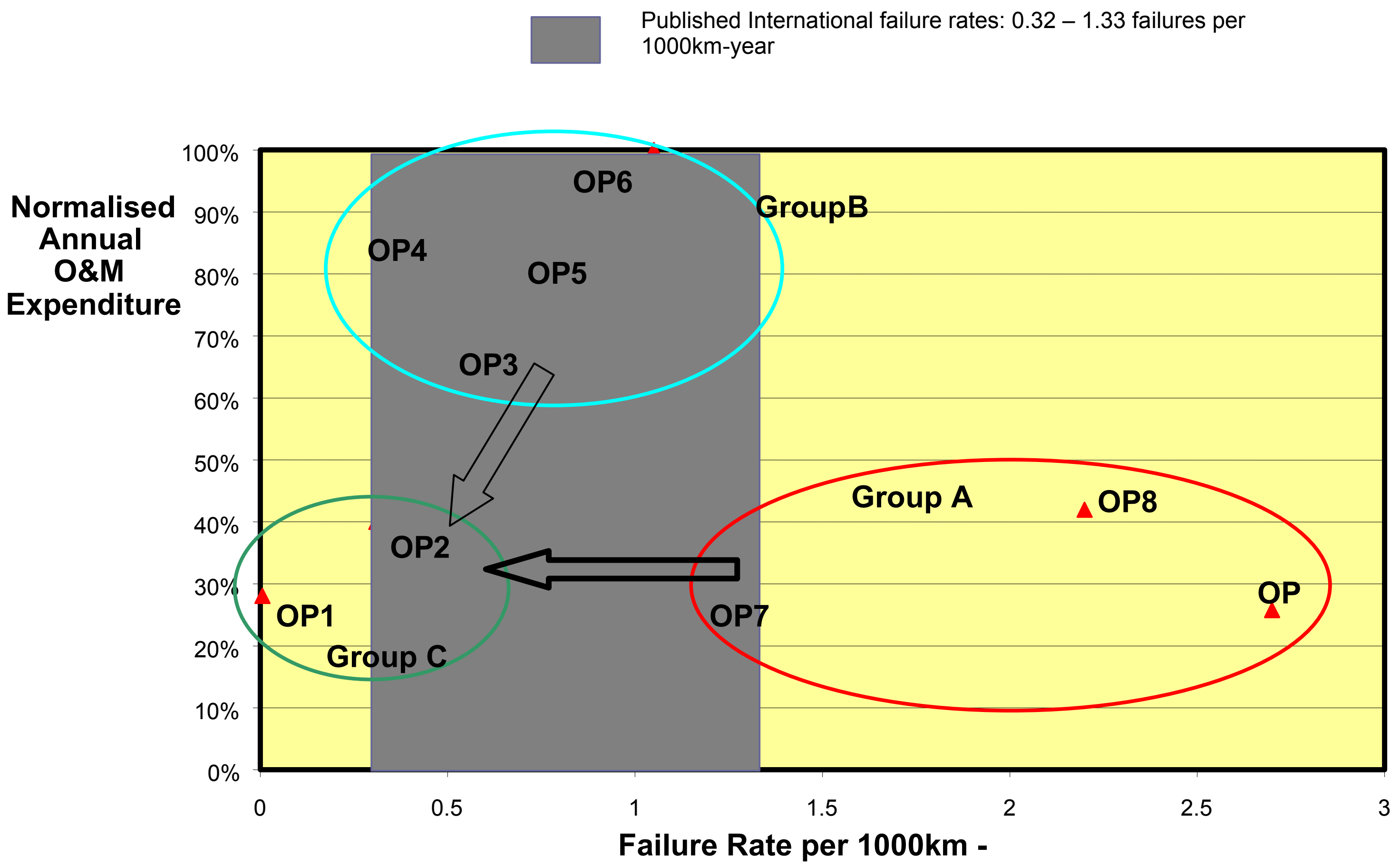

Figure 4 : Assessment of O&M expenditure versus pipeline risk (failure rate)

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